2022 Final Environmental Impact Report

Grayson Repowering Project

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INTRODUCTION AND BACKGROUND

The overall purposes of the California Environmental Quality Act (CEQA) process are to:

- Identify the significant effects to the environment of a project, identify alternatives, and indicate the manner in which those significant effects can be avoided or mitigated.
- Provide full disclosure of the project's environmental effects to the public, the agency decision makers who will approve or deny the project, and the responsible and trustee agencies charged with managing resources that may be affected by the project.
- Provide a forum for public participation in the decision-making process with respect to environmental effects.

Section 15123(b) of the CEQA Guidelines requires that an EIR contain issues to be resolved, including the choices among alternatives and whether or how to mitigate significant impacts. The major issues to be resolved regarding the Project include decisions by the lead agency as to whether:

- The EIR adequately describes the environmental impacts of the Project.
- The recommended mitigation measures should be adopted or modified.
- Additional mitigation measures need to be applied.

The Grayson Repowering Project is a power plant repowering project that removes 238 megawatts (MW) gross (219 MW net) of aging and inefficient generation equipment and replaces it with approximately 270 MW gross (262 MW net), state-of-the-art modern equipment ("Repowering Project," "Project," or the "proposed Project"). The Project is located within an industrial area of the City of Glendale, at 800 Air Way, Glendale, California 91201, just northeast of the Interstate 5 and Highway 134 interchange.

A Notice of Preparation (NOP) for the Project prepared and circulated on December 15, 2016 through January 20, 2017 for the required 30-day review period and was extended an additional six days. The public review period for the Draft EIR was September 18, 2017, to November 20, 2017, for the required 45-days, plus an additional 17 days for a total of a 62-day review period. The City received a total of 1,133 comment letters on the Draft EIR. The City responded to all comments received on the Draft EIR and prepared a Final EIR that was considered by the Glendale City Council on April 10, 2018 (the 2018 Final EIR). The City did not certify the Final EIR, instead directing GWP to consider greener alternatives as part of the Project. In response, GWP issued a Clean Energy Request for Proposals (RFP), evaluated, and modeled the proposals received through the Clean Energy RFP, and identified a cleaner portfolio to meet the City's energy needs. That portfolio was presented to the City Council in GWP's 2019 Integrated Resource Plan on July 23, 2019. This Partially Recirculated Draft EIR includes a description and analysis of two additional alternatives identified through the RFP and Integrated Resource Planning process and also updates the analysis where appropriate based on new information or requirements.; a Final EIR was completed including responses to all public comments and was agenized for review and consideration by the Glendale City Council on April 10, 2018 (the "2018 Final EIR").

The Glendale City Council reviewed and considered all the evidence, testimony, opinions, reports, and analysis presented in the 2018 Final EIR, however, the Glendale City Council decided to take no action and instead directed City staff to evaluate additional clean energy alternatives to the Project. Per the City Council's direction, the City issued a Clean Energy RFP and based on responses to that RFP two clean energy alternatives were selected for further analysis.

PARTIALLY RECIRCULATED DRAFT ENVIRONMENTAL IMPACT REPORT

As requested by the Glendale City Council, the PR-DEIR examineed new clean energy Project alternatives selected from the Clean Energy RFP, provides an update on Cultural and Paleontological Resources impacts and adds the analysis required for the new Energy and Wildfire environmental impact categories. Section 15088.5 of the CEQA Guidelines specifies that;

"A lead agency is required to recirculate an EIR when significant new information is added to the EIR after public notice is given of the availability of the draft EIR for public review under Section 15087 but before certification. As used in this section, the term "information" can include changes in the project or environmental setting as well as additional data or other information. New information added to an EIR is not "significant" unless the EIR is changed in a way that deprives the public of a meaningful opportunity to comment upon a substantial adverse environmental effect of the project or a feasible way to mitigate or avoid such an effect (including a feasible project alternative) that the project's proponents have declined to implement. "Significant new information" requiring recirculation include, for example, a disclosure showing that:

> (1) A new significant environmental impact would result from the project or from a new mitigation measure proposed to be implemented.
>
> (2) A substantial increase in the severity of an environmental impact would result unless mitigation measures are adopted that reduce the impact to a level of insignificance.
>
> (3) A feasible project alternative or mitigation measure considerably different from others previously analyzed would clearly lessen the environmental impacts of the project, but the project's proponents decline to adopt it.
>
> (4) The draft EIR was so fundamentally and basically inadequate and conclusory in nature that meaningful public review and comment were precluded.

(b) Recirculation is not required where the new information added to the EIR merely clarifies or amplifies or makes insignificant modifications in an adequate EIR.

(c) If the revision is limited to a few chapters or portions of the EIR, the lead agency need only recirculate the chapters or portions that have been modified.

(d) Recirculation of an EIR requires notice pursuant to Section 15087, and consultation pursuant to Section 15086.

(e) A decision not to recirculate an EIR must be supported by substantial evidence in the administrative record.

(f) The lead agency shall evaluate and respond to comments as provided in Section 15088. Recirculating an EIR can result in the lead agency receiving more than one set of comments from reviewers. The following are two ways in which the lead agency may identify the set of comments to which it will respond. This dual approach avoids confusion over whether the lead agency must respond to comments which are duplicates or which are no longer pertinent due to revisions to the EIR. In no case shall the lead agency fail to respond to pertinent comments on significant environmental issues.

(1) When an EIR is substantially revised and the entire document is recirculated, the lead agency may require reviewers to submit new comments and, in such cases, need not respond to those comments received during the earlier circulation period. The lead agency shall advise reviewers, either in the text of the revised EIR or by an attachment to the revised EIR, that although part of the administrative record, the previous comments do not require a written response in the final EIR, and that new comments must be submitted for the revised EIR. The lead agency need only respond to those comments submitted in response to the recirculated revised EIR.

(2) When the EIR is revised only in part and the lead agency is recirculating only the revised chapters or portions of the EIR, the lead agency may request that reviewers limit their comments to the revised chapters or portions of the recirculated EIR. The lead agency need only respond to (i) comments received during the initial circulation period that relate to chapters or portions of the document that were not revised and recirculated, and (ii) comments received during the recirculation period that relate to the chapters or portions of the earlier EIR that were revised and recirculated. The lead agency's request that reviewers limit the scope of their comments shall be included either within the text of the revised EIR or by an attachment to the revised EIR.

(3) As part of providing notice of recirculation as required by Public Resources Code Section 21092.1, the lead agency shall send a notice of recirculation to every agency, person, or organization that commented on the prior EIR. The notice shall indicate, at a minimum, whether new comments may be submitted only on the recirculated portions of the EIR or on the entire EIR in order to be considered by the agency. (g) When recirculating a revised EIR, either in whole or in part, the lead agency shall, in the revised EIR or by an attachment to the revised EIR, summarize the revisions made to the previously circulated draft EIR." (PRC Sections 21083 and 21092.1; *Laurel Heights Improvement Association v. Regents of the University of California* (1993) 6 Cal. 4th 1112.

Here, the City is recirculating two sections of the 2018 Draft EIR and is adding analysis in two new CEQA impact categories in this Partially Recirculated Draft Environmental Impact Report ("PR-DEIR"). This partial recirculation complies with CEQA Guidelines section 15088.5, and recirculation of the entire 2018 Draft EIR is not required, because:

1. The revision is limited to "a few chapters or portions" of the 2018 Final EIR. Specifically, the PR-DEIR updates two sections of the 2018 Draft EIR: Alternatives and Cultural and Paleontological Resources, and provides Project impact analysis in the two new environmental impact categories -Wildfire and Energy - that were added to CEQA Guidelines Appendix G in 2019; and
2. There are no changes to the proposed Project and no new significant environmental impacts would result from the Project that were not previously analyzed in the 2018 Final EIR; and
3. New potentially feasible Project alternatives are being added and are being analyzed in the PR-DEIR, and the City is voluntarily adding new Cultural and Paleontological Resource mitigation measures; and
4. There is no evidence to support a finding that the 2018 Draft EIR was so fundamentally and basically inadequate and conclusory in nature that meaningful public review and comment were precluded. The City received over 1100 comments on the 2018 Draft EIR and the EIR underwent an extended to 60 public comment period.

ORGANIZATION OF THE ~~PR-DEIR~~ 2022 FINAL EIR

The content and organization of this ~~PR-Draft~~ 2022 FEIR are designed to meet the requirements of CEQA. The following is a "road map" to the PR-DEIR.

Section 4.0. Environmental Impact Analysis – contains an updated, detailed environmental analysis of the potential for the Project to result in significant environmental effects with respect to the topics evaluated in the PR-DEIR. Topics included in the ~~PR-D~~ 2022 FEIR are as follows:

- **Cultural and Paleontological Resources** – At the request of the Glendale Historical Society, the City of Glendale has agreed to treat the Grayson Steam-Electric Power Plant Boiler Building as a discretionary historical resource in the ~~PR-D~~ 2022 FEIR. Therefore, the Cultural Resources Section is updated in the PR-DEIR. The paleontological resources section was updated with mitigation based on the possibility that such resources could be uncovered based on the depth of anticipated excavation for the Project.
- **Energy** – New analysis based on 2019 update to Appendix G of the CEQA Checklist.
- **Wildfire** – New analysis based on 2019 update to Appendix G of the CEQA Checklist.

Section 5.0. Alternatives, discusses the new Clean Energy alternatives to the Project that have been developed and analyzed that avoid or lessen the impacts. These alternatives include the "No Project Alternative," required by the State CEQA Guidelines, along with six other alternatives.

Section 8.0. References, presents a list of the principal documents, reports, maps, and other information sources referenced in the ~~PR-D~~ 2022 FEIR.

Section 10.0, MMRP provides the mitigation monitoring for project implementation should the project be adopted and constructed.

Appendices provides information and technical studies that support the environmental analysis contained within the 2022 FEIR ~~PR-DEIR~~. Appendices from the 2018 Final EIR and PR-DEIR can be found at: http://graysonrepowering.com/.

THE FOLLOWING DESCRIBE PROJECT-RELATED DEVELOPMENTS SINCE THE APRIL 10, 2018, HEARING ON THE 2018 FINAL EIR.

CLEAN ENERGY RFP AND 2019 INTEGRATED RESOURCE PLAN

On May 4, 2018, GWP issued a Request for Proposals ("RFP") for "Local and Regional Renewable, Low-Carbon, And Zero Carbon Energy and Capacity Resource Options to Serve the City of Glendale" i.e. the "Clean Energy RFP". The intent of the Clean Energy RFP was to identify potential clean energy alternatives to the proposed Project and to solicit offers of local clean energy resources that could supply electricity to GWP without reliance on existing or new transmission capacity. The RFP was open to any technology and the proposed projects could be as small as 1 MW in size.

GWP received proposals from 34 firms that included offers for renewable energy, energy efficiency, demand response, energy storage, and thermal generation. The proposals were screened for completeness and feasibility with proposers given an opportunity to correct deficiencies in their proposal. Proposals that satisfied the completeness and feasibility screening were evaluated based on the criteria set forth in the RFP: Proposer's experience and expertise to complete the project; environmental performance with respect to impact on Renewables Portfolio Standards, air quality and other environmental attributes; administrative burden and contract terms; and the project's ability to supply reliable energy and capacity. After the proposals were evaluated and scored, the evaluation team held in-depth interviews with the high-ranking proposers. Following interviews, the candidate pool was narrowed to seven firms. Thereafter, the City's Integrated Resource Planning consultant, Ascend Analytics, undertook in-depth modeling of the top-ranking proposals from the Clean Energy RFP, through which it identified the net benefit for individual proposals, as well as combined and tested various combinations of proposed projects to identify an optimal portfolio for GWP's Integrated Resource Plan (IRP).

An IRP is an "electricity system planning document that describes how utilities plan to meet their energy and capacity resource needs, policy goals, physical and operational constraints, and other utility priorities (such as reducing rate impacts on customer bills)."[1] Senate Bill 350 requires publicly-owned utilities of a specified size "to adopt an integrated resource plan and a process for updated the plan at least once every 5 years to ensure the utility achieves specified requirements."[2] While the requirement was to plan out to 2030, GWP elected to model using a longer horizon, to 2038 (approx. 20-years). As such, the IRP was a 20-year forecast with regards to energy demand, peak load, and the resources that GWP would deploy to meet California's regulatory and environmental requirements.

The 2019 IRP identified an expected net growth in load due to electrification of transportation and other fossil energy uses growing faster than the deployment of local renewable resources, demand response,

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[1]California Energy Commission's *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines* (Revised Second Edition; October 2018) at page 1.
[2] California Public Utilities Code Section 9621.

and energy efficiency. The IRP also identified that peak load was also expected to grow. In developing the new alternatives to include in the EIR, GWP based its evaluation on past peak loads (~350 MW) and not the forecasted higher peak loads (more than 400 MW).

The 2019 IRP modeled 7 different proposals, ranging from Portfolio A – base case of building nothing new, to Portfolio G – 100% Clean with energy storage, but no new fossil fuel assets. Intermediate portfolios between Portfolios A and G considered a variety of combinations of utility-scale batteries, local demand side management, demand response, energy efficiency, behind-the-meter (customer side) solar/storage resources, and thermal resources. All portfolios were built using resources selected from the Clean Energy RFP along with generic renewable energy resources necessary to comply with Senate Bill 100 and meet Renewables Portfolio Standard requirements.

Table ES-1 IRP Table 1 "IRP Portfolios Considered" – found within the July 23, 2019, Staff Report to the Glendale City Council

Portfolio		B-NG Repower	C-ICE Repower	D-50 MW Batt + 6xICE	E-75 MW Batt +5xICE	F-100 MW Batt +3xICE	G-100% Clean
Candidate Resource		**Nameplate Capacity (MW)**					
Clean Energy + Load Reduction	Residential DER			13	13	13	13
	Public Spaces DER			10	10	10	20
	Residential and Large Commercial EE+ER			7.5	7.5	7.5	20.5*
	Small Commercial EE+DR			20.4	20.4	20.4	20.4
Imported Renewable Resources	Solar	140	140	130	130	130	130
	Wind	140	140	130	130	130	130
Storage	Utility Battery	50	50	50	75	100	150
Conventional Generation	CC	71					
	CT	120					
	ICE		149	112	93	56	

Composition of Portfolio options considered. Portfolio A – Base Case has no assets included and has therefore been excluded from the table above.
*This resource had large segments (13 MW) of the proposal deemed infeasible due to siting, permitting, and cost concerns. For candidate portfolios B-F these infeasible portions were excluded. However, for the 100% Clean portfolio GWP took the optimistic approach of assuming that all components of this proposal were feasible and including them in the modeled portfolio.

The portfolios were evaluated for reliability, flexibility, sustainability, and cost effectiveness.

The 2019 IRP concluded that Portfolios A, F, and G are not feasible from a reliability standpoint:

- Portfolio A adds no new local generation, threatening local reliability.

- Portfolio F – 100 MW/400 MWH of energy storage -- is insufficient to ensure GWP can reliability serve peak loads as well as being reliant on full transmission to serve load and to charge the energy storage system during summer loads.
- Portfolio G – which includes 150 MW/ 600 MWH of energy storage – that level of energy storage would be sufficient to ensure GWP can reliably serve peak loads; however, it requires more transmission capacity than is available to import enough energy to serve load and to charge the energy storage system during summer loads.

From a sustainability standpoint, the 2019 IRP concluded that Portfolios B and C were not the optimal portfolio because their carbon emissions were at the upper end of the portfolios considered.

The 2019 IRP found that the remaining Portfolios, Portfolios D and E, have similar costs and reliability. Thus, the more environmentally sustainable Portfolio E was the recommended portfolio option.

The 2019 IRP-recommended Portfolio E includes five reciprocating internal combustion engines, each with 18.67 MW of capacity, totaling 93 MW of new thermal capacity, coupled with a 75 MW/ 300 MWH battery energy storage system (BESS), as well as approximately 50 MW of clean distributed energy resources, such as demand response and energy efficiency and distributed energy resources which were identified through the Clean Energy RFP process. As required by California Senate Bill 350, the Clean Energy and Pollution Reduction Act, GWP submitted its 2019 IRP to the California Energy Commission. The 2019 IRP was approved by the CEC on February 20, 2020.

The PR-DEIR evaluates the proposed 93 MW of thermal capacity coupled with a 75 MW/ 300 MWh BESS from Portfolio E of the 2019 IRP as one of the proposed Project alternatives. In addition to energy storage and thermal generation options now included in the Alternatives to the proposed Project, GWP is proceeding with implementation of several clean distributed energy resource programs, including projects identified through the Clean Energy RFP and modeled in the 2019 IRP, and intends to achieve 50 MW of distributed energy capacity in accordance with the 2019 IRP preferred Portfolio E. The PR-Draft EIR analysis assumed 50 MW of clean distributed energy resources are included in the City's resource portfolio.

GWP has executed contracts and is in the process of implementing the residential and commercial demand response and energy efficiency programs selected through the Clean Energy RFP, in addition to other demand management and energy efficiency programs implemented through GWP's Public Benefit Charge program. GWP is negotiating with the shortlisted vendor for the proposed rooftop solar plus storage (i.e. a virtual power plant). GWP has also retained a consultant to identify City-owned properties viable for solar/ storage development, and a separate Owners' Engineer to develop plans for structural upgrades to a City parking structure to accommodate a solar facility.

SCAQMD RULE 1135 "EMISSIONS OF OXIDES OF NITROGEN FROM ELECTRICITY GENERATING FACILITIES"

The South Coast Air Quality Management District (SCAQMD) amended Rule 1135 "Emissions of Oxides of Nitrogen from Electricity Generating Facilities" on November 2, 2018. This rule is applicable to all power generating facilities within SCAQMD including Grayson Units 1-9. The amended Rule, set forth in section 1135(d)(1)(A), requires that existing boilers and gas turbines, such as Units 1 through 9, must meet current-day emissions standards by January 1, 2024. Further, the Rule in section 1135(d)(7) requires that facility owners submit an application to SCAQMD prior to July 1, 2022 to modify their air permit conditions to comply with the current emissions limits if they do not already comply. In effect, the rule change requires owners to upgrade their existing units to meet current-day emissions requirements or cease to operate them prior to January 1, 2024.

At the present time, Units 1 through 8 at Grayson cannot operate in compliance with the current day emissions limits specified in Rule 1135. Upgrading the boilers for Units 1 through 5 is considered economically infeasible as well as unworkable from an operational standpoint because the boiler units are unable to start up quickly, requiring them to be kept on-line for days at a time in anticipation that they might be needed. Units 8A and 8BC could be economically upgraded to meet current emissions standards.

ADDITIONAL TRANSMISSION CAPACITY

The City is a participant in the Intermountain Power Project (IPP), a coal-fired plant located in Delta Utah. Through its participation in the IPP Project, GWP has a share of the transmission capacity on the Southern Transmission System (STS) line from Utah to Adelanto, CA. By virtue of its participation in the IPP Project, GWP also has transmission rights from Adelanto, CA to Glendale, CA under a contract with the Los Angeles Department of Water & Power (LADWP). The City's contractual transmission rights from the STS to Glendale depend on the City's continued participation in the IPP Project. The amount of transmission rights that the City receives matches the amount of the City's IPP generation rights, and if the City were to exit from the IPP project, it would forfeit those contractual transmission rights.

In 2015, the City entered into renewal agreements for the IPP project. The IPP renewal agreements allow for a repowering of the IPP project that will convert the IPP plant from an 1,800 MW coal-fired power plant to a 1,200 MW natural gas generation facility, or an "alternative repowering" as may be determined by the IPP participants. In 2015, the City Council authorized GWP to participate in an offer and acceptance process to subscribe up to a 50 MW share of the repowered IPP Power Plant, subject to the City's right to take an "off ramp" that would allow the City to decide to exit the IPP project or reduce its project share by 20 percent, if it so chose, by August 2019.

GWP participated in the IPP offer and acceptance process and subscribed to a 4.166 percent share of the proposed repowered IPP project, which would give the City approximately 55 MW of IPP generation and 128 MW of transmission through June 15, 2077, an increase of 72 MW above GWP's existing STS transmission rights. In July 2018, the Glendale City Council and the other IPP project participants authorized an Alternative Repowering that reduced the size of the IPP natural gas repowering plan from 1,200 MW to 840 MW. The Alternative Repowering reduces the City's share of IPP generation to 35 MW but the City will have 128 MW of transmission beginning in June of 2027, when the IPP repowering is scheduled to be completed.

In July of 2019, the City Council elected not to take the “off ramp” and opted to continue the City’s participation in the IPP project. The City has subscribed to a 4.166 percent share of the IPP project. Thus, the City has rights to a 4.166 percent share (128 MW) on the STS transmission line and a 128 MW contractual share of the corresponding, LADWP-owned transmission segment from Adelanto to Glendale through June 15, 2077.

Accordingly, beginning in June 2027, when the repowered IPP project is scheduled to come online, GWP will have 72 more megawatts of transmission capacity from the Southwest, compared to the amount of transmission capacity that were described in the 2018 Final EIR, The PR-Draft EIR reflectd this increase in Glendale’s transmission capacity rights starting in 2027.

SENATE BILL 100 AND THE 100% CLEAN BY 2030 STUDY

Senate Bill (SB) 100 was signed into law in September 2018. SB 100 requires utilities to generate 60 percent of their electricity from renewable resources by 2030 (increased from the 50 percent renewable by 2030 requirement under SB 350). SB 100 establishes a policy that eligible renewable energy resources and zero-carbon resources supply 100 percent of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045.[3]

Pursuant to the Glendale City Council’s direction, in 2020 and 2021, GWP undertook a study to identify a plan or methods to achieve 100 percent clean energy by 2030 (the Study), 15 years ahead of the date established by SB 100. The Study, performed by Ascend Analytics as a consultant to the City, built upon the 2019 IRP and was presented to the Glendale City Council on March 21, 2021.

Based upon the assumptions made in the Study, the Study concluded that by 2030, GWP could reliably serve 89 percent of load with clean energy, around-the-clock. In order to move past 89 percent, the Study concludes that GWP would need to acquire additional transmission capacity to import additional renewable energy, and/or technology would need to develop such that fossil-fueled resources could be powered by renewable fuels such as green hydrogen. The Study modeled various portfolios of energy resources, and concluded that 89 percent clean energy could be achieved by 2030 with the following mix of planned, proposed, and hypothetical future resources:

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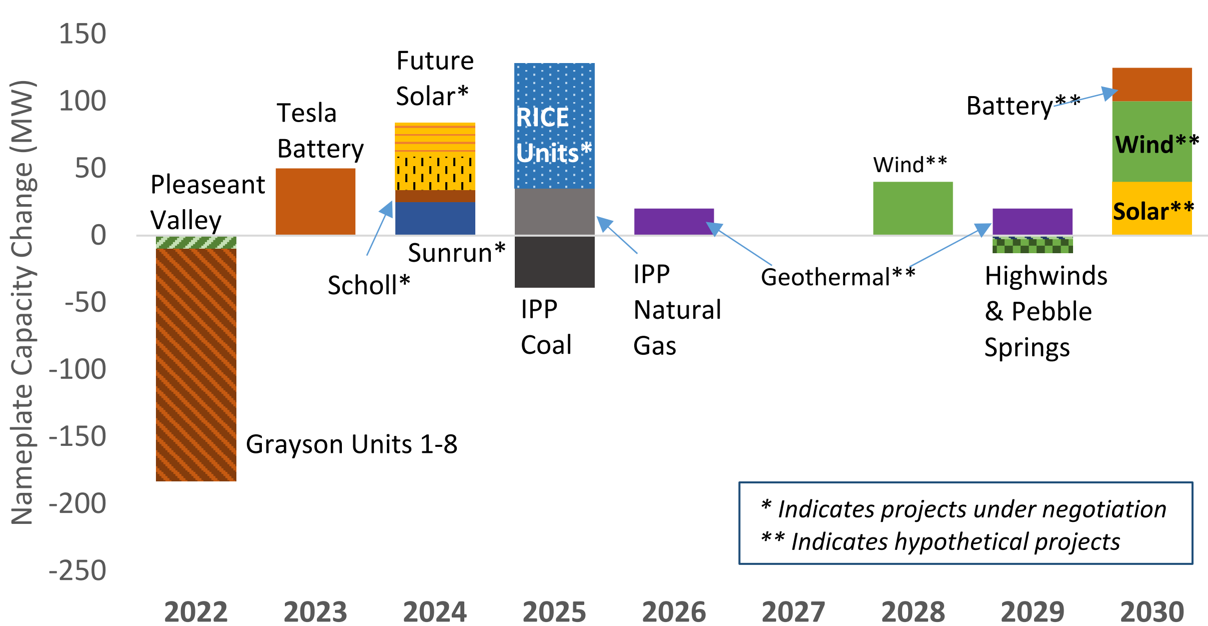
[3] California Public Utilities Code Section 454.53.

~~Figure ES-1 Figure 3 Annual Capacity Additions and Retirements for GWP in the Modeled Plan – found in the Ascend Study~~



The Study was premised on certain assumptions about GWP's power supply. It assumed that by 2022, Grayson Power Plant Units 1 through 8 would be retired, by 2023, that GWP would install 50 MW of battery energy storage at Grayson, that by 2024, GWP would add new, as-yet-unidentified wind and solar projects to its portfolio, and that by 2025, 93 MW of reciprocating internal combustion engines (RICE) would be installed at the Grayson Power Plant, The Study noted that GWP would need to acquire additional geothermal, wind, solar, and battery storage through 2030 to the extent possible given constraints on GWP's transmission capacity.

The Study found that pollution and carbon emissions would drop considerably, even with the 93 MW of RICE in the portfolio. The Study estimated achieving 89% percent Clean Energy by 2030 would raise electricity rates by 28 percent by 2030 compared to 2021 rates.

The Study and all regulatory requirements, including SB 100, inform the analysis and alternatives presented in the PR-DEIR.

SEPTEMBER 2019 ROLLING BLACKOUTS

On September 4, 2019, GWP was forced to implement rolling blackouts for several days when an auxiliary transformer on a main bank transformer failed, along with a cable failing due to being heavily loaded during a heat wave with high system load conditions. While the immediate issue was corrected and the rolling blackouts terminated after repairs and moderation of the heat wave, as a long-term solution, GWP proposes to add a new switching station (called the Glendale Switching Station) at the Grayson Power Plant. The proposed new Glendale Switching Station would provide additional resilience to the GWP system and serve as a partially redundant backup to the Kellogg Switching Station. The PR-DEIR evaluated two new Alternatives (7 and 8) which both include the proposed new Glendale Switching Station.

STORMWATER MANAGEMENT

The PR-DEIR reflects changes to the proposed stormwater plan since the 2018 Final EIR.

For the proposed Project, stormwater falling on-site, except for equipment containment areas that would be retained, would sheet flow into localized gutters and then through underground piping to infiltration basins whereupon the water could percolate into the ground. Any excess stormwater would sheet flow across the site to the south and flow into the Verdugo Wash and Los Angeles River through existing stormwater outfalls. Stormwater that fell into the containments would be retained, sampled, and only released if it was clean water.

Since the time of the proposed Project, the stormwater plan has been upgraded so that the “first flush” of stormwater falling onto and traversing the site is now collected, retained, and then sent to the GWP sewer system for processing. On-site stormwater runoff would continue to flow via surface sheet flow and localized gutters to on-site storm drain piping as before; however, the storm drain piping would now direct the stormwater to an on-site detention basin and pump station. The stormwater that is collected in the detention basin would be pumped to a new on-site storage tank. Stormwater would then flow from that tank to the Glendale sewer system. During storm events that exceed the design capacity of the stormwater system, overflow runoff would be discharged into the adjacent Verdugo Wash and Los Angeles River through existing stormwater outfalls as before; however, this would only occur after the initial stormwater flows washed over the site.

CHANGE IN AIR QUALITY/GREENHOUSE GAS EMISSIONS BASELINE CONDITIONS SINCE THE 2018 FINAL EIR

At the time the 2018 Final EIR was prepared, landfill gas from Scholl Canyon Landfill was conveyed through an existing unground pipe system to the Grayson Power Plant (Grayson), combined with natural gas, and burned in boilers at Grayson to make steam for electricity generation. Since that time, none of the existing operating turbines at Grayson have the capacity to burn landfill gas. During the process of evaluating potential environmental impacts of the proposed Project, the City learned that emissions from combusting the landfill gas in the existing Grayson boilers exceeded potential health risk notification and action plan thresholds established by the SCAQMD. Accordingly, since April 1, 2018, the City ceased combusting landfill gas at Grayson and has been flaring all the landfill gas at Scholl Canyon Landfill in compliance with the existing SCAQMD permit. As a result, the City has updated the environmental impact analysis within Section 5.0 (Alternatives) to consider air quality/greenhouse gas emissions baselines conditions of two separate scenarios: one while landfill gas was being combusted in the existing boilers at Grayson Power Plant and another one that considers flaring of landfill gas at Scholl Canyon Landfill. This analysis shows that the proposed Project’s potential air quality and greenhouse gas emissions impacts would be less than significant regardless of which of the two baseline conditions are utilized (refer to Tables 5-2, 5-8, and 5-10.

NEW INFORMATION REGARDING POTENTIAL FOR UNIT 8A AND 8BC UPGRADE

During the course of work on the Tesla/Wartsila alternative (Alternative 7), the City became aware of another utility with gas turbine generators similar to Unit 8A and 8BC that was performing an upgrade to comply with the new SCAQMD Rule 1135 air emissions requirements for older units (discussed above). Upon further review, the City concluded that Units 8A and 8BC were viable candidates for similar upgrades.

As a result, the PR-DEIR included a new Alternative (Alternative 8) that would refurbish the Unit 8A and 8BC gas turbine generators and replace the balance of the plant equipment to meet the new Rule 1135 requirements. Alternative 8 proposes the refurbished and upgraded units 8A and 8BC, in concert with the same 75 MW/300 MWH BESS that is being considered as part of Alternative 7.

COLLABORATION WITH THE GLENDALE HISTORICAL SOCIETY

The City Council requested staff work with the Glendale Historical Society ("TGHS") to resolve TGHS concerns over the demolition of the Grayson Steam-Electric Power Plant Boiler Building ("Boiler Building"). After several meetings, a site visit to the existing Power Plant, and discussions between TGHS and the City, the City agreed to treat the Boiler Building as a discretionary historical resource under CEQA and is updating and recirculating the Cultural Resources section of the 2018 Draft EIR to reflect this treatment and the addition of new mitigation measures that will require the City to perform a Historic American Engineering Record (HAER) survey of the Boiler Building. The City has also added mitigation measures requiring installation of an informational plaque on Flower Street and preservation of a piece of salvaged equipment from the Boiler Building for informational display that will provide the public with the opportunity to learn about the history of the Boiler Building and Grayson Power Plant.

CONFLUENCE PARK

Confluence Park is part of the Glendale Riverwalk plan. The construction of Phase 1 was completed in December 2012, which included half a mile of native landscaping, walking and bicycling trails, public art inspired by Stop Motion, and an equestrian facility which allows horse-owners to exercise their horses before heading out to Griffith Park. Phase 2 was completed after October 2018 and includes two small parks (Flower Plaza on Flower Street and Fairmont Avenue, and Confluence Park by the Los Angeles River and Verdugo Wash further downstream). Phase 3, otherwise known as the Glendale-Los Angeles Garden River Bridge Project, includes the planning, development, design, and construction, of the bridge over the Los Angeles River. The Final 2018 EIR proposed Project did not include Confluence Park as a potential sensitive receptor as it was not yet built. Now that the park exists, it has been included and evaluated in the PR-DEIR for the proposed Project and Alternatives evaluation.

Proposed Project Location and Description

Pursuant to the requirements of the California Environmental Quality Act (CEQA), the City of Glendale (City) has prepared this Draft Environmental Impact Report (EIR) to evaluate the potential environmental impacts of the proposed repowering of the Grayson Power Plant ("Repowering Project" or "Project"). The

Project site is located at 800 Air Way, Glendale, California 91201, northeast of the Interstate 5 freeway and Hwy 134 interchange.

A majority of the equipment and facilities at the existing Grayson Power Plant were completed between 1941 and 1977, and are proposed to be replaced with more reliable, efficient, flexible, and cleaner units. With the exception of the 2003 simple cycle peaking plant (Unit 9), the City is proposing to replace the existing generation equipment and related facilities with a combination of new combined cycle and simple cycle gas turbine generation units. The generating capacity would increase from 267 megawatts (MW) net to 310 MW net (an increase of 43 MW net) which is necessary for the City to serve its customer load and meet a regulatory requirement for reliability. Because the Project involves less than a 50 MW increase in generation capacity, it is not subject to the California Energy Commission's Power Plant Licensing jurisdiction. The City is the CEQA Lead Agency for the Project.

The Project is designed to provide reliable generating capacity, avoid electrical capacity shortages, facilitate the use of more renewable energy by freeing up transmission line capacity to bring more renewable-based electricity to the City, and to provide flexibility to operate efficiently over the wide range of electrical loads placed on the City's electric system. The Project will allow the City to maintain reliable service, keep rates affordable, and facilitate compliance with state regulations regarding renewable energy supplies mandated through the Renewable Portfolio Standards without the need for new transmission lines. The Project will also allow the City to meet its existing and future electrical demands even if the City is separated from existing interconnections with the electric grid, it will minimize the City's reliance on importing power from remote generation locations across a congested transmission grid, and it will support water conservation efforts by eliminating the use of potable water for generation purposes.

Additional background including the site's history as a power plant, purpose and need, objectives, and benefits of the Project are included in Section 2.0. A detailed Project description is included in Section 3.0. Please see http://graysonrepowering.com/ for these Sections. There are no changes to these Sections and were therefore not ~~being~~ recirculated within the PR-DEIR.

Environmental Impacts and Mitigation Measures

Topics evaluated in this Draft EIR have been identified based on preparation of an Initial Study (Appendix A [2018 Final EIR]), the responses to the Notice of Preparation (NOP), and the review of the Project by City staff. The City determined through this initial review process that impacts related to aesthetics, air quality, geology and soils, greenhouse gases, hazards and hazardous materials, hydrology and water quality, noise, traffic and transportation, and tribal cultural resources could be potentially significant and require an assessment in ~~this~~ its 2018 Final EIR.

Based on the analysis in the 2018 Final EIR, the City determined that the Project would result in less than significant impacts to air quality, geology and soils, greenhouse gas emissions, hydrology and water quality, and tribal cultural resources. However, it was also determined that aesthetics, hazards and hazardous materials, noise, and transportation and traffic would, with associated mitigation measures, also be reduced to a less than significant level. The Project has no potentially significant impacts that could not be mitigated in the 2018 Final EIR.

The City determined through this update that impacts related to the following sections and environmental topics would require an assessment in the PR-DEIR:

- Alternatives
- Cultural and Paleontology Resources;
- Energy; and
- Wildfire.

Based on the analysis in the PR-DEIR, the City determined that the Project would result in less than significant impacts to Energy and Wildfire. The Project would result in a significant and unavoidable impact to cultural resources due to the demolition of the Boiler Building, which the City has elected to consider a discretionary historic resource. Demolition of the Boiler Building would also be required for Alternatives 2 (Energy Storage Project Alternative), 4 (150 MW Project Alternative), 5 (200 MW Project Alternative), 7 (Tesla/Wartsila Repowering Project Alternative), and 8 (Tesla/Unit 8 Refurbishment Project Alternative). Alternatives 1 (No Project) and 3 (Alternative Energy Project Alternative) would do not involve re-development at Grayson Power Plant and the Boiler Building would not be demolished. Therefore, only Alternatives 1 (No Project) and 3 (Alternative Energy Project Alternative) would avoid the significant and unavoidable cultural resources impact associated with the proposed Project and five other alternatives evaluated. A statement of overriding considerations will be required should the City elect to certify the 2022 FEIR.

The required mitigation measures for the Project are summarized in Section 10.0 Mitigation Monitoring and Reporting Plan.

Aesthetics

During the construction period, construction activities may contrast with the existing visual character/quality of views in the Project area. Mitigation Measure AES-1 requires screening construction activities and laydown areas to reduce their visibility.

Cultural and Paleontological Resources

Research and analysis for the 2018 Final EIR concluded that the Boiler Building is not an historical resource due to the many additions and modifications to the Boiler Building, after further consultation with TGHS and is a reasonable abundance of caution, the City is using its discretion to treat the Boiler Building as an historic resource and impose feasible mitigation measures in in response to demolition of the Boiler Building. However, even with mitigation, the demolition of the Boiler Building, whether in connection with the Project or a Project Alternative, with exception of the No Project Alternative or Alternative Energy Project Alternative, will result in a significant and unavoidable impact on an historic resource. The. Consequently, the City will prepare a statement of overriding considerations to consider in connection with the certification of the final EIR. Mitigation Measures CR-1, CR-2, and CR-3 would be implemented to reduce this potentially significant impact but would not reduce this impact to less than significance.

The Initial Study prepared for the Project determined that paleontological resources might be present in the subsurface, and the literature review performed for the Project has confirmed that sediments in the Project area over 10 feet in depth have high paleontological potential. Implementation of Mitigation Measures PAL-1 through PAL-3 would reduce adverse impacts to paleontological resources to a level of less than significant.

Hazards and Hazardous Materials

There would be a potentially significant temporary hazards and hazardous materials impact. The demolition and construction phases of the Project may create temporary hazards and hazardous materials impacts due to the use of fuels, handling of petroleum-impacted soils, and handling of materials containing asbestos/lead based paint. Mitigation Measures HAZ-1, 2, 3, 4, and 5 require adherence to a Soil Management Plan, Hazardous Materials Management Plan, Asbestos and Lead Paint Management Plan, and safe fuel handling practices/spill response.

In addition, to mitigate the off-site consequence of the worst-case accidental release of ammonia during Project operation. Mitigation Measure HAZ-6 requires the surface area of the proposed and existing ammonia tank containment systems to be effectively reduced by 90 percent or greater which would restrict the concentrations of concern within the site boundary.

Transportation ~~and Traffic~~

During the demolition and construction phases, traffic would increase in on adjacent public roadways and the acceptable circulation standard at the San Fernando Rd./Doran St. intersection could be exceeded during construction. Mitigation Measures TRA-1, 2, 3, 4, 5, 6, 7, 8, and 9 require adherence to a Traffic Control Plan and number of public safety precautions as well as limiting the number of vehicle trips at the San Fernando Rd./Doran St. intersection during construction.

Noise

The noise from the Project operation has been reduced through engineering design and controls as described in Mitigation Measures NOI-1, 2, 3, 4, 5, 6, 7, 8, 9, and 10 which require limits on source noise levels and controls to ensure acceptable noise levels during facility operation are not exceeded.

Mitigation Measures

Implementation of the above mitigation measures would reduce the Project's potentially significant impacts to aesthetics, hazards and hazardous materials, noise, and transportation ~~and traffic~~ to a less than significant level. When the Final EIR is certified, a mitigation monitoring program would be adopted to ensure that the mitigation measures are fully implemented. With the implementation of these mitigation measures, the Project would not result in any significant and unavoidable environmental impacts for these categories. However, as previously indicated, and with exception of the No Project Alternative (Alternative 1) and the Alternative Energy Project (Alternative 3), both the Project and the remaining any Project alternatives would have significant and unavoidable cultural resources impacts due to demolition of the Boiler Building. In order to adopt the either the Project or Alternatives 2, 4 through 8, decision-making body must adopt a statement of overriding considerations in connection with certification of the Final EIR and approval of either the Project or Alternatives 2, 4 through 8.

Alternatives to the Project

A reasonable range of alternatives that could feasibly attain some of the basic objectives of the Project and their potential environmental impacts are evaluated in the Draft EIR. These alternatives include use of a battery energy storage system, off-site utility-scale renewable energy generation combined with the addition of new high voltage transmission capacity and interconnections, a combination of reduced on-site generating capacity combined with the addition of new high voltage transmission capacity and interconnections, and a combination of reduced on-site generating capacity and a battery energy storage system. A summary of each alternative evaluated in this Draft EIR is set forth below. Two additional Alternatives were ~~have been~~ included in the PR-DEIR. A more detailed evaluation of alternatives is set forth in Section 5.0.

No Project Alternative – Alternative 1

The No Project Alternative would involve running the existing power plant to failure and not proceeding with repowering of the Grayson Power Plant. The No Project Alternative would result in reduced environmental impacts over time as the units are shut down and would have less potential environmental impacts than those of the Project.

However, the No Project Alternative is not a viable alternative in that it would not serve the needs of the City as the City could no longer meet its obligations as a load serving entity for its residents and customers, placing them at significant risk for decreased electrical system reliability and availability. Moreover, the No Project Alternative would not meet the Project objectives and would fail to comply with Federal and State reliability standards.

Energy Storage Project Alternative – Alternative 2

The Energy Storage Project Alternative would involve replacing Units 1 – 8 at the existing Grayson Power Plant with a battery energy storage facility. Use of the City's existing Unit 9 electrical generation, the City's allotment from the Magnolia Power Plant, and transmission capacity to serve the City's electrical load and charge batteries when excess capacity is available. Energy stored in the batteries would then be discharged to serve the electrical load when demand exceeds available transmission and generation resources.

The Energy Storage Project Alternative's potential for local air quality, greenhouse gas emissions, hydrology and water quality, noise, and traffic and transportation impacts are less than those of the Project. More distant impacts due to the additional night-time generation needed to charge the batteries, when renewable solar energy will not be available, are potentially increased. Additionally, during the summer season, it is not possible to import enough electricity to charge the batteries to serve the daytime load. For these reasons, this Alternative was not selected because it does not feasibly meet the Project objectives to the same extent as the Project.

Alternative Energy Project Alternative – Alternative 3

The Alternative Energy Project would involve some combination of photovoltaic or wind power production (including remote and local resources) with energy storage and transmission lines. While the Alternative Energy Project Alternative reduces local potential air quality, greenhouse gas emissions, hydrology and water quality, and noise impacts local to the Grayson Power Plant site, it increases off-site impacts due to the need for increased transmission as well as the large area needed for a wind farm or solar field.

Because of the very limited ability to site solar or wind resources within the City, combined with the energy storage considerations discussed in the preceding Energy Storage Project Alternative, as well as the complications associated with building a new transmission line to import alternative energy, the Alternative Energy Project Alternative was not considered an adequate replacement for the power that would be generated by the Project. This determination is reinforced by the results of the Clean Energy RFP, the 2019 IRP, and the 100% Clean by 2030 study. Additionally, the Alternative Energy Project Alternative does not feasibly meet the Project objectives to the same extent as the Project.

150 MW Project Alternative – Alternative 4

The 150 MW Project Alternative would involve a reduced size power project located on the existing project site with a new transmission interconnection. While the 150 MW Project Alternative would have less potential air quality, greenhouse gas emissions and noise impacts than those of the Project, the potential impacts at the Grayson Power Plant site are generally similar.

The 150 MW Project Alternative also included construction of a new transmission line that has the potential to result in greater potential impacts to aesthetics, agriculture and forestry resources, cultural/tribal cultural resources, geology and soils, land use and planning, and population and housing. The subsequent availability of an additional 72 MW of additional transmission capacity starting in 2027 could meet that need. Thus, in 2027, the 150 MW Project Alternative does ~~not~~ feasibly meet many of the Project objectives or meet them as well as the Project.

200 MW Project Alternative – Alternative 5

The 200 MW Alternative would have reduced air and greenhouse gas emissions and noise from one less generation unit compared to the Project, with the reduction of one unit offset by the addition of a battery energy storage system (one that is smaller than the earlier alternative). The battery energy storage system adds the impact of the cost of periodic battery replacement as well as the need to dispose/recycle the batteries when they reach end of life. If sufficient transmission capacity were not available for charging the BESS, then the air emissions may not be reduced due to the need to operate additional unit(s) to charge the BESS.

Reconfigured Tesla/Wartsila Repowering Project - Alternative 6

This alternative is identical to Alternative 7, described immediately below, but with a different physical arrangement that would have replaced the existing units, with the exception of Unit 9, with the same equipment proposed in Alternative 7. Ultimately, during the engineering phase of the development of this

Alternative, it was determined to be technically infeasible because the design requirements for Wartsila's structures necessitate all existing on-site piles be removed and these piles could not be backfilled with anything that would impede the ability to drive new piles. Given that it was not possible to adjust the locations of the Wartsila foundations within the available space to avoid overlap and the close proximity of existing and new piles involved with this Alternative, further analysis was terminated. Rather than re-number the Alternatives that were retained for further study and consideration, Alternative 6 is mentioned in this list in order to provide information and to avoid confusion in the number of the remaining alternatives that were considered in more detail.

Tesla/Wartsila Repowering Project Alternative – Alternative 7

The Tesla/Wartsila Repowering Project Alternative, identified in the PR-DEIR as "Alternative 7," replaces the existing units with exception of Unit 9 with the following: Five Wartsila 18V50SG reciprocating internal combustion engine units producing approximately 93 MW net at average annual site conditions, and a BESS providing 75 MW/300 MWH of power and energy. This alternative, like the Project, also necessitates removal of the Boiler Building to provide sufficient space for the new facilities. Alternative 7 also adds a switching station to the site in place of the existing Glendale Rack to improve system reliability.

Tesla/Unit 8 Refurbishment Project Alternative - Alternative 8

The Tesla/Unit 8 Refurbishment Project Alternative, identified in the PR-DEIR as "Alternative 8," would replace the existing units with the exception of Unit 9 and Units 8A and 8BC. The Units 8A and 8BC gas turbine-generators would be retained, refurbished, and the units reconfigured into one simple cycle unit (8A) and one fast-start combined cycle unit (8BC) with new balance-of-plant equipment for both units. As with Alternative 7, Alternative 8 would add a 75 MW/300 MWH BESS. This alternative, like the Project, also necessitates removal of the Boiler Building to provide sufficient space for the new facilities. As with Alternative 7, a switching station would be added to the site in place of the existing Glendale Rack to improve reliability.

Alternatives Considered but Not Evaluated in this EIR

A number of alternatives were considered but eliminated from further consideration in the Draft EIR. The alternatives that were considered but not evaluated include Alternative 6, the Reconfigured Tesla/Wartsila Repowering Project, which as indicated above is identical to Alternative 7, but with a different physical layout configuration that would have replaced the existing units with the exception of Unit 9 with the same equipment proposed in Alternative 7, but in a different arrangement. Alternative 6 was determined to be infeasible from a practical standpoint because of the close proximity of existing and new piles required to implement Alternative 6. As mentioned above, rather than re-number the Alternatives that were retained for further study and consideration, Alternative 6 is mentioned in the list of Alternatives selected for further study in order to provide information and to avoid confusion in the number of the remaining alternatives that were considered in more detail.

Other alternatives considered by not evaluated further include power plant sites, and a variety of alternative technologies (generation technology, fuel technology, and alternative power plant cooling). These alternatives are more fully discussed in Section 5.1.4.2.

Environmentally Superior Alternative

The Tesla/Wartsila Project Alternative and Tesla/Unit 8 Refurbishment Project Alternative would meet all Project objectives while resulting in the fewest impacts when compared to the proposed Project and alternatives evaluated. While the potential environmental impacts between these two alternatives are very similar, the Tesla/Wartsila Project Alternative was estimated to have slightly lower noise impacts and is therefore considered the environmentally superior alternative. Refer to Section 5.2.9 for additional details on the comparison of the proposed Project to the evaluated alternatives and identification of the Environmentally Superior Alternative.

SUMMARY OF ENVIRONMENTAL IMPACTS AND MITIGATION MEASURES OF THE PROPOSED PROJECT

A summary of the potential environmental impacts of the Project and the measures identified to mitigate these impacts is provided in Table ES-2 below for each topic addressed in this EIR. Table ES-2 has been arranged in four columns: the identified impact under each EIR issue area; the level of significance prior to implementation of mitigation; mitigation measures that would avoid or reduce the level of impacts; and the level of significance after implementation of mitigation measures.

Table ES-2 Summary of Updated Project Impacts

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
Aesthetics			
The presence of demolition equipment and demolition activities would be temporarily visible to sensitive viewer groups near the southern portion of the Project site. Visual impacts associated with demolition would be localized and short term. As such, demolition activities would not contribute to the degradation of existing visual resources.	Less than significant	No mitigation is required.	Less than significant
Temporary construction activities occurring near the south side of the Project site, as well as temporary construction equipment that exceed the height of the 12-foot masonry walls would be temporarily visible to sensitive viewer groups. In addition, the construction materials stored at the off-site construction laydown area would be visible to sensitive viewer groups within the area. The increased presence of construction activities, and storage of	Potentially significant	**AES-1: Screen Laydown Areas.** Staging and laydown areas within view of residences, motorists, and recreational facilities shall be located away from public views or effectively screened using opaque fencing to limit views of materials, equipment, vehicles, and other items used during construction. All laydown areas shall be effectively reclaimed immediately following completion of their use.	Less than significant

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
construction materials would temporarily contrast with the existing visual character and quality of views throughout the Project area during the 27-month construction period.			
Key observation points (KOP) were evaluated to determine if implementation of the Project would degrade the long-term visual character of the Project site and its surroundings. KOP-1 through KOP-5 were evaluated for vividness, intactness, unity, overall existing visual quality, and overall visual quality with the Project. The overall existing visual quality at each KOP remained the same with the incorporation of the Project. The Project would have the same potential for emission of visible water vapor plumes as the existing facility and would not likely be the source of any increase in visible water vapor plumes. Operation of the Project would have a less than significant impact on the existing visual quality and character of the Project site.	Less than significant	No mitigation is required.	Less than significant
Although proposed to typically occur during daytime hours, demolition and construction activities may periodically require portable lighting for safety and security. The perimeter wall and proposed shielding of light fixtures would screen ground-level views of construction lighting. The varying lighting conditions from Project construction would be most noticeable from elevated views. Viewers on the adjacent elevated freeway are expected to have low sensitivity to visual changes since their views are of short duration. The remaining sensitive receptors with elevated views occur at distances in which these changes would blend with existing industrial and urbanized nighttime lighting conditions.	Less than significant	No mitigation is required.	Less than significant
Proposed lighting installations during Project operation would be restricted to areas required for safety and operation. The Project would design and install all permanent exterior lighting with LED lights and fixtures that would not cause obtrusive spillover beyond the Project site, excessive reflective glare, or directly	Less than significant	No mitigation is required.	Less than significant

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
illuminate the night sky. In addition, the Project would incorporate switched lighting circuits for areas that would not require lighting for normal operation or safety. These areas would remain dark at most times and would minimize the amount of lighting visible off-site.			
Air Quality			
The SCAQMD daily construction emissions thresholds are 75 pounds/day of volatile organic compounds (VOC), 100 pounds/day of nitrogen oxides (NOx), 550 pounds/per day of carbon monoxide (CO), 150 pounds/day of sulfur oxides (Sox), 150 pounds/day of particulate matter less than 10 microns (PM10), and 55 pounds/day of particulate matter less than 2.5 microns (PM2.5). The maximum daily emission caused by construction activities were calculated to be below the significance daily mass emission threshold for all criteria pollutants. Nevertheless, voluntary measures will be taken to further reduce emissions from construction equipment, and compliance with SCAQMD Rule 403 will also further reduce construction-related emissions. The Project would not conflict with or obstruct implementation of the air quality plan.	Less than significant	No mitigation is required.	Less than significant
The net increase of CO, PM10, PM2.5, and SO_X emissions from Project operations are estimated to be below the significance daily mass emission thresholds. Additionally, an ambient air quality impact analysis demonstrates that the Project would not be expected to cause or significantly add to a violation of national and California ambient air quality standards. Furthermore, the net emission increase of PM10 and SO_X will be offset using emission reductions from SCAQMD internal account to account for Rule 1304(a)(1) offset exemptions for replacement of functionally identical equipment. The net increase of NO_X emissions of 553 pounds/day (normal operation) or 1,475 pounds/day (maintenance/testing of combustion turbines, hours of operation in this mode are limited), from Project operations are estimated to	Less than significant	No mitigation is required.	Less than significant

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
exceed SCAQMD's daily mass emission significance threshold of 55 pounds/day. However, an ambient air quality impact analysis shows the NO_2 emissions from this Project will not exceed the National and California ambient air quality standards. Additionally, the increase in NO_X emissions from the Project will be offset through the purchase of Emissions Reduction Credits in the open market and allocations from SCAQMD internal accounts. The net increase of VOC emissions of 90 pounds/day (normal operation) or 102 pounds/day (maintenance/testing of combustion turbines, hours of operation in this mode are limited), from Project operations are estimated to exceed the daily mass emission significance threshold of 55 pounds/day. Additionally, there is no ambient air quality standard for VOC and no guidance to determine the significance of ambient concentrations of VOC. The increase in VOC emissions attributed to the Project will be fully offset using emission reductions from SCAQMD internal account to account for Rule 1304(a)(1) offset exemptions for replacement of functionally identical equipment.			
The net emission increase attributed to the Project are expected to be below the Prevention of Significant Deterioration significance thresholds. Based on the SCAQMD engineering evaluation, the potential annual emissions of Unit 9 are 45 tons for NO_X, 30.8 tons for CO, 15.4 tons for PM10/PM2.5, and 3.8 tons for SO_2. Therefore, the plant-wide annual emissions after the modification are estimated to be 96.5 tons for NO_2, 68.4 tons for CO, 30.5 tons for PM10/PM2.5, and 12.6 tons for SO_2. These emission levels are below the Prevention of Significant Deterioration major source threshold of 100 tons per year for any of the attainment pollutants.	Less than significant	No mitigation is required.	Less than significant
Modeling of Project operation emissions show that local ambient concentrations of NO_2, CO and SO_2 are below state and federal ambient air quality thresholds after emissions from the	Less than significant	No mitigation is required.	Less than significant

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
Project are considered. The results also show that although ambient PM2.5 and PM10 currently exceed state and federal standards, the incremental increases in ambient concentrations of these pollutants are below significance thresholds established by SCAQMD.			
The Project is not expected to violate any air quality standard or contribute substantially to an existing or projected air quality violation. The air quality impact during the construction phase does not exceed the mass daily significance thresholds; and the air quality impact in operating the facility will be below the ambient air quality standards based on the air dispersion modeling conducted.	Less than significant	No mitigation is required.	Less than significant
The closest K-12 school will be Mark Keppel Elementary school, which is located more than 0.6 miles northeast from the emission sources. The nearest residential receptor is located approximately 694 feet (211 meters) from the emission sources and the nearest worker/commercial receptor is located approximately 572 feet (174 meters) from the emission sources. Both receptors are in the northeast direction of the emission sources. Based on the results of an ambient air quality analysis, criteria pollutant concentrations from the Project are expected to disperse substantially before reaching any sensitive receptors. The Project will neither cause, nor substantially add to an existing violation of state or federal ambient air quality standards. Additionally, impacts from construction activities are expected to be below daily significance thresholds as well as localized significance levels.	Less than significant	No mitigation is required.	Less than significant
Toxic Air Contaminant emissions associated with the Project will consist primarily of combustion byproducts produced by the new turbines, the existing turbine (Unit 9), and the emergency engine. Maximum individual cancer risk (MICR) and non-cancer acute and chronic health risks were calculated for residential receptors and worker receptors. The MICR and hazard index (HI) values were calculated based on the combined impact of all chemicals. MICR	Less than significant	No mitigation is required.	Less than significant

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
was calculated as 1.09E-06 for residential receptors and 0.04E-06 for worker receptors with a significance threshold of 10.00E-06. Acute HI was calculated as 0.008 for residential receptors and 0.008 for worker receptors with a significance threshold of 1.00. Chronic HI was calculated as 0.003 for residential receptors and 0.003 for worker receptors with a significance threshold of 1.00. Therefore, health risks that the Project poses to nearby residential and worker receptors are expected to be below the significance thresholds. The MICR for residential receptors were calculated to be greater than the 1.00E-06 threshold to trigger the Cancer Burden analysis. Cancer burden of this Project were determined based on the distance of 627 meters, where the MICR falls below one in one million, a highly conservative population density default value of 7,000 persons per square kilometer, and the MICR at the residential receptor of 1.36E-06. The cancer burden was calculated to be 0.012, which is below the significance threshold of 0.5. Toxic air contaminants emissions associated with the earth moving activity will consist primarily of combustion byproducts from off-road equipment and vehicles trips. The construction of the facility is anticipated to take place over a period of 27 months. Therefore, Toxic Air Contaminants emissions from construction activity are not expected to have health significant impacts on cancer and non-cancer chronic risks because these risks are typically assessed for continuous exposure for 30 years. Additionally, the heaviest impacts of earth moving activity can be expected to occur within the fence line of the power plant. Therefore, the Toxic Air Contaminants emission impacts from the earth moving activity are expected to be less than significant.			
Cultural and Paleontological Resources			
The Boiler Building is a discretionary historical resource and is located on the Project site. Demolition of the Boiler	Potentially significant	**CR-1:** Prior to demolition of the Boiler Building, the City shall prepare Historic American Engineering	Significant and unavoidable impact

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
Building would cause a substantial adverse change in the significance of a historical resource as defined in 14 CCR Section 15064.5.		Record (HAER) documentation for the Boiler Building. That documentation shall include preparation of a written narrative, photography, and drawings that meet the latest requirements in HAER History, Photography, and Drawing Guidelines. Archival and electronic full copies of that completed documentation shall be submitted to the HAER program in accordance with the most recent edition of "Preparing HABS/HAER/HALS Documentation For Transmittal." The City shall maintain the HAER documentation at the Glendale Central Public Library and information about accessing that information shall be available on the City's website. HAER documentation, as described, shall be complete and accepted by the HAER program before any demolition or dismantling of the Boiler Building. The City shall also display up to four (4) archival quality photographs of the historic Boiler Building in a publicly accessible location within the City's Perkins Building, **CR-2:** City shall provide permanent plaque to be located at the Flower Street entrance to the Grayson Power Plant that identifies the location of the former historic Boiler Building and provides a narrative statement about the Boiler Building that provides historic context **CR-3**:City shall salvage and preserve a piece of equipment from the Boiler Building and display the piece of equipment along with an historic context statement in a publicly accessible location in the City.	
Demolition to implement the proposed Project may involve ground disturbance into previously undisturbed sediments in order to remove existing piles or soils that may have been contaminated. Construction plans include excavations across the Project area, including areas with up to 20 feet beyond current depths of development, placing the total depths of excavation into high potential	Potentially significant	**PAL-1:** Worker training. A paleontologist who meets professional paleontological standards as defined by Murphey et al. (2019) shall design a Worker's Environmental Awareness Program reviewed and approved by a qualified consultant retained by the City that will provide training that communicates requirements and	Less than significant

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
sediments that are expected to begin at around 10 feet below ground surface (bgs). Where ground disturbance extends beyond 10 feet bgs into previously undisturbed sediments, either in entirely undisturbed areas or beneath the depth of previous disturbance, sediments with high paleontological potential will be encountered. As a result, demolition and construction associated with this Project may have either direct or indirect impacts on paleontological resources.		procedures for the inadvertent discovery of paleontological resources during construction, to be delivered by the paleontologist or their designee to the construction crew prior to the onset of ground disturbance. The training will be provided by qualified consultant retained by the City. **PAL-2:** Paleontological Monitoring. A paleontologist meeting professional standards as defined by Murphey et al. (2019) shall be retained to oversee all aspects of paleontological mitigation, including the development and implementation of a Paleontological Monitoring and Mitigation Plan (PMMP) tailored to the Project that provides for paleontological monitoring of earthwork and ground disturbing activities into undisturbed geologic units with high paleontological potential (undisturbed sediments over 10 feet in depth), to be conducted by a paleontological monitor meeting professional standards (Murphey et al. 2019). **PAL-3:** Inadvertent Discoveries. In the event that paleontological resources are encountered during construction activities, all work must stop in the immediate vicinity of the finds while the paleontological monitor documents the find and the designated project paleontologist assesses the find. Should the qualified paleontologist assess the find as significant, it should be collected and curated in an accredited repository along with all necessary associated data.	
Geology & Soils			
There is low to moderate potential for surface rupture from the Verdugo fault and other nearby active faults during the design life of the Project. Strong ground shaking can be expected at the Project site during moderate to severe earthquakes in the general region and the Project area is located within a liquefaction zone and site conditions may	Less than significant	No mitigation is required.	Less than significant

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
be susceptible to seismically induced liquefaction in the event of a major earthquake. However, with the implementation of applicable building codes and recommendations made within the Geotechnical Study (Stantec, 2015), geological impacts are expected to be less than significant.			
Earth-moving activities during demolition and construction, including trenching, excavating, stockpiling, and grading would result in exposure and mobilization of onsite soils, increasing the chance of erosion. An erosion control plan, SWPPP, Dust Control Plan and BMPs would be implemented to minimize erosion. With implementation of these required plans and procedures, impacts from soil erosion are anticipated to be less than significant.	Less than significant	No mitigation is required.	Less than significant
Due to estimated surface settlements, as well as minimal slopes, depth of groundwater, and non-expansive soils at the Project site, impacts related to stability, landslide, lateral spreading, subsidence, and liquefaction of collapse are considered less than significant.	Less than significant	No mitigation is required.	Less than significant
Greenhouse Gas Emissions			
The proposed new combustion gas turbines are expected to generate less GHG emissions on a pound per megawatt-hour basis than the existing equipment that is to be removed from service. The Project will result in GHG emissions due to both construction and operation activities. The GHG construction emissions would be generated primarily by the off-road construction equipment and on-road vehicles. Total CO_2e emissions during construction of the Project would be 1,327 metric tons per year. During facility operations, natural gas combusted in the new combustion turbines, diesel fuel combusted in the emergency engine, and facility occupancy related activities will contribute to GHG emissions. The net increase of GHG emissions from the operation of the Project, 415,832 metric tons per year, exceeds the significance threshold of 10,000 metric tons per year. CO_2e emissions would be reported, and	Less than significant	No mitigation is required.	Less than significant

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
allowances and offset credits would be acquired to mitigate 100 percent of GHG emissions from the combustion equipment and transformers. Net emissions after mitigation will include only emissions related to facility occupants and will be well below the 10,000-metric ton significance threshold.			
Emissions from the Project will be fully offset through the retirement of GHG allowances held by GWP, and additional credits to be purchased by GWP. The Project will allow the City to maximize the import of renewable energy sources through the limited existing transmission capacity into the City which will further assist the City in meeting the Renewable Portfolio Standards and GHG reductions specified in the Greener Glendale Plan. The Project would not conflict with any applicable plan, policy or regulation adopted for reducing the emissions of greenhouse gases.	Less than significant	No mitigation is required.	Less than significant
Hazards & Hazardous Materials			
Demolition activities involving the removal of hazardous materials including asbestos containing material and lead-based paint could create a significant hazard to the public.	Potentially significant	**HAZ-1:** Prior to demolition of facilities associated with the Grayson Repowering Project, hazardous materials stored onsite and not required for continued operation of the facility shall be inventoried, packaged, removed, and disposed in accordance with a Hazardous Materials Management Plan prepared by the demolition contractor and submitted to the City for review and approval prior to initiating demolition activities. **HAZ-2:** Buildings or equipment to be demolished containing lead based paint or asbestos shall be either decontaminated or encapsulated prior to removal from the Project site and disposed in accordance with an Asbestos and Lead Paint Management Plan prepared by the demolition contractor and submitted to the City for review and approval prior to initiating demolition activities.	Less than significant
Petroleum hydrocarbons and VOCs may be encountered during subsurface demolition activities. Excavation,	Potentially significant	**HAZ-3:** Contaminated soil encountered during demolition activities shall be handled, removed,	Less than significant

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
handling, and transport of contaminated soil has the potential to impact workers and the public if not handled and contained properly.		and disposed in accordance with regulatory requirements and the Project's Soil Management Plan.	
Hazardous materials used during construction of the Project will include gasoline, diesel fuel, motor oil, hydraulic fluid, solvents, cleaners, sealants, welding flux, various lubricants, paint, and paint thinner. The quantities of hazardous materials that will be used onsite during construction will be limited to the quantities required to complete construction of the Project. The potential exists for fuels, oil, and grease to drip from construction equipment. Spills of fuel may occur during onsite refueling operations if refueling operations are not conducted properly. It is not anticipated that spills related to refueling operations would be large and would be limited to the immediate area and cleaned up at the time of the spill using spill kits stationed on the fuel truck. It is unlikely that the volume of refueling spills will travel beyond the immediate area of the spill and impact offsite receptors.	Potentially significant	**HAZ-4:** Hazardous materials used during construction shall be limited to the quantities required for construction and shall be stored and handled in accordance with regulatory requirements. **HAZ-5:** Utility trucks and refueling trucks operating onsite shall have a spill kit onboard at all times. Small spills of petroleum products or other hazardous materials during construction operations shall be reported to the Construction Supervisor and a Spill Response form completed with a description of the type and quantity of the spill accompanied by photographs and a description of the disposition of the spill material. Hazardous spill material shall be disposed according to regulatory requirements. In the event of a large spill of hazardous materials equal to or above reportable quantities federal, state, and local reporting requirements shall be followed.	Less than significant
The types and quantities of hazardous materials anticipated to be used and stored onsite during operation of the Project is consistent with the types and quantities of hazardous materials currently used and stored onsite. Use, storage, handling, disposal, and reporting of these hazardous materials would be consistent with current practices and regulatory requirements and not create a significant hazard to the public or the environment.	Less than significant	No mitigation is required.	Less than significant
The Project would maintain an existing 19-percent aqueous ammonia above ground storage tank and would add a second tank of the same volume and containment system. An offsite consequence analysis assumed the complete failure of the storage tank, the immediate release of the contents of the tank, and the formation of an evaporating pool of aqueous ammonia within the	Potentially significant	**HAZ-6:** The surface area of the proposed and existing ammonia tank containment systems shall be reduced by 90 percent or greater through the installation and maintenance of three-inch diameter high density polyethylene balls or similar method.	Less than significant

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
secondary containment structure. In this event, evaporative emissions of ammonia would be subsequently released into the atmosphere. The dispersion and transport of these emissions into the atmosphere would be subject to meteorological conditions at the time of the release. The offsite consequence analysis for the worst-case release of ammonia indicates that 75 parts per million concentration would extend 528 feet from the ammonia tank/release. This distance would extend beyond the Grayson Power Plant eastern property boundary and is considered a potentially significant impact.			
Hydrology & Water Quality			
Soil temporarily exposed during excavation and grading activities may be subject to sheet erosion during rain events thereby increasing the level of suspended solids in flows emanating from the site. In addition, the demolition of the existing facility may result in the exposure and/or disruption of contaminated soils, which may impact surface water quality during storm flows. A SWPPP containing structural treatment and source control measures, including BMPs, appropriate for the Project would be prepared and incorporated. Implementation of the measures included in the SWPPP as well as those included in the Project's Soil Management Plan (PR-DEIR Appendix E.4) would ensure that RWQCB water quality standards are met, the drainage pattern of the site would not result in substantial erosion or siltation on- or off-site.	Less than significant	No mitigation is required.	Less than significant
Stormwater that falls within the plant in pavement areas and outside the process equipment containment areas would flow via surface sheet flow and localized gutters to catch basins and on-site storm drain piping to be discharged to the Verdugo Wash and Los Angeles River. Stormwater that is not captured in containment areas would be captured via a storm drain system and processed before being discharged either to the sanitary sewer or to the Verdugo Wash or Los Angeles River. The system would meet all applicable effluent discharge standards set by the RWQCB and other	Less than significant	No mitigation is required.	Less than significant

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
regulatory agencies before discharging through the existing stormwater outfalls and would not substantially alter the drainage pattern or result in substantial polluted runoff. The proposed stormwater capture, treatment and infiltration system would result in improved drainage conditions and stormwater runoff quality compared to the existing system.			
Noise			
Demolition and construction would result in noise from the operation of conventional construction equipment and associated vehicles. Construction related activities will be conducted Monday through Saturday between the hours of 7:00 AM and 7:00 PM and will therefore be in accordance with the City of Glendale noise ordinance related to construction noise. It is possible that some concrete pouring activities could be conducted at night. Predicted noise levels at receptors were modeled and would be below City nighttime noise standards. Any construction work conducted outside the above times and days would be subject to issuance of a City variance. Construction related noise would therefore not expose persons to or generate noise levels in excess of established standards and potential impacts would be less than significant.	Less than significant	No mitigation is required.	Less than significant
Noise (including low frequency) from operation of the Project was modeled to predict resulting noise levels at sensitive receptors. Many of the primary noise sources and levels associated with Project operation have been guaranteed by the equipment manufacturer and were considered in the modeling. However, some ancillary equipment which would contribute to noise has not yet been identified. If this ancillary equipment does not meet specific noise levels, operation of the Project could expose persons to noise levels in excess of established City standards.	Potentially significant	**NOI-1: Noise Source and Required Noise Control Measures: Cooling Towers** - The noise emissions from each cooling tower shall be limited to 57 dBA at 400 feet (107 dBA sound power level). Mats may be required to limit the water splash noise. **NOI-2: Noise Source and Required Noise Control Measures: Cooling Tower Fan Motors and Gearboxes** - The sound power levels for cooling tower motors shall be limited to 98 dBA (85 dBA at 3’) the motors shall be placed on the west side of the towers. **NOI-3: Noise Source and Required Noise Control Measures: Fuel Gas Compressors** - The noise emissions from each of the two fuel gas	Less than significant

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
		compressor areas shall be limited to 44 dBA at 400 feet. Compressor enclosures or properly designed noise barriers can be utilized. Under the current assessment scenario open air compressor equipment packages with total sound power level of 108 dBA were treated with 21-foot sound barrier to yield appropriate results. **NOI-4: Noise Source and Required Noise Control Measures: Water Treatment Area** - The noise emissions from the water treatment area shall be limited to 48 dBA at 400 feet. It is expected that this level can be achieved through a combination of equipment selection, small enclosures and barriers **NOI-5: Noise Source and Required Noise Control Measures: Boiler Feed Water Pumps for Combined Cycle Units** - The sound power levels for boiler feed water pumps shall be limited to 105 dBA when placed outside near the respective HRSGs. **NOI-6: Noise Source and Required Noise Control Measures: Circulating Water Pumps for Cooling Towers** - The sound power levels for circulating water pumps shall be limited to 101 dBA when placed outside near the respective cooling towers. **NOI-7: Noise Source and Required Noise Control Measures: Generator Step-up Transformers** - Standard NEMA 95 MVA rated transformers or lower shall be utilized. **NOI-8: Noise Source and Required Noise Control Measures: Steam Turbine Building** - The sound power level of the noise breaking out from the steam turbine building shall be limited to 95 dBA and 115 dBC (45 dBA and 65 dBC at 400 feet).	

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
		Specialized enclosures for the gearboxes shall be required and steam turbine building walls and roofs shall have an STC 40 composite transmission loss rating. **NOI-9: Noise Source and Required Noise Control Measures: Steam Pipe Rack** - The sound power level for the steam pipe rack shall be limited to 82 dBA per meter of piping. **NOI-10: Noise Source and Required Noise Control Measures: Steam Sky vents and safety valves** - Steam sky and safety valves shall be equipped with silencers to limit their noise emissions to 115 dBA sound power (approximately, 90 dBA at 5').	
No significant ground-borne noise effects are expected during the construction or operation of the Project. Project vibration levels beyond the Project site boundary during operations are expected to be negligible. Demolition and construction activities are expected to involve potential sources of ground borne vibration such as pile driving. At the higher end of the diesel pile drivers, the expected vibration amplitude defined in terms of peak particle velocity (PPV) is 1.52 in/s. For demolition activities, the vibration levels equivalent to 1.5-ton ball drop from 10' can be used (3.89 in/s PPV at 25 feet). Predicted maximum demolition and construction vibration levels are below the preferred vibration thresholds at the nearest residential and commercial buildings. The Project would therefore not result in exposure of persons to or generation of excessive ground borne vibration or ground borne noise levels nor would damage to the nearby structures would be expected.	Less than significant	No mitigation is required.	Less than significant
The Project noise results in a permanent increase in area ambient sound levels of less than 2.5 dB during nighttime hours and less than 1 dB during daytime hours.	Less than significant	No mitigation is required.	Less than significant
A substantial temporary increase in ambient noise levels may result from the demolition and construction activities	Less than significant	No mitigation is required.	Less than significant

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
associated with the Project. Such increases will fluctuate with changing activities and duration. Construction would be limited to the daytime hours of 7:00 am to 7:00 pm Monday through Saturday, excluding Holidays consistent with the City's Noise Ordinance. It is possible that some concrete pouring activities could be conducted at night. Predicted noise levels at receptors were modeled and would be below City nighttime noise standards. Any construction work conducted outside the above times and days would be subject to issuance of a City variance. Steam blows during commissioning will utilize silencers. Other commissioning activities will be no louder than normal plant operations.			
Transportation & Traffic			
The majority of truck traffic would access the site using the northbound right-turn lane on Fairmont Avenue. The entrance driveway is 25 feet wide and is designed to accommodate most truck movements. However, larger trucks (CA-Legal 65 feet) will require a wider turn radius and encroach into the number two northbound through lane.	Potentially significant	**TRA-1**: To accommodate turning movements by large trucks (CA-Legal 65 feet) and public safety on Fairmont Avenue, the demolition and construction contractor shall be required to prepare a traffic control plan for City review and approval prior to initiating demolition and construction activities that includes the use of large trucks entering and departing the Grayson Power Plant from Fairmont Avenue.	Less than significant
During the demolition phase (June 2018 – March 2019) the Project will require between 25 and 60 construction personnel daily. Between five and 22 trucks delivering equipment or hauling demolition materials will travel to and from the project site daily. During the construction phase (April 2019 – December 2020) the Project will require between 35 and 150 construction personnel daily, with a peak demand of between 170 to 240 personnel during the December 2019 – May 2020 period. Between two and nine trucks delivering equipment or hauling demolition materials are expected to travel to and from the project site daily. In addition, soils import will require up to 50 hauling trucks per day during the first two months (April - May 2019) and up to 25 trucks per day during December 2019 and	Potentially significant	**TRA-2:** To reduce construction traffic at the San Fernando Road and Doran Street intersection during the PM peak hours, a construction traffic control plan shall be developed by the contractor, reviewed and approved by the City, and implemented for the duration of the construction phase. The plan shall include measures to limit vehicle trips to a total of 24 trips or less during the hours of 4 to 6 PM for the San Fernando Road and Doran Street intersection. Measures may include scheduling of construction activities or trip routing to minimized travel during peak PM traffic times, ride sharing, closing the parking lot, and/or other effective and verifiable measure. **TRA-3:** The applicant shall ensure that traffic control is implemented for the duration of demolition and	Less than significant

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
January 2020. Concrete delivery for foundation pilings will require an average of up to 12 trucks per day, with a maximum of 36 trucks for two days per month during four months (total of eight days during the life of the Project). During the commissioning phase (January 2021 – June 2021) the Project will require between 25 and 85 construction personnel daily. The number of hauling/delivery trucks will be reduced to an average of two trucks per day. Construction worker parking will be provided on the Caltrans/City of Glendale storage yard between the Verdugo Wash and Doran Street. Maximum construction related traffic levels are anticipated to occur from January to May 2020. The Project is expected to result in a short-term addition of 214 ADT, 27 AM peak hour trips and 40 PM peak hour trips during the demolition period. During the construction period, a short-term addition of 513 ADT, 65 AM peak hour trips and 104 PM peak hour trips would be generated. During the commissioning period, a short-term addition of 71 ADT, 9 AM peak hour trips and 17 PM peak hour trips would be generated. The project peak is during the construction phase (January 2020). The Project would generate a short-term impact at the San Fernando Road/Doran Street intersection by adding V/C 0.05 during the PM peak hour, which would exceed the City of Glendale's threshold of V/C 0.02 for signalized intersections operating at LOS D, E, or F. Project personnel expected during the construction phase is 180 persons. Project personnel trips during the demolition and commissioning phases are not expected to exceed 60 and 35 persons; respectively. This short-term significant impact is expected to be for a maximum 21-month time period (construction duration).		construction phases. Traffic control shall include construction warning signs on Fairmont Avenue (Trucks Entering Exiting), and monitoring (flag person) on public roadways as needed during large transports. **TRA-4**: A construction traffic control plan shall include provisions for days when high truck traffic is generated (soil delivery days, peak concrete delivery days). The plan will include considerations for truck staging to ensure that truck parking/staging can be accommodated off the City streets. **TRA-5**: Traffic control monitors shall direct traffic whenever heavy construction equipment is entering and exiting the plant as warranted to ensure public safety. The traffic monitor shall be posted throughout the demolition and construction periods, as necessary. The applicant shall coordinate with the Glendale Fire Department to ensure that traffic control routes and procedures would allow for adequate emergency access. **TRA-6**: All construction-related vehicles, equipment staging and storage areas shall be located in approved pre-determined areas that are outside of adjacent road right of ways. The applicant shall provide all construction personnel with a written notice of this requirement and a description of approved parking, staging and storage areas. The notice shall also include the name and phone number of the applicant's designee responsible for enforcement of this restriction. **TRA-7**: Construction traffic shall comply with the California Vehicle Code sections related to vehicle weight and width. Any extra-legal loads needed for specialized deliveries shall be subject to special permit requirements from the City of Glendale. Should roadway damage occur along the haul route that is	

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
		directly attributable to the demolition and construction of the Project, repairs will be assessed by the City and completed accordingly.	
Roadway segments in the local transportation network could potentially be damaged by truck traffic. There is also the potential for tracking dust, soils, and other materials from the construction sites onto public and private roads. The potential for damage to public and private roadways from construction traffic is considered significant.	Potentially significant	**TRA-8**: Fugitive dust control shall be implemented according to SCAQMD Rule 402, 403 and 1186, and California Vehicle Code Section 23114, and Building & Safety requirements. Dust control mitigation measures shall include: • Soil stabilizers and dust suppressants to control fugitive dust levels from exposed soils. • On-site water trucks to provide control of fugitive dust while soil is moved or disturbed. • Off-site vacuum and broom sweepers to remove any fugitive materials from the public roadways. • Track-out control to prevent dirt and mud from being spread to public roadways: ○ Sweeping or spray cleaning trucks prior to leaving project site. ○ Adequate truck load covering. Limit on-site vehicle speeds to 15 mph.	Less than significant
The existing storage length of each off-ramp in the study-area is sufficient to accommodate the expected peak hour queues of 270 feet or less under existing plus project conditions. Therefore, no impacts are anticipated. Caltrans District 7 has established LOS F0 as the minimum acceptable level of service on the freeway system (Caltrans, 1996). Segment 7 along I-5 has an existing LOS below the minimum acceptable level. The AADT for segment 7 is 294,000 vehicles. The Project would add an ADT average of 513 vehicles during the peak period (construction, January 2020). The construction trip distribution calculates that 65% of the 513 vehicles will utilize I-5. Therefore, approximately 334 vehicles may travel along segment 7 of I-5 consisting of 0.11% of the AADT along this freeway. The Project contribution of 0.11% is not	Less than significant	No mitigation is required.	Less than significant

Project Impacts	Impact without Mitigation	Mitigation Measures	Impact with Mitigation
expected to degrade the existing MOE along segment 7. Based on the foregoing analysis, and therefore will not conflict with the CMP LOS.			
Tribal Cultural Resources			
The Project would have no significant impacts.	No impact	No mitigation is required.	No impact

~~REVIEW PROCESS AND AVAILABILITY OF THE PR-DEIR~~

~~CEQA requires lead agencies to solicit and consider input from other interested agencies, citizen groups, and individual members of the public. CEQA Guidelines Section 15087 specifies that EIRs be circulated for a 45-day public comment period. The PR-DEIR will be reviewed for a 60-day period, which exceeds the 45-day circulation requirement for an EIR, in order to provide the public ample time to read, evaluate and if desired, submit written comments on the PR-DEIR. A Notice of Completion/Notice of Availability of the PR-DEIR for review will be provided with copies of the PR-DEIR to regional and local public agencies, interested groups and persons, the State Clearinghouse and Los Angeles County Clerk. In addition, the Notice of Completion/Notice of Availability and Final 2018 EIR will be made available on the City of Glendale's Project website at Graysonrepowering.com.~~

~~The PR-DEIR and supporting studies, are additionally available for review during business hours, by appointment, between 7:30 a.m. and 5:30 p.m. Monday through Thursday, and 8:00 a.m. to 5:00 p.m. on Fridays, at the City of Glendale Community Development Department, Planning Division (Planning Counter) and at the Glendale Water and Power Department. To make an appointment, please contact Erik Krause, Deputy Planning Director, at (818) 937-8156 and Catalina Lee, GWP Administration, at (818) 548-2107. Interested individuals, organizations, and public agencies can also provide written comments on the PR-DEIR to the address listed below.~~

~~City of Glendale~~
~~Community Development Department, Planning Division~~
~~633 East Broadway, Room 103~~
~~Glendale, California 91206~~
~~Attention: Erik Krause, Deputy Director~~

~~Comments may also be sent by facsimile to (818) 240-0392 or by email to ekrause@glendaleca.gov with "Grayson Repowering Project PR-DEIR" in the subject line. Agency responses should include the name of a contact person within the commenting agency.~~

~~SCOPE OF COMMENTS – REQUEST TO LIMIT COMMENTS TO RECIRCULATED INFORMATION~~

~~Because the 2018 Final EIR is revised only in part, and the City is recirculating only the revised sections of the 2018 Final EIR, the City is requesting that reviewers limit comments to the content of the PR-DEIR. The Final EIR will include the City's previously prepared responses to comments on the original 2018~~

~~Draft EIR during the initial public review period. During the preparation of the Final EIR, the City will respond to comments received during the recirculation period related to the PR-DEIR, consistent with the requirements of CEQA Guidelines Section 15988.5. The City will consider new comments by reviewers that are submitted on the content of the PR-DEIR, as the comment period on the original Draft EIR has expired.~~

Abbreviations

A	amps
AEGL	Acute Exposure Guideline Levels
ALOHA	Areal Locations of Hazardous Atmospheres
APE	area of potential effect
ASHRAE	American Society of Heating and Air-Conditioning Engineers
BA	Balancing Area
BERD	Built Environment Resource Directory
BESS	battery energy storage system
CAFE	Corporate Average Fuel Economy
CAISO	California Independent System Operator
CAL FIRE	California Department of Forestry and Fire Protection
CCR	California Code of Regulations
CEQA	California Environmental Quality Act
City	City of Glendale
CO	carbon monoxide
CPUC	California Public Utilities Commission
CRHR	California Register of Historical Resources
Db	decibel
dBA	A-weighted decibels
EIR	Environmental Impact Report
EPRI	Electric Power Research Institute
GE	General Electric
GHG	Greenhouse Gas
GPA	GPA Consulting
Grayson	Grayson Power Plant
GWP	Glendale Water and Power
HAER	Historic American Engineering Record
HASR	Historic Architectural Survey Report
HI	hazard index
IDLH	Immediately Dangerous to Life and Health
IPP	Intermountain Power Project
IRP	Integrated Resource Plan
KPO	Key observation points
Kv	kilovolt
kWH	kilowatt-hour
LACM	Natural History Museum of Los Angeles County
LADWP	Los Angeles Department of Water & Power
LORS	Laws Ordinances Regulations, and Standards
LOS	Level of Service
MICR	Maximum individual cancer risk
MMRP	Mitigation Monitoring and Reporting Plan

MPO	Metropolitan Planning Organization
MPR	Miles per hour
MVA	megavolt-amps
MW	megawatt
MWH	megawatt hour
NERC	North American Electric Reliability Corporation
NHPA	National Historic Preservation Act
NHTSA	National Highway Traffic Safety Administration
NOAA	National Oceanic and Atmospheric Administration
NOP	Notice of Preparation
Nox	nitrogen oxides
NRHP	National Register of Historic Places
OHP	California Office of Historic Preservation
OSHA	Occupational Safety and Health Administration's
PM10	particulate matter less than 10 microns
PM2.5	particulate matter less than 2.5 microns
PMMP	Paleontological Monitoring and Mitigation Plan
PPV	peak particle velocity
PRC	Public Code Resources Code
PV	photovoltaic
PR-DEIR	Partially Recirculated Draft Environmental Impact Report
RFP	Request for Proposals
RPS	Renewable Portfolio Standard
rpm	revolutions per minute
RTP	Regional Transportation Plan
RWQCB	Regional Water Quality Control Board
SB	Senate Bill
SCAG	Southern California Association of Governments'
SCAQMD	South Coast Air Quality Management District
SCS	sustainable communities strategy
SOx	sulfur oxides
STS	Southern Transmission System
SVP	Society of Vertebrate Paleontology
SWPPP	Stormwater Protection Plan
TGHS	The Glendale Historical Society
USEPA	U.S. Environmental Protection Agency
VAR	reactive power
VDC	volts direct current
VHFHSZ	Very High Fire Hazard Severity Zones
VMT	Vehicle Miles Traveled
VOC	volatile organic compounds
WECC	Western Electricity Coordinating Council
WMP	Wildfire Mitigation Plan
WOIS	Wartsila Operator Information System

Glossary

ENGINEERING TERMS

RICE	Reciprocating Internal Combustion Engine, similar to the engine in an automobile but on a larger scale.
OTB	Once Through Boiler, a variant of a heat recovery steam generator (HRSG) that transfers the heat from the gas turbine exhaust into water producing steam to be used in a steam turbine to produce additional electricity. Unlike a conventional HRSG, a OTB can be operated with no water in the tubes allowing the gas turbine to start and quickly reach the needed power level. Water can then be added, and steam production started. This system provides additional resiliency in that if the steam cycle becomes unavailable, the gas turbine can continue to operate and produce power.
Mothballed	placing equipment into long-term storage.
Glendale Rack	the switch rack that connects the existing Grayson Units 1-5 to the GWP electrical system.

ENVIRONMENTAL TERMS

2018 Final EIR	The 2018 Final Environmental Impact Report for the Grayson Power Plant (“Repowering Project” or “Project”), which was submitted to the Glendale City Council for certification.
Partially Recirculated Draft EIR	Only in part; to a limited extent to circulate again.

4.0 ENVIRONMENTAL IMPACT ANALYSIS

4.1 CATEGORIES OF ENVIRONMENTAL FACTORS

The purpose of this section is to inform decision makers and the public of the type and magnitude of the change to the existing environment that would result from the Project. This section provides a detailed discussion of the environmental and regulatory setting for each topic addressed in this EIR, the analysis of the potential impacts of the Project, potential cumulative impacts, and measures identified to mitigate these impacts, if necessary.

This Project is evaluated based upon its effect on the follow nine categories of environmental factors. These environmental factors listed below were identified during the Initial Study to potentially be affected by the proposed Project, and therefore were carried forward for analysis in this EIR.

- ☐ Aesthetics (Section 4.2)
- ☐ Air Quality (Section 4.3)
- ☐ Geology and Soils (Section 4.4)
- ☐ Greenhouse Gas (Section 4.5)
- ☐ Hazards and Hazardous Materials (Section 4.6)
- ☐ Hydrology and Water Quality (Section 4.7)
- ☐ Noise (Section 4.8)
- ☐ Transportation and Traffic (Section 4.9)
- ☐ Tribal Cultural Resources (Section 4.10)
- ☐ Cumulative (Section 4.11)

The original nine categories of environmental factors can be found in the 2018 Final EIR. The PR-DEIR evaluates the following additional three categories of environmental factors:

- ☐ Cultural and Paleontological Resources (Section 4.12)
- ☐ Energy (Section 4.13)
- ☐ Wildfire (Section 4.14)

A detailed analysis of environmental impacts will be presented for each resource area (listed above) utilizing the model Environmental Checklist Form found in Appendix G of the CEQA Guidelines Section 15063(f). Impacts to the environment for construction and operation of the Project will be assessed and described, and the level of significance of impacts will be measured against criteria that have been established by regulation, accepted standards, or other definable criteria.

Each environmental resource area is reviewed by analyzing a series of questions (i.e., Initial Study Checklist) regarding level of impact posed by the Project. Substantiation is provided to justify each determination. One of four following conclusions is then provided as a determination of the analysis for each of the major environmental factors.

- **No Impact.** A finding of no impact is made when it is clear from the analysis that the project would not affect the environment.
- **Less than Significant Impact.** A finding of a less than significant impact is made when it is clear from the analysis that a project would cause no substantial adverse change in the environment and no mitigation is required.
- **Less than Significant Impact with Mitigation Incorporated.** A finding of a less than significant impact with mitigation incorporated is made when it is clear from the analysis that a project would cause no substantial adverse change in the environment when mitigation measures are successfully implemented by the project proponent. In this case, the project proponent would be responsible for implementing measures identified in a Mitigation Monitoring Program.
- **Potentially Significant Impact.** A finding of a potentially significant impact is made when the analysis concludes that the proposed project could have a substantially adverse change in the environment for one or more of the environmental resources assessed in the checklist. In this case, overriding consideration would be required for the project to advance.

4.2 CUMULATIVE IMPACT ANALYSIS

The section below, sets forth the list of projects that is the basis for the cumulative impact analysis that appears in Sections 4.2 through 4.10 from the 2018 Final EIR as well as Sections 4.12 through 4.14 included within the PR-DEIR. Sections 4.2 through 4.14 then set forth the analysis of potentially significant environmental impacts, both Project-specific and Section 4.11 for cumulative, for each resource area evaluated in this EIR. Readers should note that a number of potential impacts were determined to be less than significant in the first instance or were determined not to be potential impacts of the project at all, and those determinations are set forth in Section 6.3 (effects Found Not to be significant) found in the 2018 Final EIR.

4.2.1 Overview

The technical analysis contained in Sections 4.2 through 4.14 examines both Project-specific impacts and the potential environmental effects associated with related cumulative development. CEQA requires that EIRs discuss cumulative impacts, in addition to Project-specific impacts. In accordance with CEQA, the discussion of cumulative impacts must reflect the severity of the impacts and the likelihood of their occurrence; however, the discussion need not be as detailed as the discussion of environmental impacts attributable to the Project alone. According to Section 15355 of the CEQA Guidelines:

> *"Cumulative impacts" refer to two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts. (a) The individual effects may be changes resulting from a single project or a number of separate projects. (b) The cumulative*

> *impact from several projects is the change in the environment which results from the incremental impact of the project when added to other closely related past, present, and reasonably foreseeable probable future projects. Cumulative impacts can result from individually minor but collectively significant projects taking place over a period of time.*

More specifically, Section 15130(a) of the CEQA Guidelines requires that EIRs discuss the cumulative impacts of a project when the project's incremental effect is "cumulatively considerable." Where a Lead Agency is examining a project with an incremental effect that is not cumulatively considerable, it need not consider the effect significant but must briefly describe the basis for its conclusion. Section 15130(a)(l) of the CEQA Guidelines further states, "a cumulative impact consists of an impact which is created as a result of the combination of the project evaluated in the EIR together with other projects causing related impacts."

If the combined cumulative impact associated with the project's incremental effect and the effects of other projects is not significant, Section 15130(a)(2) of the CEQA Guidelines requires a brief discussion in the EIR of why the cumulative impact is not significant and why it is not discussed in further detail. Section 15130(a)(3) of the CEQA Guidelines requires supporting analysis in the EIR if a determination is made that a project's contribution to a significant cumulative impact is rendered less than cumulatively considerable and, therefore, is not significant.

The fact that a cumulative impact is significant does not necessarily mean that the contribution of an individual project to the cumulative impact is significant as well. Instead, under CEQA, a project's contribution to a significant cumulative impact is only significant if the contribution is "cumulatively considerable." CEQA Guidelines 15130(a).

Section 15130(b) of the CEQA Guidelines recognizes that the analysis of cumulative impacts need not be as detailed as the analysis of project-related impacts, but instead should "be guided by the standards of practicality and reasonableness." Pursuant to this section, the following two elements should be considered as necessary to provide an adequate discussion of cumulative impacts: "(a) a list of past, present, and reasonably anticipated future projects producing related or cumulative impacts, including those projects outside the control of the Agency, or (b) a summary of projections contained in an adopted general plan or related planning document that is designed to evaluate regional or areawide conditions."

The discussion of cumulative impacts in this Draft EIR focuses on past, present, and reasonably anticipated future projects producing related or cumulative impacts, including those projects outside the control of the City of Glendale.

4.2.2 Projects Considered

The incremental effects of the Grayson Repowering Project, in connection with effects from past, current, and probable future projects that may result in similar impacts were assessed to determine potential cumulative impacts. The types of projects considered include other power generating projects in the area and projects at the Scholl Canyon Landfill. Projects of a similar nature within Glendale and neighboring areas identified through correspondence with water and power department representatives in the nearby

Cities of Los Angeles, Burbank, and Pasadena were reviewed. Based on this review, the following projects were identified for consideration within the cumulative impact analysis for the Project:

- Scholl Canyon Landfill Expansion Project —The City of Glendale previously proposed to expand the Scholl Canyon Landfill. The Landfill Expansion is no longer proposed, is no longer reasonably foreseeable and, as such, no longer carried forward to the cumulative impacts analyses included in Section 4.0 of the PR-DEIR.

- Green Waste Digester Project —The City of Glendale previously considered constructing and operating an Anaerobic Digester Project at the Scholl Canyon Landfill. The Anaerobic Digester Project would anaerobically digest organic waste and would combust the produced gas in electrical generating equipment to produce renewable electricity. The Anaerobic Digester Project is no longer proposed, is no longer reasonably foreseeable and, as such, is no longer carried forward to the cumulative impacts analyses included in Section 4.0 of the PR-DEIR.

- Biogas Renewable Generation Project - The project would include construction and operation of an approximately 12-megawatt power generation facility on approximately three-acres of land at the Scholl Canyon Landfill. The purpose of the project is to beneficially utilize methane-rich renewable landfill gas as fuel to generate electricity at the landfill where the landfill gas is generated and collected. Construction of the project will occur over a course of approximately 15 to 18 months through implementation of approximately three phases of development: demolition and removal of existing equipment, site grading and construction, and system startup. This project site is located approximately five- miles southeast of the Project. The City previously prepared an IS/MND for the proposed Project (City of Glendale and Stantec, 2018). The Final Initial Study/ Mitigated Negative Declaration (IS/MND) for the proposed Project concluded that the proposed Project would not result in potentially significant and unavoidable environmental impacts; however, City of Glendale Planning Commission elected not to adopt the Final IS/MND and requested preparation of an Environmental Impact Report (EIR) to evaluate a reasonable range of alternatives to the Project. A Draft EIR was prepared and circulated for public comment. That Draft EIR provided updated the analysis in response to comments received during the public hearing considering adoption of the previous IS/MND and the public scoping meetings for the Biogas Renewable Generation Project EIR. The Final EIR has been released and it is anticipated to be considered for certification and project adoption before the end of 2021.

- Silver Lake Reservoir Complex Storage Replacement Project – The Los Angeles Department of Water and Power is constructing the Headworks Reservoir to replace the existing Silver Lake Reservoir Complex in order to comply with State and Federal water quality regulations. The project includes the construction of two buried reservoirs (Headworks East and Headworks West), a 2-MW hydroelectric power plant, and a flow regulating station, as well as ecosystem restoration at the Headworks Spreading Grounds site. The project is scheduled to be completed within four phases. Phase One, the construction on Headworks East, was completed in 2014; Phase Two, construction on Headworks West, is scheduled to be complete in 2022; Phase Three, began in 2019, will include construction of a bypass pipeline, the hydroelectric power plant and the regulating station and is scheduled to complete in 2023; Phase Four, will involve ecosystem restoration of the project site and is scheduled to be complete in 2024. This project site is located approximately two miles northwest of the Project.

There are no additional related projects to added to the cumulative impact analysis since the 2018 Final EIR was completed. Cumulative impacts for the initial nine impact areas can be found in the 2018 Final EIR, Cumulative impacts for Cultural and Paleontological Resources, Energy, and Wildfire are presented below.

4.3 CULTURAL AND PALEONTOLOGICAL RESOURCES CUMULATIVE IMPACTS

Development of related projects can affect historical resources if such projects adversely alter and/or demolish historical resources that may be interrelated, such as historical resources that are part of a historic district or examples of the same property type as those within the Project site.

Neither the Boiler Building nor Grayson Power Plant were identified as contributors to a historic district; however, there are other extant properties within Glendale associated with the same property type. The Boiler Building represents a property type associated with municipal power generation within the City of Glendale. Research conducted as part of this analysis identified three properties that were previously identified as historical resources and are examples of the municipal power property type.

Table 4-1 Previously Identified Historical Resources of the Same Property Type

Name	Address	OHP Status Code(s)
Municipal Light & Power Building	620 E. Wilson Street (formerly 145 N. Howard Street)	3S; 5S1
Municipal Light & Power Building	6135 San Fernando Road	2S2
Water Power Light Building/ Municipal Services Building	119 N. Glendale Avenue/ 633 E. Broadway	3S; 5S1

There are no known related projects that impact other previously identified historical resources which are examples of the municipal power property type in Glendale. The three properties listed in Table 4-1 would remain. While the Project would have a direct impact on a discretionary historical resource, it would not contribute a cumulatively considerable impact, and cumulative impacts on historical resources as a whole would be less than significant.

Level of Significance before Mitigation:

Less than Significant Impact

Mitigation Measures:

No mitigation is required.

Level of Significance after Mitigation:

Less than significant Impact

4.4 ENERGY CUMULATIVE IMPACTS

The proposed Project would consume energy resources primarily including petroleum hydrocarbons during demolition and construction to fuel construction equipment and natural gas during operation to generate electricity. The Project involves replacing less energy efficient electrical generation equipment with more energy efficient electrical generation equipment. As a result, the Project would result in an improvement in long-term energy efficiency compared to existing power generation occurring at Grayson Power Plant.

The City is proposing to construct a Biogas Renewable Generation Project at Scholl Canyon Landfill to capture land fill gas and burn that gas in reciprocating internal combustion engines to destroy methane and other harmful landfill gas byproducts from the landfill and to produce electricity from that combustion. The Biogas Renewable Generation Project is a separate, independently permitted and implemented project. Implementation of the Biogas Renewable Generation Project would assist the City in meeting its renewable portfolio standards requirements compared to receiving no beneficial use from flaring the landfill gas under existing conditions. As a result, the Biogas Renewable Generation Project would result in an improvement in energy efficiency compared to baseline conditions. Considering this improvement as well as the energy benefits of the proposed Project, the proposed Project would not result in a substantial contribution to a significant energy-related cumulative environmental impact and potential impacts would therefore be less than significant.

Level of Significance before Mitigation:

Less than significant impact.

Mitigation Measures:

No mitigation is required.

Level of Significance after Mitigation:

Less than Significant Impact

4.5 WILDFIRE CUMULATIVE IMPACTS

The proposed Project would not result in a cumulatively considerable wildfire impact because the proposed Project is not located in proximity to any high fire hazard zones and is in a built out urban setting. The proposed Project is located approximately five miles from the Biogas Renewable Generation Project with a significant amount of urban development separating the two projects. The proposed Project is also located approximately three miles from the Silver Lake Reservoir Complex Project. The Silver

Lake Reservoir Complex Project is not located in proximity to any high fire hazard zones and a significant amount of urban development separates it from the proposed Project.

Level of Significance before Mitigation:

No impact.

Mitigation Measures:

No mitigation is required.

Level of Significance after Mitigation:

No Impact.

4.12 CULTURAL AND PALEONTOLOGICAL RESOURCES

This section addresses potential impacts to historical resources that could result from the Project and has been updated to provide additional analysis of new alternatives and mitigation measures pertaining to treatment of the existing Grayson Boiler Building as a discretionary historical resource under CEQA. The analysis of potential impacts to historical resources is based on the Historic Resource Inventory and Evaluation Report prepared for the Project by Stantec Consulting Services Inc. (Stantec) in 2015–2016 and revised in November 2018 and August 2020, as well as on discussions and site visits with The Glendale Historical Society.

While the City's research and analysis concluded that the Boiler Building is not an historical resource, after consultations with the Glendale Historical Society concerning the demolition of the Boiler Building or the proposed Project, the City has decided to use its discretion to treat the Boiler Building as an historic resource and has agreed to include feasible mitigation connected with demolition of the Boiler Building. However, even with mitigation, the demolition of the Boiler Building will result in a significant and unavoidable impact on an historic resource. (Demolition of the Boiler Building would be required for Alternatives 2 (Energy Storage Project Alternative), 4 (150 MW Project Alternative), 5 (200 MW Project Alternative), 7 (Tesla/Wartsila Repowering Project Alternative), and 8 (Tesla/Unit 8 Refurbishment Project Alternative). Alternatives 1 (No Project) and 3 (Alternative Energy Project Alternative) do not involve re-development at Grayson Power Plant and the Boiler Building would not be demolished.) Accordingly, the City will prepare a statement of overriding considerations to consider in connection with the certification of the final EIR based on the selection of either the Project or Alternatives 2, 4 through 8.

This section also addresses potential adverse impacts to paleontological resources that might result from the Project. This impact analysis is based on the Initial Study (IS) prepared for the project by Stantec (Stantec, 2016a) records search (Appendix A of the PR-DEIR), and a paleontological resources assessment conducted by Stantec Senior Paleontologist Alyssa Bell, Ph.D. The IS found that paleontological resources would not be impacted by the Project, assuming ground disturbance does not exceed depths of previous disturbance in the project area. Project plans now indicate excavations may exceed previous disturbance by as much as 8 feet below the current grade, indicating a paleontological resources assessment is needed.

Paleontological resources, or fossils, are any evidence of ancient life. This includes the remains of the body of an organism, such as bones, skin impressions, shell, or leaves, as well as traces of an organism's activity, such as footprints or burrows, called trace fossils. In addition to the fossils themselves, geologic context is an important component of paleontological resources, and includes the stratigraphic placement of the fossil as well as the lithology of the rock in order to assess palaeoecological (the ecology of fossils animals and plants) setting, depositional environment, and taphonomy (study of the process of fossilization). Fossils are protected by federal, state, and local regulations as nonrenewable natural resources.

The Society of Vertebrate Paleontology (SVP) defines significant paleontological resources as "identifiable vertebrate fossils, large or small, uncommon invertebrate, plant, and trace fossils, and other data that provide taphonomic, taxonomic, phylogenetic, paleoecologic, stratigraphic, and/or biochronologic information. Paleontological resources are considered to be older than recorded human history and/or older than middle Holocene (i. e., older than about 5,000 radiocarbon years)" [SVP, 2010]. It should be noted that the threshold for significance varies with factors such as geologic unit, geographic area, and the current state of scientific research, and may also vary between different agencies (Murphey et al., 2019).

Based on the findings of the Initial Study and further discussions with The Glendale Historical Society, the Project would not cause a substantial adverse change to the significance of archaeological resources as defined in 14 California Code of Regulations (CCR) Section 15064.5, nor would the Project have impacts on significant local archaeological resources as defined in Chapter 15.20 of the City of Glendale Municipal Code; however, demolition of the Boiler Building will cause a significant and unavoidable impact to a discretionary historical resource. While there is always a possibility that buried historic or cultural deposits could be found during construction and earth disturbing activities, regulatory compliance with State Health and Safety Code Section 7050.5 and Public Code Resources Code ("PRC") Section 5097.98 would be implemented in the event archeological or historic resources are discovered. Therefore, this would be a less than significant impact.

Tribal cultural resources, as that term is defined in CEQA Section 21074, are addressed in Section 4.10 of this report.

4.12.1 Environmental Setting

The Project site comprises the Grayson Power Plant, which consists of the boiler building, cooling towers, and a few other minor ancillary structures used for municipal electric power generation for the City of Glendale. This section includes contextual information for understanding the history and potential significance of the Plant and describes its existing conditions. This section also discusses the identification aspects of CEQA compliance for historical resources.

Historic Context

Electricity in California

California's growth in the first half of the twentieth century was due in part to the development of ambitious hydroelectric systems. Long-distance transmission lines linked the power generating mountainous regions with valley farms, coastal centers, and distant cities, allowing a pace and scale of development that was previously unimaginable. By the 1920s, this intricate system of hydroelectric facilities, coupled with a growing number of fuel-fired steam plants, fed into long distance transmission lines and a series of substations that transferred and distributed power to locations throughout the state for widespread public use.

In the 1880s, hydroelectric plants provided small-scale electrical development to only isolated companies, such as Standard Consolidated Mining Company in Bodie, CA and other localized concerns. However, by the early 1890s AC technological advancement allowed for a more effective means of transmitting electricity over ever-increasing distances. At the outset of this development, the San Antonio Light and

Power Company constructed a 13 mile, 5,000-volt, transmission line in 1892, with PG&E constructing the Folsom Hydroelectric Plant's 22 mile, 11,000-volt transmission line in 1895. These distances soon gave way to ever larger transmission capability, with Pacific Light and Power Company's Big Creek Hydroelectric Project running at 150 kV by 1913. Several small companies began constructing independent and local power plants as well as transmission systems. Post-World War II California residential and industrial development increased, and power companies responded with hydroelectric and steam power electrical generation. Steam power generation, however, proved to be more cost effective and municipalities and other companies began to build power generation plants close to population centers utilizing steam turbines to generate power to meet the increased demands for electricity.

California Steam and Electricity in Los Angeles County

As the City of Los Angeles and Los Angeles County experienced rapid growth during the early decades of the twentieth century, the demands for electricity increased dramatically. Prior to 1916, privately owned companies including Southern California Edison and Pacific Power & Light among others generated most of the electrical power in Los Angeles. British designer Sir Charles Parsons built the first steam turbine-generator in 1884. At the beginning of the twentieth century, engineers designed steam turbines to replace the aging steam engine power plants. Aegidius Elling of Norway is credited in 1903-1904 as being the first to apply the method of injecting steam into the combustion chambers of a gas turbine engine. The greater Los Angeles region had multiple examples of early fuel fired steam plants including the Banning Street Electrical Plant in Los Angles completed in 1883, Los Angeles Steam Plant No. 1 constructed in 1896, Pacific Light and Power Company's steam plant in Redondo Beach was completed in 1902 and the Glenarm Power Plant constructed in Pasadena in 1906. Within a relatively short time, the technology and capacity of these engines to supply power and electricity grew exponentially. These advances brought electricity to a wide range of industrial and domestic applications; however, the materials needed to withstand the high temperatures of modern turbines were not yet available. Improvements in steam turbines advanced throughout the 1920s and 1930s, leading to a generation of more efficient turbine power plants in the 1950s. During this time, utilities closed or replaced many of the older steam-electric plant generators and constructed more modern units.

Steam power generation was part of California's power production throughout the twentieth century, though it declined considerably in the period leading up to World War II as large hydroelectric generating plants came online throughout the state. As early as 1920, hydroelectric power accounted for 69% of all electrical power generated. In 1930, that figure had risen to 76%, and by 1940, hydroelectric sources provided 89% of California's electricity. After World War II this trend reversed and construction of steam-powered electric generating units grew, accounting for most of the new construction. By 1950, hydroelectricity accounted for only 59% of the total power generated, falling to 27% in 1960. Some new hydroelectric plants were built during the 1960s, chiefly associated with federal and state water projects, but by 1970, hydroelectric plants accounted for only 31% of all electricity generated in California. A combination of drought, discovery and tapping of natural gas, and lack of new hydroelectric sites led to its decline.

A persistent drought in California caused the major utilities to question the reliability of systems dependent on abundant water flows, like hydroelectricity. This drought began in 1924 and continued, on and off, for a decade. Concurrently, in the 1920s new natural gas discoveries were made and provided both Northern and Southern California with ample fuel for steam electric power generation. The confluence of these various factors – drought, new steam generator technologies, and new supplies of natural gas – prompted California utilities to begin constructing large steam plants. Steam plants built across the state shared design characteristics including locations close to load centers to reduce transmission costs, easy and efficient access to fuel supplies, near a water supply, on inexpensive land, and on geological formations that could provide a good foundation. By 1930, oil and gas-fired steam power plants accounted for more than half of all new plants under construction in California. The oil and gas-fired steam generation capacity jumped from 1924 at 407,000 kW to over 1 million kW in a mere six years later.

In 1916, the City of Los Angeles' Bureau of Power and Light provided the first municipal power distribution. The Bureau's first power generation plant, San Francisquito 1, was energized the following year. Originally some of Los Angeles' power was supplied by nearby Pasadena, but with the construction of San Francisquito 1, the City of Los Angeles was able to provide Pasadena with electrical power over 34 kV lines. By 1920, the Cities of Burbank, Pasadena, Glendale, and Los Angeles restructured their original charters in order to allow the cities to own power generation facilities and distribute electricity to their residents. After this time, municipalities began to construct larger power generation facilities. The City of Pasadena extended their electrical power distribution system by constructing the Santa Anita and Maryland power substations during the 1930s and the Glenham substation in the early 1950s. In 1941, the City of Burbank added the Magnolia Power Station, the same year as the City of Glendale's Grayson Power Plant. These factors prompted many municipalities, like Glendale to construct power plants of their own.

Early Glendale History

By the turn of the twentieth century, the town of Glendale had already experienced rapid growth resulting, in part, to the promotional efforts of Edgar D. Goode and Dr. D. W. Hunt and their Glendale Improvement Society in 1902. The growth continued with the opening of the Pacific Electric Railroad in 1904, connecting Glendale to Los Angeles. Glendale incorporated as a city in 1906 with a city limits at approximately 1,480 acres and by 1910 the population was 2,742 residents. Power generation in the City of Glendale began in earnest when the citizens voted in favor of a $60,000 bond to create the Glendale Public Service Division that purchased the Glendale Light & Power Company in 1909. By 1910 the system was already strained as energy output was a mere 107,000 kilowatts. To supplement, the city purchased additional electricity from Pacific Power & Light, now part of the Southern California Edison Company.

By 1920, Glendale began annexing neighboring communities boosting the city's population to over 13,000 residents. From 1930 to 1952, Glendale added Whiting Woods and Verdugo Mountains to their city limits a total of 23.6 square miles; two major annexations included New York Avenue (in the La Crescenta area) and Upper Chevy Chase Canyon, and several smaller annexations, which enlarged the city to 29.2 square miles by 1952. By 1950 the population was over 95,700 residents and was considered at the time to be "the fastest growing city in America." However, by the late 1930s the Glendale Public Service Commission, Electric Division could not keep pace with the population increases. Prior to 1937, Glendale purchased their power from Southern California Edison Company. This supply was supplemented with the completion of Hoover Dam hydroelectric power plant; however, continued growth indicated another plant would be necessary to supplement demand.

History of Grayson Power Plant

Building off the success of the 1920s and early 1930s and seeing the impending probability of an outbreak of hostilities in Europe, utilities and municipalities began constructing a series of oil-fired steam plants across California in the late 1930s. Northern California's PG&E began construction of three, oil-fired steam-plants located adjacent to oil refineries, in 1939. Southern California municipalities in Burbank and San Diego each completed power plants in 1941.

The City of Glendale began planning for the construction of a new power plant in 1937. However, the city's plans were met with immediate opposition by Los Angeles Bureau of Power and Light and the Southern California Edison Company, both which supplied the city with electricity. Despite this opposition, the City, led by industrial entities, pushed forward with its plan for construction of a $1.8 million-dollar plant. The City secured the services of Architect Daniel A. Elliott to design the Grayson Power Plant, referred to then as the "Glendale Power & Light" or "Steam Electric Generating Plant." Elliott designed the steam plant building (Boiler Building) in the Streamline Moderne style. It housed two boilers (Boilers 1A and 1B, and 2), which were manufactured by Combustion Engineering Company Inc. in New York. Located outside on a full-length turbine deck were the two steam turbine-generators, manufactured by General Electric.

Elliott was born in Las Vegas, New Mexico in 1898. He attended University of California at Berkley, earning an architecture degree in 1925. From 1925 through 1932 he served as a designer at the Los Angeles architecture firm of Gilbert Stanley Underwood before getting his architecture license and becoming an architect at the Metropolitan Water District of Southern California. He remained at the water district from 1932 through 1939. During World War II, he worked at Hoover and Montgomery, a firm that specialized in water-related construction projects. Following the end of the war he formed his own architecture practice, one he maintained until his retirement in 1962. Principal examples of his work are water infrastructure, most notably the Colorado River Aqueduct Pumping Plants and F.E. Weymouth Memorial Water Softening and Filtration Plant completed in 1939 and the Burbank Water & Power administrative building in 1949.

Elliott's original design laid claim to reportedly being the world's first earthquake-proof power plant, with an approximate 22-foot-deep concrete basement, turbo-generator on an uncovered open deck with a metal covering over the generator to protect from inclement weather, and a building shell built of light steel and stucco filler walls. At its start-up in 1941, the plant was capable of producing 20 megawatts of power. The City had already secured funding for a second unit set to be added in 1945. To meet increasing demands for electricity, a second unit was added in 1947, which included an additional 20-megawatt generator and single boiler increasing the plant's combined kilowatt capacity of 40 megawatts.

As demand continued to increase, a third unit was constructed in 1953 that included a new addition to the Boiler Building on its north end. The third unit at the plant was completed at a cost of over $3 million. The new integral furnace and superheater steam boiler unit was manufactured by the Babcock & Wilcox Company and the turbine-generator by General Electric. The company of Foster & Wheeler constructed the cooling tower and provided the condenser for Unit 3. Unit 3 also utilized advances in engineering and technology, which allowed for greater steam pressure than Units 1 and 2, which in turn allowed for greater operating efficiency. The steam turbine for Unit 3 is located outside the main building under a removable housing.

Between 1953 and 1954, the Grayson plant generated a total of 122,649 megawatt-hours, supplying most of the power needed for the city with the exception of supplemental power supplied by the Hoover Dam. Five more units were constructed after 1953 and included Unit 4 (1959), Unit 5 (1964), Unit 6 (1972), and Unit 7 (1974). Units 4 and 5 were housed within a new multi-story northern addition to the main Boiler Building, while Units 6 and 7, both simple cycle units, were located to the north of the Boiler Building in separate stand-alone enclosures. The boilers and turbine-generators for Units 4 and 5 were manufactured by Riley Stoker Corporation and General Electric, respectively; Unit 6 gas turbine was manufactured by General Electric; and the Unit 7 gas turbine by the Curtiss-Wright Company.

The portions of the Boiler Building that house Units 1 through 3 maintain Elliott's original design, however the structure's shape and detailing shifted with the addition of Units 4 and 5, to a significantly taller, less detailed utilitarian structure located north of the original 1941 boiler structure. As the building was expanded north, lower-level fenestration of the first three phases was repeated but without the vertical glass block panels. Little significant architectural detail was included in Unit 4 & Unit 5's building expansion. In 1972, the Plant was renamed the "L.W. Grayson Steam-Electric Generating Station" after the City of Glendale General Manager and Chief Engineer, Lauren W. (L.W.) Grayson who at the time was the longest serving employee. Grayson accepted a position at the City of Glendale in 1951. His most notable achievement was in bringing power to Southern California through the Pacific Northwest Intertie.

Unit 8 (Unit 8A and 8BC) was constructed in 1977 and, until the addition of Unit 9 in 2004, was one of the last to be installed at the power plant. These combined cycle units produced more energy more efficiently and with fewer emissions than conventional units as they generated electricity not only from the gas turbine-generators, but also used the exhaust energy to produce steam that generated electricity via the Unit 1 and 2 steam turbine-generators. The new system cost $20 million dollars and at the time, lessened air pollution.

Further environmental improvements to the Plant included the construction of a phosphate removal and treatment plant in 1978. The treatment plant was connected to the Los Angeles-Glendale Water Reclamation Plant by a pipeline, which directly pumped raw reclaimed (recycled) water to the treatment plant for phosphate removal before it was pumped to the Grayson Power Plant as water for the cooling towers. In addition, in the mid-1990's the Units 3, 4, and 5 boilers were retrofitted with landfill gas burners and from 1994 to 2018, the Plant combined landfill gas containing approximately thirty percent methane gas from the Scholl Canyon Landfill with natural gas to generate power from Units 3, 4, and 5. In the mid-1990's, these units were also retrofitted with emission control systems and continuous emissions monitoring systems to meet South Coast Air Quality Management District requirements. And in the early 2000's, Unit 8 was also retrofitted with emission control systems and continuous emissions monitoring systems. The Units 1A and 1B, and 2 boilers were mothballed in the 1990's and are no longer used, however their steam turbines are still utilized with steam supplied from Units 8A and 8BC.

Continuous improvements in efficiency and power generation capacity have been one of the priorities at the Grayson Power Plant throughout its history including the construction of Unit 9, a new 48-megawatt net power generator that was completed in 2004 at a cost of $33.5 million. It replaced Units 6 and 7, two of the older, outdated units, which were subsequently removed. Unit 9 consists of a gas turbine generator, fuel gas compressors, other balance of plant equipment, and an emissions control system to treat the exhaust gas to reduce emissions. The unit is fueled with natural gas and operates during peak hours.

In July 2010, a fire at Cooling Tower 3 caused severe damage to the structure rendering the cooling tower beyond repair and necessitating its replacement. Repairs to other portions of the Plant included the replacement of the superheater tubes in Boiler No. 4 in 2001, among other updates.

In 2020, the power plant generated approximately 7% of the energy needed for the City of Glendale with the remaining power coming from a combination of both local and remote generation (owned and leased), coupled with spot market purchases from a variety of suppliers throughout the Western United States.

Grayson Power Plant Construction Chronology

The earliest known aerial photograph of the Grayson Power Plant site dates to 1952. The 1952 aerial photograph of the site includes the original 1941 Boiler Building and the 1952–1953 addition to the northeast. The photograph shows the Glendale Switchyard located to the northeast of the Boiler Building, and Cooling Tower 1 and Cooling Tower 2 located southwest of the Boiler Building. In the aerial photograph, Cooling Towers 1 and 2 are rectangular structures. Between the Boiler Building and Cooling Tower 1, the photograph shows several auxiliary structures. No other structures were located on the site besides these four resources.

The Plant site expanded between 1952 and 1964. According to the 1964 aerial, the Boiler Building's multi-story addition was constructed, and Unit 5 was completed on its northwest end. The Glendale Switchyard was expanded to the northwest. Several new structures were constructed to the northwest by 1964, including Cooling Tower 3, Cooling Tower 4, and Cooling Tower 5. In addition to these three cooling towers, the 1964 aerial photograph shows a rectangular-shed building, a rectangular garage with two add-ons, and an L- shaped warehouse are located north of the towers as gabled buildings. These additional buildings, however, were not part of the Plant. Instead, they were built for the operations of other sections of the Public Service Department. No changes are evident in Cooling Tower 1 and Cooling Tower 2.

The Plant site between 1964 and 1977 changed significantly. Based on 1977 aerial photograph, Cooling Tower 1 was demolished and replaced with a utility structure addition to the northwest. A chemical storage tank was added between the Unit 1 and 2 cooling towers and an existing one demolished to make room for the addition of Unit 8. A second water treatment (demineralizer) unit was also added to the northwest corner of the Boiler Building. Unit 6 was constructed adjacent to the new demineralizer and the

Boiler Building at its northwest corner. Unit 7 was constructed to the northwest of Unit 6. In addition, Units 8A and 8BC were constructed by 1977 in the middle of the site, between Cooling Towers 1, 2, 3, and 4. A 120-feet diameter fuel tank was constructed south of the Boiler Building.

The open-air Kellogg Switchyard, which was constructed in the mid-1970's, was expanded to the northwest by 1977 with the removal of half of the oval- shaped parking lot. In addition, three parking sheds, again for use by other sections of the Public Service Department, are constructed between three existing buildings at the northwest end of the site. Based on the 1977 aerial photograph, no visual changes are apparent on Cooling Tower 2, Cooling Tower 3, Cooling Tower 4, and Cooling Tower 5, as well as the superintendents building, garage, and warehouse.

The Plant site changed very little, if at all, between 1977 and 1979.

The Plant site between 1979 and 1981 had one significant change completed, which was the demolition and replacement of Cooling Tower 2.

The Plant site between 1981 and 1989 was little changed. A 1989 aerial photograph shows a new switchyard (Air Way) was added north of the warehouse. The Plant site between 1989 and 1994 had no changes. The Plant site between 1994 and 2002 had one change to the site, which was the removal of the 1972 120' diameter fuel tank to make room for the future Unit 9 site.

The Plant site between 2002 and 2005 evolved with additional changes. Unit 9 was constructed on the 1972 fuel tank site, which was completed in 2003. In addition, the open-air Kellogg Switchyard continued to expand again to the north, replacing a parking lot. A building to the north of this switchyard was demolished and replaced with a parking lot.

The Plant site between 2005 and 2009 underwent a few changes that included the removal of Units 6 and 7, the addition of office trailers where Units 6 and 7 were, the replacement of the open-air Kellogg switchyard with a new gas insulated switchgear type switchyard (Kellogg GIS), and the demolition of another building north of the Kellogg switchyard. The most significant change in these years is the construction of the Fairmont Avenue—the on-ramp visibly started off the south corner of the plant's site. Off Fairmont Avenue, the front entrance to the plant site was added off this avenue, fronting the riverside of the property.

The Plant site between 2009 and 2011 was little changed; the most significant change was the relocation of the main entrance from Air Way to Fairmont Avenue. With the entrance changed, a parking lot was constructed, and an on-site parking shed was removed.

The Plant site between 2011 and 2012 included a new structure (office trailer), located northwest of the Boiler Building, to replace an existing smaller office trailer that was previously located on the former site of Unit 6 as well as the construction of a training center, at the northeast corner of the facility, on an existing parking lot.

In conclusion, the only pre-1970 structures that appear to retain their original footprint at the Plant are the Boiler Building, Glendale Switchyard, Cooling Tower 4, Cooling Tower 5, warehouse, superintendents building, garage and two parking sheds. The only pre-1970 structure that remains intact with no modification or alteration is Cooling Tower 5.

Existing Conditions

The Grayson Power Plant site is situated on a 11-acre parcel with its main entrance off Fairmont Avenue. The property is bounded by Flower Street on the north, the railroad right-of-way and San Fernando Road to the east, Fairmont Avenue and the Los Angeles River to the west, and the Verdugo Wash to the south. The site is composed of several buildings and structures that include a Boiler Building, five large cooling towers, five boiler units, four gas turbines, two switchyards, balance of plant equipment, and miscellaneous buildings.

Boiler Building

The Boiler Building is a Streamline Moderne-style steam power generation plant building, initially built in 1941, and expanded in 1953, 1959, and 1964. Facing southeast, the Boiler Building is set on a northwest-southeast axis on the Grayson Power Plant site. Its massing is predominantly rectangular divided into three levels and each elevation is asymmetrical. The older part of the Boiler Building, i.e. that which was originally built in 1941 and later expanded in 1953, is 2 to 3-stories high and constructed with structural steel frame set on a poured concrete pier foundation. The 1959 and 1964 additions rise up to a maximum height of 6 stories. Streamline Moderne details are evident as linear lines in the cementitious paneling, illuminating stringcourses on the building's upper southeast corner addition, added during a 1959 expansion of the building for Unit 4.

The building has a flat roof topped by metal coping. The exterior of the building is clad with multiple building materials that include horizontal cementitious siding and horizontal metal sheathing that is bolted to the steel framing. The cementitious siding is visible on the interior of the building as well. A Streamline Moderne style-rolling directional crane, which services the turbines and generators, is located on the northeast elevation. Each of the five steam turbines is covered with a Streamline Moderne enclosure. Copper box lettering in the same style is located on the corner and states: "CITY OF GLENDALE/PUBLIC SERVICE DEPARTMENT/STEAM ELECTRIC GENERATING PLANT". The northeast elevation of the building has a turbine deck with five steam turbine-generators, and the crane. The northwest elevation is where all the other mechanical equipment and boiler stacks are located.

Multiple openings punctuate the elevations of the Boiler Building on all elevations. The Boiler Building retains its original windows, which include structural glass blocks on the northeast elevation and metal-framed industrial awning windows on the southeast elevation.

Currently, the building houses six boilers (1A, 1B, 2,3,4, and 5) and a centrally located control room. A second control room is located at the northwest corner of the building. The interior of the building is open with a catwalk or mezzanine floor of metal grating constructed on the west wall used in operating the power equipment that include the boilers and steam turbines, which are attached to the concrete floor platforms. The corresponding boiler stacks are located on the exterior of building along the west wall.

Generating Units

The Grayson Power Plant has six generating Units in total comprising of six boilers, three of which have been mothballed (i.e. Units 1A, 1B, and 2) (meaning they have been put in storage), five steam turbines, two of which are part of the combined cycled units (i.e. 8A and 8BC), and four gas turbines, two of which drive a single generator (i.e. 8BC), that range in construction dates. Units 8A and 8BC, the two combined cycle units, utilize gas turbines similar to what was used on a Boeing 707 aircraft, to drive two heat recovery generators. The unit's exhaust heat is used to power the first two steam turbines (i.e. Units 1 and 2) constructed at the plant.

Tables 4-2 through 4-5 below note the construction and alteration dates of components and structures on the Plant site. The "Architectural Integrity" column notes whether or not components/structures over 45 years of age have been substantially altered. If a component or structure is noted as retaining architectural integrity, it has not been substantially altered from its date of construction.

Table 4-2 Construction and Alteration Dates of Boiler Units

Unit No.	Built Date[1]	Alteration Dates[2]	Architectural Integrity Yes/No?
Unit 1[3]	1941	Intact; Mothballed	No
Unit 2	1947	Intact; Mothballed	No
Unit 3	1953	Modified 1994	No
Unit 4	1959	Modified 1994	No
Unit 5	1964	Modified 1994	No
Unit 6	1972	Demolished	N/A
Unit 7	1974	Demolished	N/A
Unit 8A and 8BC	1977	Intact	N/A (less than 45 years old)
Unit 9	2003	Intact	N/A (less than 45 years old)

1 Built Dates from the City of Glendale Department of Water & Power.

2 Aerial analysis from 1952-2005 at the Nationwide Environmental Tile Research, LLC (NETR), www.historicaerials.com.

3 Unit 1 includes boilers 1A and 1B.

As utilitarian structures, the exterior surfaces of the boiler units are constructed of metal with various pipes and venting systems throughout. Units 1A, 1B, 2, 3, 4 and 5 boilers are located within the Boiler Building. Boilers 1A, 1B, and 2 have been mothballed. Units 3, 4 and 5 were retrofitted in 1994 with landfill gas burners and emissions control and monitoring systems. Oil tanks, adjacent and connected to the units have been removed or retired. Units 6 and 7 were demolished in 2003. Units 8A and 8BC, were constructed in 1977, and are not 45-years old or older, and therefore were not considered for the purposes of this evaluation. The last unit added to the plant was Unit 9, built in 2003.

Cooling Towers

The Grayson Power Plant has five large cooling towers consisting of Units 1-5 and two smaller cooling towers (an auxiliary tower and a Unit 9 cooling tower) located on the property, which were initially constructed between 1941 and 2003.

Table 4-3 Construction and Alteration Dates of Cooling Towers

Cooling Tower No.	Built Date[1]	Alteration Dates[2]	Architectural Integrity Yes/No?
Auxiliary Cooling Tower	1941	Intact	Yes
Cooling Tower 1	1941	Altered 1977	No
Cooling Tower 2	1947	Altered 1977	No
Cooling Tower 3	1953	Burned & rebuilt in 2010	No
Cooling Tower 4	1959	Intact	No
Cooling Tower 5	1964	Intact	No
Unit 9 Cooling Tower	2003	Intact	NA (less than 45 years)

1 Built Dates from the City of Glendale Department of Water & Power.

2 Aerial analysis from 1952-2005 at the Nationwide Environmental Tile Research, LLC (NETR), www.historicaerials.com.

Each large cooling tower is associated with one steam turbine, such as Cooling Tower 1 is associated with the Unit 1 steam turbine, and, with the exception of the Unit 5 cooling tower, is set on a reinforced poured concrete fuel oil tank that is located belowground. The towers' walls are between 2-3-feet thick and are poured concrete walls that enclose the tanks. Each large cooling tower has a unique number of fans that vary from 4 to 8 on top. Cooling Towers 1 and 2 are designed with four fans, which has splayed fiberglass or plastic sidewalls, while Cooling Tower 3 is constructed with six fans, Cooling Tower 4 has eight fans, and Cooling Tower 5 has five fans. Additional features of the cooling towers include a louvered wall for Units 2 and 5, which provides cross-flow air circulation to cool the water from the steam turbine condensers and wooden roof decks.

All the large cooling towers, with exception of Cooling Towers 4 and 5, have been either rebuilt or significantly altered. Cooling Tower 1 was altered in 1977 when it was demolished and rebuilt for the Unit 8 project with the construction of a maintenance shop east of the tower. Cooling Tower 2 was altered in 1977 when it was demolished and rebuilt for the Unit 8 project with a reduced number of fans (from twelve fans to four fans). Cooling Tower 3 caught fire and was significantly damaged in 2010; as a result, it was demolished and rebuilt. Cooling Tower 5 is the only tower that appears to have not been altered. Of the five large cooling towers located on the Plant site, only one tower has architectural integrity, meaning it has not been substantially altered or rebuilt in any way since its original construction over 45 years ago.

Switchyards

There are two switchyards on the Grayson Power Plant property east of the Boiler Building. They are labeled as the Kellogg GIS and the Glendale switchyards and are located adjacent to the railroad right-of-way as well as parallel with San Fernando Road.

Table 4-4 Construction and Alteration Dates of Switchyards

Switchyard	Built Date[1]	Alteration Dates[2]	Architectural Integrity Yes/No?
Glendale	1941	1953-1972	No
Kellogg (open-air)	1974	1977; demolished 2009	No
Kellogg GIS	2005	N/A	N/A (less than 45 years old)

1 Built Dates from the City of Glendale Department of Water & Power.

2 Aerial analysis from 1952-2005 at the Nationwide Environmental Tile Research, LLC (NETR), www.historicaerials.com

The switchyards are used as part of the power grid in transferring power into lines; the switchyards are not 45 years old or older and were constructed between 2005 to the present, which included new equipment. One switchyard, Kellogg GIS, is not 45 years old or older, whereas the Glendale switchyard has been altered and expanded over time.

Grayson Power Plant, Miscellaneous Buildings

Five miscellaneous utilitarian buildings are located on the Grayson Power Plant site northwest of the Boiler Building. These five buildings are typical gable or flat-roof buildings with roll-up doors and aluminum sliding glass windows. The parking sheds are flat-roof open structures where vehicles are housed. None of these buildings will be impacted by the proposed project.

Table 4-5 Construction and Alteration Dates of Miscellaneous Buildings at Plant

Building	Built Date[1]	Alteration Dates[2]	Architectural Integrity Yes/No?
Superintendents building	c.1964	Intact	Yes
Warehouse	c.1964	Intact	Yes
Garage	c.1964	Intact	Yes
Parking sheds (2)	1977	Not Historic	N/A (less than 45 years old)

1 Built Dates from the City of Glendale Department of Water & Power.

2 Aerial analysis from 1952-2005 at the Nationwide Environmental Tile Research, LLC (NETR), www.historicaerials.com

Identified Historical Resources on the Project Site

Generally, a lead agency must consider a property a historical resource under CEQA if it is eligible for listing in the California Register of Historical Resources (CRHR) (PRC Section 5024.1 and 14 California Code or Regulations [CCR] Section 4850 & Section 15064.5[a][2]). The CRHR is modeled after the National Register of Historic Places (NRHP). Properties listed in, or determined to be eligible for listing in, the NRHP or CRHR are mandatory historical resources, and the lead agency must treat such properties as historical resources under CEQA.

A property is presumed to be historically significant if it is listed in a local register of historical resources or has been identified as historically significant in a historic resources survey (provided certain statutory criteria and requirements are satisfied) unless a preponderance of evidence demonstrates that the property is not historically or culturally significant (PRC Section 5024.1 and 14 CCR Section 4850 & Section 15064.5[a][2]). The City of Glendale maintains the Glendale Register of Historic Resources. Properties included in a local register or identified in a historic resources survey are commonly considered by the lead agency to be presumptive historical resources under CEQA.

Finally, a lead agency may use its discretion to treat a resource as if it meets statutory requirements for the purposes of CEQA (PRC Section 5024.1 and 14 CCR Section 4850 & Section 15064.5[a][2]). These are discretionary resources and may be deemed significant if substantial evidence supports the conclusion regardless of any official listing in a historical register.

Refer to the Laws Ordinances Regulations, and Standards (LORS) section below for more information regarding the NRHP, CRHR, and City of Glendale Register of Historic Resources.

As part of the Historic Resource Inventory and Evaluation Report prepared by Stantec in 2015 and revised in 2018 and 2020, Stantec conducted archival research on the Grayson Power Plant and documented the site taking digital photographs of building exteriors and select building interiors. As many of the existing buildings and structures at the site are over 45 years of age, the Grayson Power Plant was evaluated for national, state, and local listing. The boundary of the potential historical resource was the property boundary associated with the Grayson Power Plant site.

After careful inspection, investigation, and evaluation, Stantec concluded that the Grayson Power Plant is ineligible for listing in the NRHP, CRHR, and City of Glendale Historic Register due to a lack of integrity. Stantec determined that the Plant is not associated with important events and does not exemplify significant contributions to the broad cultural, political, economic, social, or historic heritage of the nation, state, or city; therefore, it is ineligible under Criterion A/1/1. Stantec found no evidence that the property has any important associations with any person or persons who made significant contributions to history at the local, state, or national level; therefore, it is ineligible under Criterion B/2/2. While it is reportedly an early example of a power plant with an earthquake resistant design, Stantec concluded that the Plant has been substantially altered since its construction in 1941 and no longer retains integrity. For this reason, it is ineligible under Criterion C/3/3. Stantec determined that the property does not appear likely to yield significant informational associations under Criterion D/4/4 as the Plant does not appear to yield information important to archaeological pre-history or history of the nation, state, region, or city. Finally, the property's integrity of design, materials, workmanship, and feeling has been diminished due to the cumulative impact of alterations over time described within the Grayson Power Plant Construction Chronology section above.

After Stantec completed its initial evaluation in 2015, the Project site was evaluated for listing in the NRHP and CRHR by GPA Consulting (GPA) in 2016 as part of the preparation of a Historic Architectural Survey Report (HASR) for the California High-Speed Rail (HSR) Authority Burbank to Los Angeles Project Section. GPA concluded that while the Grayson Power Plant is ineligible for listing in the NRHP and CRHR as a whole, the Boiler Building individually meets the criteria for listing in the NRHP and CRHR as a locally significant example of a property associated with the developmental history of power generation in Glendale under Criterion A/1. The State Historic Preservation Officer (SHPO) concurred with GPA's findings in the HASR in a letter to the HSR Authority dated May 2, 2019, including the determination that the Boiler Building was eligible for listing in the NRHP (See PR-DEIR **Attachment D**).

In their study, GPA refers to the Boiler Building as the "Grayson Steam-Electric Generating Station" and notes that the City of Glendale constructed the steam-electric generating plant in 1941 in order to provide sufficient power to a growing population after World War II. The period of significance was identified as 1941 to 1955, which encompasses the date of construction for the Boiler Building through the year the Grand Central Air Terminal was redeveloped into the Grand Central Industrial Center. GPA determined the Boiler Building eligible under Criterion A/1 as noted above, and ineligible under Criteria B/2, C/3, and D/4. Lastly, the 2016 study concluded that the Boiler Building retains integrity of location, materials, design, workmanship, feeling, and association. However, GPA concluded that the integrity of setting has been diminished by ongoing development on the site and in the area since the property's construction.

The Glendale Historical Society (TGHS) sent a letter to the City of Glendale Community Development Department dated November 19, 2017 with comments on the Grayson Repowering Project Draft Environmental Impact Report (Draft EIR). TGHS determined that the Boiler Building, referred to in their letter as the Grayson Steam Electric Power Plant, may be eligible for listing in the NRHP, CRHR, and City of Glendale Historic Register for its important association with the history of local development as well as for the significance of its design. TGHS wrote that the power generated by the Boiler Building following its completion in 1941 helped fuel Glendale's post-war growth, and therefore is significant under CRHR Criterion 1 for its important association with the history of Glendale's development. TGHS asserted that the Boiler Building is significant for its association with Chief Engineer and General Manager Lauren W. Grayson under CRHR Criterion 2. TGHS wrote that the Boiler Building is an excellent example of Stripped Classicism and the work of master architect Daniel Anthony Elliot under CRHR Criterion 3, as well as notable for its engineering and construction methods as an early example of an earthquake proof power plant. Additionally, TGHS concluded that although diminished by subsequent alterations, the Boiler Building retained integrity of location, design, workmanship, materials, association, and feeling.

The 2016 Initial Study found Cultural Resources to be a less than significant impact and was therefore not carried forward for further evaluation into the Draft EIR. The 2016 Resource Study evaluated the Project per the CRHR and GRHR and found the structures not eligible for listing on the State or local registers under CRHR Criterions 1, 2, 3, 4, and GRHR Criterion 5. Based on previous studies and the 2016 Resource Study, the Project would not cause a substantial adverse change to the significance of historical resources as defined in Section 15064.5, nor would the Project have impacts on significant local resources as defined in Chapter 15.20 of the City of Glendale Municipal Code.

Based upon comments received during the public review of the DEIR for the Project, Stantec revised the Historic Resources Inventory and Evaluation Report and DPR-523 form for the Grayson Power Plant in 2018. Comments include several clarifications, which support the conclusion that the Grayson Power Plant is not an historic resource eligible for listing in the National Register of Historic Places, the California

Registry of Historical Resources or the Glendale Register. Where noted, revisions were made to the Architectural Resource Evaluation. The Architectural Resource Evaluation was re-titled “Historic Resource Inventory and Evaluation” to make it consistent with information provided. The revised Architectural Resource Evaluation was included as Appendix A to the 2018 Final EIR. It was also established that the Project is not considered an “undertaking” subject to Section 106 of the National Historic Preservation Act and is not subject to compliance with the National Environmental Policy Act.

Additionally, the 2018 revised report included an introduction with the project location and description, identified the area of potential effect (APE) for the redevelopment project, noted team qualifications, described research and field methods, and included an in-depth historic context which covers the history of electricity in California, steam generation in Los Angeles County, Glendale history, and the history and evolution of the power plant.

As part of the California HSR Authority’s public comment process for their DEIR, the City of Glendale submitted a public comment letter to the California HSR Authority dated August 31, 2020, providing comments on the California High-Speed Rail Project, Burbank to Los Angeles Project Section Draft EIR. In the letter, the City asked the HSR Authority to reconsider GPA’s 2016 determination of eligibility for the Boiler Building based on information outlined in Stantec’s revised 2018 report. The City disagreed with GPA’s assessment that the Boiler Building retained integrity. The City reported that the Boiler Building has undergone numerous alterations since the end of the period of significance identified by GPA (1941–1955). Most notably a multi-story addition on the north end of the building was added between 1959 and 1964. Furthermore, the City noted that the GPA study does not address why the year 1955 is significant to the history of the Boiler Building. By choosing 1955, the GPA study suggests that the Power Plant’s significance is derived to its association with the Grand Central Air Terminal. However, the City noted that there is no historic context to support this assertion; the airfield was developed in 1928, whereas the Power Plant was constructed 13 years later.

On November 3, 2020, the HSR Authority forwarded the City of Glendale’s August 31, 2020 letter to the California SHPO as part of their continuing consultation regarding the Burbank to Los Angeles Project Section of the California HSR. In their letter, the HSR Authority requested SHPO concurrence with the City’s determination that Grayson Power Plant is ineligible for listing in the NRHP. Julianne Polanco, SHPO, responded to the HSR Authority on December 3, 2020. After reviewing the November 3, 2020 submittal, the SHPO concurred that the Grayson Power Plant is ineligible for listing on the NRHP under all criteria for the reasons outlined in Stantec’s revised DPR 523 form.

Since 2020, the City has been consulting with TGHS regarding the Project. This consultation has included a visit to the Project site and multiple meetings and conference calls between City staff, Project consultants, and representatives from TGHS. As a result of this consultation, the City has elected to exercise its discretion to consider the Boiler Building a discretionary historical resource for the Project as defined by CEQA (PRC Section 5024.1 and 14 CCR Section 4850 & Section 15064.5[a][2]), and to adopt feasible mitigation measures to compensate for demolition of the Boiler Building. These mitigation measures will include recordation to Historic American Engineering Record standards, display of photography of the Boiler Building, provision of identifying signage and informational plaque located on

Flower Street near the Grayson Power Plant entrance, provision of identifying signage and informational plaque located on Flower Street and the display and interpretation of an original piece of Boiler Building equipment in a public location.

Previously Identified Historical Resources in the Vicinity of the Project Site

As the Project involves new construction, adjacent parcels within a 100-foot radius from the center of the Project site were surveyed to account for potential impacts on historical resources in the vicinity. Parcels beyond the 100-foot radius were not included because the Project would have no potential to directly or indirectly impact the buildings on these distant parcels or their surrounding setting. The buildings, and streets immediately surrounding the Project site as well as the Los Angeles River to the west, the Verdugo Wash to the south, and railroad right-of-way to the east create a geographic and visual separation between the parcels beyond the 100-foot radius and the Project site. The Project site therefore cannot be reasonably considered part of the environmental setting of historical resources beyond the 100-foot due to this intervening space.

To identify historical resources in the Project's vicinity for this analysis, the following resources were consulted:

Consulted the California Office of Historic Preservation (OHP) Built Environment Resource Directory (BERD) to determine if the 100-foot radius contains any properties listed and determined eligible for listing in the National Register, listed and determined eligible for listing in the California Register, or that had been evaluated in historic resource surveys and other planning activities.

Consulted the Glendale Register of Historic Resources to determine if the 100-foot radius contains any properties listed in the local register.

The results of this research are that there are no previously identified historical resources in the vicinity of the Project site.

4.12.2 Laws, Ordinances, Regulations, and Standards (LORS)

Table 4-6 Applicable Federal, State, Local LORS for Cultural Resources

LORS	Administering Agency
Federal	
National Historic Preservation Act	National Park Service
State	
California Public Resource Code	State Historical Resources Commission
Local	
City of Glendale Municipal Code	City of Glendale

Table 4-7 Applicable Federal, State, Local LORS for Paleontological Resources

LORS	Administering Agency
State	State of California
California Environmental Quality Act	State of California
California Public Resource Code	State of California
California Code of Regulations	
Local	
City of Glendale General Plan	City of Glendale
Professional Standards	
Society of Vertebrate Paleontology	Society of Vertebrate Paleontology

Cultural Resources

Federal LORS

The National Historic Preservation Act (NHPA) of 1966, as amended, authorized the creation of the NRHP. The NRHP is "an authoritative guide to be used by federal, state, and local governments, private groups, and citizens to identify the nation's cultural resources and to indicate what properties should be considered for protection from destruction or impairment" (Title 36 Code of Federal Regulations [CFR] Part 60.2). For a property to be considered for inclusion in the NRHP, it must typically be at least 50 years old and meet one or more of the four criteria for evaluation set forth in 36 CFR Part 60.4, as follows:

> *The quality of significance in American history, architecture, archaeology, engineering, and culture is present in districts, sites, buildings, structures, and objects that possess integrity of design, setting, materials, workmanship, feeling, and association and:*

A) That are associated with events that have made a significant contribution to the broad patterns of our history; or

B) That are associated with the lives of persons significant in our past; or

C) That embody the distinctive characteristics of a type, period, or method of construction or that represent the work of a master or that possess high artistic values or that represent a significant and distinguishable entity whose components may lack individual distinction; or

D) That have yielded, or may be likely to yield, information important in prehistory or history.

A property must also be significant within a historic context under one or more of the criteria listed above. "National Register Bulletin: How to Apply the National Register Criteria for Evaluation" states that the significance of a historic property can be judged only when it is evaluated within its historic context. Historic contexts are "those patterns, themes, or trends in history by which a specific...property or site is understood and its meaning...is made clear" (National Park Service [NPS] 2002). A property must therefore represent an important aspect of the area's history or prehistory.

In addition to possessing significance, a property must possess integrity, defined by seven aspects as follows:

> *Location: the place where the historic property was constructed or the place where the historic event took place.*
>
> *Design: the composition of elements that constitute the form, plan, space, structure, and style of a property.*
>
> *Setting: the physical environment of a historic property that illustrates the character of the place.*
>
> *Materials: the physical elements combined in a particular pattern or configuration.*
>
> *Workmanship: the physical evidence of the crafts of a particular culture or people during any given period of history.*
>
> *Feeling: the quality that a historic property has in evoking the aesthetic or historic sense of a past period of time.*
>
> *Association: the direct link between a property and the event or person for which the property is significant.*

State LORS

The CRHR was established in 1992 by Assembly Bill 2881. It is an authoritative guide used by state and local agencies, private groups, and citizens to identify historical resources and to indicate what properties are to be protected, to the extent prudent and feasible, from substantial adverse impacts (PRC Section 5024.1[a]). The criteria for eligibility of listing in the CRHR are based upon NRHP criteria, but are identified as 1-4 instead of A-D. To be eligible for listing in the CRHR, a property generally must be at least 50 years of age and must possess significance at the local, state, or national level, under one or more of the following four criteria:

1. It is associated with events that have made a significant contribution to the broad patterns of local or regional history, or the cultural heritage of California or the United States; or

2. It is associated with the lives of persons important to local, California, or national history; or

3. It embodies the distinctive characteristics of a type, period, or method of construction or represents the work of a master, or possesses high artistic values; or

4. It has yielded, or has the potential to yield, information important in the prehistory or history of the local area, California, or the nation.

Like the NRHP, properties eligible for listing in the CRHR may include buildings, sites, structures, objects, and historic districts. While the enabling legislation for the CRHR is less rigorous with regard to the issue of integrity, there is the expectation that properties retain enough of their historic character or appearance to be recognizable as historical resources and to convey the reasons for their significance (California OHP 2001).

Evaluations for the CRHR are based upon the evaluation instructions and classification system prescribed by the California OHP in its "Instructions for Recording Historical Resources," which include Status Codes for use in classifying potential historical resources. These Status Codes are used statewide in the preparation of historical resource surveys and evaluation reports. The specific Status Codes referred to in this analysis are as follows:

2S2 Individual property determined eligible for the NRHP by a consensus through the Section 106 process. Listed in the CRHR.

3S Appears eligible for NRHP as an individual property through survey evaluation.

5S1 Individual property that is listed or designated locally.

6Z Ineligible for the NRHP, CRHR, and local designation through survey evaluation.

The CRHR may also include properties identified during historic resource surveys. However, the survey must meet all of the following criteria:

1. The survey has been or will be included in the State Historic Resources Inventory;
2. The survey and the survey documentation were prepared in accordance with office [SOHP] procedures and requirements;
3. The resource is evaluated and determined by the office [SOHP] to have a significance rating of Category 1 to 5 on a DPR Form 523; and
4. If the survey is five or more years old at the time of its nomination for inclusion in the California Register, the survey is updated to identify historical resources that have become eligible or ineligible due to changed circumstances or further documentation and those that have been demolished or altered in a manner (PRC Section 5024.1).

Local LORS

The City of Glendale adopted the Historic Preservation Ordinance in 1985 (Glendale Municipal Code Section 15.20) and amended it in 2020. The Historic Preservation Ordinance created the Glendale Register of Historic Resources and established the criteria for listing. The four criteria for listing in the Glendale Register of Historic Resources are listed below:

A. The resource is identified with important events in national, state, or city history, or exemplifies significant contributions to the broad cultural, political, economic, social, tribal, or historic heritage of the nation, state, or city, and retains historic integrity.

B. The resource is associated with a person, persons, or groups who significantly contributed to the history of the nation, state, region, or city, and retains historic integrity.

C. The resource embodies the distinctive and exemplary characteristics of an architectural style, architectural type, period, or method of construction; or represents a notable work of a master designer, builder, or architect whose genius influenced his or her profession; or possesses high artistic values and retains historic integrity.

D. The resource has yielded, or has the potential to yield, information important to archaeological pre-history or history of the nation, state, region, or city, and retains historic integrity.

The 2020 amended Ordinance defines historic integrity as:

> The authenticity of a resource's historic identity, evidenced by the survival of physical characteristics that existed during the resource's prehistoric or historic period and which allow it to continue to convey its significance. Historic integrity is the composite of seven aspects or qualities: location; design; setting; materials; workmanship; feeling; and association (as defined by the National Park Service). All seven aspects or qualities do not need to be present for eligibility for designation as a historic resource as long as the overall sense of past time and place is evident (Glendale Municipal Code Section 15.20.050).

Unlike the NRHP, properties do not have to reach a minimum age requirement, such as 50 years, to be listed in the Glendale Register of Historic Resources.

4.12.3 Paleontological Resources

State LORs

California Environmental Quality Act

The California Environmental Quality Act (CEQA) requires that before approving most discretionary projects, the Lead Agency must identify and examine any significant adverse environmental effects that may result from activities associated with such projects. The Appendix G checklist (Title 14, Division 6, Chapter 3, California Code of Regulations [CCR] 15000 et seq.) includes the following threshold of significance: "Will the proposed project directly or indirectly destroy a unique paleontological resource or site or unique geologic feature?"

California Public Resources Code

The California Public Resources Code (PRC) (Chapter 1.7, Sections 5097 and 30244) includes additional state-level requirements for the assessment and management of paleontological resources. These statutes require reasonable mitigation of adverse impacts to paleontological resources resulting from development on state lands, define the removal of paleontological sites or features from state lands as a misdemeanor, and prohibit the removal of any paleontological site or feature from state land without permission of the applicable jurisdictional agency.

California Code of Regulations

The California Code of Regulations (CCR) 14 Section 4307, Geological Resources, recognizes paleontological resources for preservation, establishing that paleontological resources cannot be destroyed, disturbed, mutilated, or removed. Furthermore, CCR 20 Appendix B establishes the environmental information necessary for permit applications, including a discussion of geologic and paleontological setting, paleontological sensitivity assessment, museum records searches and relevant locality information, and a discussion of necessary mitigation measures for the protection of resources.

Local LORs

City of Glendale General Plan

The Open Space and Conservation Element of the City of Glendale General Plan (City of Glendale, 1998) recognizes paleontological resources in the Open Space and Conservation Plan under Policy 3: Cultural, historical, archaeological and paleontological structures and sites are essential to community life and identity and should be recognized and maintained (1998, Chapter 3).

Professional Standards

The Society of Vertebrate Paleontology (2010), the Bureau of Land Management (BLM) (2016) and a number of scientific studies (Eisentraut and Cooper, 2002; Murphey et al., 2019; Scott and Springer, 2003) have developed guidelines for professional qualifications, conducting paleontological assessments, and developing mitigation measures for the protection of paleontological resources. These guidelines are broadly similar, and include the use of museum records searches, scientific literature reviews, and, in some cases, field surveys to assess the potential of an area to preserve paleontological resources. Should that potential be high, accepted mitigation measures include paleontological monitoring, data recordation of all fossils encountered, collection and curation of significant fossils and associated data, and in some cases screening of sediment for microfossils.

The Society of Vertebrate Paleontology has developed a paleontological potential ranking system. These rankings are designed to inform the development of appropriate mitigation measures for the protection of paleontological resources and are widely accepted as industry standards in paleontological mitigation (Murphey et al. 2019; Scott and Springer 2003). These rankings are as follows:

> **High Potential**. Rock units from which vertebrate or significant invertebrate, plant, or trace fossils have been recovered are considered to have a high potential for containing additional significant paleontological resources. Rock units classified as having high potential for producing paleontological resources include, but are not limited to, sedimentary formations that are temporally or lithologically suitable for the preservation of fossils (e. g., middle Holocene and older, fine-grained fluvial sandstones, argillaceous and carbonate-rich paleosols, cross-bedded point bar sandstones, fine-grained marine sandstones, etc.), some volcaniclastic formations (e. g., ashes or tephras), and some low-grade metamorphic rocks.

> **Low Potential**. Rock units that are poorly represented by fossil specimens in institutional collections or, based on general scientific consensus, only preserve fossils in rare circumstances (e. g., basalt flows or recent colluvium) have low paleontological potential.
>
> **No Potential**. Some rock units have no potential to contain significant paleontological resources, for instance high-grade metamorphic rocks (such as gneisses and schists) and plutonic igneous rocks (such as granites and diorites).
>
> **Undetermined Potential**. Rock units for which little information is available in the literature or museum records concerning their paleontological content, geologic age, and depositional environment are considered to have undetermined potential. Further study and field work is necessary to determine if these rock units have high or low potential to contain significant paleontological resources.

4.12.4 Environmental Impacts

4.12.5 Cultural Resources

Methodology

Under CEQA, the evaluation of impacts to historical resources consists of a two-part inquiry: (1) a determination of whether the Project Site contains or is adjacent to a historically significant resource or resources and, if so, (2) a determination of whether the proposed project will result in a “substantial adverse change” in the significance of the resource or resources. A discussion of the identification aspects of CEQA compliance for this Project are described above under the Environmental Setting section.

The State CEQA Guidelines set the standard for determining whether a proposed project will result in a “substantial adverse change” in the significance of historical resources in Title 14 CCR Section 15064.5(b), which states:

> A project with an effect that may cause a substantial adverse change in the significance of an historical resource is a project that may have a significant effect on the environment.

Title 14 CCR Section 15064.5(b)(1) further clarifies “substantial adverse change” as follows:

> Substantial adverse change in the significance of an historical resource means physical demolition, destruction, relocation, or alteration of the resource or its immediate surroundings such that the significance of an historical resource would be materially impaired.

Title 14 CCR Section 15064.5(b)(2) in turn explains that a historical resource is “materially impaired” when a project:

> Demolishes or materially alters in an adverse manner those physical characteristics of an historical resource that convey its historical significance and that justify its eligibility for inclusion in the California Register of Historical Resources as determined by a lead agency for purposes of CEQA.

As such, the test for determining whether or not a proposed project will have a significant impact on an identified historical resource is whether or not the project will alter in an adverse manner the physical integrity of the historical resource such that it would no longer be eligible for listing in the NRHP or CRHR or other landmark programs such as the Glendale Register of Historic Resources.

This analysis considers direct and indirect impacts to historical resources using the following definitions of each:

- Direct or primary impacts are caused by the project and occur at the same time and place (14 CCR Section 15358 [a][1]).
- Indirect impacts, or secondary effects, are reasonably foreseeable and caused by a project but occur at a different time or place (14 CCR Section 15358 [a][2]).

4.12.6 Paleontological Resources

Methodology

Under CEQA, a paleontological assessment must answer the following question in the Appendix G checklist: “Will the proposed project directly or indirectly destroy a unique paleontological resource or site or unique geologic feature?” The destruction of paleontological resources would thus constitute an adverse impact under CEQA.

The paleontological assessment and this section evaluate 1) if paleontological resources may be present in the Project area and, if so, 2) would the proposed Project activities risk damaging those resources. In order to address this, background research was conducted consisting of a review of the scientific literature, the most recent geologic mapping, and geotechnical investigations that have been conducted in the Project area (Stantec, 2016b), and a paleontological records search from the Natural History Museum of Los Angeles County (LACM, 2021). The results of this background research were then used to rank the geologic units present at the Project area, either at the surface or in the subsurface, on the paleontological potential scale of the Society of Vertebrate Paleontology (2010).

Results

Paleontological Setting

The Grayson Power Plant is located in the Los Angeles Basin, at the northern end of the Peninsular Ranges and bounded to the north by the Transverse Ranges and to the east by the Mojave Desert (Norris and Webb 1990). The Los Angeles Basin developed as a result of tectonic forces and the San

Andreas fault zone, with subsidence occurring 18 – 3 million years ago (Mya) (Critelli et al. 1995). While sediments dating back to the Cretaceous (66 Mya) are preserved in the basin, continuous sedimentation began in the middle Miocene (around 13 million years ago) (Yerkes et al., 1965). Since that time, sediments have been eroded into the basin from the surrounding highlands, resulting in thousands of feet of accumulation (Yerkes et al., 1965). Most of these sediments are marine, until sea level dropped in the Pleistocene and deposition of the approximately 1,000 feet of alluvial sediments that compose the uppermost units in the Los Angeles Basin began.

Paleontological Potential of the Project Area

Geologic mapping of the Project Area indicates the surficial geology at and around the Grayson Power Plant is alluvium that dates from 1000-10,000 years ago (Holocene) (Yerkes, 1996). These sediments consist of unconsolidated silt, sand, and gravel. Geotechnical borings conducted in the Project area evaluated 16 borings that extended to depths of 11-50 feet below ground surface (bgs). These borings indicate the subsurface of the Project area is predominantly sands, with lenses of silt, clay, and clayey sands beginning at around 15 feet bgs (Stantec, 2016b). The increase of fine sediments and absence of coarse materials in the subsurface indicate a lower energy depositional setting, which is conducive to the preservation of fossil resources.

At the surface these sediments are too young to preserve fossil resources (i.e., under 5,000 years in age, as per the Society of Vertebrate Paleontology [2010]), these sediments increase in age with depth, and therefore fossil resources may be encountered in the deeper levels of this unit. While the exact depth at which the transition to older sediments in which fossils might be preserved is not known, fossils have been discovered in the Los Angeles Basin as shallowly as 5-10 feet below ground surface (Jefferson, 1991a and b; Miller, 1941). Alluvial sediments that date to the middle Holocene or beyond have a rich fossil history in southern California. The most common fossils include the bones of mammoth, bison, horse, lion, cheetah, wolf, camel, antelope, peccary, mastodon, capybara, and giant ground sloth, as well as small animals such as rodents and lizards (Hudson and Brattstrom, 1977; Jefferson, 1991a and b; McDonald and Jefferson, 2008; Miller, 1941, 1971; Roth, 1984; Scott, 2010; Springer et al. 2009).

The Los Angeles County Museum of Natural History has records of numerous Pleistocene-aged fossil localities in the Los Angeles Basin. The closest of these to the Project area are shown in Table 4-8 below (LACM, 2021). While the depths of discovery are not documented for all sites, the recorded depths begin as shallowly as 11 feet below ground surface. Fossils found at these sites include the remains of iconic Ice Age animals including sabertooth cat, mammoth, mastodon, and giant ground sloth, as well as bison, horse, and camel (LACM, 2021).

Table 4-8 Results of the Paleontological Records Search from the LACM

Locality Number	Proximity to Project Area	Location	Fossil Materials	Depth
LACM VP CIT342	2 miles	Sparkletts property near 45th St and Highland Park near 45th & Lincoln in Highland Park	Mammoth (*Mammuthus*), Bison (*Bison*)	14 ft bgs

Locality Number	Proximity to Project Area	Location	Fossil Materials	Depth
LACM VP 6297-6299	3.4 miles	Metro Rail Red Line Hollywood Blvd. subway tunnel, from St. Andrews Place to Western Ave.	Horse (*Equus*), Bison (*Bison*), Mastodon (*Mammut americanum*)	47 ft bgs
LACM VP 1023	3.8 miles	Workman St. and Alhambra St.	Sabertooth cat (*Smilodon*), horse (*Equus*), deer (*Odocoileus*), Turkey (*Meleagris*)	Unknown
LACM VP 6970	7 miles	Lankershim Blvd. and Bloomfield St.	Ground Sloth (*Glossotherium*), Camel (*Camelops*); Bison (*Bison*)	60-80 ft bgs
LACM VP 6208	12.5 miles	Burbank Blvd. and Kester Ave.	Bison (*Bison*)	20 ft bgs
LACM VP 3263	12.5 miles	5112 Kester Ave.	Horse family (Equidae)	11-20 ft bgs

The review of paleontological literature and geologic mapping presented above indicates that while the alluvium present at the surface of the Project area is too young to preserve fossil resources, deeper sediments have a demonstrated record of preserving significant fossil resources in the Los Angeles Basin beginning at around 10 feet in depth. Therefore, the Project area is assessed as having Low-to-High paleontological potential, increasing with depth, following the guidelines of the Society of Vertebrate Paleontology (2010).

Should the Project involve excavations into previously undisturbed sediments at depths of greater than approximately 10 feet bgs, the Project would risk damage or destruction of paleontological resources.

4.12.7 Cultural Resources Project Impacts

Threshold: Would the Project cause a substantial adverse change in the significance of a historical resource pursuant to § 15064.5?

As discussed above, the lead agency has elected to consider the Boiler Building a discretionary historical resource pursuant to CEQA and thus potential direct and indirect Project impacts were analyzed based on this determination.

Demolition

The Boiler Building is a discretionary historical resource and is located on the Project site. It would be demolished as part of the Project. The Project would therefore have a direct impact on the Boiler Building and would cause a substantial adverse change in the significance of a historical resource as defined in 14 CCR Section 15064.5. Mitigation Measures CR-1, CR-2, and CR-3 would be implemented to reduce this potentially significant impact but would not reduce this impact to less than significance.

As noted in the Environmental Setting section, there are no previously identified historical resources in the vicinity of the Project site. Therefore, the demolition of existing buildings and structures on the Project site would have no indirect impact on identified historical resources in the vicinity.

Construction

After the demolition phase, the Project would have no potential to impact historical resources from new construction either directly or indirectly. The discretionary historical resource on the Project site, the Boiler Building, would be demolished prior to construction, and there are no other previously identified historical resources on the Project site or in the vicinity of the Project site.

<u>Operation</u>

The Project would have no potential to impact historical resources from operation either directly or indirectly. The discretionary historical resource on the Project site, the Boiler Building, would be demolished prior to new construction and operation, and there are no previously identified historical resources in the vicinity of the Project site.

Level of Significance before Mitigation:

Potentially significant impact.

Mitigation Measure(s):

CR-1: Prior to demolition of the Boiler Building, the City shall prepare Historic American Engineering Record (HAER) documentation for the Boiler Building. That documentation shall include preparation of a written narrative, photography, and drawings that meet the latest requirements in HAER History, Photography, and Drawing Guidelines. Archival and electronic full copies of that completed documentation shall be submitted to the HAER program in accordance with the most recent edition of "Preparing HABS/HAER/HALS Documentation For Transmittal." The City shall maintain the HAER documentation at the Glendale Central Public Library and information about accessing that information shall be available on the City's website. HAER documentation, as described, shall be complete and accepted by the HAER program before any demolition or dismantling of the Boiler Building. The City shall also display up to four (4) archival quality photographs of the historic Boiler Building in a publicly accessible location within the City's Perkins Building,

CR-2: City shall provide permanent plaque to be located at the Flower Street entrance to the Grayson Power Plant that identifies the location of the former historic Boiler Building and provides a narrative statement about the Boiler Building that provides historic context

CR-3: City shall salvage and preserve a piece of equipment from the Boiler Building and display the piece of equipment along with an historic context statement in a publicly accessible location in the City.

Level of Significance after Mitigation:

The Boiler Building would be materially impaired by the demolition component of the Project; therefore, the Project would cause a substantial adverse change in the significance of a historical resource as defined in Section 15064.5. Implementation of Mitigation Measures CUL-1 through CUL-3 would not reduce the impact to a level of less than significant. Therefore, the demolition of the Boiler Building would result in a significant and unavoidable impact to historical resources.

4.12.8 Paleontological Project Impacts

Threshold: Would the proposed project directly or indirectly destroy a unique paleontological resource or site or unique geologic feature?

The Initial Study prepared for the Project determined that paleontological resources might be present in the subsurface, and the literature review performed for the Project has confirmed that sediments in the Project area over 10 feet in depth have high paleontological potential. Potential direct and indirect Project impacts to paleontological resources were analyzed based on this determination, as described below.

<u>Demolition</u>

Demolition to implement the proposed Project may involve ground disturbance into previously undisturbed sediments in order to remove existing piles or soils that may have been contaminated. Therefore, demolition associated with this Project may have either direct or indirect impacts on paleontological resources.

<u>Construction</u>

Construction plans include excavations across the Project area, including areas with up to 20 feet beyond current depths of development, placing the total depths of excavation into high potential sediments that are expected to begin at around 10 feet bgs. Where ground disturbance extends beyond 10 feet bgs into previously undisturbed sediments, either in entirely undisturbed areas or beneath the depth of previous disturbance, sediments with high paleontological potential will be encountered. Such ground disturbance may damage or destroy paleontological resources, a direct adverse impact. As noted in the Initial Study, the implementation of an appropriate mitigation program can avoid these adverse impacts to resources. It should also be noted that should fossils be encountered and safely salvaged, this would constitute a beneficial indirect impact to paleontological resources, as once discovered they may be used for research or education purposes to further our understanding of the ancient history of the Los Angeles area.

<u>Operation</u>

Operation plans do not involve ground disturbance into previously undisturbed sediments. Therefore, the Project would have no potential to directly or indirectly impact paleontological resources from operation.

Level of Significance before Mitigation:

Potentially significant impact.

Mitigation Measures:

> **PAL-1: Worker training.** A paleontologist who meets professional paleontological standards as defined by Murphey et al. (2019) shall design a Worker's Environmental Awareness Program reviewed and approved by a qualified consultant retained by the City that will provide training that communicates requirements and procedures for the inadvertent discovery of paleontological resources during construction, to be delivered by the paleontologist or their designee to the

construction crew prior to the onset of ground disturbance. The training will be provided by a qualified paleontologist.

PAL-2: Paleontological Monitoring. A paleontologist meeting professional standards as defined by Murphey et al. (2019) shall be retained to oversee all aspects of paleontological mitigation, including the development and implementation of a Paleontological Monitoring and Mitigation Plan (PMMP) tailored to the Project that provides for paleontological monitoring of earthwork and ground disturbing activities into undisturbed geologic units with high paleontological potential (undisturbed sediments over 10 feet in depth), to be conducted by a paleontological monitor meeting professional standards (Murphey et al. 2019).

PAL-3: Inadvertent Discoveries. In the event that paleontological resources are encountered during construction activities, all work must stop in the immediate vicinity of the finds while the paleontological monitor documents the find and the designated project paleontologist assesses the find. Should the qualified paleontologist assess the find as significant, it should be collected and curated in an accredited repository along with all necessary associated data.

Level of Significance after Mitigation:

Implementation of Mitigation Measures PAL-1 through PAL-3 would reduce adverse impacts to paleontological resources to a level of less than significant.

4.13 ENERGY

Since the circulation of the Draft EIR, the CEQA Guidelines were amended to require mitigation for significant effects due to wasteful, inefficient, or unnecessary use of energy (CEQA Guidelines Section 15126.2(b)). In addition, CEQA Guidelines Appendix G was amended to add new thresholds of significance related to energy use. Appendix F of the CEQA Guidelines specifies that energy conservation may be achieved by reducing overall energy consumption, reducing reliance on fossil fuels, and increasing reliance on renewable energy sources. The cost effectiveness of a Project may be evaluated in terms of energy requirements or efficiency, rather than by a traditional dollar basis. Mitigation for energy use is required if a Project "may result in significant environmental effects due to wasteful, inefficient, or unnecessary use of energy, or wasteful use of energy resources".

This section describes and evaluates the energy conservation impacts from the Project. The energy use for all phases and components of the Project as it relates to greenhouse gas emissions, utilities, transportation (during construction and operation), equipment use, renewable energy features, land use characteristics, and Project design features, are included in the analysis. This section incorporates information from the air quality, greenhouse gas emissions, transportation and traffic, and utilities and service systems sections for analysis.

4.13.1 Environmental Setting

Existing Conditions

Electricity

Electricity, a consumptive utility, is a man-made resource. The generation of electricity requires the consumption or conversion of energy resources, including water, wind, oil, gas, coal, solar, geothermal, and nuclear resources, into energy. The delivery of electricity involves a number of system components, including substations and transformers that lower transmission line power (voltage) to a level appropriate for on-site distribution and use. The electricity generated is distributed through a network of transmission and distribution lines commonly called a power grid. Conveyance of electricity through transmission lines is typically responsive to market demands.

Electrical power is generally measured in watts (W) while energy use is measured in watt-hours (WH). For example, if a light bulb has a capacity rating of 100 W, the energy required to keep the bulb on for one hour (1 H) would be 100 WH. If ten 100 W bulbs were on for one hour, the energy required would be 1,000 WH or one kilowatt-hour (kWH). On a utility scale, a generator's capacity is typically rated in megawatts (MW), which is one million watts, while energy usage is measured in megawatt-hours (MWH), which is one million watt-hours, or gigawatt-hours (GWH), which is one billion watt-hours.

GWP provides electrical service throughout the City of Glendale, including the proposed Project site, serving approximately 201,361 residents across an approximately 31-square mile area in 2018. GWP serves nearly 90,300 electrical customers and provides service to the homes, businesses and institutions within its service area. GWP's annual retail electrical load obligation is approximately 1,400,000 MWH.

As provided in GWP's 2019 Integrated Resources Plan, the City currently relies on the Grayson Power Plant to provide electricity. However, all but one of the existing generation units (Unit 9) at the Grayson Power Plant are beyond their expected retirement age. Due to normal degradation of the existing Grayson Power Plant equipment, over time, the reliability, efficiency, and cost effectiveness of the facility has continuously declined.

By January 1, 2024, the units at the existing Grayson Power Plant must meet current SCAQMD emissions standards, take a low-use exemption, or be shutdown. The combination of the age of the units and new regulatory requirements is expected to result in GWP facing a potential electricity shortage in the early 2020's. GWP's 2019 Integrated Resource Plan proposes to meet power reliability requirements, which includes a mix of energy efficiency and demand response programs, locally generated and imported renewable resources (such as solar and wind), a battery energy storage system, and conventional internal combustion generation.

It is not economically viable to upgrade the boiler Units 1-5 to meet the new SCAQMD Rule 1135 requirement, and if upgraded, the units would not meet the Project objectives due to their lengthy startup times and lower efficiency as compared to Units 8A, 8BC, or 9. Additionally, these units are old, operationally not very flexible, and well past the end of their normal operating lives. Units 8A and 8BC, while more than 40 years old, could be upgraded to meet SCAQMD Rule 1135, and Unit 9 already is capable of meeting SCAQMD Rule 1135 with minor tuning changes to the emissions control system.

Natural Gas

Natural gas is a combustible mixture of simple hydrocarbon compounds (primarily methane) that is used as a fuel source. Natural gas consumed in California is obtained from naturally occurring reservoirs, mainly located outside the State, and delivered through high-pressure transmission pipelines. The natural gas transportation system is a nationwide network, and, therefore, resource availability is typically not an issue. Natural gas provides almost one-third of the state's total energy requirements and is used in electricity generation, space heating, cooking, water heating, industrial processes, and as a transportation fuel. Natural gas is measured in terms of cubic feet (cf).

SoCalGas is the principal distributor of natural gas in Southern California, serving residential, commercial, and industrial markets. SoCalGas serves approximately 21.8 million customers in more than 500 communities encompassing approximately 24,000 square miles throughout Central and Southern California, from the City of Visalia to the Mexican border.

SoCalGas receives gas supplies from several sedimentary basins in the western United States and Canada, including supply basins located in New Mexico (San Juan Basin), West Texas (Permian Basin), the Rocky Mountains, and Western Canada as well as local California supplies. The traditional, southwestern United States sources of natural gas will continue to supply most of SoCalGas's natural gas demand. The Rocky Mountain supply is available but is used as an alternative supplementary supply source, and the use of Canadian sources provide only a small share of SoCalGas supplies due to the high cost of transport. Gas supply available to SoCalGas from California sources averaged 97 million cf per day in 2019 (the most recent year for which data are available).

Transportation Energy

According to the California Energy Commission (CEC), transportation accounted for nearly 40 percent of California's total energy consumption in 2018. In 2020, California consumed 14.0 billion gallons of gasoline and 3.0 billion gallons of diesel fuel. Petroleum-based fuels currently account for 89 percent of California's transportation fuel use. However, the state is now working on developing flexible strategies to reduce petroleum use. Over the last decade, California has implemented several policies, rules, and regulations to improve vehicle efficiency, increase the development and use of alternative fuels, reduce air pollutants and greenhouse gas (GHG) from the transportation sector, and reduce vehicle miles travelled (VMT). Accordingly, gasoline consumption in California has declined. The CEC predicts that the demand for gasoline will continue to decline over the next ten years, and there will be an increase in the use of alternative fuels, such as natural gas (NG), biofuels and electricity. In January of 2018, Executive Order B-48-18 was signed to "boost the supply of zero-emission vehicles and charging and refueling stations in California." The Executive Order directs state government to meet a series of milestones toward a long-term target of 1.5 million zero-emission vehicles on California's roadways by 2025 and 5 million by 2030.

4.13.2 Laws, Ordinances, Regulations, and Standards (LORS)

Local LORS

Greener Glendale Plan for Community Activities

The Greener Glendale Plan for Community Activities, adopted by the City Council on March 27, 2012, is the City's plan for helping its residents achieve better sustainability. The Greener Glendale Plan for Community Activities provides objectives and strategies for increased sustainability within the City, assesses what actions the City and community have already taken to be more sustainable, and recommends how to build on these efforts, such as using biogas to create clean, renewable energy. The Greener Glendale Plan for Community Activities includes focus areas addressing environmental issues including, but not limited to, energy use, water supplies, solid waste and recycling, transportation, urban design, urban nature, environmental health and economic development. Based on the City's forecasts and reduction targets, the City was on track to meet Southern California Association of Governments' ("SCAG") regional GHG reduction targets of eight percent by 2020 and is on track to meet the 13 percent GHG reduction target by 2023. The City's goal was to achieve a 25 percent reduction in transportation related GHGs by 2020, and an additional 10 percent by 2035, in order to meet RPS goals and AB 1493 standards.

Greener Glendale Plan for Municipal Operations

The Greener Glendale Plan for Municipal Operations, adopted by the City Council on November 1, 2011, is the City's plan for achieving better sustainability in municipal operations. The Greener Glendale Plan for Municipal Operations indicated that the City of Glendale has already completed or initiated many sustainability programs, achieving overall energy and water consumption reductions in its buildings, even though there was an increase in public services, including a 30 percent growth in the municipal vehicle fleet and the opening of a new Glendale Police Department building. The Greener Glendale Plan for Municipal Operations includes the same focus areas as the Greener Glendale Plan for Community Activities, with an additional focus on climate change adaptation and adherence to climate change policies.

Glendale Green Building Standards

The City adopted 12 measures, in addition to the mandatory CALGreen Code, for new projects, which went into effect on July 7, 2011. These measures include requirements to reduce consumption of electricity and NG by 15 percent more than the California Energy Code standards, among others.

Glendale Solid Waste and Construction Waste Diversion Programs

The recycling of solid waste materials also contributes to reduced energy consumption. Specifically, when products are manufactured using recycled materials, the amount of energy that would have otherwise been consumed to extract and process virgin source materials is reduced. For example, in 2015, 3.61 million tons of aluminum were produced by recycling in the United States, saving enough energy to provide electricity to 7.5 million homes. In 1989, California enacted AB 939, the California Integrated Waste Management Act which establishes a hierarchy for waste management practices such as source reduction, recycling, and environmentally safe land disposal. Importantly, the City requires the diversion of at least 65 percent of construction and demolition debris from a landfill, through recycling, salvage or deconstruction. Compliance with this requirement must be documented.

Regional LORS

Southern California Gas

SoCalGas, along with five other utility providers released the 2020 California Gas Report, presenting a comprehensive outlook for natural gas supplies and requirements for California through the year 2035. The report predicts gas demand for all sectors and presents best estimates, as well as hot and cold year scenarios. Overall, SoCalGas predicts a decrease in natural gas demand in future years, due to a decrease in per capita usage, energy efficiency policies, and California’s transition to renewable energy displacing fossil fuel use, including natural gas.

State LORS

California Building Standards Code (Title 24)

California Building Energy Efficiency Standards (Title 24, Part 6)

The California Building Energy Efficiency Standards for Residential and Nonresidential Buildings (CCR, Title 24, Part 6) were adopted to ensure that building construction and system design and installation achieve energy efficiency and preserve outdoor and indoor environmental quality. The current California Building Energy Efficiency Standards (Title 24 standards) are the 2019 Title 24 standards, which became effective on January 1, 2020. The 2019 Title 24 standards include efficiency improvements to the residential standards for attics, walls, water heating, and lighting, and efficiency improvements to the non-residential standards include alignment with the American Society of Heating and Air-Conditioning Engineers (ASHRAE) 90.1-2013 national standards.

California Green Building Standards (Title 24, Part 11)

The California Green Building Standards Code (CCR, Title 24, Part 11), commonly referred to as the CALGreen Code, most recently went into effect on January 1, 2020. The 2019 CALGreen Code includes mandatory measures for non-residential development related to site development; energy efficiency; water efficiency and conservation; material conservation and resource efficiency; and environmental quality.

California's Renewable Portfolio Standard

First established in 2002 under Senate Bill 1078, California Renewable Portfolio Standards (RPS) require retail sellers of electric services to increase procurement from eligible renewable energy resources to 33 percent by 2020 and 50 percent by 2030. Signed into law in 2018, Senate Bill 100 again increased the RPS to 60% by 2030 The California Public Utilities Commission (CPUC) and the CEC jointly implement the RPS program. The CPUC's responsibilities include: (1) determining annual procurement targets and enforcing compliance; (2) reviewing and approving each investor-owned utility's renewable energy procurement plan; (3) reviewing contracts for RPS-eligible energy; and (4) establishing the standard terms and conditions used in contracts for eligible renewable energy.

Assembly Bill 32 /California Global Warming Solutions Act

In 2006, the California State Legislature adopted Assembly Bill (AB) 32 (codified in the California Health and Safety Code [HSC], Division 25.5 – California Global Warming Solutions Act of 2006), which focuses on reducing GHG emissions in California to 1990 levels by 2020. Under HSC Division 25.5, the California Air Resources Board (CARB) has the primary responsibility for reducing the State's GHG emissions, however, it also tasked CEC and the CPUC with providing information, analysis, and recommendations to CARB regarding strategies to reduce GHG emissions in the energy sector.

In 2016, the California State Legislature adopted Senate Bill (SB) 32 and its companion bill AB 197; both were signed by Governor Brown. SB 32 and AB 197 amend HSC Division 25.5 and establishes a new climate pollution reduction target of 40 percent below 1990 levels by 2030 and includes provisions to ensure that the benefits of state climate policies reach into disadvantaged communities.

Senate Bill 350 /Clean Energy and Pollution Reduction Act of 2015

SB 350, signed October 7, 2015, is the Clean Energy and Pollution Reduction Act of 2015. SB 350 is the implementation of some of the goals of Executive Order B-30-15, issued in April 2015, which established a new statewide policy goal to reduce GHG emissions 40 percent below their 1990 levels by 2030. The objectives of SB 350 are 1) to increase the procurement of our electricity from renewable sources from 33 percent to 50 percent; and 2) to double the energy efficiency savings in electricity and natural gas final end uses of retail customers through energy efficiency and conservation by 2030.

Senate Bill 100 /100 Percent Clean Energy Act of 2018

SB 100, signed September 10, 2018, is the 100 Percent Clean Energy Act of 2018. SB 100 updates the goals of California's RPS and SB 350, discussed above, in the following ways: 1) achieve the 50 percent renewable resources target by December 31, 2026, and 2) achieve a 60 percent target by December 31, 2030. SB 100 also establishes a state policy that eligible renewable energy resources and zero-carbon resources supply 100 percent of electricity procured to serve all state agencies by December 31, 2045.

Assembly Bill 1493 (Pavley Regulations)

AB 1493 (commonly referred to as CARB's Pavley Regulations) was the first legislation to regulate GHG emissions from new passenger vehicles. Under this legislation, CARB adopted regulations to reduce GHG emissions from non-commercial passenger vehicles (cars and light-duty trucks) for model years 2009–2016 and model years 2017-2025.

California Air Resources Board

Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling

In 2004, the CARB adopted an Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling in order to reduce public exposure to diesel particulate matter emissions (CCR, Title 13, Section 2485). The measure applies to diesel-fueled commercial vehicles with gross vehicle weight ratings greater than 10,000 pounds that are licensed to operate on highways, regardless of where they are registered. This measure does not allow diesel-fueled commercial vehicles to idle for more than five minutes at any given location. While the goal of this measure is primarily to reduce public health impacts from diesel emissions, compliance with the regulation also results in energy savings in the form of reduced fuel consumption from unnecessary idling.

Regulation to Reduce Emissions of Diesel Particulate Matter, Oxides of Nitrogen and other Criteria Pollutants, from In-Use Heavy-Duty Diesel-Fueled Vehicles

In addition to limiting exhaust from idling trucks, CARB also promulgated emission standards for off-road diesel construction equipment of greater than 25 horsepower (hp) such as bulldozers, loaders, backhoes and forklifts, as well as many other self-propelled off-road diesel vehicles. The In-Use Off-Road Diesel-Fueled Fleets regulation adopted by CARB on July 26, 2007 aims to reduce emissions by installation of diesel soot filters and encouraging the retirement, replacement, or repower of older, dirtier engines with newer emission-controlled models (13 CCR Section 2449). The compliance schedule requires full implementation by 2023 in all equipment for large and medium fleets and by 2028 for small fleets. While the goal of this measure is primarily to reduce public health impacts from diesel emissions, compliance with the regulation has shown an increase in energy savings in the form of reduced fuel consumption from more fuel-efficient engines.

Senate Bill 375 /Sustainable Communities Strategy

SB 375, the Sustainable Communities and Climate Protection Act of 2008, coordinates land use planning, regional transportation plans, and funding priorities to help California meet the GHG reduction mandates of AB 32. SB 375 specifically requires the Metropolitan Planning Organization (MPO) to prepare a "sustainable communities strategy" (SCS) as a part of its Regional Transportation Plan (RTP) that will achieve GHG emission reduction targets set by CARB for the years 2020 and 2035 by reducing VMT from light-duty vehicles through the development of more compact, complete and efficient communities. The Project Site is located within the planning jurisdiction of the SCAG, which is the MPO responsible for the preparation of the SCS. SCAG's has most recently adopted the 2020-2045 RTP/SCS, with a number of goals focusing on transportation and land use planning.

Senate Bill 1389 /Integrated Energy Policy Reporting

SB 1389 (Public Resources Code [PRC] Sections 25300–25323; SB 1389) requires CEC to prepare a biennial integrated energy policy report that assesses major energy trends and issues facing the state's electricity, natural gas, and transportation fuel sectors and provides policy recommendations to conserve resources; protect the environment; ensure reliable, secure, and diverse energy supplies; enhance the state's economy; and protect public health and safety (PRC Section 25301[a]). The 2015 Integrated Energy Policy Report provides the results of the CEC's assessments of a variety of energy issues facing California including energy efficiency, strategies related to data for improved decisions in the Existing Buildings Energy Efficiency Action Plan, building energy efficiency standards, the impact of drought on California's energy system, achieving 50 percent renewables by 2030, the California Energy Demand Forecast, the Natural Gas Outlook, the Transportation Energy Demand Forecast, Alternative and Renewable Fuel and Vehicle Technology Program benefits updates, update on electricity infrastructure in Southern California, an update on trends in California's sources of crude oil, an update on California's nuclear plants, and other energy issues.

California Environmental Quality Act

In accordance with the CEQA Guidelines, including Appendix F, *Energy Conservation*, in order to assure that energy implications are considered in project decisions, EIRs are required to include a discussion of the potential significant energy impacts of proposed projects, with particular emphasis on avoiding or reducing inefficient, wasteful, and unnecessary consumption of energy. Appendix F of the CEQA Guidelines provides a list of energy-related topics that should be analyzed in the EIR. In addition, while not described or required as significance thresholds for determining the significance of impacts related to energy, Appendix F provides the following topics that the lead agency may consider in the discussion of energy use in an EIR, where topics are applicable or relevant to the project:

- The project's energy requirements and its energy use efficiencies by amount and fuel type for each stage of the project including construction, operation, maintenance, and/or removal. If appropriate, the energy intensiveness of materials may be discussed;

- The effects of the project on local and regional energy supplies and on requirements for additional capacity;
- The effects of the project on peak and base period demands for electricity and other forms of energy;
- The degree to which the project complies with existing energy standards;
- The effects of the project on energy resources;
- The project's projected transportation energy use requirements and its overall use of efficient transportation alternatives;
- The degree to which the project design and/or operations incorporate energy-conservation measures, particularly those that go beyond City requirements; and
- Whether the project conflicts with adopted energy conservation plans.

Federal LORS

Federal Corporate Average Fuel Economy Standards

First established by the U.S. Congress in 1975, the Corporate Average Fuel Economy (CAFE) standards reduce energy consumption by increasing the fuel economy of cars and light trucks. The National Highway Traffic Safety Administration (NHTSA) and U.S. Environmental Protection Agency (USEPA) jointly administer the CAFE standards. The U.S. Congress has specified that CAFE standards must be set at the "maximum feasible level" with consideration given for: (1) technological feasibility; (2) economic practicality; (3) effect of other standards on fuel economy; and (4) need for the nation to conserve energy.

Fuel efficiency standards for medium- and heavy-duty trucks have been jointly developed by USEPA and NHTSA. The Phase 1 heavy-duty truck standards apply to combination tractors, heavy-duty pickup trucks and vans, and vocational vehicles for model years 2014 through 2018 and result in a reduction in fuel consumption from six to 23 percent over the 2010 baseline, depending on the vehicle type. The USEPA and NHTSA also adopted the Phase 2 heavy-duty truck standards, which cover model years 2021 through 2027 and require the phase-in of a five to 25 percent reduction in fuel consumption over the 2017 baseline depending on the compliance year and vehicle type.

4.13.3 Environmental Impacts

Methodology

This analysis addressed the Project's potential energy usage, including electricity, natural gas, and transportation fuel, as well as solid waste generation associated with Project activities. Energy usage during both Project demolition, construction and operation are addressed.

4.13.4 Project Impacts

Threshold: Result in potentially significant environmental impact due to wasteful, inefficient, or unnecessary consumption of energy resources, during project construction or operation?

Demolition

Project demolition would occur over an approximately 12-month period, during which approximately 60 workers would be on-site and engaged in activities related to the demolition of generating units, cooling towers, some infrastructure, foundation and piles, and related ancillary facilities. A variety of heavy equipment, including cranes, excavators, loaders, dozers, and support vehicles and trucks would be actively engaged in demolition activities.

Electricity

Electrical power would be consumed to demolish the Project. The demand would be supplied from existing electrical services at the Project site. Initial site work would include installation of temporary construction power throughout the Project site, which may also be utilized for demolition activities. Overall, demolition would require minimal electricity consumption and would not be expected to have any adverse impact on available electricity supplies and infrastructure. Therefore, proposed Project impacts to the consumption of electricity during demolition activities would be less than significant.

Natural Gas

Natural gas is not expected to be consumed in any substantial quantities during demolition activities of the proposed Project. Therefore, Project impacts on natural gas associated with demolition activities would be less than significant.

Transportation Fuel

The proposed Project will result in GHG emissions due to consumption of fuels during demolition. GHG emissions would be generated primarily by the off-road construction equipment and on-road worker vehicles. As part of the proposed Project, all heavy vehicles operating on the Project site would be required to utilize ultra-low sulfur diesel fuel, utilizing fuel efficient equipment consistent with state and federal regulations. As such, these requirements would ensure that Project demolition activities comply with State measures to reduce the inefficient, wasteful, or unnecessary consumption of energy. While these regulations are intended to reduce construction emissions, compliance with anti-idling and emissions regulations would also result in energy savings from the use of more fuel-efficient engines.

While demolition of the proposed Project would result in a temporary fuel demand, according to the US Energy Information System's International Energy Outlook 2020, the global supply of crude oil, other liquid hydrocarbons, and biofuels is expected to be adequate to meet the world's demand for liquid fuels through 2050. Furthermore, as of December 31, 2020, California had approximately 2,213 million barrels (approximately 93.9 trillion gallons) of crude oil left in the state's reserves. Therefore, Project impacts on transportation fuel and related GHG emissions associated with demolition activities would be less than significant.

Solid Waste

As part of the proposed Project, all non-hazardous demolition materials would be reclaimed or recycled, ensuring that equipment and building materials comprised of steel, aluminum, copper and other metals would be recycled. Machinery and other equipment that can still be utilized by other companies could be refurbished and resold by others. Asphalt and concrete that is removed during demolition would be crushed and either reused on-site, properly disposed of if hazardous, or otherwise used as aggregate by the City. The proposed Project would be required to comply with applicable solid waste ordinances, and thus, would meet Glendale's and California's solid waste diversion regulations. Therefore, Project impacts related to wasteful practices associated with demolition would be less than significant.

<u>Construction</u>

Project construction is anticipated to occur over a period of approximately 27 months, during which 115 workers to a peak amount of 260 workers people would be engaged in construction activities on the Project site. As described in the Project Description, construction activities would include the installation of underground electrical ductbanks and vaults, underground piping for water, sewer, gas, air, and fire protection, engineered backfill up to finished grade, construction of concrete foundations to support the generation and ancillary equipment, driving of approximately 1,000 piles as part of the major equipment foundations, erection of all the equipment and ancillary equipment, above ground piping and electrical wiring, installation of storm drains piping and catch basins, finished paving, and startup and commissioning of the plant.

Electricity

Electrical power would be consumed to construct the proposed Project, and as with demolition activities, the demand would be supplied from existing electrical services at the Project site. Initial site work would include installation of temporary construction power throughout the Project.

With respect to electricity required for lighting, construction is not anticipated to routinely take place during darkness when lighting would be required. During those periods when concrete is poured, or during commissioning when nighttime activities cannot be avoided, concentrated area specific lighting in compliance with worker safety regulations would be utilized. During limited construction periods and during the commissioning/startup phase of the proposed Project, some activities would continue 24 hours per day, 7 days per week. Task-specific lighting would be used to the extent practical while complying with worker safety regulations.

Overall, construction activities would require minimal electricity consumption and would not be expected to have any adverse impact on available electricity supplies and infrastructure. As Project construction would entail energy demands largely associated with equipment and transportation fuels, construction of the Project would not increase demands on the electric power network during peak and base period demand periods. Therefore, Project impacts to the consumption of electricity during construction activities would be less than significant.

Natural Gas

Natural gas is not expected to be consumed in any substantial quantities during construction of the Project. Therefore, proposed Project impacts on energy and gas associated with construction activities would be less than significant.

Transportation Fuel

As with Project demolition activities, as part of the proposed Project, all heavy vehicles operating on the Project site would be required to utilize ultra-low sulfur diesel fuel, utilizing fuel efficient equipment consistent with state and federal regulations. Based on the available data, construction would utilize energy for necessary on-site activities and to transport construction materials and demolition debris to and from the Site. As discussed above, idling restrictions and the use of cleaner, energy-efficient equipment would result in less fuel combustion and energy consumption and thus minimize the Project's construction-related energy use. Therefore, construction of the proposed Project would not result in the wasteful, inefficient, or unnecessary consumption of energy.

Similar to demolition, construction of the proposed Project would also result in a temporary fuel demand. According to the US Energy Information System's International Energy Outlook 2020, the global supply of crude oil, other liquid hydrocarbons, and biofuels is expected to be adequate to meet the world's demand for liquid fuels through 2050. Furthermore, as of December 31, 2020, California had approximately 2,213 million barrels (approximately 93.9 trillion gallons) of crude oil left in the state's reserves.

Energy demands during the construction of the Project would not represent a substantial fraction of the available energy supply in terms of equipment and transportation fuels and would not substantially affect existing local and regional supply and capacity for the future. Furthermore, construction of the Project would use equipment that would be consistent with the energy standards applicable to construction equipment including limiting idling fuel consumption and using contractors that comply with applicable CARB regulatory standards that affect energy efficiency. As such, construction of the Project would not conflict with energy standards applicable to heavy-duty construction equipment and associated on-road trucks and vehicles. As a result, construction energy impacts on supplies and infrastructure related to construction activities would be less than significant.

Solid Waste

Similar to demolition activities, all non-hazardous demolition materials would be reclaimed or recycled, ensuring that equipment and building materials comprised of steel, aluminum, copper and other metals would be recycled. Furthermore, the Project would be required to comply with applicable solid waste ordinances, and thus, would meet Glendale's and California's solid waste diversion regulations.

Therefore, Project impacts related to wasteful practices associated with construction would be less than significant.

Operation

A primary objective of the proposed Project is to provide efficient operational flexibility with quick-start high ramp rate generation to facilitate increasing the contribution of renewable energy (such as wind and solar) into the City's electrical grid and to support California's Renewable Portfolio Standards. Project operation would facilitate the desired integration of renewables and would also replace less efficient generation equipment with cleaner and more sustainable technologies. The Project would also be designed to include numerous energy and waste saving features as well as waste reduction features that would allow the Project to comply with and exceed the Title 24 standards and achieve greater energy savings than required by State regulations.

After construction and commissioning of the Project, the facility would be capable of operating at any time as needed to support GWP needs 24 hours per day, seven days per week. Project operation would generate electricity for GWP requiring natural gas and water supply, as well as producing some wastewater requiring conveyance, treatment and disposal off-site and municipal solid waste requiring collection and transport off-site. The Project would meet or exceed the applicable provisions of Title 24 and the CALGreen Code in affect at the time of building permit issuance.

Importantly, the Project has integrated many energy saving features, including a recycled water-cooled condenser system, a heat recovery steam generator feed water system, and the elimination of the use of potable water in the generation process by increasing use of recycled water. The Project will rely on recycled water for generation process use and will result in a reduction of groundwater use compared to existing power plant operation. The volume of recycled water necessary for the Project's operation is well within the City's allocation from the Los Angeles-Glendale Water Reclamation Plant that maintains a connection infrastructure with the Grayson Power Plant. The Project will also incorporate on-site water treatment to convert recycled water into demineralized water that can then be used for process purposes.

Electricity

The proposed Project will utilize the existing infrastructure to deliver electrical power from the Project to the GWP electrical distribution system. No new offsite transmission lines will be constructed for the proposed Project. Existing transmission lines would be utilized to connect the electric generating equipment to the City's distribution grid. Therefore, Project impacts related to wasteful use of electricity associated with operation would be less than significant.

Natural Gas

The proposed Project would utilize only natural gas provided by SoCalGas. An existing SoCalGas high pressure pipeline serving the existing Grayson Power Plant would provide natural gas at pressures ranging from 250 pounds per square inch gauge to 550 pounds per square inch gauge. Maximum fuel demand during full load operations, including Unit 9, is less than the existing units use. The existing pipeline is capable of delivering this volume of natural gas to the Grayson Power Plant. SoCalGas has available and has the capabilities to provide up to 64 million cubic feet of natural gas per day through a single meter station to be located within the Utility Operations Center site. The Project design achieves a high level of thermal efficiency across a wide range of generating capacity. The Project will utilize the existing pipelines for natural gas supply, water supply, and sewer discharge; therefore, no new construction of offsite pipelines is anticipated. Therefore, Project impacts related to natural gas use associated with operation would be less than significant.

Transportation Fuel

The net increase of GHG emissions from the operation of the Project would exceed the significance threshold of 10,000 metric tons per year. The GHG emissions exceedance is solely contributed from operating the proposed combustion turbines and transformers. However, the Project is required comply with the State cap and trade program by reporting CO2e emissions from the Grayson Power Plant and acquiring allowances and offset credits to mitigate 100 percent of GHG emissions from the combustion equipment and transformers. Net emissions after mitigation will include only emissions related to facility occupants, which would be well below the 10,000-metric ton significance threshold.

The proposed Project includes installing and operating newer equipment that generates fewer GHG emissions on a pound per megawatt-hour basis than the existing equipment at Grayson Power Plant. In addition, the Project will allow the City to maximize the import of renewable energy sources through the limited existing transmission capacity into the City which will further assist the City in meeting the Renewable Portfolio Standards and GHG reductions specified in the Greener Glendale Plan, thereby demonstrating consistency with the Greener Glendale Plan. The use of transportation fuel by the 50 full-time employees would be similar to existing conditions, and Project operations would not cause a measurable increase in transportation fuel energy use in this regard. Therefore, Project impacts related to the use of transportation fuel associated with operation would be less than significant.

Solid Waste

Similar to existing conditions on the Project Site, waste generated by operation of existing power generating units and associated facilities would be properly managed and/or disposed of in compliance with federal, state, and local statutes and regulations related to solid and hazardous waste management. Because the Project involves the replacement of the existing generation units and would not increase the number of employees full-time on site, the Project would not result in increased waste disposal over existing conditions. The minimal hazardous waste that would be generated during project construction would be transported to a Class 1 landfill in California. The amount of waste disposed would remain similar to existing conditions and additional capacity would not be required. Project operation would require compliance with applicable solid waste ordinances, thereby meeting Glendale’s and California’s solid waste diversion regulations. Therefore, Project impacts related to wasteful practices associated with operation would be less than significant.

Level of Significance before Mitigation:

Less than Significant Impact.

Mitigation Measures:

No mitigation is required.

Level of Significance after Mitigation:

Less than Significant Impact.

Threshold: Conflict with or obstruct a state or local plan for renewable energy or energy efficiency?

Demolition and Construction

Project related demolition and construction activities would utilize construction contractors who demonstrate compliance with CARB regulations restricting the idling of heavy-duty diesel motor vehicles and governing the accelerated retrofitting, repowering, or replacement of heavy-duty diesel on- and off-road equipment. These activities will be undertaken in accordance with all applicable regulations related to energy use and more fuel-efficient engines and would not conflict with or obstruct with a state or local plan for renewable energy or efficiency, and impacts would be less than significant.

Operation

Implementation of the proposed Project is intended to help lower the overall GHG emissions resulting from electrical generation for the City. The increased requirement for California's renewable energy portfolio requires a stable energy source to support the intermittent characteristics of photovoltaic and wind resources. The Project's ability to provide rapid startup, operate over a wide range of load, and the ability to quickly adjust load are necessary for the City to be able to integrate additional renewable electric energy sources to meet California's Renewable Portfolio Standards. By being able to deliver flexible operating characteristics across a wide range of efficient generating capacity, at a relatively consistent and superior heat rate, and replacing older, less efficient generation, the proposed Project would demonstrate its ability to achieve reduced GHG emissions.

The proposed Project includes installing and operating newer equipment that generates less GHG emissions on a pound per megawatt-hour basis than the existing equipment at Grayson Power Plant. This is consistent with the Greener Glendale Plan's objectives related to the increased use of renewable energy Citywide and achieving Renewable Energy Portfolio goals. In addition, the proposed Project will allow the City to maximize the import of renewable energy sources through the limited existing transmission capacity into the City which will further assist the City in meeting the Renewable Portfolio Standards and GHG reductions specified in the Greener Glendale Plan, thereby further demonstrating consistency with the Greener Glendale Plan.

While the proposed repowering of the Grayson Power Plant is considered necessary to meet current and future City energy needs and California Renewables Portfolio Standard requirements, the proposed Project represents a commitment to maintaining a portion of the City's energy portfolio from non-renewable resources over the long-term. In accordance with Senate Bill 100, the Renewables Portfolio Standard requires retail sellers and publicly owned utilities including GWP, to procure at least 60 percent of their electricity through renewable energy by 2030. The City currently serves its power system through a combination of renewable energy sources (both local and imports), non-renewable imports, and local generation. While the proposed Project does include the use of natural gas, the Project will facilitate increased reliance on renewable sources and the City remains committed to achieving or beating the SB 100 requirements, including the requirement to procure at least 60 percent of its electricity through renewable energy by 2030.

Construction and operation of the proposed Project would be consistent with State and federal energy standards and would be designed to include numerous energy and waste saving features as well as waste reduction features that would achieve greater energy savings than required. Therefore, operation of the proposed Project would not conflict with or obstruct with a state or local plan for renewable energy or efficiency, and impacts would be less than significant.

Level of Significance before Mitigation:

Less than Significant Impact.

Mitigation Measures:

No mitigation is required.

Level of Significance after Mitigation

Less than Significant Impact.

4.14 WILDFIRE

Since the circulation of the 2018 Final EIR, CEQA Appendix G was amended to add Wildfire as a new environmental factor to be evaluated within CEQA documents. This section evaluates the wildfire impacts of the Project in accordance with the new thresholds of significance set out in CEQA Appendix G.

4.14.1 Environmental Setting

Existing Conditions

The proposed Project is located within the City's Utility Operations Center and would utilize additional space within the Utility Operations Center and would temporarily use City-owned and CalTrans-owned area located underneath the adjacent Highway 134 partially owned by the City and partially leased by the City from the State Caltrans division for parking.

The Project site is within an urban area and is not within a State Responsibility Area or within a Very High Fire Hazard Severity Zone. The existing site is predominantly paved (concrete and asphalt) around existing electrical generating equipment and ancillary buildings and equipment to support the generation of electricity for the City.

Topography

The site topography is relatively flat with a slight upward slope to the north and west. The elevation is approximately 465 feet above mean sea level.

Climate

The Project area has a semi-arid climate characterized as having long, hot summers and moderately cooler winters, which is a typical Mediterranean climate. Mild, wet winters have led to an annual growth of plants and grasses. This vegetation dries out during the hot summer months and becomes exposed to Santa Ana wind occurrences during the fall. In general, much of southern California is at baseline risk of wildfires due to regional weather conditions, topography, and native vegetation. Southern California, including the proposed Project site, is periodically affected by Santa Ana wind occurrences, where hot and dry winds blow from the interior regions towards the Pacific Ocean coastline. The hot and dry nature of these winds, combined with their gusting potential, can create hazardous wildfire conditions. During Santa Ana wind occurrences, winds in excess of 40 miles per hour (mph) are common, and gusts may exceed 100 mph locally (Glendale 2003).

The average annual precipitation is approximately 17 to 18 inches, with over 74 percent of precipitation occurring between December and March and over 94 percent occurring between November and April (Glendale 2003). However, during dry years, precipitation could be less. Little precipitation occurs during summer, because a high-pressure cell blocks migrating storm systems over the eastern Pacific Ocean.

Winds across the proposed Project area are an important meteorological parameter, as they control both the potential for wildfire spread and the initial rate of dilution and direction of pollutant dispersion. When averaged over the whole day, the typical wind speeds and directions effecting the proposed Project area are generally south to southeasterly, ranging in speeds from between 4 to 13 mph. However, predominantly during the daytime hours, there is a strong onshore flow from the south through southwest, with higher wind speeds. The average wind speed between 1943 to 2019 was approximately 5.5 mph (aggregate average).

Vegetation and Fuel Load

“Fuels” are organic material (living or dead) in or on the ground or in the air that would ignite and burn. Fuel conditions are considered as one of two elements of wildfire behavior having anthropogenic (originating from human activities) and natural components. Anthropogenic influences on fuel conditions are a result of active vegetation management (i.e., prescribed burning, brush removal, or eradication of non-native species), which alters the regions vegetation mixture and structure. Moisture content, amount of fuel, and fuel structure and composition are natural components of fuel conditions. Since the proposed Project is located within a predominantly paved environment, little fuel is present.

Regional Fire Response

The proposed Project is located within the California Governor’s Office of Emergency Services, Southern Region, Region I, Area C. Area C covers approximately 126 square miles of Los Angeles County and includes 12 major cities, each with their own fire department. Each of these cities participates in the regional Unified Response, covered by the Verdugo Fire Communications Center dispatch. Unified Response is a regional borderless fire incident response system. The system covers 12 major cities including Alhambra, Arcadia, Burbank, Glendale, Monrovia, Montebello, Monterey Park, Pasadena, San Gabriel, San Marino, Sierra Madre, South Pasadena, and the Hollywood Burbank Airport. As part of Unified Response, there are 46 engines, 13 trucks, five water tenders, and other specialized units such as Hazmat and Urban Search and Rescue equipment. Within this established aid agreement, the Verdugo Fire Communications Center immediately dispatches the closest available units, regardless of city boundary (Glendale 2019a).

According to the City of Glendale Fire Department, in the past several years, only three fires have exceeded three-alarm status within Area C. Each of these were brush fires which reached a four-alarm level, requiring a 20-engine response. As part of Unified Response, even if 20 engines were required in order to fight a wildland fire, at least 20 engines would remain available for other Area C incidents. Many would be deployed at Key Stations (such as those described in the table below) to minimize response times regardless of where any additional incidents may occur (Glendale 2019a).

Local Fire Departments and Stations

As discussed above, the City of Glendale is responsible for providing fire protection to the proposed Project, though other nearby stations could respond as part of the Area C Unified Response system or other existing mutual aid agreements, such as those with County of Los Angeles Fire Department, City of

Los Angeles Fire Department, and the U.S. Forest Service. Table 4-9 lists the closest regional fire stations to the proposed Project site.

Table 4-9 Regional Fire Stations

Station	Address	Distance (miles)
Glendale Fire Department Station 27	1127 Western Ave, Glendale, CA 91201	1.23
Glendale Fire Department Station 21	405 Oak St, Glendale, CA 91204	1.34
Glendale Fire Department Station 26	1145 N Brand Blvd, Glendale, CA 91202	1.44
Glendale Fire Department Station 25	353 N Chevy Chase Dr, Glendale, CA 91206	2.43
Glendale Fire Department Station 24	1734 Canada Blvd., Glendale, CA 91208	3.13
Glendale Fire Department Station 23	3301 E. Chevy, Chase Dr. Glendale, CA 91206	4.69

<u>Baseline Fire Risk</u>

The proposed Project is solely located within the City, an area mapped by the California Department of Forestry and Fire Protection (CAL FIRE) as a Local Responsibility Area (CAL FIRE 2008a). Fire protection and response within the Local Responsibility Area is provided by Glendale Fire Department. The proposed Project site is not classified within the Very High Fire Hazard Severity Zone (CAL FIRE 2008b). The lands surrounding the Project are also mapped as within the Local Responsibility Area. Nearby land, located approximately 0.10 mile to the southwest of the proposed Project, on the other side of the Los Angeles River, is classified as Very High Fire Hazard Severity Zone. To the west, north, east, and south, immediate surrounding land is not classified within the Very High Fire Hazard Severity Zone.

In general, the fire hazard of an area is based on a combination of several variables. Some of these include:

- Fuel Load (vegetation type, density, moisture content)
- Topography (slope)
- Weather
- Building construction (considering combustible roof coverings)
- Wildfire history, and
- Whether there are local measures in place to help reduce the zone’s fire rating.

According to the City of Glendale General Plan Safety Element (Glendale 2003), the region has a history of fires, with the entire northern two-thirds of the City having burned since the 1800s. According to the Safety Element, some areas within the City experience a wildfire at least once a decade. In order to reduce the risk of fires, the City has adopted a stringent fuel modification ordinance and requires the use of fire-resistant building materials in accordance with the City’s Building and Safety Code (Glendale 2003). There is no record of a wildfire in close proximity to the Grayson Power Plant.

4.14.2 Laws, Ordinances, Regulations, and Standards (LORS)

This section contains a summary of the Laws, Ordinances, Regulations, and Standards which are applicable to the proposed Project.

Local LORS

City of Glendale

Wildfire Mitigation Plan

In accordance with SB 901 the City Council of the City of Glendale, on December 17, 2019 adopted the Glendale Water and Power Wildfire Mitigation Plan (WMP). The WMP has been reviewed and accepted by both the Glendale Fire Department and the City Council. The WMP considers and includes all required and necessary elements of SB 901 including, but not limited to, an accounting of the responsibilities of persons responsible for executing the WMP, a description of the preventive strategies and programs to minimize the risk of its electrical equipment causing catastrophic wildfires, protocols for de-energizing portions of the electrical distribution system, and its plans for vegetation management. The WMP can be accessed, in its entirety at https://www.glendaleca.gov/home/showdocument?id=54585.

General Plan Safety and Seismic Safety Element

The 2003 City of Glendale General Plan Safety Element describes the natural conditions that pose a hazard within the City of Glendale and presents goals, policies, and programs to reduce the risk to the City and its residents. The goals, policies, and programs outlined in the General Plan are implemented as a part of Project design, and include (but are not limited to) the following:

Policy 4-1: The City shall ensure to the extent possible that fire services, such as fire equipment, infrastructure, and response times, are adequate for all sections of the City.

- **Program 4-1.3**: The City shall ensure that road standards meet the needs for emergency access.

Policy 4-2: The City shall require all new development in areas with a high fire hazard incorporate fire resistant landscaping and other fire hazard reduction techniques into the project design in order to reduce fire hazard.

- **Program 4-2.1**: The City shall encourage residents to plant and maintain drought-resistant, fire-resistant landscape species to reduce the risk of brush fire and soil erosion in areas adjacent to canyons and develop stringent site design and maintenance standards for areas with high fire hazard or soil erosion potential.
- **Program 4-2.2**: The City shall enforce the Weed Abatement Program in high fire hazard areas.
- **Program 4-2.3**: Fuel management plans shall be required for all new development in areas subject to wildfire.
- **Program 4-2.4**: The City shall enforce the Uniform Fire Code and Municipal Fire Code Amendments for new construction in fire hazard areas, including the use of sprinklers in residential structures.
- **Program 4-2.8**: The City shall enforce a Class A Roofing ordinance or better for residential and commercial developments. Residents with existing wood-shingle or unrated roofing materials

shall be encouraged to upgrade to fire resistive building materials, including fire resistive eaves and awnings.

Glendale Fire Code Amendments

The Glendale Fire Code Amendments most recently updated in 2020, contain information regarding the implementation and enforcement of regulations and guidelines for fire safety within the City. These amendments have been adopted by the City as local changes to the California Fire Code and contain more site-specific guidance and requirements.

State LORS

Assembly Bill 337 – The Bates Bill

Assembly Bill (AB) 337 (September 29, 1992) known as The Bates Bill was a direct result of the great loss of lives and homes in the Oakland Hills Tunnel Fire of 1991. The Bates Bill requires CalFire, in cooperation with local fire authorities, to identify Very High Fire Hazard Severity Zones in Local Responsibility Areas throughout California. Local jurisdictions that do not follow the Bates system are required to follow, at a minimum the model ordinance developed by the State Fire Marshal for mitigation purposes. The City has developed its own fire hazard maps and has adopted stringent hazard mitigation programs which exceed the requirements established by state regulations.

Assembly Bill 3819 – The Brown Bill

AB 3819 (September 25, 1994) known as The Brown Bill expands the roof covering requirements of The Bates Bill. The Brown Bill requires a Class A roof for all new buildings, all roof repairs, and replacements, and for existing buildings where 50 percent or more of the roof area is re-roofed, for buildings located within Very High Fire Hazard Severity Zones. Class A roofs provide the highest resistance to fire, and include coverings such as concrete, metal, or clay roof tiles.

Senate Bill 1028

Senate Bill (SB) 1028 was signed into law in September 2016. It requires electric utilities to construct, maintain, and operate their electrical lines and equipment in a manner that will reduce the risk of catastrophic wildfire, and requires the governing bodies of publicly owned utilities (such as GWP) to determine whether any portion of the area where the electrical lines and equipment are located has a significant risk of catastrophic wildfire due to such electrical lines or equipment, and if so, for the utility to present to the governing board, at intervals to be established by the board, the mitigation measures that the utility will undertake to minimize the risk.

Senate Bill 901

SB 901 was signed into law in September 2018. It establishes the requirement for municipally owned electric utilities to have a wildfire mitigation plan and sets an independent review requirement for the plan.

It sets a deadline of January 1, 2020 for the adoption of a wildfire mitigation plan by the governing board of municipal/public utilities, with plans to be updated annually.

Assembly Bill 1054

AB 1054 was signed into law in July 2019. It enables the California Wildfire Safety Advisory Board to: make recommendations to the Wildfire Safety Division (now part of the Office of Energy Infrastructure Safety) related to wildfire safety and mitigation; make recommendations related to contents of wildfire mitigation plans; and provide other advice and recommendations related to wildfire safety as requested by the Wildfire Safety Division. Publicly owned electric utilities (POUs), including municipally owned utilities such as GWP, must submit their adopted WMP to the California Wildfire Safety Advisory Board no later than July 1, 2020 and annually thereafter, and must comprehensively revise such plan at least once every 3 years.

California Building Code

The California Building Code (CBC) contains applicable fire safety standards and the California Fire Code. The CBC follows standards recommended by the California Building Standards Commission and the latest International Fire Code. The CBC sets buildings standards ensuring all structures are designed to provide the required emergency access. Additionally, the CBC contains guidance on design features, including fire sprinklers, fire flow standards, emergency access roads standards, and/or storage of flammable materials, which comply with fire department minimum requirements. The City has adopted the 2019 with 2020 local amendments version of the California Building Code with local amendments.

California Fire Code (California Code of Regulations Title 24, Part 9)

Based on the 2018 International Fire Code, and as published by the California Building Standards Commission, the California Fire Code regulates minimum fire safety requirements for new and existing buildings, facilities, storage, and processes. The Fire Code addresses fire prevention and protection, life safety, safe storage, and use of hazardous materials. The Fire Code is a design document which sets forth the minimum requirements for hazards and contains the requirements for maintaining life safety of building occupants, protection of emergency responders, and limits damage to a building and its contents as a result of a fire, explosion, or unauthorized hazardous materials discharge. The City has adopted the 2019 version of the California Fire Code with local amendments for site-specific guidance and requirements.

California Public Resources Codes

California Public Resources Code (PRC) sections are applicable to the proposed Project, including as listed below:

Code 4119: Authorizes agencies to inspect all properties, except a dwelling's interior, to ascertain compliance with state forest and fire laws, regulations, or use permits.

Code 4291: Requires 100 feet of defensible space around all structures.

Federal LORS

National Fire Protection Association

The National Fire Protection Association (NFPA) provides codes and standards (including the National Electrical Code [NEC]), research, trainings, and education for fire protection. The NFPA publishes more than 300 codes and standards intended to minimize the possibility and effects of fire and other risks.

4.14.3 Environmental Impacts

Methodology

The proposed Project includes the proposed replacement of the majority of the existing electrical generation equipment and infrastructure at the existing Grayson Power Plant. Baseline conditions within this area are defined as the existing physical environmental setting by which a lead agency determines whether an impact is significant. (State California Environmental Quality Act [CEQA] Guidelines, § 15125, subd. (a)). A significant environmental effect or impact is defined as a substantial or potentially substantial change in the environment. (Pub. Resources Code, §§ 21068, 21100, subd. (d); 20 State CEQA Guidelines, § 15358). The impact analysis in this section examines the changes in the environment, specifically related to wildfire risk, which may result from the construction and operation of the proposed Project.

The analysis in this section relies on numerous publicly available maps and datasets, including those published by the City of Glendale, County of Los Angeles, CalFire, aerial imagery and photographs, and site reconnaissance documenting the vegetative conditions. These sources were used to determine wildfire risk in the vicinity of the proposed Project site. Published literature on fire behavior and indirect impacts on natural resources were also reviewed to assess potential indirect impacts.

This analysis evaluates the wildfire impacts in accordance with the CEQA Appendix G thresholds, which evaluate whether a project located in or near State Responsibility Areas or lands classified as within a Very High Fire Hazard Severity Zone:

Thresholds of Significance

As determined in the Grayson Repowering Project Initial Study, the proposed Project would not substantially impair an adopted emergency response plan or emergency evacuation plan. The proposed Project is not located within the wildfire hazard zone as specified by the City of Glendale General Plan. Areas surrounding the Project site consist of urban development with minimal ground cover or vegetation.

In accordance with Appendix G of the State CEQA Guidelines, the proposed Project would have a significant impact related to wildfire if it is located in or near state responsibility areas or lands classified as very high fire hazard severity zones and the proposed Project would:

- Substantially impair an adopted emergency response plan or emergency evacuation plan.
- Substantially impair an adopted emergency response plan or emergency evacuation plan.
- Due to slope, prevailing winds, and other factors, exacerbate wildfire risks, and thereby expose Project occupants to, pollutant concentrations from a wildfire or the uncontrolled spread of wildfire.
- Require the installation or maintenance of associated infrastructure (such as roads, fuel breaks, emergency water sources, power lines or other utilities) that may exacerbate fire risk or that may result in temporary or ongoing impacts to the environment.
- Expose people or structures to significant risks, including downslope or downstream flooding or landslides, as a result of runoff, post-fire slope instability, or drainage changes.

4.14.4 Project Impacts

Threshold: Substantially impair an adopted emergency response plan or emergency evacuation plan?

<u>Demolition, Construction, and Operation</u>

The proposed Project is not listed within a Very High Fire Hazard Severity Zone; however, the land located to the southwest across the Los Angeles River is so classified. The Project site is already developed, and the Project will not block or hinder existing vehicular or pedestrian access along public roads. The Project would be designed, constructed, and maintained in accordance with applicable standards associated with vehicular access. By complying with applicable standards, the proposed Project would provide adequate vehicular access that would ensure adequate emergency access and evacuation as described in the City of Glendale Emergency Plan (Glendale 2008). In the event of a wildfire, traffic control points would be established that would ensure people will be safely evacuated from the Project area. Demolition and construction activities may temporarily restrict vehicular traffic on Fairmont Avenue and San Fernando Road; however, in the event of an emergency during construction, the Project would be required to facilitate the passage of persons and vehicles through/around any required road closures. Adherence to these standards would reduce potential impacts related to this issue to a less than significant level.

Level of Significance before Mitigation:

Less than Significant Impact.

Mitigation Measures:

No mitigation is required.

Level of Significance after Mitigation:

Less than Significant Impact.

Threshold: Due to slope, prevailing winds, and other factors, exacerbate wildfire risks, and thereby expose project occupants to, pollutant concentrations from a wildfire or the uncontrolled spread of a wildfire?

Demolition and Construction

The proposed Project is not located within a Very High Fire Hazard Severity Zone. The nearest Very High Fire Hazard Severity Zone is located approximately 0.10 miles from the Project across the concrete-lined channel of the Los Angeles River. The Project site is flat, and urban, and winds are generally not strong, with the strongest winds blowing south to southwest towards the land classified as Very High Fire Hazard Severity Zone. The probability of a wildfire to spread from the Project site to the Very High Fire Hazard Severity Zone as a result of Project demolition and construction would be low due to the divide created by the concrete-lined channel of the Los Angeles River. Moreover, the existing Grayson Power Plant is completely paved and flat, within an urban environment, and no vegetative fuel is present onsite.

All demolition and construction equipment are required to have fire suppression equipment (such as a fire extinguisher) on board or at the work site. As described in Section 3.2.5, the first demolition activity to occur would be to temporarily reroute existing fire protection water system to be available for fire protection during demolition and construction. There are two fire hydrants adjacent to the existing Unit 9 as well as two additional temporary fire hydrants to be located along the westerly boundary of the Project Site which would remain in place and operational during the demolition and construction phases.

While there are materials, equipment and fuels on-site that would burn if ignited, it is unlikely that fire would spread beyond the Project site for the reasons discussed above, including proximity of fire suppression equipment on-site and the concrete-lined river channel between the site and the Very High Fire Hazard Severity zone located nearby.

Operation

Operational impacts associated with exacerbated wildfire risks and increased potential exposures to pollutant concentrations from a wildfire or an uncontrolled spread of wildfire could occur if operation of the proposed Project would result in an increased baseline wildfire risk or generate increased sources of ignition.

All critical equipment would be separated by rated fire barriers, thereby reducing related ignition risks. The proposed Project would remain paved with low vegetative fuel present to reduce the potential for ignition and create a low risk of fire.

The fire protection system would be designed to protect personnel and limit property loss and plant downtime in the event of a fire and would be designed to meet all laws, ordinances, regulations, and standards (LORS) for the Project. The fire protection system design basis for the Project has been previously reviewed and approved by the Glendale Fire Department, as the Certified Unified Program Agency.

Additionally, fire protection water for the Project would be supplied via connection to the City's 8- and 12-inch potable water distribution system that is currently providing fire protection for the existing Grayson Power Plant. The layout of new equipment and systems would require replacement of most of the existing fire water distribution system within the Grayson Power Plant site. New on-site dedicated underground fire loop piping system with fire hydrants connected to the fire-water loop would be constructed for the Project in compliance with National Fire Protection Association guidelines and the City of Glendale Fire Department requirements. Compliance with existing rules and regulations would serve to ensure that wildfire related impacts during operation would be less than significant.

Level of Significance before Mitigation:

Less than Significant Impact.

Mitigation Measures:

No mitigation is required.

Level of Significance after Mitigation

Less than Significant Impact.

Threshold: Require the installation or maintenance of associated infrastructure (such as roads, fuel breaks, emergency water sources, power lines or other utilities) that may exacerbate fire risk or that may result in temporary or ongoing impacts to the environment?

<u>Demolition</u>

Primary access to the Project site would be provided via the main existing entrance off Fairmont Avenue. In addition, there is a secondary metal gate directly into the Grayson Power Plant site from Fairmont Avenue that would be used for truck hauling of demolition debris and truck delivery of equipment and material. The primary freeway access is the San Fernando Road exit from CA-134 or from the Western exit on Interstate 5. No additional roads would be required for access.

The existing site is predominantly paved (concrete and asphalt) with no vegetation. Fuel breaks would not be required.

As described above in Section 3.2.5 (Demolition Activities), initial demolition activities would include temporarily rerouting the existing fire protection water system to be available for fire protection during demolition and construction. Fire protection water for the Project would be supplied via connection to the City's 8- and 12-inch potable water distribution system that is currently providing fire protection for the existing Grayson Power Plant. Demolition activities would utilize existing power lines or other utilities as needed for completion. As a result, no additional infrastructure would be required, and impacts are expected to be less than significant.

Construction

As described above in Section 3.3.2 (Construction Plans), construction mobilization would require installation of temporary construction power throughout the Project. This would be provided by the City. A rock aggregate would be used for temporary roads, laydown, work areas, and on-site construction parking areas. All temporary construction power or rock aggregate infrastructure will be removed at completion of the Project. As a result, impacts are expected to be less than significant.

The proposed Project is an electrical generation facility located at and within the exiting Utility Operations Center. All electrical connections would be within the Utility Operations Center and no new external connections are required. During construction, the existing Utility Operations Center utilities would be used for the construction offices, laydown area, and the Project site. As a result, Project- related construction impacts related to the installation or maintenance of associated infrastructure that may exacerbate fire risk or that may result in temporary or ongoing impacts to the environment would be less than significant.

Operation

Operation of the proposed Project would be limited to activities related to energy generation within the enclosed Project site footprint. During operation of the proposed Project, the City's existing 8- and 12-inch potable water distribution system that is currently providing fire protection for the existing Grayson Power Plant would provide access to water for fire protection at all times. Therefore, the proposed Project would ensure adequate on-site water is available for firefighting and would not exacerbate fire risk. Additionally, the proposed Project would utilize the existing predominantly paved site requiring no additional fuel break. Operation-related impacts for this threshold would be less than significant, no mitigation measures are warranted.

Level of Significance before Mitigation:

Less than Significant Impact.

Mitigation Measures:

No mitigation is required.

Level of Significance after Mitigation

Less than Significant Impact.

Threshold: Expose people or structures to significant risks, including downslope or downstream flooding or landslides, as a result of runoff, post-fire slope instability, or drainage changes?

Demolition

Demolition activities would result in temporary exposure of on-site soils. As described further in Section 4.4 (Geology and Soils), an erosion control plan, which is subject to review and approval by the City Engineer, would be required prior to any demolition- and construction-related activities. Such plans must include procedures and equipment necessary to contain on-site soils and minimize potential for contaminated runoff from the Project site. In addition to the erosion control plan, preparation, and implementation of a Stormwater Prevention Plan, Dust Control Plan and (BMPs would also minimize erosion. The proposed Project topography is relatively flat resulting in low risk for landslides. The proposed Project would not increase the risk of flooding or landslides after a wildfire compared to existing conditions. As a result, Project-related impacts from demolition would be less than significant.

<u>Construction</u>

As discussed in Section 4.4 (Geology and Soils), due to minimal slopes at the Project Site, landslides are not considered a potential hazard. While grading would be performed as part of the proposed Project, the grading would be conducted in accordance with applicable codes/standards pursuant to a grading permit.

In the proposed condition, on-site stormwater runoff from the Project would flow via surface sheet flow and localized gutters to catch basins and on-site storm drain piping. The proposed Project would not substantially alter the existing drainage pattern of the site and surrounding area. Therefore, the proposed Project would not increase the risk of flooding or landslides after a wildfire compared to existing conditions. Construction impacts would be less than significant. As discussed above, construction of the proposed Project would not expose people or structures to increased or significant risks as a result of runoff, post-fire slope instability, or drainage changes.

<u>Operation</u>

The proposed Project would not require periodic earthmoving or drainage changes which could substantially alter the condition of the site during the operation phase. Impacts which could result from increased risks to downslope or downstream areas would be similar to those currently posed by the existing Grayson Power Plant and would not increase during operation of the proposed Project. As discussed above, operation of the proposed Project would not expose people or structures to increased or significant risks as a result of runoff, post-fire slope instability, or drainage changes. Operation of the proposed Project would be restricted to the proposed Project site and would not result in ongoing earthmoving or drainage changes which could substantially change the area. Operation of the proposed Project would not substantially alter the risk of landslides after a wildfire, as compared to other uses and risks in the area. As such, impacts would be less than significant, and no mitigation measures are warranted.

Level of Significance before Mitigation:

Less than Significant Impact.

Mitigation Measures:

No mitigation is required.

Level of Significance after Mitigation

Less than Significant Impact.

5.0 ALTERNATIVES

5.1 INTRODUCTION

A reasonable range of alternatives that could feasibly attain some of the basic objectives of the Proposed Grayson Repowering Project (Project) are identified and evaluated within this section.

5.1.1 Project Objectives

Pursuant to Section 15124(b) of the CEQA Guidelines, the description of the project must contain "a clearly written statement of objectives" that would aid the lead agency in developing a reasonable range of alternatives to evaluate in the EIR, and to aid decision makers in preparing findings~~,~~ and a statement of overriding considerations.

Within the context of the City's overarching need to ensure a reliable year round supply of power to its residents and customers under various planning contingencies[4], the primary objective of the Project is to replace the aged, less efficient, less flexible, and unreliable generation units at the Grayson Power Plant with approximately 262 megawatts (MW) net of modern power generation that is efficient, reliable, operationally flexible, and can easily integrate into the City of Glendale's existing power system. This Project would ensure system reliability, facilitate and balance renewable imports, and supply the balance of the City's power needs when transmission imports are insufficient, curtailed, or not available to serve its electrical load[5]. In addition, the Project will be able to integrate and accept increasingly available renewable energy resources.

The Project objectives are:

1. Integrate with local and remote distributed renewable energy resources to provide sufficient capacity and energy to ensure reliable service at all times for the City and to support the City's compliance with California's Renewable Portfolio Standards.

2. Utilize current and reliable technology and control systems to provide reliable, cost effective, and flexible generation capacity for the City to serve its customer load.

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[4] Required planning contingencies include a generating unit suddenly going off-line and no longer generating power, the loss of a transmission system (100 MW), or the loss of the source of power being imported over a transmission system. These types of planning contingencies have in fact occurred. Also, while not a required planning contingency, during the Sylmar earthquake the City lost its outside electricity supplies and was islanded (not connected to an off-site power supply through the transmission grid) with only internal generation available.

[5] The City's ability to import power is limited by the capacity of two existing transmission systems, which combined are less than the full load demands of the City. The transmission lines are subject to curtailments (partial or full reductions in capacity). For example, the capacity of the Pacific DC Intertie (100 MW) was reduced for six months in 2004 and then was completely out of service for an additional three months.

3. Provide a local generation resource sufficient to meet resource adequacy requirements, and the City's obligations within the Balancing Area[6] (BA) to balance load and resource at the interconnection with the BA, in accordance with industry standards including North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) requirements; thus, providing local reliability and contributing to grid stability within the Los Angeles Basin.

4. Provide sufficient locally controlled generation to minimize the City's reliance on importing power from remote generation locations through a congested transmission grid system subject to planned and unplanned outages and de-rates, making the delivery of energy to serve load less reliable than local generation.

5. Replace the aged, unreliable, less efficient, high maintenance steam boilers with new, efficient, and less environmentally impactful generation technologies that meet South Coast Air Quality Management District's (SCAQMD) Rule 1304(a)(2).

6. Locate the proposed Project at existing City property already permitted and used for generation to minimize the need for major infrastructure improvements such as fuel supply, water, wastewater, recycled water and transmission facilities, or the need to purchase additional property.

7. Provide generation that is highly efficient to maintain reasonable cost of generation to minimize the impact on customer electric rates and help manage costs of delivering energy to the City's customers.

8. Support water conservation efforts by eliminating the use of potable water for generation purposes.

9. Reduce the per megawatt-hour (MWH) creation of emissions and consumption of water.

5.1.2 Significant Impacts of the Project

The Project would result in a significant and unavoidable impact to cultural resources due to the demolition of the Boiler Building, which the City has elected to consider a discretionary historic resource. Demolition of the Boiler Building would also be required for Alternatives 2 (Energy Storage Project Alternative), 4 (150 MW Project Alternative), 5 (200 MW Project Alternative), 7 (Tesla/Wartsila Repowering Project Alternative), and 8 (Tesla/Unit 8 Refurbishment Project Alternative). Alternatives 1 (No Project) and 3 (Alternative Energy Project Alternative) would do not involve re-development at Grayson Power Plant and the Boiler Building would not be demolished. Therefore, only Alternatives 1 (No

[6] A geographic area defined by the interconnected transmission/distribution systems. The boundaries of the Balancing Area are defined by the points of interconnection to other Balancing Areas. The generation within a Balancing Area must be constantly adjusted so that the sum of the power generated within the Balancing Area, plus power imported into the Balancing Area, less the power exported from the Balancing Area, less the load within the Balancing Area is maintained at zero, e.g., in balance. For the Grayson project, the Balancing Area is composed of Los Angeles Water and Power, Glendale Water & Power, and Burbank Water & Power.

Project) and 3 (Alternative Energy Project Alternative) would avoid the significant and unavoidable cultural resources impact associated with the proposed Project and five other alternatives evaluated. A statement of overriding considerations will be required should the City elect to certify the EIR.

5.1.3 Requirements for Alternatives Analysis

CEQA requires an evaluation of project alternatives based on the comparative merits of "a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project and evaluate the comparative merits of the alternatives" (Title 14, CCR, 15126.6(a)). Thus, the focus of the alternative's analysis should be on alternatives that "could feasibly accomplish most of the basic objectives of the project and could avoid or substantially lessen one or more significant effects" (14 CCR 15126.6(c)). Feasible is defined to include the consideration of economic, environmental, social, legal, and technological factors and includes site suitability, economic viability, availability of infrastructure, general plan consistency, other plans or regulatory limitations, jurisdictional boundaries, and whether the proponent can reasonably acquire, control, or otherwise have access to alternative sites.

The analysis must also address the "no project" alternative (Title 14, CCR, Section 15126.6(e)). The CEQA Guidelines further state that the range of alternatives is governed by the "rule of reason," which requires consideration only of those alternatives necessary to permit a reasoned choice and to foster informed decision making and public participation (CCR, Title 14, Section 15126.6 (f) (3)).

There is no ironclad rule governing the nature or scope of the alternatives to be discussed other than the rule of reason. *Citizens of Goleta Valley v. Board of Supervisors (1990) 52 Cal.3d 553; Laurel Heights Improvement Association v. Regents of the University of California (1988) 47 Cal.3d 376*. Because the primary purpose of an EIR is to mitigate or avoid significant environmental effects, the alternatives discussion is focused on alternatives to the project that are capable of avoiding or substantially lessening any significant effects of the project, even if those alternatives would impede to some degree the attainment of the project objectives or would be more costly. CEQA Guidelines Section 15126.6(b).

Of the alternatives that fit the above criteria, the EIR need examine in detail only those alternatives that the Lead Agency determines could feasibly attain most of the basic objectives of the project. CEQA Guidelines Section 15126.6(f). An EIR need not present alternatives that are incompatible with the project's fundamental purpose. *Bay-Delta Programmatic Envt'l Impact Report Coordinated Proceedings (2008) 43 Cal.4th 1143, 1164; Bay Area Citizens v. City of Oceanside (2004) 119 Cal.App.4th 477; Jones v. Regents of Univ. of Cal. (2010) 183 Cal.App.4th 818.*

No set number of alternatives is necessary to constitute a legally adequate range of alternatives. The scope will vary from case to case depending on the nature of the project and the Lead Agency has discretion to determine how many alternatives constitute a reasonable range. *Citizens of Goleta Valley v. Board of Supervisors (1990) 52 Cal.3d 553, 566.*

5.1.4 Selection of Alternatives to be Evaluated in EIR

5.1.4.1 Overview of Alternatives Selected for Further Analysis

In addition to a No Project Alterative, the following alternatives, which meet some of the project goals and objectives, are summarized in this section.

Alternatives 1 through 5 were evaluated in the Final 2018 EIR. Alternatives 7 and 8 were evaluated as new alternatives for consideration following the Clean Energy RFP process and City Council direction to study additional alternatives that would reduce natural-gas electricity generation compared to the proposed Project. All seven[7] alternatives evaluated in the PR-DEIR involve less natural gas-fueled electricity generation compared to the proposed Project. The proposed Project, as well as all alternatives with the exception of the No Project Alternative and Alternative 3, necessitate removal of the Boiler Building to provide sufficient space for the new facilities.

The potential environmental impacts of Alternatives 7 and 8 evaluated in Section 5.2.6 and 5.2.7 of the PR-DEIR include technical study for key environmental factors for direct comparison to the proposed Project. These studies include photo simulations, criteria air pollutant emissions estimates, air pollutant dispersion modeling, heath risk assessments, greenhouse gas emissions estimates, noise modeling, and offsite consequence analyses for reasonable worst-case accidental release scenarios involving hazardous materials.

- **No Project Alternative (Alternative 1)**: The old, less efficient, and existing electrical generation units built between 1941 and 1977 would continue to operate until the end of 2023 and then would be shut down as a result of SCAQMD regulations that would make it cost-prohibitive to retrofit the boiler units for continued maintenance and operation.

- **Energy Storage Project Alternative (Alternative 2)**: Replace Units 1 – 8 at the existing Grayson Power Plant site with a battery energy storage facility. Use of existing City Unit 9 electrical generation, the City's allotment from the Magnolia Power Plant, and transmission capacity to serve the City's electrical load and charge batteries when excess capacity is available. Energy stored in the batteries would then be discharged to serve the electrical load when demand exceeds available transmission and generation resources.

- **Alternative Energy Project Alternative (Alternative 3)**: A project with some combination of photovoltaic or wind power production with energy storage and new electrical transmission lines into the City.

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[7] Alternative 6, a reconfigured version of Alternative 7 was screened out from further review after the initial engineering phase of its development due to site constraints (see Section 5.3.6), but a decision was made to not renumber the remaining alternatives 7 and 8. Accordingly, in the final analysis there are a total of seven alternatives that received more in-depth review and consideration.

- **150 MW Project Alternative (Alternative 4)**: A reduced size natural gas-fueled power project (150 MW) located ~~on~~ at the existing ~~project~~ Grayson Power Plant site with a new off-site electrical transmission line ~~interconnection~~ into the City.
- **200 MW Project Alternative (Alternative 5)**: A reduced size natural gas-fueled power project (200 MW) ~~located on the existing project site~~ with a battery energy storage system (50 MW/200 MWH) located at the existing Grayson Power Plant site.
- **Tesla/Wartsila Repowering Project Alternative (Alternative 7):** A reduced size natural-gas fueled power project (92.5 MW) with a battery energy storage system (75 MW/300 MWH) located at the existing Grayson Power Plant site.
- **Tesla/Unit 8 Refurbishment Project Alternative (Alternative 8):** A reduced size natural gas-fueled power project (101 MW) that would retain and refurbish existing Units 8A and 8BC gas turbines, converting Unit 8A to simple cycle, and converting Unit 8BC to a fast start combined cycle unit and add battery energy storage system (75 MW/300 MWH) located at the existing Grayson Power Plant site.

5.1.4.2 Overview of Alternatives Not Selected for Further Analysis

Section 15126.6, subdivision (c) of the CEQA Guidelines describes selection of a reasonable range of alternatives and the requirement to include those that could feasibly accomplish most of the basic project objectives while avoiding or substantially lessening one or more of the significant effects. The analysis should identify any alternatives that were considered by the lead agency but were rejected as infeasible. CEQA requires a brief explanation of the reasons underlying the lead agency’s determination to eliminate alternatives from further analysis.

A number of alternatives were considered but eliminated from further consideration. The alternatives that were not evaluated further in the Final 2018 EIR and/or the PR-DEIR include alternative sites, and a variety of alternative technologies (generation technology, fuel technology, and alternative power plant cooling). These alternatives are more fully discussed in Section 5.3.

5.2 ANALYSIS OF ALTERNATIVES

5.2.1 Alternative 1 - No Project Alternative

5.2.1.1 Description

Under the No Project Alternative, the existing Grayson Power Plant would not be repowered. Aside from Unit 9, the boiler units and Units 8A and 8BC as currently configured with the old steam turbines, do not offer quick starting capability hampering their usefulness and effectiveness in the current energy environment. The old, less efficient equipment built between 1941 and 1977 would continue to operate until the end of 2023 and then would be shut down as a result of SCAQMD regulations that would make it cost-prohibitive to retrofit the boiler units for continued maintenance and operation.

As of December 2012 (Source – SNL Energy) the average retirement age of fossil fuel plants is forty-three (43) years for combustion turbines and fifty-four (54) years for steam turbines. All the existing generating units, except for Unit 9 (a simple cycle combustion turbine-generator) which is not being replaced, were built between 1941 and 1977 and are at least 40 years old. With exception of Unit 9, all the units are at or past the end of their design lives and are increasingly difficult to maintain feasibly and economically.

The No Project Alternative would result in a total Grayson Power Plant generating capacity of up to 48 MW (net) from Unit 9, with the remaining electrical energy to meet Glendale's customer load being supplied from the Magnolia Power Plant (35-39 MW[8]), and electricity imports over transmission systems from outside of the City (200 MW plus an additional 72 MW from the Southern Transmission System starting in 2027 as a result of the City's Intermountain Power Project entitlements). In addition, there is also an additional 50 MW expected from demand response programs and the proposed virtual power plant. This could provide the City a maximum total supply of 213 MW, which is less than the City's summertime (June-September) peak loads[9], and only 213 MW with the loss of the single largest contingency. This reduced capacity would come at a significantly increased risk to reliability potentially culminating in the inability to serve load at all times of the year without blackouts. Since 2009, the City's electric system load was more than 213 MW an average of eight-one (81) days per year. Additionally, at these minimum levels of generation/supply, the City would not meet its NERC reliability obligations to the Balancing Authority. Therefore, the No Project Alternative does not provide a viable means to serve the electric load of the City's residents and customers.

5.2.1.2 Potential Environmental Impacts – No Project Alternative

The No Project Alternative would result in no action if the City does not approve the proposed Project or a Project alternative. Following are the potential environmental impacts that would result from the No Project Alternative.

<u>Potential Environmental Impacts Less than Those of the Project</u>

Emissions, noise, and traffic associated with Project demolition and construction would be avoided with the No Project Alternative. The Boiler Building would not be demolished, and the significant and unavoidable impact on a discretionary historic resource would be avoided. As generation units are retired and only Unit 9 remains operating, there would be a reduction in emissions, noise, and traffic from plant operation. Potential air quality, cultural resources, greenhouse gas emissions, noise, and traffic and transportation impacts of the No Project Alternative would be less than those of the Project.

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[8] Glendale's allocation of Magnolia is 46 MW; however, 7 MW of that amount is only available when Magnolia utilizes the supplementary gas-fired burners to increase the combustion turbine exhaust energy in order to produce more steam and hence increase the steam turbine output. However, the supplementary burners are typically not used, and thus 39 MW is a more realistic value.
[9] The all-time peak load was 346 MW.

<u>Potential Environmental Impacts Similar to Those of the Project</u>

The Grayson Power Plant would continue to operate, with older generation units being retired until only Unit 9 remains in operation. The existing power plant facility would remain to have a similar aesthetic impact to that of the Project's. The No Project Alternative would also have similar impacts as the Project to agriculture and forestry resources, biological resources, environmental justice, geology and soils, hazards and hazardous materials, hydrology and water quality, land use and planning, mineral resources, population and housing, public services, recreation, socioeconomics, tribal cultural resources, utilities and service systems, and wildfire as the land use would be consistent and restricted to the same site.

<u>Potential Environmental Impacts Greater than Those of the Project</u>

While the No Project Alternative would avoid use of construction fuels that would be consumed during Project construction, the No Project Alternative includes existing power generation equipment that is old and less efficient than that of the proposed Project. As a result, the No Project Alternative requires more natural gas combustion per MW of electricity generated compared to the proposed Project. As a result, the No Project Alternative would be more wasteful of energy compared to the proposed Project in the short term. A primary objective of the Project is to provide efficient operational flexibility with quick-start high ramp rate generation to facilitate an increasing contribution of renewable energy (such as wind and solar) into the City's electrical grid and to support California's Renewable Portfolio Standards. The No Project Alternative would significantly challenge the City's ability to integrate renewable resources because only Unit 9 would remain available to balance the intermittency of renewable imports. The No Project Alternative would therefore have a greater potential to conflict with or obstruct a state or local plan for renewable energy or energy efficiency. The No Project Alternative would therefore have greater potential energy impacts than the proposed Project.

5.2.1.3 Objectives Consistency Evaluation

A primary objective of the Project is to provide efficient operational flexibility with quick-start high ramp rate generation to facilitate increasing the contribution of renewable energy (such as wind and solar) into the City's electrical grid and to support California's Renewable Portfolio Standards. The No Project Alternative would significantly challenge the City's ability to integrate renewable resources because only Unit 9 would remain available to balance the intermittency of renewable imports.

As a result of the continued challenges in maintaining reliable operation of old units as well as their less efficient operation, the unavailability of additional transmission capacity for increased electrical imports, the City's customers would not gain the reliability, financial, and environmental benefits a new efficient power plant would offer, and would be subjected to degraded system reliability, including likely rolling blackouts under peak load or contingency conditions.

One of the main objectives of the Project is to ensure continued reliability of the City's generation and transmission systems' ability to serve the City's full load for any given period of time. Due to transmission constraints, this requires that local generation be available to meet the City's load and reserve requirements in combination with the ability to optimize its transmission rights to import energy from external sources, including renewable energy to meet the Renewable Portfolio Standards.

Even if the City were able to construct new high voltage transmission lines, which is economically and environmentally challenging, local generation would still be required to provide reserve margins and regulation, and to serve the City's load when external sources are curtailed or not available. Thus, the No Project Alternative would not meet NERC/WECC reliability standards or meet the Project's objectives.

The No Project Alternative would fail to fulfill the City's objectives, the City would not be able to meet the State's Renewable Portfolio Standards, and the City would not ensure a reliable and continuous electric supply for the City.

The No Project Alternative does not feasibly meet many of the Project objectives or meet them as well as the Project. Specifically, the No Project Alternative:

1. Would only be able to integrate with local and remote distributed renewable energy resources to a limited and declining extent as units are shut down. This declining resource would not be sufficient to provide enough capacity and energy to ensure reliable service at all times for the City, and to support the City's compliance with California's Renewable Portfolio Standards.

2. Would not be using current and reliable technology and control systems to provide reliable, cost effective, and flexible generation capacity for the City to serve its customer load.

3. Would provide a local generation resource, but that source would diminish with time and would not be sufficient to meet resource adequacy requirements, and the City's obligation within the Balancing Area to balance load and resource at the interconnection with the BA, in accordance with industry standards including NERC/WECC requirements; thus, would not provide local reliability or contribute to grid stability within the Los Angeles Basin.

4. Would provide a locally controlled but declining source of generation. The No Project Alternative would not be sufficient to back up the City's reliance on importing power from remote generation locations through a congested transmission grid system subject to planned and unplanned outages and de-rates, making the delivery of energy to serve load less reliable than local generation.

5. Would not replace the aged, unreliable, less efficient, high maintenance steam boilers with new efficient and less environmentally impactful generation technologies that meet SCAQMDs Rule 1304(a)(2).

6. Would be located at the existing City property already permitted and used for generation, and would, due to units eventually coming off-line, minimize the need for major infrastructure improvements such as fuel supply, water, wastewater, recycled water, and for the construction of transmission facilities, or need to purchase additional property.

7. Would not provide generation that is highly efficient to maintain reasonable cost of generation to minimize the impact on the rates and help manage costs of delivering energy to the City's customers.

8. Would not support water conservation efforts by eliminating the use of potable water for generation purposes, until most of the aging units are depowered.

9. Would not reduce the per megawatt-hour (MWH) creation of emissions and consumption of water.

5.2.1.4 Summary – No Project Alternative

The No Project Alternative would involve continuing to operate the old, less efficient equipment built between 1941 and 1977 until the end of 2023 and then the equipment would be shut down as a result of SCAQMD regulations that would make it cost-prohibitive to retrofit the boiler units for continued maintenance and operation. The No Project Alternative would result in reduced environmental impacts over time as the units are shut down and would have less potential environmental impacts than those of the Project. The Boiler Building would not be demolished, and the significant and unavoidable discretionary historic resource impact of the proposed Project would be avoided. However, the City would need to replace that reduction in electrical capacity with additional sources of currently unknown electricity; the potential environmental impacts of which are not and cannot yet be evaluated as part of this Project EIR. The No Project Alternative is not a viable alternative in that it would not serve the needs of the City as the City could no longer meet its obligations as a load serving entity for its residents and customers, placing them at significant risk for decreased electrical system reliability and availability. Moreover, the No Project Alternative would not satisfactorily meet the Project objectives and would fail to comply with Federal and State reliability standards.

5.2.2 Alternative 2 - Energy Storage Project Alternative

5.2.2.1 Description

If the City does not replace the existing generation facilities, the City would need to either build additional transmission capacity or build "time shifting" energy storage systems to provide the requisite capacity. Given the significant difficultly in locating suitable right-of-ways and permitting new large capacity transmission connections due to the dense urban development in the Los Angeles basin, as well as the potential for significant environmental impacts from the development of new transmission facilities, a Project alternative involving large capacity energy storage system at the Grayson site was deemed a reasonable Project alternative worthy of further evaluation.

The Energy Storage Project Alternative involves an energy storage system (i.e., batteries, typically lithium ion) that would be charged during times of the day when there is available transmission capacity not needed to serve the City's load. The available energy would be stored and "time shifted" to be used during high load periods when the available transmission capacity is inadequate to serve the City's load.

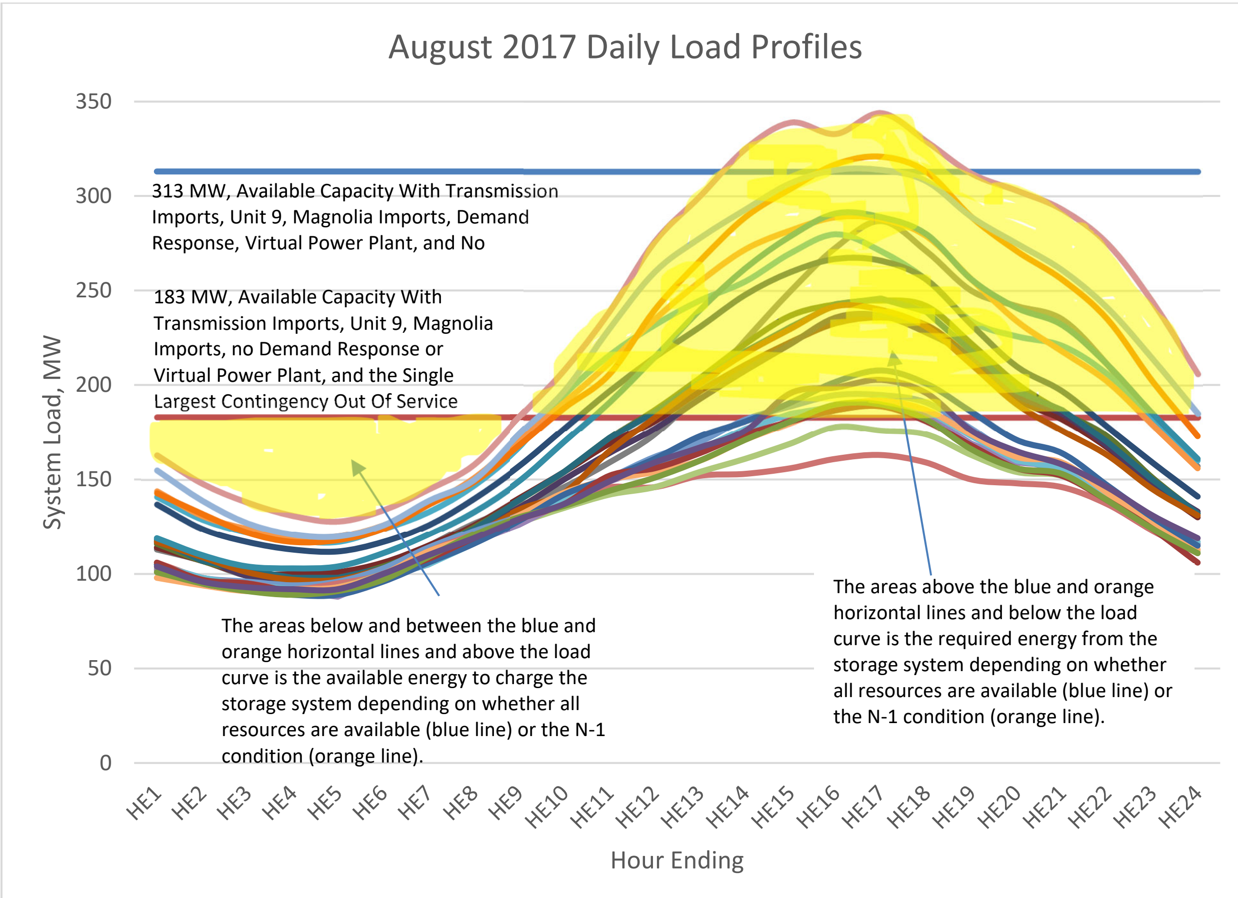
On high load days, however, the ability to store sufficient energy and transmission capacity may need to be supplemented with additional transmission or local generation.

In this Alternative, which presumes all units but Unit 9 will ultimately be shut down, the City would use the available 48 MW (net) from Unit 9, 39 MW from the Magnolia Power Plant, and 200 MW imported over transmission lines from outside of the City. This would provide the City a total supply of 287 MW, which is less than the City's peak loads[10]. With the NERC required planning assumption that the single largest source of power will unexpectedly cease to be available (an event known in the power industry as "the loss of the single largest contingency") which would be losing the 100 MW delivered to Glendale over the Pacific DC Intertie transmission line), available capacity would fall to 187 MW increasing the shortfall in capacity. The 2019 IRP analysis concluded that a portfolio relying on large-scale energy storage would not provide sufficient power to serve the City's energy demands.

Figure 5.1 below illustrates the City's daily load profiles for Mondays through Fridays in August 2017 (each of the different colored curves is a different day). Each day, energy generated during the late night and early morning hours when GWP's electrical load is less than the available electrical supply capacity is energy that would be available to be stored. Later in the day, when system load is greater than the available electrical supply, energy would be discharged from the energy storage system to serve GWP's load. The blue horizontal line represents maximum available capacity to the City without the Repowering Project and the single largest contingency remaining in service. The red horizontal line represents the maximum available capacity to the City without the Repowering Project and with the loss of the single largest contingency (the "N-1" condition).

[10] The City had yearly peak loads of 329 MW, 329 MW, and 346 MW in 2015, 2016, and 2017 respectively. Prudent system planning would typically include some reserve above the peak load.

Figure 5-1 August 2017 Monday Through Friday Daily Load Profiles



With transmission imports, Unit 9's output, Glendale's share of the Magnolia Power Plant, demand response, and the proposed virtual power plant, there would be sufficient excess energy available overnight to store and time shift to serve the daytime and early evening peak load hours. However, if one of these sources of power were to be ~~lost~~ unavailable, this is no longer possible for the higher load days as the amount of excess energy that could be supplied during late evening and early morning hours is less ~~that~~ than what would be consumed from mid-morning into the evening hours.

To serve peak load and accommodate the NERC required consideration that the single largest source of power could be lost unexpectedly and ignore the requirement to also cover the N-1-1 contingency, this Alternative would require an energy storage system to make up the difference[11]. From the above chart, there are two periods of subsequent days (August 2-3 and August 28-31) where there would be a shortfall between the energy that could be stored the previous night and what would be needed the following day

[11] For this evaluation, demand response and the Virtual Power Plant were not included because they cannot contribute energy to be stored on a 24 hours per day and 7 days per week basis.

of between 165 and 1,262 MWH daily[12]. Additionally, because this condition occurs on succeeding days, the shortfalls are cumulative. To meet load during the four-day period would have required stored energy of 2,940 MWH with a peak capacity of 161 MW with the loss of the single largest contingency, and no demand response or virtual power plant.

Of necessity, since solar energy is not available during late evening and early morning hours when excess transmission capacity was available, the energy stored overnight would come from non-solar resources as well as energy from Unit 9 and Magnolia. It should also be noted that the 2,940 MWH of additional energy needed would have to have been stored prior to the four high load days occurring.

Energy storage options currently available include battery systems, thermal energy storage, hydrogen production, and mechanical energy storage.

- Battery storage systems include several types of batteries and capacitors which meet specific needs and requirements in certain application.
- Thermal energy storage utilizes a source of heat, such as solar thermal or electrical heating, to generate steam for power production during evening hours. However, this technology is not feasible at Grayson or within the City because inadequate available space exists on site to develop a solar array facility for this purpose, and there are no feasible options in Glendale on property owned by the City, including rooftops.
- Hydrogen production involves "storing" energy by using surplus energy to generate hydrogen through hydrolysis, and then burning the hydrogen (in a turbine) to generate electricity. While small projects have been built, large scale electricity production solely fueled with hydrogen has not been commercially demonstrated. Additionally, lacking a pipeline supply of hydrogen, hydrogen would need to be generated and stored on or close to the Grayson site which may be problematic due to lack of on-site space to accommodate a hydrogen facility[13]. Thus, this option was not considered feasible for the Energy Storage Project Alternative.
- Compressed air technology also stores energy by using surplus electrical energy to operate compressors that store high-pressure air for later release through an air-powered turbine. Flywheel technology utilizes surplus energy to accelerate large rotors (flywheels) to very high speeds, and then uses that stored rotational energy to spin a generator when power is needed. While promising, compressed air and flywheel technology have not yet been demonstrated to be cost-effective methods for storing energy on a large scale, a scale sufficient to store enough energy to meet peak load. The site does not have any capability or capacity to store compressed air for the purpose of shifting load.

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[12] 165, 256, 380, 688, 825, and 1,262 MWH. The four days of August 28-31 total 2,940 MWH.

[13] Space at Grayson, or elsewhere in the City, would need to be allocated for the construction of a hydrolysis facility and the storage of hydrogen. Recycled water could serve as a source of water for hydrolysis. Renewable energy imports in excess of what is needed to serve load could be used to power the facility primarily during the fall, winter, and spring seasons when imports are greater than demand.

- Pumped-storage hydroelectricity entails storing surplus energy by pumping water from a lower reservoir to a higher reservoir, and then releasing it through a turbine-generator when additional generation is needed. These projects require two reservoirs at significantly different elevations, plus a pumping/generating station and connecting penstock, and therefore have very specific siting requirements not generally found in the population centers of the greater Los Angeles Basin (CEC, 2011), let alone in Glendale.

Based on the above, a Battery Energy Storage System (BESS) was considered the only feasible energy storage technology that can be sited at Grayson at this time and is therefore the energy storage system analyzed in this Alternative. The BESS could utilize either Lithium-ion rechargeable battery or reduction-oxidation flow battery technologies.

If adequate storage capacity could be achieved through a BESS, the Energy Storage Project Alternative using the BESS method would meet most of the Project objectives.

However, the BESS presents some challenges that place its ultimate feasibility in question. For example:

- 2,940 MWH of energy storage is about ten times more storage than is proposed under Alternatives 7 and 8 of the PR-DEIR (300 MWH). There is insufficient space to place a BESS of that size at Grayson. The general arrangement drawing for Alternative 7 illustrates the footprint of the 75/300 MWH of energy storage. 2,940 MWH would require approximately nine additional 300 MWH BESS facilities (energy storage capacity drives the required space; the requisite power is less of a driver).

- 2,940 MWH of storage represents a cost of approximately $588,000,000. This estimate is based on the Clean Energy proposals that GWP received (~$200,000/MWH and higher).

- Additionally, the batteries have a finite life requiring periodic augmentation (replacing degraded batteries with new or refurbished ones). Depending on use, the long-term annual capacity maintenance contract costs would likely be on the order of several millions of dollars per year.

- These costs do not include the cost to produce and transmit the energy to charge the batteries.

5.2.2.2 Potential Environmental Impacts

Following are the potential environmental impacts that would result from the Energy Storage Project Alternative.

Potential Environmental Impacts Less than Those of the Project

The Energy Storage Project Alternative would involve less construction and have a lower intensity of structures and heights on the site and would therefore contribute to less of a short-term and long-term aesthetic impact compared to the Project. Construction and operation air emissions, noise and traffic would be lower due to less construction activity and the sites long-term use for energy storage rather than generation (which has fewer sources of noise and requires fewer personnel to operate). The Energy

Storage Project Alternative would consume less water than the Project and generally involve the use of fewer types and volumes of hazardous materials such as liquid petroleum hydrocarbons that could contribute to off-site stormwater pollution. Potential aesthetics, air quality, energy, greenhouse gas emissions, hydrology and water quality, noise, and traffic and transportation impacts of the Energy Storage Project Alternative would be less than those of the Project.

<u>Potential Environmental Impacts Similar to Those of the Project</u>

The Energy Storage Project Alternative would have similar impacts as the Project to agriculture and forestry resources, biological resources, cultural/tribal cultural resources, environmental justice, geology and soils, hazards and hazardous materials, land use and planning, mineral resources, population and housing, public services, recreation, socioeconomics, tribal cultural resources, ~~and~~ utilities and service systems, and wildfire as the land use would be consistent and restricted to the same site. The Boiler Building would be demolished and similar to the proposed Project, this Alternative, would result in a significant and unavoidable impact to a discretionary historic resource. While the Energy Storage Project Alternative would not involve the use of hazardous materials common to the power plants, it would result in the need for battery replacement and battery disposal every five to ten years.

<u>Potential Environmental Impacts Greater than Those of the Project</u>

The Energy Storage Project Alternative would not have any potential environmental impacts greater than those of the Project.

5.2.2.3 Objectives Consistency Evaluation

The Energy Storage Project Alternative does not feasibly meet many of the Project objectives or meet them as well as the Project. Specifically, the Energy Storage Project Alternative:

1. Would integrate with local and remote distributed renewable energy resources, but based on the above discussion, and the 2019 IRP modeling, sufficient energy would not be available to charge the BESS during high load periods, and thus the BESS would not ~~to~~ provide sufficient energy to ensure reliable service at all times for the City and would therefore not support the City's compliance with California's Renewable Portfolio Standards.

2. Would utilize current technology and control systems, but the quantity and required integration would require a very significant upscaling compared to existing projects.

3. Would provide a local source of energy if sufficient excess energy is available to charge the batteries. However, sufficient excess energy is not available, particularly during high load periods, therefore the Energy Storage Project Alternative will not provide a local power resource sufficient to meet resource adequacy requirements, and the City's obligation within the Balancing Area to balance load and resources at the interconnection with the Balancing Authority in accordance with industry standards including NERC/WECC requirements. Thus, the Energy Storage Project

Alternative would not provide local reliability that would also contribute to grid stability within the Los Angeles Basin.

4. Would provide sufficient locally controlled source of power as long as sufficient excess energy is available (this Alternative provides storage of excess Unit 9, Magnolia, and off-site generation). However, as the bulk of the energy needed to charge the battery system would be imported over the transmission systems, this Alternative would not minimize the City's reliance on importing power from remote generation locations through a congested transmission grid system subject to planned and unplanned outages and de-rates that make the delivery of energy to serve load less reliable than local generation.

5. Would replace the aged, unreliable, less efficient, high maintenance steam boilers with no local air emissions. To the extent that non-greenhouse gas free excess energy power is imported during low load times to charge the batteries (such as at night), air emissions would be created elsewhere.

6. Would be located at existing City property already permitted and used for generation and thus would minimize the need for major infrastructure improvements to the fuel supply, water, wastewater, recycled water and transmission facilities, or the need to purchase additional property.

7. Would not provide generation (only provides storage of Unit 9, Magnolia, and off-site generation) that is highly efficient to maintain reasonable cost of generation to minimize the impact on the rates and help manage costs of delivering energy to the City's customers.

8. Would support water conservation efforts by eliminating the use of potable water for generation purposes.

9. Would reduce the per megawatt-hour (MWH) creation of emissions and consumption of water because there would not be any new generation facilities on the site that create new emissions and which consume water.

5.2.2.4 Summary

The Energy Storage Project Alternative would involve replacing Units 1 – 8 at the existing Grayson Power Plant with a battery energy storage facility. Use of the City's existing Unit 9 electrical generation, the City's allotment from the Magnolia Power Plant, and transmission capacity to serve the City's electrical load and charge batteries when excess capacity is available. Energy stored in the batteries would then be discharged to serve the electrical load when demand exceeds available transmission and generation resources.

The Energy Storage Project Alternative's potential for local air quality, greenhouse gas emissions, hydrology and water quality, noise, and traffic and transportation impacts are less than those of the Project. More distant impacts due to the additional night-time generation needed to charge the batteries, when renewable solar energy will not be available, are potentially increased. Additionally, during the summer season because of high demands on the system, it is not possible to import enough electricity to charge the batteries to serve the daytime load. For these reasons, this Alternative was not selected because it does not feasibly meet the Project objectives to the same extent as the Project.

5.2.3 Alternative 3 - Alternative Energy Project Alternative

5.2.3.1 Description

The Alternative Energy Project Alternative evaluates the feasibility of local and remote photovoltaic (PV) solar and wind powered production, in combination with transmission and geothermal alternative energy options.

Utility-Scale PV Solar.

If the Project consisted entirely of PV power, this Alternative would require approximately 4 – 6 acres per MW of electricity depending on the specific PV technology used (e.g., crystalline vs thin film) and configuration of the solar array tracker system (single or dual axis). The Project site is approximately ~~10~~ ten acres in size~~,~~ and could only support PV power production up to 2.5 MW. In order to generate power equivalent to the Project, the Alternative Energy Project Alternative would need to acquire an approximately 1,310-acre site that is capable of development as a remote (not on site). Utility scale PV solar energy produced outside of Glendale and imported via transmission lines would require complementary storage and new transmission capacity to deliver energy to the City.

The City does not own or control 1,310 acres that are developable as a utility-scale PV solar project. Glendale is predominantly urbanized with open space reserved within its existing parks and mountainous areas, much of which is preserved open space, designated as significant ecological areas, in a high fire danger area, or too steep for any form of development. The City is working with an engineering firm to investigate the feasibility of developing solar facilities on City-owned properties, and has preliminarily determined, subject to further analysis, that of the approximately 150 acres of City-owned property under consideration, approximately 40 acres may have some potential for PV development, however this acreage is far below the 1,310 acres necessary to locally power a PV project.

Based on the lack of access to sufficient local acreage to support a utility- scale PV Project, development of a utility-scale PV solar project as an equivalent power source as the Project within the City of Glendale is not feasible. Accordingly, the only path to using PV solar as an alternative energy source in place of the Project is to procure remote PV solar and construct a new transmission line to bring the energy to Glendale, and to provide complimentary battery storage. Similarly, access to wind, and geothermal resources outside the Los Angeles basin would also require the construction of new transmission facilities. Building additional transmission is a significant undertaking that has its own potential environmental impacts stemming from such large-scale development and includes potential property acquisition expense and third-party permitting issues.

As noted, PV solar only generates power during daylight hours and can be substantially curtailed during cloudy days or rain events, and by itself would not provide a reliable source of power for the City of Glendale's power customers without additional transmission and complementary battery storage.

Distributed Solar.

Distributed solar PV deployed on residential and commercial rooftops was explored through the Clean Energy RFP and after evaluating and modeling the proposals, GWP is negotiating contracts with Sunrun, Inc. for a proposed a virtual power plant of approximately 28 MW of solar capacity and 25.25 MW/50.50 MWH of battery storage. GWP is also implementing other distributed energy programs. While this 25-year program, if approved by the City Council, will assist GWP, it would provide capacity and storage that will only meet a fraction of GWP's needs. The Clean Energy RFP proposals for commercial solar and storage were not viable. However, as noted above, the City is investigating solar and storage on City-owned properties and intends to install at least 50 MW of distributed energy resources per the 2019 IRP portfolio, including demand response, energy efficiency, and other distributed resources. Given the broad opportunity available to the Clean Energy bidders and the responses received, which did not yield enough clean energy capacity to meet the City's capacity and energy to meet the City's needs, and the analysis and modeling from the 2019 IRP and the 100% Clean by 2030 study, this approach was not considered a viable Alternative to the proposed project.

Wind Power.

For reasons, similar to those affecting the feasibility of developing solar resources, siting a wind farm within Glendale is not considered a feasible option because Glendale does not have the land needed for such a wind turbine project and does not have adequate wind resources. The existing site has room for a few wind turbines depending on their size. In the same way that solar resources are limited to day-time generation, Glendale does not have adequate wind resources to justify wind farm development as an alternative to the Project and would require remote wind production and transmission to complimentary battery storage facilities located on site.

Given the lack of an available wind farm site within Glendale, the only means to employ an alternative energy source is to locate it outside of Glendale and import the energy over a new transmission line. This creates impacts due to both the large site needed to build a project of sufficient generating capacity, and the additional transmission line or lines that would need to be built. As discussed within the PV option for an Energy Storage Project Alternative, building additional transmission capacity involves additional significant investment, land acquisition challenges and new environmental impacts stemming from project development.

Due to the intermittent nature of electrical generation from solar or wind resources, energy storage would need to be a component of the Alternative Energy Project Alternative. Storage is required to cover the "gaps" due to the intermittency of renewable generation as well as at night when solar resources are not available. A portion of this energy storage could be located at Grayson but would most likely require some form of energy storage located in and or outside the city of Glendale dependent on what type of energy storage is selected (See Section 5.2.2.1 for a description of various energy storage alternatives). Energy storage is not a generation source itself and relies upon excess available electricity that can be stored and then used to supply load over an extended period of time. The main function of energy storage is to provide various ancillary services and some load shifting. The Alternative Energy Project Alternative would need to include an energy storage component to be used to serve load during times of the day when the alternative energy source may not be available.

5.2.3.2 Potential Environmental Impacts – Alternative 3

Following are the potential environmental impacts that would result from the Alternative Energy Project Alternative.

Potential Environmental Impacts Less than Those of the Project

The Alternative Energy Project Alternative and Project would involve large construction efforts with short-term air emissions, noise and potential water quality impacts stemming therefrom. However, long-term operation phase emissions associated with the renewable energy facility and transmission system would be less than those of the Project. The Alternative Energy Project Alternative would also consume less water and energy operationally than the Project and generally involve the use of fewer types and volumes of hazardous materials such as liquid petroleum hydrocarbons that could contribute to off-site stormwater pollution. Renewable energy facilities such as PV solar, transmission lines, and energy storage systems do not contribute as much to community noise levels during operation compared to thermal generation power plants in an urbanized area such as the Project. Increased use of renewable energy would be more consistent with the State's Renewable Portfolio Standard requirements than the natural gas combustion to generate electricity associated with the proposed Project. While this Alternative would involve a new transmission line that would have the potential to significantly impact cultural resources, it was assumed that the Boiler Building would not be demolished at Grayson Power Plant as part of this Alternative and it would therefore avoid the significant and unavoidable discretionary historic resource impact of the proposed Project. Potential air quality, cultural resources, energy, greenhouse gas emissions, hydrology and water quality, and noise impacts of the Alternative Energy Project Alternative would be less than those of the Project.

Potential Environmental Impacts Similar to Those of the Project

Similar to the Project, construction, operation and maintenance would involve the use of hazardous materials. These facilities would be required to be in conformance with applicable LORS related to the transport, handling, use, storage, and disposal of hazardous materials. Considering the Project has been issued will serve letters for public services (Appendix B of the 2018 Final EIR), would be limited to an existing 10-acre power plant site not used for mineral resource production, and does not require off-site utility extensions, potential impacts of the Alternative Energy Project Alternative to mineral resources, public services, recreation, socioeconomics, and utility and service systems would not be less than those of the Project. Construction traffic from the Alternative Energy Project Alternative would likely be similar or greater than that of the Project due to the size difference (1,300 acres plus a long, new transmission line vs. 10 acres). Operation and maintenance of the Alternative Energy Project Alternative would also involve a similar level of traffic as the Project. The Alternative Energy Project Alternative would have similar potential impacts as the Project to hazards and hazardous materials, mineral resources, public services, recreation, socioeconomics, transportation and traffic, and utilities and service systems.

Potential Environmental Impacts Greater than Those of the Project

The Alternative Energy Project Alternative would involve development of approximately 1,300 acres of off-site land for renewable energy generation and the construction of an extensive new transmission line to import the electricity into the City. While a specific location for this Alternative has not been identified, utility scale renewable energy and transmission line development projects would have the potential to create new impacts on agriculture and forestry resources, biological resources, tribal cultural resources, environmental justice, geology and soils, land use and planning, and population and housing, and wildfire compared to the Project. The Project would be developed on the existing 10-acre industrial site that is already permitted as a power plant, is developed, and operated as a power plant, and which does not contain agriculture lands, sensitive biological resources, or cultural/tribal cultural resources. The installation of a new electrical transmission line associated with the Alternative Energy Project Alternative would represent a greater potential for wildfire compared to the proposed Project that would not include transmission and be restricted to an existing industrial site not located in a high fire hazard area. Project development would also involve less earthwork compared to this Alternative. The Alternative Energy Project Alternative would ~~also~~ have greater off-site aesthetic, agriculture and forestry resources, biological resources, ~~cultural/~~tribal cultural resources, environmental justice, geology and soils, land use and planning, ~~and~~ population and housing, and wildfire impacts than those of the Project.

5.2.3.3 Objectives Consistency Evaluation – Alternative 3

The Alternative Energy Project Alternative does not feasibly meet many of the Project objectives or meet them as well as the Project. Specifically, the Alternative Energy Project Alternative:

1. Would integrate with local and remote distributed renewable energy resources but would not provide sufficient capacity and energy to ensure reliable service at all times for the City without the construction of additional transmission systems.

2. Would utilize current technology and control systems, but the technology and control systems would not provide reliable, cost effective, and flexible generation capacity for the City to serve its customer load and comply with California's Renewable Portfolio Standards without the construction of additional transmission systems.

3. Would not provide a local generation resource sufficient to meet resource adequacy requirements, and the City's obligation within the Balancing Area to balance load and resource at the interconnection with the Balancing Authority, in accordance with industry standards including NERC/WECC requirements. Thus, the Alternative Energy Project Alternative would not provide all the required local reliability needs and would not contribute to grid stability within the Los Angeles Basin.

4. Would not provide a sufficient locally controlled source of generation to support the City's reliance on importing power from remote generation locations through a congested transmission grid system subject to planned and unplanned outages and de-rates making the delivery of energy to serve load less reliable than local generation.

5. Would replace the aged, unreliable, less efficient, high maintenance steam boilers, with an energy source that does not create operational air emissions.

6. Would be able to locate only a small portion of the needed capacity at the existing site, which is already permitted and used for generation. It would require major infrastructure improvements such as new transmission facilities as well as additional property for solar or wind farms to meet existing power demands.

7. Would not provide generation that is ~~highly~~ efficient to maintain with a reasonable cost of generation to minimize the impact on the rates and help manage costs of delivering energy to the City's customers because of the need to acquire land for additional solar or wind generation facilities and associated transmission.

8. Would support water conservation efforts by eliminating the use of potable water for generation purposes.

9. Would reduce the per megawatt-hour (MWH) creation of emissions and consumption of water.

5.2.3.4 Summary – Alternative 3

The Alternative Energy Project Alternative would involve some combination of photovoltaic or wind power production with energy storage and transmission lines. While the Alternative Energy Project Alternative reduces local potential air quality, cultural resources, energy, greenhouse gas emissions, hydrology and water quality, and noise impacts local to the Grayson Power Plant site, it increases off-site impacts to aesthetics, agriculture and forestry resources, biological resources, cultural/tribal cultural resources, environmental justice, geology and soils, land use and planning, and population and housing impacts due to the need for increased transmission as well as the large area needed for a wind farm or solar field.

Because of the very limited ability to site solar or wind resources within the City and insufficient feasible local clean energy resources proposed in the Clean Energy RFP, combined with the energy storage considerations discussed in the preceding Energy Storage Project Alternative, as well as the results of the 2019 IRP modeling and 100% Clean Energy by 2030 analysis, and complications associated with building a new transmission line to import alternative energy, the Alternative Energy Project Alternative was not considered an adequate replacement for the power that would be generated by the Project. Additionally, the Alternative Energy Project Alternative does not feasibly meet the Project objectives to the same extent as the Project.

5.2.4 Alternative 4 - 150 MW Project Alternative

5.2.4.1 Description – Alternative 4

This Alternative would consist of three simple cycle combustion turbines at the Grayson Power Plant and a new transmission line to import additional electricity into the City. A 150 MW Project Alternative was selected because it was one of the alternatives studied within the 2015 Integrated Resource Plan study[14]. However, due to the reduction in generating capacity, this Alternative consequently also requires additional transmission and energy imports into Glendale to provide sufficient capacity.

Although feasible to develop, the 150 MW Project Alternative would not provide sufficient capacity or generate sufficient energy under all required planning scenarios necessary to meet load demands and reliability requirements. In addition, this Alternative would not be able to meet the spinning reserve[15] requirements set forth by NERC/WECC. Thus, the 150 MW Project Alternative would require additional import capacity (transmission capacity) for the City to meet load and reliability criteria.

The City has explored participating with LADWP in the development of new transmission; however, LADWP would not consider building new transmission to the Victorville area at this time, which is required for Glendale to access additional generation, particularly new generation from renewable resources.

Connection to the California Independent System Operator (CAISO) system through interconnection to Southern California Edison is also not a viable option because the City is within the LADWP Balancing Area and cannot connect to another Balancing Area other than as an emergency source. The other option would be for the City to become part of the CAISO balancing authority in place of being part of Los Angeles Department of Water and Power's balancing authority. There is no existing transmission corridor for Glendale to connect to the CAISO system without new development. The cost for a new interconnection – which is different than the much more significant new transmission line discussed in the Alternative Energy Project Alternative - is significant itself (estimated at $66 million in the 2015 Integrated Resource Plan). Such a new interconnection to CAISO and dropping out of the Los Angeles Department of Water and Power Balancing Authority will result in significant electric transmission system impacts exacerbating some existing issues (circulating currents) in the LADWP/CAISO electrical system design and if feasible, would require further mitigation and result in considerable financial impacts, and probable significant opposition from the current Balancing Authority.

Building and owning new transmission capacity carries several significant risks and uncertainties, costs, and potentially significant environmental impacts associated with transmission system development that may require mitigation and additional Project upgrade costs. There is also uncertainty with respect to the reliability of a new connection to the CAISO system, which would increase Glendale's single largest contingency because of expanded reliance on imported power transmission that a new large transmission

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[14] In addition to a 200 MW and a 250 MW option that were also studied.

[15] "Spinning reserve" refers to generators on-line and able to immediately respond to the loss of another generator or transmission import up to the single largest contingency. Simple cycle units, because they are less efficient than combined cycle units, are limited by their air permit in how many hours they can operate on an annual basis.

interconnection presents. The City requires local generation because the available transmission into the City from the Pacific DC Interconnection transmission line and the Southwest A/C Transmission System are congested, subject to curtailments, and would not be able to fully serve the City's load at all historical levels of load.

Given the difficulty of financing, permitting, and constructing new transmission through limited rights-of-way in an existing urban environment and in high fire risk areas, the 2019 IRP concluded that construction of new transmission is not feasible.

5.2.4.2 Potential Environmental Impacts – Alternative 4

Following are the potential environmental impacts that would result from the 150 MW Project Alternative.

Potential Environmental Impacts Less than Those of the Project

The 150 MW Project Alternative and Project would involve large construction efforts with short-term air emissions and noise, however, long-term operation phase emissions and noise associated with this Alternative would be less than those of the Project due to the reduction in the number of generation units and capacity. Potential air quality, energy, greenhouse gas emissions, and noise impacts of the 150 MW Project Alternative would be ~~incrementally~~ less than those of the Project.

Potential Environmental Impacts Similar to Those of the Project

Similar to the Project, construction, operation and maintenance would involve the use of hazardous materials. These facilities would be required to be in conformance with applicable LORS related to the transport, handling, use, storage, and disposal of hazardous materials. Even with a reduction in generating capacity at the Grayson Power Plant, the 150 MW Project Alternative would have similar on-site impacts as the Project with respect to hydrology and water quality, mineral resources, public services, recreation, socioeconomics, and utility and service systems. The construction of an extensive new off-site transmission line only increases the potential for impacts to these resource categories and potential impacts would not be less than those of the Project. Construction traffic from the 150 MW Project Alternative would likely be similar or greater than that of the Project due to addition of the off-site transmission line component. Operation and maintenance of the 150 MW Project would also involve a similar level of traffic as the Project. The 150 MW Project Alternative would have similar impacts as the Project to hazards and hazardous materials, hydrology and water quality, mineral resources, public services, recreation, socioeconomics, transportation and traffic, and utilities and service systems.

Potential Environmental Impacts Greater than Those of the Project

Both the 150 MW Project Alternative involve comparable demolition, construction and operating electrical generation facilities at the at the Grayson Power Plant site. The 150 MW Project Alternative includes construction of an extensive new transmission line to import additional electricity into the City to serve the City's load. Long transmission line development projects commonly have the potential to impact agriculture and forestry resources, biological resources, cultural/tribal cultural resources, environmental justice, geology and soils, land use and planning, and population and housing. Comparatively, the Project would be developed on the existing 10-acre industrial site that is already permitted, developed and operated as a power plant. Further development on the Grayson Power Plant site will not impact agriculture lands, sensitive biological resources, or ~~cultural/~~tribal cultural resources. The 150 MW Project Alternative also requires substantially more earthwork related to the transmission line development than the Project. This Alternative would necessitate demolition of the Boiler Building, and similar to the proposed Project, would therefore result in a significant and unavoidable impact on a discretionary historic resource. Because of the transmission line component, the 150 MW Project Alternative would have greater off-site potential aesthetic, agriculture and forestry resources, biological resources, cultural/tribal cultural resources, environmental justice, geology and soils, land use and planning, ~~and~~ population and housing, and wildfire impacts than those of the Project.

5.2.4.3 Objectives Consistency Evaluation – Alternative 4

The 150 MW Project Alternative does not feasibly meet many of the Project objectives or meet them as well as the Project. Specifically, the 150 MW Project Alternative:

1. Would integrate with local and remote distributed renewable energy resources but would not provide sufficient capacity and energy to ensure reliable service at all times for the City and to support the City's compliance to California's Renewable Portfolio Standards.

2. Would utilize current technology and control systems, but the technology and control systems would not provide reliable, cost effective, and flexible generation capacity for the City to serve its customer load.

3. Would provide a local generation resource, but not one that is sufficient to meet resource adequacy requirements, and the City's obligation within the Balancing Area to balance load and resource at the interconnection with the Balancing Authority, in accordance with industry standards including NERC/WECC requirements. Thus, the 150 MW Alternative would not provide local reliability and would not contribute to grid stability within the Los Angeles Basin to the same extent as the Project.

4. Would provide a locally controlled source of generation, but the amount of generation would not be sufficient to minimize the City's reliance on importing power from remote generation locations through a congested transmission grid system subject to planned and unplanned outages and de-rates making the delivery of energy to serve load less reliable than local generation. This Alternative would need additional transmission capacity to adequately respond to and serve customer load.

5. Would replace the aged, unreliable, less efficient, high maintenance steam boilers, with new generation, but this new generation would create emissions that are not likely to comply with SCAQMDs Rule 1304(a)(2).

6. Would be able to locate at the existing City property already permitted and used for generation, but it would not minimize the need for major infrastructure improvements such as fuel supply, water, wastewater, recycled water and transmission facilities.

7. Would not provide generation that is highly efficient to maintain at a reasonable cost of generation (due to the inherently poorer efficiency of simple cycle units as compared to combined cycle units) to minimize the impact on the rates and help manage costs of delivering energy to the City's customers because the amount of power generated would require supplementation for new transmission sources that are limited both in terms of negotiating their development with applicable agencies, but in terms of the ability to physically develop these sites.

8. Would support water conservation efforts by eliminating the use of potable water for generation purposes.

9. Would reduce the per megawatt-hour (MWH) creation of emissions and may reduce the water consumption

5.2.4.4 Summary – Alternative 4

The 150 MW Project Alternative would involve a reduced size power project located on the existing project site with a new transmission interconnection. While the 150 MW Project Alternative would have less potential air quality, greenhouse gas emissions and noise impacts than those of the Project, the potential impacts at the Grayson Power Plant site are generally similar.

The 2019 IRP analysis concluded that this alternative would not provide sufficient power to serve the City's energy demands.

5.2.5 Alternative 5 - 200 MW Project Alternative

5.2.5.1 Description – Alternative 5

A 200 MW Project Alternative would consist of two simple cycle units and one combined cycle unit. A 200 MW Project Alternative was selected because it was one of the alternatives studied within the 2015 Integrated Resource Plan study[16]. This alternative also included a 50 MW/200 MWH BESS to replace one of the turbines from the proposed Project to arrive at this Alternative.

5.2.5.2 Potential Environmental Impacts – Alternative 5

Following are the potential environmental impacts that would result from the 200 MW Project Alternative.

<u>Potential Environmental Impacts Less than Those of the Project</u>

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[16] In addition to a 150 MW and a 250 MW option that were also studied.

The 200 MW Project Alternative would combust a lower volume of natural gas and generate less electricity than the proposed Project. As a result, the 200 MW Project Alternative could be more consistent with the State's Renewable Portfolio Standard requirements compared to the proposed Project (if the BESS was charged with renewable sources). The 200 MW Project Alternative and Project would involve large construction efforts with short-term air emissions and noise, however, long-term operation phase emissions and noise associated with this Alternative would be less than those of the Project due to the reduction in the number of generation units and capacity. Potential air quality, energy, greenhouse gas emissions, and noise impacts of the 200 MW Project Alternative would be less than those of the Project.

Potential Environmental Impacts Similar to Those of the Project

Similar to the Project, the 200 MW Project Alternative involves electrical generation at the same 10-acre urban industrial site already permitted, developed, and operated as a power plant. The primary difference is that the 200 MW Project Alternative includes a 50 MW BESS in lieu of one of the two combined cycle generation units associated with the Project. This Alternative would necessitate demolition of the Boiler Building and similar to the proposed Project, would therefore result in a significant and unavoidable impact to a discretionary historic resource. As a result, the 200 MW Project Alternative would have similar environmental impacts as the Project on aesthetics, agriculture and forestry resources, biological resources, cultural/tribal cultural resources, environmental justice, geology and soils, hazards and hazardous materials, hydrology and water quality, land use and planning, mineral resources, population and housing, public services, recreation, socioeconomics, transportation and traffic, ~~and~~ utilities and service systems, and wildfire.

Potential Environmental Impacts Greater than Those of the Project

The 200 MW Project Alternative would not have any potential environmental impacts greater than those of the Project.

5.2.5.3 Objectives Consistency Evaluation – Alternative 5

The 200 MW Project Alternative meets most of the Project objectives, but not to the same extent as the Project. Specifically, the 200 MW Project Alternative:

1. Would integrate with local and remote distributed renewable energy resources and provide sufficient reliable capacity and energy to ensure reliable service at all times for the City and to support the City's compliance to California's Renewable Portfolio Standards.

2. Would utilize current technology and control systems, and the technology and control systems would provide reliable, cost effective, and flexible generation capacity to support the City to serve its customer load.

3. obligation within the Balancing Area to balance load and resource at the interconnection with the BA, in accordance with industry standards including NERC/WECC requirements as well as the Project.
4. Would provide a locally controlled source of generation, that would support the City's reliance on power imports from remote generation locations through a congested transmission grid system subject to planned and unplanned outages and de-rates.
5. Would replace the aged, unreliable, less efficient, high maintenance steam boilers, with new generation that would comply with SCAQMDs Rule 1304(a)(2).
6. Would be able to be located at the existing City property already permitted and used for generation and would minimize the need for major infrastructure improvements such as fuel supply, water, wastewater, recycled water, and transmission facilities to the same extent as the Project.
7. Would provide generation that is efficient to maintain.
8. Would support water conservation efforts by eliminating the use of potable water for generation purposes.
9. Would reduce the per megawatt-hour (MWH) creation of emissions and water consumption to the same extent as the Project.

5.2.5.4 Summary – Alternative 5

The 200 MW Alternative would ~~have~~ reduce~~d~~ air pollutant and greenhouse gas emissions and noise because this Alternative has one less generation unit compared to the Project, with the reduction of one unit offset by the addition of a battery energy storage system (one that is smaller than the earlier alternative). The BESS, if charged with renewable sources, would represent a reduced potential energy impact compared to the proposed Project that involves only natural gas fueled electricity generation. If sufficient transmission capacity were not available for charging the BESS, then the air emissions may not be reduced due to the need to operate additional unit(s) to charge the BESS.

For these reasons, the overall environmental impacts of a 200 MW Alternative are expected to be comparable to the Project.

5.2.6 Alternative 7 - Tesla/Wartsila Repowering Project Alternative[17]

5.2.6.1 Project Description – Alternative 7

The Tesla/Wartsila Repowering Project Alternative demolishes all units and buildings on the Project site, replaces the existing units with the exception of Unit 9, and replaces it with the following:

- Five Wartsila 18V50SG reciprocating internal combustion engine units producing approximately 93 MW net at average annual site conditions.

- A battery energy storage system producing approximately 75 MW with a storage capacity of 300 MWH net at average annual site conditions. Through the Clean Energy RFP process, the City selected Tesla's Megapack technology as the preferred energy storage technology amongst the several different technologies offered based on the consideration of several factors such as performance, capacity maintenance/degradation, guarantees, long-term service agreement, space utilization, and cost. Therefore, the environmental evaluation of this alternative assumes the Tesla Megapack design and the supporting engineering and test data supplied by Tesla.

  The final choice of design technology for the battery energy storage system will be determined as part of the final design for the Project. Depending on further information that may be available at the final design stage, this alternative could be re-configured to use an alternative or updated battery energy storage technology. If the environmental impacts resulting from the use of an updated or alternative battery energy storage technology were substantially different than what is evaluated in the PR-DEIR, then the PR-DEIR would be updated.

  As the PR-DEIR was being finalized for release, information became available regarding a fire incident on Friday July 30, 2021, in which a Tesla Megapack caught fire during testing at the Victorian Big Battery Project in Victoria, Australia. Following the incident, visible flames had subsided by approximately 5.5 hours later and the Country Fire Association (CFA) with assistance from Fire Rescue Victoria have remained on site to continue to monitor the temperature decline of the two battery packs impacted by the fire. The EPA's air monitoring has shown there has been good air quality in the local community. There were no injuries, the site was disconnected from the grid and there has been no impact to electricity supply. Investigation preparations are underway and physical inspections will commence once the CFA have completed their procedures. This is the first Megapack fire that has occurred other than those started artificially for testing purposes.

  Tesla is still in the process of investigating what occurred, what actions need to be taken to prevent reoccurrence, and whether any changes may be needed to avoid or combat a Megapack fire. Installation of the battery energy storage system at Grayson is not anticipated to begin until the first quarter of 2023. If the results of the investigation into the Tesla fire find that changes in

[17] Alternative 6 was screened out from further consideration. See Executive Summary and Section 5.3.6.

design, testing, or other factors impact the technical studies supporting the PR-DEIR, they will be re-assessed to determine whether any changes in the conclusions of the PR-DEIR are warranted.

- A new switching station, and related facilities.

The Wartsila power island would be located on the northern side of the Project (about the middle of the Utility Operations Center) and the Tesla power island would be located to the southwest. The Boiler Building would need to be removed in order to provide room for a portion of the 75 MW of battery energy storage system and to make room for the new Workshop and Warehouse building.

Additional engineering information regarding the Alternative 7 is provided below:

1) The Wartsila 18V50SG reciprocating internal combustion engine would utilize air-cooled radiators to dissipate heat from the engine jacket water and engine-generator lube oil systems to reduce water consumption. These closed cooling systems require minimal make-up water, reducing the plant's consumptive use of cooling water. Recycled water, processed into demineralized water and then treated to meet Wartsila's requirements, will be used for occasional make-up to the closed cooling systems and on-line turbocharger washes. The engines would be located within an Engine Hall to reduce the radiated noise. The stack emissions control systems and air-cooled radiators would be located outside the building.

2) Each Wartsila unit would include a stack emission control system featuring SCAQMD approved best available control technology consisting of selective catalytic reduction system for the control of nitrogen oxides (NO_x) emissions and an oxidation catalyst to control carbon monoxide (CO) and volatile organic compound (VOC) emissions.

3) The Wartsila units would feature fast starting (from off to full load within ten minutes or less), and fast ramping up and down to support spinning and non-spin reserves, regulation and reactive power support, and integration of renewable resources.

4) The Tesla Megapack Lithium-ion battery energy storage systems utilize an integrated liquid cooling and heating system to maintain the battery operating temperature within operating limits. No other external cooling system is needed, further reducing the need for consumptive cooling water use.

5) A new water treatment system would treat and demineralize the recycled water, primarily for use in Unit 9 for power augmentation and NO_x reduction, and occasional use by the Wartsila engines for makeup to the closed cooling water systems and turbocharger on-line water washing. The water treatment system would use a combination of installed equipment in combination with mobile trailer-mounted micro-filtration, reverse osmosis, and demineralizer systems to batch process recycled water that would then be stored on-site in tanks. The mobile trailer-mounted demineralizer would be regenerated off-site and brought back as needed to maintain minimum storage volumes. Reject water from the

reverse osmosis system would be discharged to the process drains and from there to the Glendale sewer system.

6) New plant control room and plant operations offices would also be constructed.

7) A new Workshop/Warehouse to serve the Grayson Power Plant would also be constructed.

8) All interconnections to the City's electrical grid would occur on-site and no new off-site electrical transmission line modification or construction would be necessary for the Project.

9) The Project would be designed, constructed, and inspected in accordance with the current California Building Standards Code, also known as Title 24, California Code of Regulations, which encompasses the California Building Code, California Administrative Code, California Electrical Code, California Mechanical Code, California Plumbing Code, California Energy Code, California Fire Code, California Code for Building Conservation, California Reference Standards Code, and all other applicable laws, ordinances, regulations, and standards in effect at the time initial design plans are submitted to the City for review and approval.

10) The Project would utilize certified engineers and geologists to perform design reviews, obtain approval by the City, and monitor construction to ensure compliance with laws, ordinances, regulations, and standards. In addition, certified third party inspections would be performed to ensure that any work requiring such inspection is constructed in accordance with LORS, including excavation and backfill work and the installation of piles.

11) Structural support would be in accordance with the recommendations provided in Section 8.0 of the Geotechnical Investigation Report prepared by Black & Veatch and as may be updated after demolition and improving the site geotechnical condition (Appendix B of the PR-DEIR). Deep foundations for power plant structures would utilizes piles.

This Alternative would encompass approximately ten acres within the City's Utility Operations Center located within the Grayson Power Plant existing site.

This Alternative would also include a new Glendale Switching Station to add resiliency to the GWP electrical distribution system, as well as a new aqueous ammonia storage tank and unloading facility for the Wartsila engines.

Additionally, this Alternative would connect to existing off-site linear facilities, such as, natural gas, potable water, recycled water, stormwater discharge, processed wastewater discharge, and sanitary sewer pipelines, and electrical transmission lines that are currently serving the existing facilities.

Underground 69 kV electrical interconnections would connect the new power islands to the existing Kellogg Switching Station and the new Glendale Switching Station. Both Switching Stations are or would be located within the Project boundaries, and entirely within the footprint of the existing City Utility Operations Center property boundaries. From the existing Kellogg Switching Station and new Glendale Switching Station, power generated by the Project would interconnect to GWP's existing distribution system serving the City's electric load.

All interconnections to the City's electrical grid would occur on-site and no new off-site electrical transmission line modification or construction would be necessary for the Project.

This Alternative would use recycled water for the majority of plant operations and would reduce even further the use of potable water provided by the City at the Grayson Power Plant. Potable water would, after completion of the Project, only be used for domestic use, eye wash stations, fire protection, and as an emergency source of water. Potable water would no longer be normally used for equipment cooling or process water purposes, eliminating the use of potable water for Unit 9 and the units that would be demolished.

Wastewater and other process waste generated by the Project and Unit 9 would be treated as required by the discharge permit and discharged into the existing sanitary sewer connection. This discharge would be conveyed back to the Los Angeles-Glendale Water Reclamation Plant, where it would be processed and again recycled to be made available for use at the Project site or at other facilities as recycled water for beneficial use.

On-site stormwater runoff from within the Project site would flow via surface sheet flow and localized gutters to on-site storm drain piping. The storm drain piping would be connected to an on-site detention basin and pump station. Stormwater from the 85th percentile storm would be collected and pumped to a new aboveground storage tank. Stormwater would then be gravity drained from that tank to the Glendale sewer system. During storm events that exceed the design capacity of the stormwater system, overflow runoff would be discharged into the adjacent Verdugo Wash and Los Angeles River through existing stormwater outfalls.

Stormwater that falls within process equipment containment areas would be collected separately from typical site runoff, treated, and discharged into the existing public sanitary sewer system.

Tesla Megapack

The Tesla Megapack is an all-in-one utility-scale energy storage system, fully integrated and AC coupled (electrical connections are made at the 480 V AC terminals). It includes the DC batteries, bi-directional inverter, and thermal management system. A single Tesla Site Controller with intelligent software manages the Megapacks and interfaces with the overall Plant Control System.

The Megapack is capable of various on-grid applications, such as tariff optimization, peak load shaving, energy shifting, and demand response. In addition, the system can operate as a microgrid to support backup and islanded systems.

Each Megapack enclosure includes the following components provided by Tesla:

- A Smart Inverter composed of multiple Powerstage inverters.
- An AC main breaker on the 480 VAC output from the Megapack.
- Battery modules to store electrical energy.
- A thermal system to cool the inverters and batteries.
- A Tesla Site Controller that provides a control interface between the plant control system and the Megapacks as well as an interface for remote diagnostic monitoring of the Megapacks.
- A low voltage interface panel that provides power for auxiliary equipment.

The bi-directional Smart Inverter converts supplied AC power to DC power to charge the rechargeable lithium-ion battery packs as well as converting DC power from the battery packs to supply AC power to the GWP transmission system.

The Megapack is rated in terms of net power and energy at the AC output terminals of the Megapack. Loads and losses, including converters efficiency losses, thermal system losses, auxiliary loads, and chemical/ionic losses are considered internal to the system and ratings are net of these loads.

The Tesla Site Controller is a turnkey controller that actively monitors the system's performance, displays operating information to the control room and system operators via various interfaces, and offers multiple automated modes of operation.

The Tesla Site Controller communicates to each Megapack over a private Transmission Control Protocol (TCP) network. The controller aggregates real-time information from all Megapacks and leverages the information to optimize the commands sent to and operation of each Megapack.

Tesla's BESS power island would be comprised of the following major components

- Each Megapack is rated at approximately 3,000 kilowatt-hour (kWH) and 750 kilovolt-amps (kVA), 480 V output, three-phase 60 hertz (Hz).
- Each medium voltage step up transformer is rated at 3,400 kVA with a 34.5 kV delta primary connection and 480 V wye solidly grounded secondary connection, FR3 (a natural ester derived from renewable vegetable oils) filled, outdoor rated, and pad-mounted with secondary oil containment for spill prevention.
- Medium Voltage switchgear lineups based on an aisleless outdoor rated metal clad Main-Tie-Main configuration providing full power redundancy to the medium voltage collection system. The switchgear is rated nominally at 34.5 kV, 1200 amps (A), and 25 kiloamps (kA) short circuit interrupt rating and includes microprocessor-based protective relays.

- A Controls Equipment Building - consisting of a prefabricated, outdoor rated and temperature-controlled metal enclosed building. It will house all the control equipment such as the Tesla Site Controller, control, and data acquisition system, 125 volts direct current (VDC) low voltage auxiliary power distribution, and 125 VDC station battery system.

- Each generator step-up transformer is rated at 55 megavolt-amps (MVA) with a 69 kV delta primary connection and 34.5 kV wye resistance grounded secondary connection, and FR3 filled. Each transformer is located within a secondary oil containment for spill prevention with fire barriers as needed to protect adjacent equipment in the event of catastrophic failure. Each transformer would deliver the full output of the Tesla power island to its respective switching station (Kellogg and Glendale).

The energy storage system would provide capacity for:

- A fast response source of power (within the limits of the stored energy),

- Spinning reserve, regulation up and down, and reactive power (VAR) support without the need to operate thermal generation, and

- A means to store and time-shift excess renewable energy (within the limits of the available storage capacity).

Wartsila 18V50SG

The Wartsila 18V50SG is a four-stroke, spark-ignited lean-burn gas engine. The eighteen-cylinder engine is arranged in a “V” configuration. Each bank of nine cylinders is fed by its own exhaust gas driven turbocharger. Each cylinder is approximately 19.7 inches in diameter with a stroke of approximately 22.8 inches. The engine has a net thermal efficiency of approximately 41 percent and operates at 514 revolutions per minute (rpm). The engines are started using high pressure compressed air. They can start and be at full power within ten minutes.

The thermal power island would consist of five Wartsila W18V50SG reciprocating internal combustion engines, each connected to their own electric power generator. Each engine would have its own emission control system, air-cooled radiator, and auxiliary equipment. Each unit has a capacity of 18.8 MW_{gross} and 18.5 MW_{net} at average annual ambient site conditions. The five units would be located within a common Engine Hall with an adjacent Utility Building containing the electrical and mechanical rooms, and a local control room. The five engine-generators would each connect to two fully redundant generator step-up transformers, with one connected to the existing Kellogg Switching Station and the second to a new Glendale Switching Station. The Wartsila engines provide quick-starting operational flexibility to efficiently serve peak load and other services on an as-needed basis.

The Wartsila power island would be comprised of the following major components:

- Five 18V50SG reciprocating internal combustion engine generators - each engine is rated at 18,817 kW, 0.8 power factor, 13,800 V output, three-phase 60 Hz.

- One Wartsila Operator Information System (WOIS) to manage the Wartsila engines and which interfaces with the overall Plant Control System through which the plant operators control the Tesla. Wartsila, and other plant equipment.

- Two (2) three-winding generator step-up transformers – each transformer is rated at 142 MVA with a 69 kV wye primary connection and two 13.8 kV delta resistance grounded secondary connections and are FR3 filled. One of the two secondary windings is connected to a bus that has three engine generators connected to it, and the other secondary winding is connected to a bus that has two engine generators connected to it. This allows one transformer to deliver the full output of all five generators when needed. Each transformer is located within a secondary oil containment for spill prevention with fire barriers as needed to protect adjacent equipment in the event of catastrophic failure. Each transformer can deliver the full output of the Wartsila power island to its respective switching station (Kellogg and Glendale).

- One (1) Medium Voltage switchgear lineup - the switchgear lineup is an indoor rated metal clad system rated nominally at 13.8 kV, 4000 A, and includes microprocessor-based protective relays.

- One (1) Low Voltage switchgear lineup - the switchgear lineup is based on an indoor rated metal clad Main-Tie-Main configuration providing full power redundancy to the low voltage auxiliary loads. The switchgear is rated nominally at 480 V, 3200 A, and includes protective trips.

- Two (2) auxiliary transformers – each dry type transformer is rated at 2.5 MVA with a 13.8 kV primary connection and a 480 V secondary connections. Each transformer can carry the full auxiliary load of the five engines.

- Two (2) 69 kV breakers and associated disconnect switches, microprocessor-based protective relays, and transition structures for the underground 69 kV cable interconnection for both the existing Kellogg and new Glendale Switching Stations.

- One Gas Pressure Reduction Station to filter and reduce the pressure of the incoming natural gas from approximately 300 psig down to 100 psig.

- One 15,000-gallon 19 percent aqueous ammonia storage tank with containment.

- One (1) Engine Hall - consisting of a steel and concrete construction building that encloses the engines.

- One (1) Utility Building – consisting of a steel construction building adjacent to the Engine Hall the electrical room, mechanical equipment room, and a local control room.

Demolition

The Grayson Power Plant currently has eight operating generating units (Units 1, 2, 3, 4, 5, 8A, 8BC, and 9) and ancillary facilities that, except for Unit 9, will be removed as part of this Alternative. Units 1 through 5, 8A, and 8BC along with their existing cooling towers, buildings, and all ancillary systems including foundations and underground utilities not associated with Unit 9 or required as part of the repowered facility (such as the Kellogg Switching Station) would be demolished and removed in order to make room for the new facilities. Unit 9 would remain in operation during the demolition and construction phases and would be integrated into the Project facilities.

The existing water treatment facilities are old and would be replaced in a different location with a new smaller capacity system that uses recycled water in place of potable water and a combination of permanently installed and mobile trailer-mounted equipment. This system, if space permits for its installation, would support Unit 9 operation during demolition and construction, and Unit 9 and the Wartsila engines during operations. If space does not permit, a smaller temporary system with potable water as feed will be installed to serve Unit 9 until space is made available for the larger recycled water treatment system to be installed. The existing potable water system would be modified to provide fire protection during demolition, construction, and operations as well as potable water.

Demolition and removal work are expected to take twelve (12) months and if this project alternative were selected, would start during the first quarter of 2022.

Construction

Construction of the Tesla BESS and the Wartsila power islands would commence in the first quarter of 2023 and would be expected to extend through the third quarter of 2024.

In addition to field office siting, areas within the site would be used for offloading and staging and for storage of materials, equipment, and vehicles. This Alternative would utilize space within the Utility Operations Center and under adjacent Highway 134 to provide construction laydown and construction parking.

Some limited off-site laydown space is planned at this time for the following reasons:

1. Construction of the Tesla power island would begin after demolition is complete. The Tesla power island would be built early in the construction sequence in order to supplement Glendale's local energy sources as soon as practical. Because the Megapacks arrive by truck and are off-loaded directly onto their foundations, no off-site laydown would be needed.

2. Construction of the Wartsila power island would also begin after demolition is complete. However, as the engines must be assembled on site, it is expected that the engine components may need to be staged at an off-site location between their off-loading from the ship bringing them from Finland and their delivery to the Project site for assembly.

Construction access would be generally from Fairmont Avenue. Large or heavy equipment, such as the Tesla Megapacks, Wartsila engines, and generator step-up transformers would be delivered to the site by heavy haul truck/trailer.

Construction activities at the site would proceed in parallel with the normal GWP work activities taking place at other areas of the Utility Operations Center.

New construction for the Tesla/Wartsila Repowering Project Alternative would include the following new buildings:

- An Engine Hall approximately 43-feet tall, 160-feet long and 104-feet wide.
- A Utility Building approximately 26-feet tall, 107-feet long and 31-feet wide.
- A control room/operations building approximately 25 feet tall, 140-feet long and 70 feet wide.
- A Workshop and Warehouse Building approximately 20-feet tall, 95-feet long and 55-feet wide.
- Small single-story buildings/enclosures to serve as enclosure for the Continuous Emissions Monitoring Systems, and house control and communication equipment.

In addition, there would be five exhaust stacks, each approximately 80 feet tall.

The Project would be designed using commercially-proven technology equipped with stringent environmental protection, monitoring, and safety systems to provide safe and reliable operation over a 30-year operating life. The Tesla/Wartsila Alternative’s reciprocating internal combustion engines and associated equipment would feature the use of South Coast Air Quality Management District (SCAQMD) approved best available control technology to meet air pollution emission standards.

During construction, existing Utility Operations Center utilities would be used for the construction offices, laydown area, and the Project site. The City would provide temporary construction power. Area lighting would be provided and strategically located for safety and security.

Construction water would be potable water supplied by the existing GWP water system and by water truck deliveries, as necessary. Water use would be primarily for dust suppression as well as hydro testing of piping as needed. The hydro test water would be tested, and if suitable, reused, or disposed of in accordance with applicable LORS. Other construction water uses may include compaction, concrete placement, grouting, curing, and cleaning. Portable toilets would be provided on-site.

Operations

The facility would be manned and capable of being operated year-round (24 hours per day, 7 days per week, 365 days a year) to serve electricity demand and provide ancillary services necessary for GWP to integrate renewable energy into its energy portfolio, manage the intermittent energy at the interconnection with the Balancing Authority Area (LADWP), and provide local system reliability.

With exception of planned and unplanned outages, the BESS would be in-service year-round with its primary application being to provide spinning reserve which can be accomplished without creating any emissions. Its secondary application would be to provide load regulation up/down, as well as voltage and frequency support, serving as a generator or a load as needed to help keep transmission imports and system load in balance, including integrating renewables. When import capability is greater than the GWP load, the BESS could also be used for "time-shifting" excess energy from the middle of the day when solar energy is abundant to early evening periods when solar energy is not available. The BESS would be committed to provide up to the full 75 MW of output during peak load periods subject to available energy.

The Wartsila units would be dispatched when needed to 1) provide ancillary services when the Grayson BESS is incapable of doing so due to its energy state, or 2) serve load when imports and the Grayson BESS alone are incapable of doing so. The Wartsila units would be operated preferentially over Unit 9 because 1) they are more efficient, particularly at low loads, and 2) with their increased granularity (18 MW full load for a single Wartsila engine versus 48 MW for Unit 9), they can better match changes in load in a stepwise fashion.

Both the BESS and Wartsila units would be able to provide ancillary services and serve system load, offering GWP a flexible resource to meet future needs as forecasted in the 2019 Integrated Resource Plan. All would have fast startup, significant turndown, fast ramp rates, automatic generation control, and 0.8 power factor generators.

While the BESS and Wartsila units, in concert with Unit 9 and other resources, would be able to cover peak load, it would not fully cover required contingencies.

5.2.6.2 Potential Environmental Impacts – Alternative 7

Following are the potential environmental impacts that would result from the Tesla/Wartsila Repowering Project Alternative.

Potential Environmental Impacts Less than those of the Project

The Tesla/Wartsila Repowering Project Alternative emissions are significantly reduced compared to the proposed Project. This reduction is largely achieved through a reduction in operating hours resulting in fewer emissions and reduced capability to cope with contingent events. The Tesla/Wartsila Repowering Project Alternative would involve the same demolition and similar construction activities as the proposed Project. Consequently, the short-term aesthetics impacts, criteria air pollutant emissions, and greenhouse gas emissions associated with demolition and construction of the Tesla/Wartsila Repowering Project Alternative would be similar to the proposed Project. However, the Tesla/Wartsila Repowering Project Alternative would include different physical components and equipment with different emissions of criteria air pollutants, toxic air contaminants, and greenhouse gases during operation. See analysis below in Tables 5-2 and 5-4. The Tesla/Wartsila Repowering Project Alternative would combust a lower volume of natural gas and generate less electricity than the proposed Project but would include a BESS that could be charged with renewable sources. See comparison below in Table 5-1.

Aesthetics

Photo simulations representing the Tesla/Wartsila Repowering Project Alternative from Key Observation Points 1 (Fairmont Avenue and Flower Street), 4 (San Fernando Road and Highland Avenue), 5 (Skyline Trail), and 6 (Confluence Park) are included below as Figures 5-2, 5-3, 5-4, and 5-5.

a) Simulation of Proposed Project from Fairmont Avenue and Flower Street.

b) Simulation of the Tesla / Wartsilla Repowering Project Alternative.

Stantec

Project Location
Glendale, CA

Project
Grayson Repowering Project

Figure No.
5-2

Title
KOP 1 – View of Proposed Project and Alternative 7 from Intersection of Fairmont Avenue and Flower Street

a) Simulation of Proposed Project from San Fernando Road and Highland Avenue.

b) Simulation of the Tesla / Wartsilla Repowering Project Alternative.

Stantec

Project Location
Glendale, CA

Project
Grayson Repowering Project

Figure No.
5-3

Title
KOP 4 – View of Proposed Project and Alternative 7 from Intersection of San Fernando Road and Highland Avenue

a) Simulation of Proposed Project from Skyline Trail.

b) Simulation of the Tesla / Wartsilla Repowering Project Alternative.

Stantec

Project Location
Glendale, CA

Project
Grayson Repowering Project

Figure No.
5-4

Title
KOP 5 – View of Proposed Project and Alternative 7 from Skyline Trail

a) Simulation of Proposed Project from Confluence Park.

b) Simulation of the Tesla / Wartsilla Repowering Project Alternative.

Stantec

Project Location
Glendale, CA

Project
Grayson Repowering Project

Figure No.
5-5

Title
KOP 6 – View of Proposed Project and Alternative 7 from Confluence Park

As shown in Figure 5-2, the internal combustion engine generator exhaust stacks associated with the Tesla/Wartsila Repowering Project Alternative as well as the existing Unit 9 exhaust stacks are prominently visible from Key Observation Point 1. However, the five exhaust stacks associated with the Tesla/Wartsila Repowering Project Alternative would be approximately 80 feet above surrounding ground level. As shown in Figure 5-2 and evidenced by the visibility of two existing trees, the exhaust stacks and visible structures associated with the Tesla/Wartsila Repowering Project Alternative and the existing Unit 9 exhaust stack would obscure the existing viewshed from Key Observation Point 1 less than the proposed Project. The Tesla/Wartsila Repowering Project Alternative would therefore have less aesthetics impacts from Key Observation Point 1 compared to the proposed Project.

As shown in Figure 5-3, the new Glendale Switching Station associated with the Tesla/Wartsila Repowering Project Alternative would be visible from Key Observation Point 4 and partially obscure the Santa Monica Mountains in the background. The five internal combustion engine generator exhaust stacks and engine hall are also subtly visible between the structural elements of the new Glendale Switching Station. The generation units, four exhaust stacks, and other structures associated with the proposed Project would be higher in the skyline and obscure more of the viewshed from Key Observation Point 4 compared to the Tesla/Wartsila Repowering Project Alternative. The Tesla/Wartsila Repowering Project Alternative would therefore have less aesthetics impacts from Key Observation Point 4 compared to the proposed Project.

As shown in Figure 5-4, the internal combustion engine generator building, exhaust stacks, radiators, Tesla Megapacks, smaller single-story enclosures and control buildings, and Glendale Switching Station associated with the Tesla/Wartsila Repowering Project Alternative are visible from Key Observation Point 5. While the visible components of the Tesla/Wartsila Repowering Project Alternative and proposed Project only occupy a small portion of the viewshed and appear largely comparable, the facilities associated with the proposed Project occupy more of the viewshed compared to the Tesla/Wartsila Repowering Project Alternative. The Tesla/Wartsila Repowering Project Alternative would therefore have less aesthetics impacts from Key Observation Point 5 compared to the proposed Project.

As shown in Figure 5-5, the internal combustion engine generator building, exhaust stacks, radiators, Tesla Megapacks, gathering system transformers, and stormwater storage tank associated with the Tesla/Wartsila Repowering Project Alternative are visible from Key Observation Point 6. However, facilities associated with the proposed Project would occupy the viewshed and obscure the mountains in the background substantially more than the Tesla/Wartsila Repowering Project Alternative. The Tesla/Wartsila Repowering Project Alternative would therefore have less aesthetics impacts from Key Observation Point 6 compared to the proposed Project.

Because the Tesla/Wartsila Repowering Project Alternative would have less aesthetics impacts from all the Key Observation Points modeled, the Tesla/Wartsila Repowering Project Alternative would have less aesthetics impacts compared to the proposed Project.

Air Quality

The generation capacity and natural gas combustion associated with the Tesla/Wartsila Repowering Project Alternative and proposed Project are summarized below in Table 5-1.

Table 5-1 Natural Gas-Fueled Generation Capacity and Combustion of Wartsila Reciprocating Internal Combustion Engines and Proposed Project

Scenario	Natural Gas-Fueled Generation Capacity (MW)	Natural Gas Combustion (MMBtu/Yr)
Proposed Project	262	9,740,104
Five Wartsila RICEs (Alternative 7)	93	1,018,080
Note: Does not include existing Unit 9 that would be retained under the Tesla/Wartsila Repowering Project Alternative and the proposed Project.		

As shown in Table 5-1, the Tesla/Wartsila Repowering Project Alternative involves substantially less natural gas-fueled generation capacity (-169 MW) and natural gas combustion (-89.5 percent) than the proposed Project. Criteria air pollutant, hazardous air pollutant, and greenhouse gas emissions were estimated for the Tesla/Wartsila Repowering Project. Details and assumptions used for estimating emissions are included in Appendix C.1 of the PR-DEIR. Table 5-2 below summarizes the annual emissions of criteria air pollutants for the Tesla/Wartsila Repowering Project Alternative and the proposed Project.

Table 5-2 Summary of Tesla/Wartsila Repowering Project Alternative and Proposed Project Criteria Air Pollutant Emissions

Equipment	NO_2 (tons/year)	CO (tons/year)	PM10 (tons/year)	VOC (tons/year)	SO_2 (tons/year)
Total Emissions from Proposed Project Emissions Units	51.5	37.6	15.1	13.1	3.0
Total Emissions from Tesla/Wartsila Repowering Project Alternative Emissions Units	8.2	13.9	5.0	8.4	0.4
Total 2015-2016 Baseline Emissions[1]	29.9	67.0	15.4	12.0	2.2
Total Updated 2018 Baseline Emissions[1]	28.5	56.9	8.6	6.1	1.0
Net Emissions Increase (Decrease) of Proposed Project relative to 2015-2016 Baseline Emissions	21.6	(29.4)	(0.3)	1.1	0.8
Net Emissions Increase (Decrease) of Tesla/Wartsila Repowering Project Alternative relative to 2015-2016 Baseline Emissions	(21.7)	(53.1)	(10.4)	(3.6)	(1.8)
Net Emissions Increase (Decrease) of Tesla/Wartsila Repowering Project Alternative relative to Updated 2018 Baseline	(20.3)	(43.0)	(3.6)	2.3	(0.6)
Note:					

Equipment	NO_2 (tons/year)	CO (tons/year)	PM10 (tons/year)	VOC (tons/year)	SO_2 (tons/year)
1. The emissions of replaced units were calculated based on the average emissions reported in SCAQMD Annual Emission Reports. Emissions from unit 9 are not included in this table because there are no modifications on Unit 9. Therefore, emissions from unit 9 will not have any effect on the net emission increase/decrease.					

As shown in Table 5-2, annual emissions of criteria air pollutants of the Tesla/Wartsila Repowering Project Alternative are lower than the proposed Project, with the exception of VOC, and represent a net reduction compared to existing emissions. Potential VOC emissions of Alternative 7, however, remain lower than potential emissions from the proposed Project and will be offset through the application of emission reduction credits pursuant to SCAQMD requirements if warranted. Table 5-3 below summarizes the potential health risks to residential receptors located adjacent to the Grayson Power Plant for the Tesla/Wartsila Repowering Project Alternative and the proposed Project.

Table 5-3 Summary of Tesla/Wartsila Repowering Project Alternative and Proposed Project Health Risks to Adjacent Residential Receptors

Health Risk	Significance Threshold	Tesla/Wartsila Repowering Project Alternative	Proposed Project
Maximum Individual Cancer Risk	≤10	0.5	0.91
Acute Hazard Index	≤1	0.06	Less than 0.01
Chronic Hazard Index	≤1	0.03	Less than 0.01
Note: Health risks expressed as number in one million. Rounded to nearest hundredth.			

As shown in Table 5-3, the maximum individual cancer rate of the Tesla/Wartsila Repowering Project Alternative and the proposed Project are both substantially lower than the significance threshold. However, the maximum individual cancer rate of the Tesla/Wartsila Repowering Project Alternative is lower than the proposed Project. Additionally, the acute and chronic hazard index of the Tesla/Wartsila Repowering Project Alternative and the proposed Project are both substantially lower than the significance thresholds. While the acute and chronic hazard index of the Tesla/Wartsila Repowering Project Alternative is higher than the proposed Project, they respectively remain 94 and 97 percent below the significance thresholds.

Energy

The Tesla/Wartsila Repowering Project Alternative would increase the City's ability to integrate renewable resources as a result of the BESS compared to the proposed Project that only includes natural gas fueled electricity generation. The Tesla/Wartsila Repowering Project Alternative would therefore have a lower potential to conflict with or obstruct a state or local plan for renewable energy or energy efficiency and would therefore have lower potential energy impacts than the proposed Project.

Greenhouse Gas Emissions

Table 5-4 below summarizes the annual greenhouse gas emissions for the Tesla/Wartsila Repowering Project Alternative and the proposed Project.

Table 5-4 Summary of Tesla/Wartsila Repowering Project Alternative and Proposed Project Greenhouse Gas Emissions

	Annual Greenhouse Gas Emissions (Metric Tons CO2e)
Proposed Project	476,040
Tesla/Wartsila Repowering Project Alternative	54,063

As shown in Table 5-4 the natural-gas fueled generation units associated with this Alternative would emit approximately 54,063 metric tons of CO2e/year. By comparison, the natural gas-fueled electrical generation units associated with the proposed Project would emit approximately 476,040 metric tons of CO2e/year. This Alternative therefore has less potential greenhouse gas emissions impacts than the proposed Project.

Noise

Operation of the Wartsila engines and related equipment would generate noise. Table 5-5 shows a compassion of Project and Alternative 7 operation noise at sensitive receptors during the day and night. See Appendix E in the PR-DEIR for additional details.

Table 5-5 Predicted Operation Phase Noise Levels – Proposed Project and Alternative 7

Scenario	**Receptor**	**Predicted Operational Noise (dBA)**	**Daytime Ambient Sound Levels (dBA)**			**Nighttime Ambient Sound Levels (dBA)**		
			Current	**New**	**Increase**	**Current**	**New**	**Increase**
Proposed Project	R1	51.0	54.2	55.9	**1.7**	49.6	53.4	**3.8**
	R2	53.1	64.7	65.0	**0.3**	52.8	56.0	**3.2**
	R3	52.6	57.1	58.4	**1.3**	52.8	55.7	**2.9**
	R7	57.5	60.6	62.3	**1.7**	58.8	61.2	**2.4**
	R8	58.4	69.6	69.9	**0.3**	65.6	66.4	**0.8**
Alternative 7	R1	47.6	54.2	55.1	**0.9**	49.6	51.7	**2.1**
	R2	50.7	64.7	64.9	**0.2**	52.8	54.9	**2.1**
	R3	52.2	57.1	58.3	**1.2**	52.8	55.5	**2.7**
	R7	53.8	60.6	61.4	**0.8**	58.8	60.0	**1.2**
	R8	55.0	69.6	69.7	**0.1**	65.6	66.0	**0.4**

As shown in Table 5-5, the Tesla/Wartsila Repowering Project Alternative would result in lower noise level increases during the day and night compared to the proposed Project at all receptors modelled. Therefore, the Tesla/Wartsila Repowering Project Alternative would have lower noise impact than the proposed Project.

In summary, potential aesthetics, air quality, energy, greenhouse gas emissions, and noise impacts of the Tesla/Wartsila Repowering Project Alternative would be less than those of the proposed Project.

Potential Environmental Impacts Similar to Those of the Project

Similar to the Project, this Alternative involves electrical generation at the same 10-acre urban industrial site already permitted, developed, and operated as a power plant. The primary difference is that this Alternative includes a 75 MW/300 MWH BESS and five Wartsila reciprocating internal combustion engines with an approximate thermal generation capacity of 93 MW, compared to no BESS and a total thermal generation capacity of approximately 262 MW from two simple cycle and two combined cycle generation units associated with the proposed Project.

Agriculture and Forestry Resources, Biological Resources, Cultural/Tribal Cultural Resources, Environmental Justice, Land Use and Planning, Mineral Resources, Population and Housing, Public Services, Recreation, Socioeconomics, and Wildfire.

Similar to the proposed Project, the Tesla/Wartsila Repowering Project Alternative would not occur on lands zoned or used for agriculture or forestry resources, or mineral resources. Both this Alternative and the proposed Project would occur within the limits of the developed power plant site which lacks sensitive biological, archaeological, and tribal cultural resources and high fire hazard areas. The surrounding community was determined not to be considered an environmental justice community (refer to Appendix A, Section 2.19 of the Initial Study included in the 2018 Final EIR). The Boiler Building would be demolished and this Alternative, similar to the proposed Project, would result in a significant and unavoidable discretionary historic resource impact.

Geologic, Traffic, and Utilities and Service Systems

Demolition activities, ground disturbances during construction, site drainage, susceptibility to geologic hazards such as seismically induced ground shaking and liquefaction potential, operation phase vehicle trips, and utility/service systems needs associated with the Tesla/Wartsila Repowering Project Alternative would be similar to the proposed Project.

Hazards and Hazardous Materials

The emissions control system for the Wartsila reciprocating internal combustion engines would utilize 19 percent aqueous ammonia stored in a 15,000-gallon capacity above ground storage tank. An off-site consequence analysis was performed for the accidental release of aqueous ammonia from the 15,000-gallon storage tank associated with the Tesla/Wartsila Repowering Project Alternative. The analysis consists of a worst-case accidental release scenario involving the failure and complete discharge of the contents of the storage tank into the secondary containment structure below the tank. Similar to aqueous ammonia associated with the proposed Project, the results of the off-site consequence analysis for the Tesla/Wartsila Repowering Project Alternative which are included in Appendix D.1 of the PR-DEIR demonstrate that the worst-case release of ammonia would not exceed applicable Occupational Safety and Health Administration, U.S. Environmental Protection Agency, and California Energy Commissions health thresholds.

Under normal operations, the Megapacks do not store or generate hazardous materials in quantities that would represent a risk to off-site receptors. However, a fire or thermal runaway event of a Megapack may release hazardous materials to the environment. Based on the design of the Megapack and confirmed through testing conducted by Tesla, a reasonable worst-case scenario for Alternative 7 would be a fire or thermal runaway event consuming one Tesla Megapack and releasing carbon monoxide and hydrogen fluoride. An analysis of an Alternative 7 BESS fire and subsequent release of carbon monoxide and hydrogen fluoride was prepared using the U.S. Environmental Protection Agency's (USEPA) Areal Locations of Hazardous Atmospheres (ALOHA) model to identify estimated distances to regulatory-established toxic endpoints to determine potential significance of hazards impacts pursuant with CEQA. The analysis showed no significant impact.

With respect to the assessment of potential impacts associated with an accidental release of carbon monoxide, four offsite "bench mark" exposure levels were evaluated, as follows: (1) the Occupational Safety and Health Administration's (OSHA) Immediately Dangerous to Life and Health (IDLH) level; (2) the National Oceanic and Atmospheric Administration (NOAA) Office of Response and Restoration's Acute Exposure Guideline Levels (AEGLs) AEGL-3 which predicts that the general population, including susceptible individuals, could experience life-threatening health effects or death; (3) AEGL-2 which predicts that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape; and (4) AEGL-1 level (not established for carbon monoxide) which predicts that the general population, including susceptible individuals, could experience notable discomfort, irritation, or certain asymptomatic non-sensory effects. However, the effects are not disabling and are transient and reversible upon cessation of exposure.

The results of the BESS fire OCA for Alternative 7 are included in Appendix D.2 of the PR-DEIR and summarized below in Table 5-6 below.

Table 5-6 Carbon Monoxide and Hydrogen Fluoride Modeling Results

Chemical	Distance to IDLH[a]	Distance to AEGL-3[b]	Distance to AEGL-2[b]	Distance to AEGL-1[b]
Carbon Monoxide	Not Exceeded	Not Exceeded	167.98 ft	Not Established
Hydrogen Fluoride	Not Exceeded	Not Exceeded	Not Exceeded	108.01 ft

[a] Benchmark based on a 30-minute exposure or averaging time

[b] Benchmark based on a 60-minute exposure or averaging time

The power plant facility boundary would be located approximately 76 feet (23.16 meters) from a Megapack. The results of the OCA for the worst-case release of carbon monoxide indicates that the concentrations for benchmark criteria IDLH (1200 ppm) and AEGL-3 (330 ppm) would not extend beyond the facility fence line. AEGL-1 thresholds have not been established for carbon monoxide. However, the distance to AEGL-2 thresholds could potentially extend beyond the fence line by a distance of approximately 91.99 feet (28.04 meters). As displayed in PR-DEIR Figure 1 of Attachment D.2, this would be mainly in a lightly trafficked segment of Fairmont Avenue on the southwestern fence line of the Grayson Power Plant. Thresholds would not be exceeded for any residences, schools, or commercial land uses. Receptors along Fairmont Avenue would be predominantly mobile receptors such as vehicles that would not be exposed to substantial concentrations of carbon monoxide for the 60 minutes assumed in the reasonable worst-case scenario and AEGL thresholds. For example, the carbon monoxide AEGL-2 for a 30-minute and 10-minute exposures are 150 ppm and 420 ppm.

The results of the OCA for the worst-case release of hydrogen fluoride indicates that concentrations for benchmark criteria IDLH (30 ppm), AEGL-3 (44 ppm), and AEGL-2 (24) would not extend beyond the facility fence line. However, the distance to the AEGL-1 benchmark criteria (1 ppm) could potentially extend beyond the fence line by a distance of approximately 32.02 feet (9.76 meters).

An infrared camera system would be installed as part of this Project alternative to monitor the Megapacks. In the event of thermal runaway within the Megapack, the camera would detect the unit's change in temperature and provide notification to the plant operators. The plant operators would then contact the local fire department. The initial detection occurs approximately 15 minutes prior to smoke being released from the Megapack units. According to the City of Glendale, the average response time for the Local Fire Department is four minutes and 36 seconds[18]. The Fire Department would arrive on site in less than five minutes of the initial notification as the nearest fire station, Station 27, is located approximately 1.23 miles from the proposed Project. The affected section of Fairmont Avenue and the adjacent pedestrian bike path on the west side of Fairmont Avenue would immediately be closed to the public. The closure would remain in place until the area is deemed safe to the public. As a result, any long-term or permanent effects to the public from carbon monoxide are unlikely to occur. Additionally, the AEGL-1 threshold of exceedance for hydrogen fluoride predicts that the general population, including susceptible individuals, could experience temporary symptoms of exposure.

As a result, this Alternative would have similar environmental impacts as the proposed Project on agriculture and forestry resources, biological resources, cultural/tribal cultural resources, environmental justice, geology and soils, hazards and hazardous materials, hydrology, noise, and water quality, land use and planning, mineral resources, population and housing, public services, recreation, socioeconomics, transportation, utilities and service systems, and wildfire.

<u>Potential Environmental Impacts Greater than those of the Project</u>

This Alternative would not have any potential environmental impacts greater than those of the proposed Project.

5.2.6.3 Objectives Consistency Evaluation – Alternative 7

This Alternative would meet some of the Project objectives but would also not meet or meet them as well as the proposed Project. Specifically, the Tesla/Wartsila Repowering Project Alternative:

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[18] City of Glendale, 12.4 Public Safety Response, available at https://www.glendaleca.gov/government/departments/community-development/neighborhood-services/glendale-quality-of-life-indicators/12-4-public-safety-response.

1. Would integrate with local and remote distributed renewable energy resources to provide sufficient and flexible power and energy capacity to meet peak load while accommodating the loss of the single largest contingency. However, while the Tesla/Wartsila Repowering Project Alternative meets the N-1 contingency reserve requirements, until 2027, when the City will acquire an additional 72 MW of transmission, it does not meet the N-1-1 contingency reserve requirements and therefore, in the short term, would not provide sufficient capacity and energy to ensure reliable service at all times for the City.

2. Would utilize current and reliable technology and control systems to provide reliable, cost effective, and flexible generation to support the City's compliance with California's Renewable Portfolio Standards.

3. Would provide a local generation resource, but until the City acquires the additional 72 MW of additional transmission in 2027, is not one that is sufficient to meet resource adequacy requirements, and the City's obligation within the Balancing Area (BA) to balance load and resource at the interconnection with the BA, in accordance with industry standards including NERC/WECC requirements (including the N-1-1 contingency condition); thus, in the short term, would not fully provide local reliability or contribute to grid stability within the Los Angeles Basin.

4. Would provide a locally controlled source of generation and would support the City's reliance on power imports from remote generation locations through a congested transmission grid system subject to planned and unplanned outages and de-rates.

5. Would replace the aged, unreliable, less efficient, high maintenance steam boilers, with new generation that would comply with offset exemption provisions of SCAQMDs Rule 1304(a)(2) for advanced technology replacement of electric utility steam boilers.

6. Would be able to be located at the existing City property already permitted and used for generation and would minimize the need for major infrastructure improvements such as fuel supply, water, wastewater, recycled water, and transmission facilities to the same extent as the proposed Project.

7. Would provide generation that is efficient to maintain and would necessitate power imports from remote generation with less cost certainty which does not minimize the impact on the rates and help manage costs of delivering energy to the City's customers to the same degree as the proposed Project.

8. Would support water conservation efforts by eliminating the use of potable water for generation purposes.

9. Would have a higher reduction in emissions and water consumption than the proposed Project. The Tesla/Wartsila Repowering Project Alternative involves substantially less natural gas-fueled generation capacity (-169 MW) and natural gas combustion (-89.5 percent) than the proposed Project. Additionally, the Wartsila engines have virtually no consumptive water use.

5.2.6.4 Summary – Alternative 7

The Tesla/Wartsila Repowering Project Alternative would involve 89.5 percent less combustion of natural gas compared to the Project. As a result, it would have lower air pollutant and greenhouse gas emissions compared to the Project. The BESS, if charged with renewable sources, would represent a reduced potential energy impact compared to the proposed Project that involves only natural gas fueled electricity generation. It would also virtually eliminate all consumptive water use. The physical components of the Tesla/Wartsila Repowering Project Alternative would obscure views less than the proposed Project from the key observation points simulated and result in a lower increase in noise levels at sensitive receptors compared to the Project. The Tesla/Wartsila Repowering Project Alternative would have similar potential environmental impacts to all other environmental factors evaluated pursuant to CEQA. The Tesla/Wartsila Repowering Project Alternative would not result in any potential environmental impacts greater than the proposed Project.

For these reasons, the overall environmental impacts of the Tesla/Wartsila Repowering Project Alternative are expected to be less than the proposed Project.

5.2.7 Alternative 8 - Tesla/Unit 8 Refurbishment Project Alternative

5.2.7.1 Project Description

The Tesla/Unit 8 Refurbishment Project Alternative would retain and refurbish the existing Units 8A and 8BC gas turbine combined cycle units and add 75 MW/300 MWH Battery Energy Storage System (BESS). All the existing Units 1-5 boiler and steam turbine equipment, and Units 8A and 8BC equipment except for the gas turbine generators, will be shut down and removed (Units 6 and 7 were previously removed). Grayson’s generating capabilities would be comprised of the following generation and storage units totaling 101 MW net at average annual site conditions and 75MW/300 MWH of energy storage:

- A 75MW/300 MWH battery energy storage system. Through the Clean Energy RFP process, the City selected Tesla’s Megapack technology as the preferred energy storage technology amongst the several different technologies offered based on the consideration of several factors such as performance, capacity maintenance/degradation, guarantees, long-term service agreement, space utilization, and cost. Therefore, the environmental evaluation of this alternative assumes the Tesla Megapack design and the supporting engineering and test data supplied by Tesla. The final choice of design technology for the battery energy storage system will be determined as part of the final design for the project.

- Refurbishing the existing Unit 8A combined cycle unit. The refurbishment would retain the existing gas turbine generator and convert the unit from its current combined cycle configuration to a simple cycle configuration by replacing the existing heat recovery steam generator and associated steam turbine cycle with a new simple cycle emissions control system. This would allow Unit 8A to start and achieve full load within ten minutes thereby providing GWP with an additional quick starting resource that it needs to meet reserve requirements and integrate intermittent resources.

- Refurbishing the existing Unit 8BC combined cycle unit. The refurbishment would retain the existing gas turbine generator and replace the existing heat recovery steam generator and associated steam turbine cycle with a new once through boiler and new steam turbine cycle. This would allow Unit 8BC to start and achieve full load on the gas turbine within ten minutes thereby providing GWP with an additional quick starting resource it needs to meet reserve requirements and integrate intermittent resources. The steam turbine cycle could start and reach full load in approximately two hours providing additional energy and improved thermal efficiency.

Additional engineering information regarding the Project is provided below:

1) The Unit 8A and 8BC gas generators, power turbines, and generators would be refurbished by removing their rotating elements for inspection and overhaul. The stationary elements would be refurbished in place.

2) The rest of the Unit 8A and 8BC infrastructure including heat recovery steam generators, steam turbines, piping, cooling towers, transformers, control module, etc. would be demolished as is the case for the other alternatives.

3) Unit 8A would be equipped with an emission control system consisting of a selective catalytic reduction system for the control of nitrogen oxides (NOx) emissions and an oxidation catalyst to control carbon monoxide (CO) and volatile organic compound (VOC) emissions.

4) Unit 8A would feature fast starting (from off to full load within ten minutes or less), and fast ramping up and down to support spinning and non-spin reserves, regulation and reactive power support, and integration of renewable resources.

5) Unit 8BC would be equipped with a once through boiler with an integral emission control system consisting of selective catalytic reduction system for the control of nitrogen oxides (NOx) emissions and an oxidation catalyst to control carbon monoxide (CO) and volatile organic compound (VOC) emissions. The once through boiler would allow operation of Unit 8BC in a “dry” simple cycle mode allowing the unit to quickly startup like a simple cycle unit. The once through boiler could then transition to “wet” combined cycle mode and transfer the exhaust heat energy to water to produce steam for use in a new steam turbine to produce additional power.

6) A new water treatment system would treat and demineralize the recycled water, primarily for use in Unit 8A for NOx reduction, Unit 8BC for NOx reduction and steam production, and Unit 9 for power augmentation and NOx reduction. The water treatment system would use a combination of installed equipment and mobile trailer-mounted demineralizer systems to batch process recycled water that would then be stored on-site in tanks. The mobile trailer-mounted demineralizer would be regenerated off-site and brought back as needed to maintain minimum storage volumes. Reject water from the micro-filtration and

reverse osmosis system would be discharged to the process drains and from there to the Glendale sewer system.

7) New plant control room and plant operations offices would also be constructed.

8) A new Workshop/Warehouse to serve the Grayson Power Plant would also be constructed.

9) All interconnections to the City's electrical grid would occur on-site and no new off-site electrical transmission line modification or construction would be necessary for the Project.

10) The Project would be designed, constructed, and inspected in accordance with the current California Building Standards Code, also known as Title 24, California Code of Regulations, which encompasses the California Building Code, California Administrative Code, California Electrical Code, California Mechanical Code, California Plumbing Code, California Energy Code, California Fire Code, California Code for Building Conservation, California Reference Standards Code, and all other applicable LORS in effect at the time initial design plans are submitted to the City for review and approval.

11) The Project would utilize certified engineers and geologists to perform design reviews, obtain approval by the City, and monitor construction to ensure compliance with laws, ordinances, regulations, and standards. In addition, certified third party inspections would be performed to ensure that any work requiring such inspection is constructed in accordance with LORS, including excavation and backfill work and the installation of piles.

12) Structural support would be in accordance with the recommendations provided in Section 8.0 of the Geotechnical Investigation Report prepared by Black & Veatch, as may be updated by the Engineer-Procurement-Construction Contractors (Appendix B of the PR-DEIR). Deep foundations for power plant structures would utilizes piles.

This Alternative would encompass approximately ten acres within the City's Utility Operations Center located within the Grayson Power Plant existing site.

This Alternative would also include a new aqueous ammonia storage tank and unloading facility for Units 8A and 8BC.

Additionally, this Alternative would connect to the existing off-site linear facilities, such as, natural gas, potable water, recycled water, stormwater discharge, processed wastewater discharge, and sanitary sewer pipelines, and electrical transmission lines that are currently serving the existing facilities.

Underground 69 kV electrical interconnections would connect the new power islands to the existing Kellogg Switching Station and the new Glendale Switching Station. Both Switching Stations are or would be located within the Project boundaries, and entirely within the footprint of the existing City Utility Operations Center property boundaries. From the existing Kellogg Switching Station and new Glendale Switching Station, power generated by the proposed Project would interconnect to the GWP's existing distribution system serving the City's electric load.

All interconnections to the City's electrical grid would occur on-site and no new off-site electrical transmission line modification or construction would be necessary for the proposed Project.

This Alternative would use recycled water for a majority of plant operations and would reduce even further the use of potable water provided by the City at the Grayson Power Plant. Potable water would, after completion of the proposed Project, only be used for domestic use, eye wash stations, fire protection, and as an emergency source of water. Potable water would no longer be normally used for equipment cooling or process water purposes, eliminating the use of potable water for Unit 9 and the units that would be demolished.

Wastewater and other process waste generated by the Project and Unit 9 would be treated as required by the discharge permit and discharged into the existing sanitary sewer connection. This discharge would be conveyed back to the Los Angeles-Glendale Water Reclamation Plant, where it would be processed and again recycled to be made available for use at the Project site or at other facilities as recycled water for beneficial use.

On-site stormwater runoff from within the Project site would flow via surface sheet flow and localized gutters to on-site storm drain piping. The storm drain piping would be connected to an on-site detention basin and pump station. Stormwater from the 85th percentile storm would be collected and pumped to a new aboveground storage tank. Stormwater would then be gravity drained from that tank to the Glendale sewer system. During storm events that exceed the design capacity of the stormwater system, overflow runoff would be discharged into the adjacent Verdugo Wash and Los Angeles River through existing stormwater outfalls.

Stormwater that falls within process equipment containment areas would be collected separately from typical site runoff, treated, and discharged into the existing public sanitary sewer system.

Demolition

The Grayson Power Plant currently has eight operating generating units (Units 1, 2, 3, 4, 5, 8A, 8BC, and 9) and ancillary facilities that, except for Units 8A, 8BC, and 9, will be removed as part of this Alternative. Units 1 through 5 along with their existing cooling towers, boiler building, buildings, and all ancillary systems including foundations and underground utilities not associated with Unit 9 or required as part of the repowered facility (such as the Unit 8A and 8BC gas turbine generators and Kellogg Switching Station) would be demolished and removed. Unit 9 would remain in operation during the demolition and construction phases and would be integrated into the Project facilities.

The existing water treatment facilities are old and would be replaced in a different location with a new smaller capacity system that uses recycled water in place of potable water, and a combination of permanently installed and mobile trailer-mounted equipment. This system, if space permits its installation, would support Unit 9 operation during demolition and construction, and Units 8A, 8BC, and 9 during operations. If space does not permit, a smaller temporary system with potable water as feed will be installed to serve Unit 9 until space is made available for the larger recycled water treatment system to be installed. The existing potable water system would be modified to provide fire protection during demolition, construction, and operations as well as potable water.

Demolition and removal work are expected to take twelve (12) months and if this Alternative is selected, would start during the first quarter of 2022.

Construction

Construction of the 75 MW/300 MWH Tesla BESS and the refurbishments of Units 8A and 8BC would commence in the first quarter of 2023 and would be expected to extend through the third quarter of 2024.

In addition to field office siting, areas within the site would be used for offloading and staging and for storage of materials, equipment, and vehicles. This Alternative would utilize space within the Utility Operations Center and under adjacent Highway 134 to provide construction laydown and construction parking.

No off-site laydown space is planned at this time for the following reasons:

1. Construction of the Unit 8A and 8BC power island would begin after demolition is complete. Because the Megapacks arrive by truck and are off-loaded directly onto their foundations, no off-site laydown would be needed.
2. Construction of the Unit 8A and 8BC power island would begin after demolition is complete. Thus, all of the remaining site would be available for laydown and construction.

Construction access would be generally from Fairmont Avenue. Large or heavy equipment, such as the Tesla Megapacks, steam turbine, and generator step-up transformers would be delivered to the site by heavy haul truck/trailer.

Construction activities at the site would proceed in parallel with the normal GWP work activities taking place at other areas of the Utility Operations Center.

New construction for the Tesla/Unit 8 Refurbishment Project Alternative would include the following new buildings:

- A control room/operations building approximately 12-feet tall, 75-feet long and 45-feet wide.
- A Workshop and Warehouse Building approximately 20-feet tall, 100-feet long and 50-feet wide.
- Small single-story buildings/enclosures to serve as a water lab, enclosure for the Continuous Emissions Monitoring Systems, and house control and communication equipment.

In addition, Units 8A and 8BC would each have 115 feet tall exhaust stacks.

The Project would be designed using commercially proven technology equipped with stringent environmental protection, monitoring, and safety systems to provide safe and reliable operation over a 30-year operating life. The project would comply with South Coast Air Quality Management District (SCAQMD) air pollution emission standards.

During construction, existing Utility Operations Center utilities would be used for the construction offices, laydown area, and the Project site. The City would provide temporary construction power. Area lighting would be provided and strategically located for safety and security.

Construction water would be potable water supplied by the existing GWP water system and by water truck deliveries, as necessary. Water use would be primarily for dust suppression as well as hydro testing of piping. The hydro test water would be tested, and if suitable, reused, or disposed of in accordance with applicable LORS. Other construction water uses may include compaction, concrete placement, grouting, curing, and cleaning. Portable toilets would be provided on-site.

Operations

The facility would be manned and capable of being operated year-round (24 hours per day, 7 days per week, 365 days a year) to serve electricity demand and provide ancillary services necessary for GWP to integrate renewable energy into its energy portfolio, manage the intermittent energy at the interconnection with the Balancing Authority Area (LADWP), and provide local system reliability.

With the exception of planned and unplanned outages, the BESS would always be in-service year-round with its primary application being to provide spinning reserve as they can do so without creating any emissions. Its secondary application would be to provide load regulation up/down, as well as voltage and frequency support, serving as a generator or a load as needed to help keep transmission imports and system load in balance, including integrating renewables. When import capability is greater than the GWP load, the BESS could also be used for “time-shifting” excess energy from the middle of the day when solar energy is abundant to early evening periods when solar energy is not available. The BESS would be committed to provide up to the full 75 MW of output during peak load periods subject to available energy.

Units 8A and 8BC would be dispatched when needed to 1) provide ancillary services when the Grayson BESS is incapable of doing so due to its energy state, or 2) serve load when imports and the Grayson BESS alone are incapable of doing so. As Units 8A, 8BC, and 9 will all be equally capable of fast starts, the units would be operated holistically depending on how much power is needed and for how long. For example, while Unit 8A would be the least efficient, being a smaller unit, it will likely be more efficient than the other two units operating at part load to match Unit 8A’s output. Unit 8BC would be both the largest and most efficient unit when operating at full load in combined cycle.

Both the BESS and Units 8A and 8BC would be able to provide ancillary services and serve system load offering GWP a flexible resource to meet future needs. All would have fast startup, significant turndown, fast ramp rates, automatic generation control, and 0.9 power factor gas turbine generators and 0.8 power factor steam turbine generator.

5.2.7.2 Potential Environmental Impacts – Alternative 8

Following are the potential environmental impacts that would result from the Tesla/Unit 8 Refurbishment Project Alternative.

Potential Environmental Impacts Less than those of the Project

The Tesla/ Unit 8 Refurbishment Project Alternative emissions are significantly reduced compared to the proposed project. This reduction is largely achieved through a reduction in operating hours resulting in fewer emissions and reduced capability to cope with contingent events. The Tesla/Unit 8 Refurbishment Project Alternative would involve the same demolition and similar construction activities as the proposed Project. Consequently, the short-term aesthetics impacts, criteria air pollutant emissions, and greenhouse gas emissions associated with demolition and construction of the Tesla/ Unit 8 Refurbishment Project Alternative would be similar to the proposed Project. However, the Tesla/Unit 8 Refurbishment Project Alternative would include different physical components and equipment with different emissions of criteria air pollutants, toxic air contaminants, and greenhouse gases during operation. The Tesla/ Unit 8 Refurbishment Project Alternative would combust a lower volume of natural gas and generate less electricity than the proposed Project but would include a BESS that could be charged with renewable sources. As a result, the Tesla/ Unit 8 Refurbishment Project Alternative could be more consistent with the State’s Renewable Portfolio Standard requirements compared to the proposed Project (if the BESS was charged with renewable sources).

Aesthetics

Photo simulations representing the Tesla/Unit 8 Refurbishment Project Alternative from Key Observation Points 1 (Fairmont Avenue and Flower Street), 4 (San Fernando Road and Highland Avenue), 5 (Skyline Trail), and 6 (Confluence Park) are included below as Figures 5-6, 5-7, 5-8, and 5-9.

a) Simulation of Proposed Project from Fairmont Avenue and Flower Street.

b) Simulation of the Tesla / Unit 8 Refurbishment Project Alternative.

Stantec

Project Location
Glendale, CA

Project
Grayson Repowering Project

Figure No.
5-6

Title
KOP 1 – View of Proposed Project and Alternative 8 from Intersection of Fairmont Avenue and Flower Street

a) Simulation of Proposed Project from San Fernando Road and Highland Avenue.

b) Simulation of the Tesla / Unit 8 Refurbishment Project Alternative.

Stantec

Project Location
Glendale, CA

Project
Grayson Repowering Project

Figure No.
5-7

Title
KOP 4 – View of Proposed Project and Alternative 8 from Intersection of San Fernando Road and Highland Avenue

a) Simulation of Proposed Project from Skyline Trail.

b) Simulation of the Tesla / Unit 8 Refurbishment Project Alternative.

Stantec

Project Location
Glendale, CA

Project
Grayson Repowering Project

Figure No.
5-8

Title
KOP 5 – View of Proposed Project and Alternative 8 from Skyline Trail

a) Simulation of Proposed Project from Confluence Park.

b) Simulation of the Tesla / Unit 8 Refurbishment Project Alternative.

Stantec

Project Location
Glendale, CA

Project
Grayson Repowering Project

Figure No.
5-9

Title
KOP 6 – View of Proposed Project and Alternative 8 from Confluence Park

As shown in Figure 5-6, the cooling tower, steam turbine building, once through boiler, once through boiler exhaust stack, selective catalytic reduction and exhaust stack, demineralized water storage tank, and stormwater storage tank associated with the Tesla/ Unit 8 Refurbishment Project Alternative as well as the existing warehouse and Unit 9 are prominently visible from Key Observation Point 1. The Tesla Megapacks, while visible, are not substantially higher than the existing facility boundary wall. The two exhaust stacks associated with the Tesla/ Unit 8 Refurbishment Project Alternative would be approximately 115 feet above surrounding ground level. As shown in Figure 5-6, the exhaust stacks and visible structures associated with the Tesla/ Unit 8 Refurbishment Project Alternative and the existing Unit 9 exhaust stack would obscure the existing viewshed from Key Observation Point 1 less than the proposed Project. The Tesla/ Unit 8 Refurbishment Project Alternative would therefore have less aesthetics impacts from Key Observation Point 1 compared to the proposed Project.

As shown in Figure 5-7, the new Glendale Switching Station, the cooling tower, steam turbine building, once through boiler, once through boiler exhaust stack, selective catalytic reduction and exhaust stack, two demineralized water storage tanks, and stormwater storage tank associated with the Tesla/ Unit 8 Refurbishment Project would be visible from Key Observation Point 4 and partially obscure the Santa Monica Mountains in the background. The generation units, four exhaust stacks, and other structures associated with the proposed Project would be higher in the skyline and obscure more of the viewshed from Key Observation Point 4 compared to the Tesla/ Unit 8 Refurbishment Project Alternative. The Tesla/ Unit 8 Refurbishment Project Alternative would therefore have less aesthetics impacts from Key Observation Point 4 compared to the proposed Project.

As shown in Figure 5-8, the Tesla MegaPacks, cooling tower, steam turbine building, once through boiler, once through boiler exhaust stack, selective catalytic reduction and exhaust stack, two demineralized water storage tanks, stormwater storage tank, and Glendale Switching Station associated with the Tesla/ Unit 8 Refurbishment Project as well as the existing warehouse and Unit 9 are prominently visible from Key Observation Point 5 and Glendale Switching Station associated with the Tesla/Wartsila. While the visible components of the Tesla/Wartsila Repowering Project Alternative and proposed Project only occupy a small portion of the viewshed and appear largely comparable, the cooling towers and exhaust stacks associated with the proposed Project occupies more of the viewshed compared to the Tesla/Wartsila Repowering Project Alternative. The Tesla/ Unit 8 Refurbishment Project Alternative would therefore have less aesthetics impacts from Key Observation Point 5 compared to the proposed Project.

As shown in Figure 5-9, the cooling tower, steam turbine building, once through boiler, once through boiler exhaust stack, selective catalytic reduction and exhaust stack, two demineralized water storage tanks, and stormwater storage tank associated with the Tesla/ Unit 8 Refurbishment Project would be visible from Key Observation Point 6 and partially obscure the mountains in the background. The generation units, four exhaust stacks, and other structures associated with the proposed Project would be higher in the skyline and obscure more of the viewshed from Key Observation Point 6 compared to the Tesla/ Unit 8 Refurbishment Project Alternative. The Tesla/ Unit 8 Refurbishment Project Alternative would therefore have less aesthetics impacts from Key Observation Point 6 compared to the proposed Project.

Because the Tesla/Unit 8 Refurbishment Project Alternative would have less aesthetics impacts from all of the Key Observation Points modeled, the Tesla/Unit 8 Refurbishment Project Alternative would have less aesthetics impacts compared to the proposed Project.

Air Quality

The generation capacity and natural gas combustion associated with the Tesla/ Unit 8 Refurbishment Project Alternative and proposed Project are summarized below in Table 5-7.

Table 5-7 Natural Gas-Fueled Generation Capacity and Combustion of Refurbished Unit 8A and 8BC and Proposed Project

Scenario	Natural Gas-Fueled Generation Capacity (MW)	Natural Gas Combustion (MMBtu/Yr)
Proposed Project	262	9,740,104
Refurbished Unit 8A and 8BC (Alternative 8)	101	1,260,000
Note: Does not include existing Unit 9 that would be retained under the Tesla/Unit 8 Refurbishment Project Alternative and the proposed Project.		

As shown in Table 5-7, the Tesla/Unit 8 Refurbishment Project Alternative involves substantially less natural gas-fueled generation capacity (-172 MW) and natural gas combustion (-87 percent) than the proposed Project. Criteria air pollutant, hazardous air pollutant, and greenhouse gas emissions were estimated for the Tesla/Unit 8 Refurbishment Details and assumptions used for estimating emissions are included in Appendix C.2 of the PR-DEIR. Table 5-8 below summarizes the annual emissions of criteria air pollutants for the Tesla/Wartsila Repowering Project Alternative and the proposed Project.

Table 5-8 Summary of Tesla/ Unit 8 Refurbishment Project Alternative and Proposed Project Criteria Air Pollutant Emissions

Equipment	NO_2 (tons/year)	CO (tons/year)	PM10 (tons/year)	VOC (tons/year)	SO_2 (tons/year)
Total Emissions from Proposed Project Emissions Units	51.5	37.6	15.1	13.1	3.0
Total Emissions from Tesla/ Unit 8 Refurbishment Project Alternative Emissions Units	10.9	53.9	2.0	7.6	0.5
Total 2015-2016 Baseline Emissions[1]	29.9	67.0	15.4	12.0	2.2
Total Updated 2018 Baseline Emissions[1]	28.5	56.9	8.6	6.1	1.0
Net Emissions Increase (Decrease) of Proposed Project relative to 2015-2016 Baseline Emissions	21.6	(29.4)	(0.3)	1.1	0.8
Net Emissions Increase (Decrease) of Tesla/ Unit 8 Refurbishment Project Alternative relative to 2015-2016 Baseline Emissions	(19.0)	(13.1)	(13.4)	(4.4)	(1.8)
Net Emissions Increase (Decrease) of Tesla/ Unit 8 Refurbishment	(17.6)	(3.0)	(6.6)	1.5	(0.5)

Equipment	NO_2 (tons/year)	CO (tons/year)	PM10 (tons/year)	VOC (tons/year)	SO_2 (tons/year)
Project Alternative relative to Updated 2018 Baseline Emissions					
Note: 1. The emissions of replaced units were calculated based on the average emissions reported in SCAQMD Annual Emission Reports. Emissions from unit 9 are not included in this table because there are no modifications on Unit 9. Therefore, emissions from unit 9 will not have any effect on the net emission increase/decrease.					

As shown in Table 5-8, annual emissions of criteria air pollutants of the Tesla/Unit 8 Refurbishment Project Alternative are lower than the proposed Project, and with the exception of VOC, represent a net reduction compared to existing emissions. Potential VOC emissions of Alternative 8, however, remain lower than potential emissions from the proposed project and will be offset through the application of emission reduction credits pursuant with SCAQMD requirements if warranted. Table 5-9 below summarizes the potential health risks to residential receptors located adjacent to the Grayson Power Plant for the Tesla/Unit 8 Refurbishment Project Alternative and the proposed Project.

Table 5-9 Summary of Tesla/Unit 8 Refurbishment Project Alternative and Proposed Project Health Risks to Adjacent Residential Receptors

Health Risk	Significance Threshold	Tesla/Unit 8 Refurbishment Project Alternative	Proposed Project
Maximum Individual Cancer Risk	≤10	0.014	0.91
Acute Hazard Index	≤1	0.0007	0.0073
Chronic Hazard Index	≤1	0.0004	0.0024
Note: Health risks expressed as number in one million			

As shown in Table 5-9, the maximum individual cancer rate of the Tesla/Unit 8 Refurbishment Project Alternative and the proposed Project are both substantially lower than the significance threshold. Additionally, the acute and chronic hazard index of the Tesla/Unit 8 Refurbishment Project Alternative and the proposed Project are both substantially lower than the significance thresholds. In comparison to the proposed Project, the maximum individual cancer rate, acute, and chronic hazard index of the Tesla/Unit 8 Refurbishment Project Alternative are also significantly lower.

Energy

The Tesla/Unit 8 Refurbishment Project Alternative would increase the City's ability to integrate renewable resources as a result of the BESS compared to the proposed Project that only includes natural gas fueled electricity generation. The Tesla/Unit 8 Refurbishment Project Alternative would therefore have a lower potential to conflict with or obstruct a state or local plan for renewable energy or energy efficiency and would therefore have lower potential energy impacts than the proposed Project.

Greenhouse Gas Emissions

Table 5-10 below summarizes the annual greenhouse gas emissions for the Tesla/Unit 8 Refurbishment Project Alternative and the proposed Project.

Table 5-10 Summary of Tesla/Unit 8 Refurbishment Project Alternative and Proposed Greenhouse Gas Emissions

	Annual Greenhouse Gas Emissions Operations plus Occupancy (Metric Tons CO2e)
Proposed project	476,040
Tesla/Unit 8 Refurbishment Project Alternative (refurbished Unit 8A and 8BC)	67,195

As shown in Table 5-10 the natural-gas fueled generation units associated with the Tesla/Unit 8 Refurbishment Project Alternative would emit approximately 67,195 metric tons of CO2e/year. By comparison, the natural gas-fueled electrical generation units associated with the proposed Project would emit approximately 476,040 metric tons of CO2e/year. The Tesla/Unit 8 Refurbishment Project Alternative therefore has significantly less potential greenhouse gas emissions impacts than the proposed Project.

<u>Potential Environmental Impacts Similar to Those of the Project</u>

Agriculture and Forestry Resources, Biological Resources, Cultural/Tribal Cultural Resources, Environmental Justice, Geology and Soils, Hydrology and Water Quality, Land Use and Planning, Mineral Resources, Noise, Population and Housing, Public Services, Recreation, Socioeconomics, Transportation, Utilities and Service Systems, and Wildfire

Similar to the Project, the Tesla/Unit 8 Refurbishment Project Alternative involves electrical generation at the same 10-acre urban industrial site already permitted, developed, and operated as a power plant. The primary difference is that the Tesla/Unit 8 Refurbishment Project Alternative includes a 75 MW/300 MWH BESS and refurbishing of Units 8A and 8BC with an approximate thermal generation capacity of 101 MW, compared to no BESS and a total thermal generation capacity of approximately 262 MW from two simple cycle and two combined cycle generation units associated with the proposed Project.

Similar to the proposed Project, the Tesla/Unit 8 Refurbishment Project Alternative would not occur on lands zoned or used for agriculture, forestry resources, or mineral resources. Both the Tesla/Unit 8 Refurbishment Project Alternative and the proposed Project would occur within the limits of the developed power plant site which lacks sensitive biological, archaeological, and tribal cultural resources and high fire hazard areas. The surrounding community was determined not to be considered an environmental justice community (refer to Appendix A, Section 2.19 of the Initial Study included in the 2018 Final EIR). The

Boiler Building would be demolished and this Alternative, similar to the proposed Project, would result in a significant and unavoidable discretionary historic resource impact.

Demolition activities, ground disturbances during construction, site drainage, susceptibility to geologic hazards such as seismically induced ground shaking and liquefaction potential, operation phase vehicle trips, and utility/service systems needs associated with the Tesla/Unit 8 Refurbishment Project Alternative would be similar to the proposed Project.

Hazards and Hazardous Materials

The emissions control system for Units 8A and 8BC would utilize 19 percent aqueous ammonia stored in a 15,000-gallon capacity above ground storage tank. An off-site consequence analysis was performed for the accidental release of aqueous ammonia from the 15,000-gallon storage tank associated with the Tesla/Unit 8 Refurbishment Project Alternative. The analysis consists of a worst-case accidental release scenario involving the failure and complete discharge of the contents of the storage tank into the secondary containment structure below the tank. Similar to aqueous ammonia associated with the proposed Project, the results of the off-site consequence analysis for the Tesla/Unit 8 Refurbishment Project Alternative which are included in Appendix D.1 of the PR-DEIR demonstrate that the worst-case release of ammonia would not exceed applicable Occupational Safety and Health Administration, U.S. Environmental Protection Agency, and California Energy Commissions health thresholds.

Under normal operations, the Megapacks do not store or generate hazardous materials in quantities that would represent a risk to off-site receptors. However, a fire or thermal runaway event of a Megapack may release hazardous materials to the environment. Based on the design of the Megapack and confirmed through testing conducted by Tesla, a reasonable worst-case scenario for Alternative 8 would be a fire or thermal runaway event consuming one Tesla Megapack and releasing carbon monoxide and hydrogen fluoride that could impact off-site receptors. An analysis of an Alternative 8 BESS fire and subsequent release of carbon monoxide and hydrogen fluoride was prepared using the U.S. Environmental Protection Agency's (USEPA) Areal Locations of Hazardous Atmospheres (ALOHA) model to identify estimated distances to regulatory-established toxic endpoints to determine potential significance of hazards impacts pursuant with CEQA.

With respect to the assessment of potential impacts associated with an accidental release of carbon monoxide, four offsite “bench mark” exposure levels were evaluated, as follows: (1) the Occupational Safety and Health Administration's (OSHA) Immediately Dangerous to Life and Health (IDLH) level; (2) the National Oceanic and Atmospheric Administration (NOAA) Office of Response and Restoration's Acute Exposure Guideline Levels (AEGLs) AEGL-3 which predicts that the general population, including susceptible individuals, could experience life-threatening health effects or death; (3) AEGL-2 which predicts that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape; and (4) AEGL-1 level (not established for carbon monoxide) which predicts that the general population, including susceptible individuals, could experience notable discomfort, irritation, or certain asymptomatic non-sensory effects. However, the effects are not disabling and are transient and reversible upon cessation of exposure.

The results of the BESS fire OCA for Alternative 8 are included in Attachment D.2 and summarized below in Table 5-11 below.

Table 5-11 Carbon Monoxide and Hydrogen Fluoride Modeling Results

Chemical	Distance to IDLH[a]	Distance to AEGL-3[b]	Distance to AEGL-2[b]	Distance to AEGL-1[b]
Carbon Monoxide	Not Exceeded	Not Exceeded	167.98 ft	Not Established
Hydrogen Flouride	Not Exceeded	Not Exceeded	Not Exceeded	108.01 ft

[a] Benchmark based on a 30-minute exposure or averaging time

[b] Benchmark based on a 60-minute exposure or averaging time

The power plant facility boundary would be located as close as 40 feet (12.19 meters) from a Megapack. The results of the OCA for the worst-case release of carbon monoxide indicates that the concentrations for benchmark criteria IDLH (1200 ppm) and AEGL-3 (330 ppm) would not extend beyond the facility fence line. AEGL-1 thresholds have not been established for carbon monoxide. However, the distance to AEGL-2 thresholds could potentially extend beyond the fence line by a distance of approximately 127.99 feet (39.01 meters). As displayed in PR-DEIR Figure 1 of Attachment D.2, this would be mainly in a lightly trafficked segment of Fairmont Avenue on the southwestern fence line of the Grayson Power Plant. Thresholds would not be exceeded for any residences, schools, or commercial land uses. Receptors along Fairmont Avenue would be mobile receptors such as vehicles that would not be exposed to substantial concentrations of carbon monoxide for the 60 minutes assumed in the reasonable worst-case scenario and AEGL thresholds. For example, the carbon monoxide AEGL-2 for a 30-minute and 10-minute exposures are 150 ppm and 420 ppm. Consequently, it would be unlikely that a receptor on Fairmont Avenue would be exposed to carbon monoxide concentrations of significant concern for a substantial period of time.

The results of the OCA for the worst-case release of hydrogen fluoride indicates that concentrations for benchmark criteria IDLH (30 ppm), AEGL-3 (44 ppm), and AEGL-2 (24) would not extend beyond the facility fence line. However, the distance to the AEGL-1 benchmark criteria (1 ppm) could potentially extend beyond the fence line by a distance of approximately 68.01 feet (20.73 meters). As displayed in PR-DEIR Figure 2 of Attachment D.2, this would be similar to the AEGL-2 distance of threshold exceedance for carbon monoxide, concentrated mainly in a lightly trafficked segment of Fairmont Avenue on the southwestern fence line of the Grayson Power Plant.

An infrared camera system would be installed as part of this Project alternative to monitor the Megapacks. In the event of thermal runaway within the Megapack, the camera would detect the unit's change in temperature and provide notification to the plant operators. The plant operators would then contact the local fire department. The initial detection occurs approximately 15 minutes prior to smoke being released from the Megapack units. According to the City of Glendale, the average response time for the Local Fire Department is four minutes and 36 seconds[19]. The Fire Department would arrive on site in less than five minutes of the initial notification as the nearest fire station, Station 27, is located approximately 1.23 miles from the proposed Project. The affected section of Fairmont Avenue and the adjacent pedestrian bike path on the west side of Fairmont Avenue would immediately be closed to the public before carbon monoxide levels exceed AEGL-2 thresholds in the area. The closure would remain in place until the area is deemed safe to the public. As a result, any long-term or permanent effects to the public from carbon monoxide are unlikely to occur. Additionally, the AEGL-1 threshold of exceedance for hydrogen fluoride predicts that the general population, including susceptible individuals, could experience notable discomfort, irritation, or certain asymptomatic non-sensory effects. These effects would not be disabling and are transient and reversible upon cessation of exposure. Considering the above, the No long-term or permanent effects to the public from hydrogen fluoride exposure would likely result.

As a result, the Tesla/Unit 8 Refurbishment Project Alternative would have similar environmental impacts as the proposed Project on agriculture and forestry resources, biological resources, cultural/tribal cultural resources, environmental justice, geology and soils, hazards and hazardous materials, hydrology, noise, and water quality, land use and planning, mineral resources, population and housing, public services, recreation, socioeconomics, transportation, utilities and service systems, and wildfire.

Potential Environmental Impacts Greater than Those of the Project

Noise

Operation of refurbished Units 8A and 8BC and related equipment would generate noise. Table 5-12 shows a compassion of Project and Alternative 8 operation noise at sensitive receptors during the day and night. See Appendix E in the PR-DEIR for additional details.

Table 5-12 Predicted Operation Phase Noise Levels – Proposed Project and Alternative 8

Scenario	Receptor	Predicted Operational Noise (dBA)	Daytime Ambient Sound Levels (dBA)			Nighttime Ambient Sound Levels (dBA)		
			Current	New	Increase	Current	New	Increase
Proposed Project	R1	51.0	54.2	55.9	**1.7**	49.6	53.4	**3.8**
	R2	53.1	64.7	65.0	**0.3**	52.8	56.0	**3.2**
	R3	52.6	57.1	58.4	**1.3**	52.8	55.7	**2.9**
	R7	57.5	60.6	62.3	**1.7**	58.8	61.2	**2.4**
	R8	58.4	69.6	69.9	**0.3**	65.6	66.4	**0.8**
Alternative 8	R1	49.3	54.2	55.4	**1.2**	49.6	52.5	**2.9**
	R2	52.6	64.7	65.0	**0.3**	52.8	55.7	**2.9**

[19] City of Glendale, 12.4 Public Safety Response, available at https://www.glendaleca.gov/government/departments/community-development/neighborhood-services/glendale-quality-of-life-indicators/12-4-public-safety-response.

Scenario	Receptor	Predicted Operational Noise (dBA)	Daytime Ambient Sound Levels (dBA)			Nighttime Ambient Sound Levels (dBA)		
			Current	New	Increase	Current	New	Increase
	R3	53.1	57.1	58.6	**1.5**	52.8	56.0	**3.2**
	R7	57.5	60.6	62.3	**1.7**	58.8	61.2	**2.4**
	R8	59.1	69.6	70.0	**0.4**	65.6	66.5	**0.9**

As shown in Table 5-12, the Tesla/Unit 8 Refurbishment Project Alternative would result in four slightly higher noise level increases as compared to the proposed Project (two during the day [R3 + 0.2 dBA, R8 + 0.1 dBA] and two during the night [R3 + 0.3 dBA, R8 + 0.1 dBA]), with impacts remaining less than significant. Alternative 8 would also result in three similar noise level increases (two during the day [R2, R3] and one during the night [R7]) and three lower noise levels increases (one during the day [R1 – 0.5 dBA] and two at night [R1 – 0.9 dBA, R2 – 0.2 dBA]) compared to the proposed Project at the receptors modeled.

As a result, Tesla/Unit 8 Refurbishment Project Alternative would have a slight but incrementally higher modeled noise impact than the Project. It should be noted that the assumptions used for modeling proposed Project and Alternative 7 operation noise levels were in part, based on data obtained through detailed engineering design. A similar level of detail was not available for Alternative 8 and therefore conservative assumptions were made for modeling operation noise associated with refurbished Unit 8. It is possible that Tesla/Unit 8 Refurbishment Project Alternative could result in lower noise levels than those conservatively modeled and predicted in Table 5-12.

5.2.7.3 Objectives Consistency Evaluation – Alternative 8

The Tesla/Unit 8 Refurbishment Project Alternative would meet most of the Project objectives. Specifically, the Tesla/Unit 8 Refurbishment Project Alternative:

1. Would integrate with local and remote distributed renewable energy resources and support the City's ability to meet peak load with the N-1 (or single largest) contingency.

2. Would utilize reliable technology and current control systems to support the City's ability to comply with California's Renewable Portfolio Standards.

3. Would not provide a local generation resource that is sufficient to meet resource adequacy requirements for the N-1-1 contingency before the additional planed 72 MW of additional transmission imports becomes available in 2027. The City would be able to meet its obligations within the Balancing Area (BA) to balance load and resource at the interconnection with the BA, in accordance with industry standards including NERC/WECC requirements (the N-1-1 contingency in particular) after 2027.

4. Would provide a locally controlled source of generation that could support the City's power imports from remote generation locations through a congested transmission grid system subject to planned and unplanned outages and de-rate.

5. Would replace the aged, unreliable, less efficient, high maintenance steam boilers and steam turbines, with new generation that would comply with SCAQMDs Rule 1304(a)(2). Additionally, the removal of existing boilers would comply with SCAQMD Rule 1305(d)(6).

6. Would be able to be located at the existing City property already permitted and used for generation and would minimize the need for major infrastructure improvements such as fuel supply, water, wastewater, recycled water, and transmission facilities to the same extent as the proposed Project.

7. Aside from retaining the existing gas turbines and generators which would be refurbished, all other equipment would be replaced providing generation that is more efficient to maintain than the current units helping to minimize the impact on the rates and help manage costs of delivering energy to the City's customers.

8. Would support water conservation efforts by eliminating the use of potable water for generation purposes.

9. Would have a greater reduction in emissions and water consumption than the proposed Project. The Tesla/Unit 8 Refurbishment Project Alternative involves substantially less natural gas-fueled generation capacity (-172 MW) and natural gas combustion (-87 percent) than the proposed Project.

5.2.7.4 Summary – Alternative 8

The Tesla/Unit 8 Refurbishment Project Alternative would reduce air and greenhouse gas emissions compared to the Project, with the reduction of generation capacity and 87 percent less combustion of less natural gas. The physical components of the Tesla/Unit 8 Refurbishment Project Alternative would obscure views less than the proposed project from the key observation points. The Tesla/Unit 8 Refurbishment Project Alternative would have similar potential environmental impacts to all other environmental factors evaluated pursuant to CEQA. The Tesla/Unit 8 Refurbishment Project Alternative would not result in any potential environmental impacts greater than the proposed Project.

For these reasons, the overall environmental impacts of the Tesla/Unit 8 Refurbishment Project Alternative are expected to be less than the proposed Project.

5.2.8 Comparison of Alternatives

A comparison of the Project alternatives carried forward for further analysis with respect to each alternative's ability to meet the Project objectives and a comparison of each alternative's environmental impacts compared to the Project is summarized below in Tables 5-13, 5-14, and 5-15.

Table 5-13 Comparison of GWP Resources with Peak Load and Required Contingencies

		Project Alternative Number						
		1	2	3	4	5	7	8
Resource (MW)	**Proposed Project**	**No Project**	**Energy Storage**	**Alternative Energy**	**150 WM**	**200 MW**	**Tesla/ Wartsila**	**Tesla/ Unit 8 Refurbishment**
Pacific DC Intertie Transmission Imports	100	100	100	100	100	100	100	100
Southwest Area Transmission Imports	112	112	112	112	112	112	112	112
Existing Unit 9	48	48	48	48	48	48	48	48
Existing Magnolia Imports	35	35	35	35	35	35	35	35
Demand Response plus Virtual Power Plant	50	50	50	50	50	50	50	50
Alternative Energy	0	0	0	3	0	0	0	0
Energy Storage	0	0	161	0	0	50	75	75
Thermal Generation	262	0	0	0	150	200	93	101
Pre-2027 Total	**587**	**325**	**486**	**328**	**475**	**575**	**493**	**501**
Post-2027 Additional Southern Transmission System Transmission Imports from IPP	72	72	72	72	75	72	72	72
Post-2027 Total	**679**	**417**	**578**	**420**	**570**	**667**	**585**	**593**
Loss of Single Largest Contingency (N-1)	-100	-100	-100	-100	-100	-100	-100	-100
Pre-2027 Loss of Second Largest Contingency (N-1-1)	-70 (new CCGT)	-48 (U9)	-48 (U9)	-48 (U9)	-50 MW (new SCGT)	-70 (new CCGT)	-48 (U9)	-74 (U8BC)
Post-2027 Loss of Second Largest Contingency (N-1-1)	-70 (new CCGT)	-64 (STS)	-64 (STS)	-64 (STS)	-64 (STS)	-70 (new CCGT)	-64 (STS)	-74 (U8BC)
Pre-2027 Available Capacity with Loss of N-1 and N-1-1	**437**	**197**	**358**	**200**	**345**	**425**	**365**	**347**
Post-2027 Available Capacity with Loss of N-1 and N-1-1	**509**	**253**	**414**	**256**	**406**	**497**	**421**	**419**
Peak Load	**346**	**346**	**346**	**346**	**346**	**346**	**346**	**346**

Table 5-14 Objectives Comparison of Project and Alternatives

		Project Alternative Number						
		1	2	3	4	5	7	8
	Proposed Project	**No Project Alternative**	**Energy Storage Project Alternative**	**Alternative Energy Project Alternative**	**150 MW Project Alternative**	**200 MW Project Alternative**	**Tesla/Wartsila Repowering**	**Tesla/ Unit 8 Refurbishment**
Ability to Meet Project Objective								
1. Integrate with local and remote distributed renewable energy resources to provide sufficient capacity and energy to ensure reliable service at all times for the City and to support the City's compliance with California's Renewable Portfolio Standards	**Yes**	No	No	No	**Yes**	**Yes**	**Yes**	**Yes**
2. Utilize current and reliable technology and control systems to provide reliable, cost effective, and flexible generation capacity for the City to serve its customers load.	**Yes**	No	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
3. Provide a local generation resource sufficient to meet resource adequacy requirements, and the City's obligation within the Balancing Area to balance load and resource at the interconnection with the BA, in accordance with industry standards including NERC/WECC requirements; thus, providing local reliability and contributing to grid stability within the Los Angeles Basin.	**Yes**	No	No	No	**Yes***	**Yes**	**Yes***	**Yes***
4. Provide sufficient locally controlled generation to minimize the City's reliance on importing power from remote generation locations through a congested transmission grid system subject to planned and unplanned outages and de-rates making the delivery of energy to serve load less reliable than local generation.	**Yes**	No	No	No	No	**Yes**	**Yes**	**Yes**
5. Replace the aged, unreliable, less efficient, high maintenance steam boilers with new efficient and less environmentally impactful generation technologies that meet SCAQMD Rule 1304(a)(2).	**Yes**	No	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
6. Locate the proposed Project at existing City property already permitted and used for generation to minimize the need for major infrastructure improvements such as fuel supply, water, wastewater, recycled water, and transmission facilities, or need to purchase additional property.	**Yes**	**Yes**	**Yes**	No	No	**Yes**	**Yes**	**Yes**

	Project Alternative Number							
		1	2	3	4	5	7	8
	Proposed Project	**No Project Alternative**	**Energy Storage Project Alternative**	**Alternative Energy Project Alternative**	**150 MW Project Alternative**	**200 MW Project Alternative**	**Tesla/Wartsila Repowering**	**Tesla/ Unit 8 Refurbishment**
Ability to Meet Project Objective								
7. Provide generation that is highly efficient to maintain reasonable cost of generation to minimize the impact on the rates and help manage costs of delivering energy to the City's customers.	**Yes**	No	No	No	No	**Yes**	**Yes**	**Yes**
8. Support water conservation efforts by eliminating the use of potable water for generation purposes.	**Yes**	No	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
9. Reduce the per megawatt-hour (MWH) creation of emissions and consumption of water.	**Yes**	No	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Total Number of Objectives Met (of 9)	9	1	5	4	6	9	9	9
Percent of Objectives Met	100%	11%	56%	44%	67%	100%	100%	100%
* Alternatives 7 and 8 would meet Project Objective #3 in 2027.								

Table 5-15 Potential Environmental Impacts Comparison of Project and Alternatives

		Project Alternative Number						
		1	**2**	**3**	**4**	**5**	**7**	**8**
		No Project Alternative	**Energy Storage Project Alternative**	**Alternative Energy Project Alternative**	**150 MW Project Alternative**	**200 MW Project Alternative**	**Tesla/Wartsila Repowering Alternative**	**Tesla/Unit 8 Refurbishment Alternative**
Resource Category	**Proposed Project Impacts**							
Aesthetics	Less than Significant Impact with Mitigation	Similar	Less	Greater	Greater	Similar	Less	Less
Agriculture & Forestry Resources	No Impact	Similar	Similar	Greater	Greater	Similar	Similar	Similar
Air Quality	Less than Significant Impact	Less	Less[20]	Less	Less	Less	Less	Less
Biological Resources	No Impact	Similar	Similar	Greater	Greater	Similar	Similar	Similar
Cultural Resources	Less than Significant Impact	Less	Similar	Less	Greater	Similar	Similar	Similar
Energy	Less than Significant Impact	Greater	Less	Less	Less	Less	Less	Less
Environmental Justice	No Impact	Similar	Similar	Greater	Greater	Similar	Similar	Similar
Geology & Soils	Less than Significant Impact	Similar	Similar	Greater	Greater	Similar	Similar	Similar
Greenhouse Gas Emissions	Less than Significant Impact	Less	Less	Less	Less	Less	Less	Less
Hazards & Hazardous Materials	Less than Significant Impact with Mitigation	Similar	Similar	Similar	Similar	Similar	Similar	Similar
Hydrology & Water Quality	Less than Significant Impact	Similar	Less	Less	Similar	Similar	Similar	Similar
Land Use and Planning	No Impact	Similar	Similar	Greater	Greater	Similar	Similar	Similar
Mineral Resources	No Impact	Similar	Similar	Similar	Similar	Similar	Similar	Similar
Noise	Less than Significant Impact with Mitigation	Less	Less	Less	Less	Less	Less	Greater
Population & Housing	No Impact	Similar	Similar	Greater	Greater	Similar	Similar	Similar
Public Services	No Impact	Similar	Similar	Similar	Similar	Similar	Similar	Similar
Recreation	No Impact	Similar	Similar	Similar	Similar	Similar	Similar	Similar
Socioeconomics	No Impact	Similar	Similar	Similar	Similar	Similar	Similar	Similar
TransportatioN	Less than Significant Impact with Mitigation	Less	Less	Similar	Similar	Similar	Similar	Similar
Tribal Cultural Resources	Less than Significant Impact	Similar	Similar	Greater	Greater	Similar	Similar	Similar
Utilities and Service Systems	Less than Significant Impact	Similar	Similar	Similar	Similar	Similar	Similar	Similar
Wildfire	Less than Significant Impact	Similar	Similar	Greater	Greater	Similar	Similar	Similar
# of Environmental Categories with Greater Impacts		1	0	9	9	0	0	1
# of Environmental Categories with Similar Impacts		16	15	7	9	18	17	17
# of Environmental Categories with Less Impacts		5	7	6	4	4	5	4

While not the purpose of the EIR process, the following provides some relative cost perspective for the two new alternatives evaluated in the PR-DEIR and the proposed Project. Development of final cost estimates for Alternatives 7 and 8 are still underway.

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[20] Does not include non-local air emissions resulting from generation of electricity to be imported to charge the BESS when renewables are not available.

- The demolition and site improvement scope of work is largely the same for all three with the exception that Alternative 7 is probably the most expensive of the three as it requires removal off all existing piles under the new Wartsila foundations.
- The proposed Project, which lacks the Glendale Switching Station, is the most expensive of three as it is the largest project and entails the most major equipment.
- The battery energy storage system scope of work is essentially the same between Alternatives 7 and 8.
- The Glendale Switching Station scope of work is essentially the same between Alternatives 7 and 8.
- Alternative 8 is likely the least cost alternative as it reuses some existing equipment whereas Alternative 7 utilizes all new equipment.

5.2.9 Identification of the Environmentally Superior Alternative

CEQA requires that an EIR identify the environmentally superior alternative(s) of a project other than the proposed project or the “no project” alternative (CEQA Guidelines Section 15126.6 (e)(2)). As stated at the beginning of this chapter, the purpose of this alternatives analysis is to consider a reasonable range of alternatives that could feasibly attain most of the basic project objectives and avoid or substantially lessen significant program impacts.

The No Project Alternative would have lower potential air quality, cultural resources, greenhouse gas emissions, noise, and traffic and transportation impacts compared to the Project. The No Project Alternative would additionally avoid the significant and unavoidable impact of the proposed Project’s demolition of the Boiler Building, which is considered a significant cultural resources impact. The No Project Alternative requires more natural gas combustion per MW of electricity generated compared to the proposed Project. As a result, the No Project Alternative would be more wasteful of energy and have a greater energy impact compared to the proposed Project. Potential impacts to all other environmental resource categories would be similar. The No Project Alternative would not satisfactorily meet the Project objectives and would fail to comply with Federal and State reliability standards. The No Project Alternative would result in the City needing additional transmission capacity if available, causing additional environmental impacts and necessitating power imports at a much higher cost to its customers.

The Energy Storage Project Alternative would have lower potential aesthetics, air quality, energy, greenhouse gas emissions, hydrology and water quality, noise, and transportation and traffic impacts compared to the Project. Potential impacts to all other environmental resource categories would be similar and the Energy Storage Project Alternative would not have any greater impacts compared to the proposed Project. The Energy Storage Project Alternative is completely dependent on excess energy being available to charge the batteries, primarily through daily imports over the existing transmission systems. During high load periods, there will not be sufficient excess capacity to charge the batteries thus compromising the ability of this Alternative to reliably serve the residents and customers of the City. While this Alternative, using batteries alone, does have reduced local environmental impacts, it does not meet several critical project objectives with regards to assuring reliability of supply at reasonable cost. It additionally does not consider potential environmental impacts of new transmission lines into the City which the 2019 IRP determined infeasible.

The Alternative Energy Project Alternative would have lower potential air quality, energy, greenhouse gas emissions, hydrology and water quality, and noise impacts compared to the Project. The Alternative Energy Project Alternative would additionally avoid the significant and unavoidable discretionary cultural resources impact of the proposed Project. As a result of new transmission into the City, the Alternative Energy Project Alternative would have greater impacts to aesthetics, agriculture and forestry resources, biological resources, environmental justice, geology and soils, land use and planning, population and housing, tribal cultural resources, and wildfire compared to the proposed Project. Potential impacts to all other environmental resource categories would be similar. As discussed and summarized in this Chapter, this Alternative would only meet 44% of the Project objectives. Additionally, the 2019 IRP determined that new transmission into the City is not feasible and concluded that Portfolio G, the 100% Clean alternative modeled in the 2019 IRP, would require more transmission than is available to charge the batteries and serve summer loads.

The 150 MW Project Alternative would have lower potential air quality, energy, greenhouse gas emissions, and noise impacts compared to the Project. Because the 150 MW Project Alternative would require new transmission into the City, construction and operation of those new transmission facilities would result in greater impacts to aesthetics, agriculture and forestry resources, biological resources, cultural resources, environmental justice, geology and soils, land use and planning, population and housing, tribal cultural resources, and wildfire compared to the proposed Project. Potential impacts to all other environmental resource categories would be similar. This Alternative would ~~not~~ meet ~~most~~ only 67% of the Project objectives. Additionally, the 2019 IRP determined that building new transmission lines into the City is not feasible.

The 200 MW Alternative would have ~~incrementally~~ lower potential air quality, greenhouse gas emissions, and noise impacts compared to the Project. Potential impacts to all other environmental resource categories would be similar and the 200 MW Project Alternative would not have any greater impacts compared to the proposed Project. This Alternative would meet the Project objectives. However, this Alternative represents a higher cost option than the proposed Project.

The Tesla/Wartsila Project Alternative would have lower potential aesthetics, air quality, energy, greenhouse gas emissions, and noise impacts compared to the Project. The Tesla/Wartsila Project Alternative would not have any greater potential environmental impacts compared to the proposed Project. The Tesla/Wartsila Project Alternative would meet the Project objectives.

The Tesla/Unit 8 Refurbishment Project Alternative would have lower potential aesthetics, air quality, energy, and greenhouse gas emissions impacts compared to the Project. The Tesla/Unit 8 Refurbishment Project Alternative would only have a slight increase in noise impacts compared to the proposed Project.

Potential impacts to all other environmental resource categories would be similar. The Tesla/Unit 8 Refurbishment Project Alternative would meet the Project objectives.

As a result of this analysis, the Tesla/Wartsila Project Alternative and Tesla/Unit 8 Refurbishment Project Alternative would meet all project objectives while resulting in the fewest impacts when compared to the feasible alternatives evaluated. While the potential environmental impacts between these two alternatives are very similar, the Tesla/Wartsila Project Alternative would have slightly lower noise impacts and is therefore considered the environmentally superior alternative.

5.3 FINDINGS REGARDING ALTERNATIVES NOT SELECTED FOR FURTHER ANALYSIS

Section 15126.6, subdivision (c) of the CEQA Guidelines describes selection of a reasonable range of alternatives and the requirement to include those that could feasibly accomplish most of the basic project objectives while avoiding or substantially lessening one or more of the significant effects. The analysis should identify any alternatives that were considered by the lead agency but were rejected as infeasible. CEQA requires a brief explanation of the reasons underlying the lead agency’s determination to eliminate alternatives from further analysis.

A number of alternatives were considered but eliminated from further consideration. The alternatives that were not evaluated further in Final 2018 EIR and/or the PR-DEIR include alternative sites, and a variety of alternative technologies (generation technology, fuel technology, and alternative power plant cooling). These alternatives are more fully discussed below.

5.3.1 Power Plant Site Alternatives

The proposed Project would be located within the boundary of the existing power plant property (Glendale’s Grayson Power Plant) with operating power plant units. Although the Project is not under the jurisdiction of the California Energy Commission (CEC) and is under the jurisdiction of the City of Glendale as the Lead Agency, the Project is being analyzed in a consistent manner to that applied by the CEC. The Public Resources Code 25540.6 (b) provides direction to the CEC that in part reads:

- The commission may also accept an application for a non-cogeneration project at an existing industrial site without requiring a discussion of site alternatives if the commission finds that the project has a strong relationship to the existing industrial site and that it is therefore reasonable not to analyze alternative sites for the project.

Locating the new units at the existing Grayson site minimizes the environmental impact of the Project that could result from a greenfield or infill development in another location and the attendant need to construct new utility and transmission connections. Utilizing the same location as the existing facility means the proposed Project can use the same recycled and potable water as well as sanitary wastewater connection that support the existing Grayson Power Plant. In addition, the Project site would also use the same high-voltage electric transmission lines and the natural gas pipeline that serve the existing facility. The Project site has favorable geology and soils suitable for power plant development and has no significant engineering constraints. The land use designation of the site is consistent with power plant development and use.

However, as a part of preparing the EIR, a review of industrial zones with the lowest concentration of building was conducted and identified two alternative locations that were reviewed. One alternative site is located at the corner of Western and Flower and the other potential alternative site is located at 5426 San Fernando Road. The first site is approximately 13 acres and consists of four different parking lots and two buildings. Two vacant lots on the site are designated for a road widening project. A substantial portion of the property is owned by Disney. The second property is zoned Industrial/Commercial Mixed Use (IMU) and is approximately 9.5 acres, which is not sufficient size ~~for~~ to accommodate the Project. Both sites would require the construction of new transmission lines to connect with the ones currently at the Grayson site as well as the extension of the recycled water line, high pressure gas line, and wastewater line. Neither site presents an environmentally superior alternative to the existing site. As a result, no alternate Project sites were analyzed in the 2018 Draft EIR and are also not considered in this ~~EIR~~ PR-DEIR~~ and onlyo ~~Only the proposed site for the Project is discussed.

Locating the Project at a different site would also result in the loss of SCAQMD's "offset exemption for replacement in kind~~.~~" per SCAQMD Rule 1304(a)(2) that are applicable as long as the Project is located at the current site.

5.3.1.1 Project Site

The proposed Project would be located on the same site as the existing Grayson Power Plant at 800 Air Way, Glendale, CA 91201. The existing site consists of following generating units:

1. Unit 1 – 20 MW (gross) steam turbine-generator, built in 1941
2. Unit 2 – 20 MW (gross) steam turbine-generator, built in 1947
3. Unit 3 – 20 MW (gross) steam boiler turbine-generator, built in 1953
4. Unit 4 – 44 MW (gross) steam boiler turbine-generator, built in 1959
5. Unit 5 – 44 MW (gross) steam boiler turbine-generator, built in 1964
6. Unit 8-A – 32 MW (gross) combustion turbine-generator – combined cycle, built in 1977
7. Unit 8-BC – 55 MW (gross) combustion turbine-generator – combined cycle, built in 1977
8. Unit 9 – 50 MW (gross) combustion turbine-generator, simple cycle, built in 2003

With the exception of Unit 9, all the other units would be demolished and removed and replaced as part of the proposed Project.

The existing Grayson Power Plant is designated and zoned as industrial, which allows for the construction and operation of the proposed Project.

The Project site:

- Is located adjacent to a high-pressure natural gas pipeline
- Is located adjacent to an existing high voltage switchyard
- Is located adjacent to existing recycled water pipeline
- Minimizes construction impacts on existing residences and businesses
- Has good truck access
- Is owned by the City
- Is zoned for industrial use

5.3.2 Project Technology Alternatives

The Project configuration was selected from a wide array of technology alternatives. This includes generation technology alternatives, alternative fuel technology, and alternative power plant cooling alternatives. The following Project Technology Alternatives which were not selected for in depth analysis are discussed below.

5.3.2.1 Combustion Generation Technology Alternatives

Combustion Generation Technology Alternatives

Conventional boiler and steam turbine, large gas simple cycle combustion turbine, large combined cycle combustion turbine generator, and reciprocating engine generators were all considered as natural gas combustion generation technology alternatives and are discussed below in more detail.

Conventional Boiler and Steam Turbine

This technology burns fuel in the furnace of a conventional boiler to create steam. The steam is used to drive a steam turbine generator, and the steam is then condensed and returned to the boiler. This technology is less efficient and would not meet the California's SB 1368 Emission Performance Standard of less than 1,100 lbs of CO_2/MWh for new non-peaking generation; therefore, the conventional boiler and steam turbine generator technology was eliminated from consideration.

Large Simple Cycle Combustion Turbine Generator

Large aero-derivative gas turbines, such as the 100-megawatt General Electric (GE) LMS-100, is an efficient simple cycle gas turbine with a 50% turn down ratio. However, its size is such that it is as big as the City's existing single largest contingency. This size of a unit would further complicate the planning reserve situation.

The LMS100 generates more power from a single turbine than is required by the City. As such, this turbine is too large to provide the required need for flexibility of operation that allows for integration of the startup and shut down of the unit, load following, or the efficient integration of renewable resources into the City's electric grid.

Furthermore, one of the Project objectives is for the City to provide its own economic spinning and non-spinning reserve required by the WECC. Large turbines do not meet this requirement.

Lastly, simple cycle turbines are restricted in their operating hours by the air permitting process as the regulatory perspective is that units with high utilization should be combined cycle, not simple cycle. With only large simple cycle turbines, the capacity would be available however the total energy may not. Because of the reasons stated above, large turbines like the GE LMS-100 were eliminated from consideration.

Large Combined Cycle Combustion Turbine Generator

Large combined cycle combustion turbine generator, including 2x1 and large Frame type combustion turbines, are an efficient source of generation. These units typically range in size from 150 to over 500 MW in capacity and are too large given the City's existing single largest contingency. This technology does not provide the required need for flexibility of operation nor allows for the efficient integration of renewable resources into the City's electric grid.

Furthermore, one of the project objectives is for the Project is to provide its own economic spinning and non-spinning reserve required by the WECC for system stability. Large combined cycle combustion turbine generators would be considered as a single generator for spinning reserve requirement and would need spinning for one-half of the combined cycle unit capacity and therefore could not meet the WECC requirement. Because of the reasons stated above, large combined cycle units were eliminated from consideration.

Reciprocating Engine Generators (REGs)

Reciprocating engine generators are evaluated as part of the Tesla/Wartsila Repowering Project Alternative (Alternative 7). Please refer to Section 5.2.6.

5.3.3 Alternative Fuel Technologies

Technologies based on fuels other than natural gas were eliminated from consideration because they do not meet the Project objectives for the reasons stated below:

- No geothermal or hydroelectric resources are available within Glendale.
- Biomass fuels such as wood waste, digester or landfill gas are not locally available in sufficient quantities to make them practical as alternative fuels.
- Coal, nuclear, and oil technologies would not meet the environmental stewardship objective of the Project.

Distributed energy resources or microgrids are not practical for two reasons: 1) the City cannot mandate its customers to self-supply and 2) the City would still need to provide a reliable source of standby power to its customers. Renewable distributed energy resources are considered in Alternative 3.

5.3.4 Power Plant Cooling Alternatives

Heat from the Project would be by a combination of dry and wet cooling. In dry cooling, air-cooled heat exchangers transfer heat directly to the ambient air. Fans move the air across finned heat exchanger tubes containing the fluid to be cooled. Dry cooling would be used for such applications as combustion turbine generator cooling, lube oil cooling, and compressor cooling.

Wet cooling is used for the combined cycle turbine generators and their auxiliaries. In wet cooling, the cooling water is cooled in cooling towers where a portion of the water is evaporated to carry away the rejected heat, lost due to drift (circulating water that is emitted with the exhaust air of the tower), and blown down to maintain water quality. Recycled water is used to replace the water lost by evaporation, drift, and blowdown.

Wet cooling using fresh or potable water uses an essential resource that has a much higher beneficial use other than use for power plant cooling and was therefore eliminated from consideration. Wet cooling using recycled water is acceptable under state policy and is available at the Project site in sufficient quantity required by the Project.

Dry cooling using an air-cooled ~~steam~~ condenser (AC~~S~~C) was considered as an alternative to the use of wet cooling. Air-cooled condensers use fans to draw air through a heat exchanger where the air is exposed to pipes carrying exhaust steam from a steam turbine. The steam condenses to water and is pumped back through the steam cycle in a closed loop. Air-cooled condensers require much more space on the site than a conventional wet cooling system using cooling towers. They also consume more electricity, thereby reducing the efficiency of the power plant. There is also a performance penalty for using dry cooling in hot weather. Air-cooled condensers cannot produce as low a condensing pressure in hot weather as wet-cooled condensers. This results in higher steam turbine exhaust pressures and lower steam turbine output. According to a California Energy Commission report (Comparison of Alternate Cooling Technologies for California Power Plants, CEC, Sacramento 2002), the performance penalty for dry cooling can be between 5% and 20%. The report also finds that the capital cost is 1.5 to 3.0 times the cost of wet cooling. For these reasons, and since recycled water is available, dry cooling was not selected.

A third alternative that was considered was a hybrid of wet and dry cooling. These systems have the potential to offset the performance penalties of dry cooling while reducing the water consumption of wet cooling. There are several methods for implementing hybrid cooling. Some of these are currently being tested by the Electric Power Research Institute (EPRI). However, only two methods can be considered commercially available at this time.

The first of these methods is the plume abatement cooling tower. This is similar to a conventional cooling tower except that the hot cooling water return is first pre-cooled in an air-cooled heat exchanger before being fed to the cooling tower. This reduces the thermal load on the tower and consequently reduces the evaporation loss. The amount of water saved is roughly proportional to the amount of cooling duty done by the air-cooled exchanger. By locating the air cooling coils above the cooling tower fill, the cooling tower fans can serve both the air cooler and the cooling tower. According to the CEC report (see above) the capital cost of this Alternative is about the same as for dry cooling but the performance penalty is avoided. Since the cost of this Alternative is 1.5 to 3.0 times the cost of wet cooling, and commercial experience with these hybrid systems is limited, and there is available recycled water, this Alternative was not selected.

The second method is to have an AC~~S~~C and cooling tower in parallel service. When ambient air temperatures are low enough, only the AC~~S~~C is used. When the ambient temperature is high, the cooling tower is used to reduce the load on the AC~~S~~C. The water savings would depend on the operating profile of the power plant but would be between 20% and 80% per the CEC study. The parallel cooling method requires more land than any of the other options. According to the CEC study, the capital costs for this Alternative are 3 to 5 times that of straight wet cooling. For these reasons, as well as the limited commercial experience with hybrid systems, this Alternative was not selected for detailed analysis.

5.3.5 Boiler Building Alternatives

As part of the Project, the Boiler Building would be demolished to provide adequate space for construction of the power plant facilities. As discussed in Section 4.12 (Cultural/Paleontological Resources) of the PR-DEIR, the City has elected to consider the Boiler Building a discretionary historic resource; the demolition of which, even after implementation of feasible mitigation measures would constitute a significant and unavailable environmental impact.

The Boiler Building is located within the Grayson Power Plant site and does not connect directly to any publicly accessible area. The Kellogg Switching Station lies to the north, the Glendale Rack (a GWP 34.5 kV switchyard and substation for Units 1-5) lies to the east, Unit 9 lies to the south, and Units 8A and 8BC and cooling towers 1 through 5 are to the west.

The Boiler Building was constructed in different phases and the youngest portions of the building are more than 50 years old. Due to its age, the building has the typical ills of an older structure such as roof leaks, rusted structural members, and cracks in the walls and foundation. Additionally, the building was designed to earlier building codes that do not incorporate later changes in building codes to address increased seismic design requirements based on earthquake experience such as the Northridge earthquake. Lastly the building is a repository for significant amounts of hazardous materials such as asbestos (in pipe, wiring, and boiler insulation as well as the Transite exterior siding), lead based paint, and other materials.

The building footprint represents a significant portion of the Grayson Power Plant site that is not already used for other critical purposes such as the Kellogg Switching Station or reserved for the future Glendale Switching Station. Of the remaining space, a significant portion is required for the energy resources to be sited at Grayson, be they thermal or energy storage. Given that Grayson is the only feasible site within Glendale for high density energy development, the building footprint has an intrinsically high value in supporting Glendale's future energy needs.

The No Project alternative clearly would allow for retention of the Boiler Building. However, this alternative also does not address Glendale's long-term energy reliability needs and thus was not considered feasible.

The Alternative Energy alternative is space intensive and would need as much space at Grayson as could be made available. Thus, retaining the Boiler Building for the Alternative Energy alternative is not feasible.

For the 200 MW alternative, as with the Project, there is insufficient space to retain the Boiler Building. As with the proposed project, the gas turbines and the associated infrastructure would not allow the Boiler Building to be retained.

The Tesla/Wartsila and Tesla/ Unit 8 Refurbishment Project Alternatives require the space currently occupied by the Boiler Building to accommodate the development of 75 MW/300 MWH of energy storage. The general arrangement drawings for these alternatives portray the energy storage in addition to the thermal generation component (either Wartsila engines or refurbishing Units 8A and 8BC). A portion of the BESS overlays where the Boiler Building is located as there is no other space at Grayson that can accommodate the footprint and retain the Boiler Building.

Retention of the Boiler Building would logistically complicate and preclude development of the energy storage that is needed which make its retention infeasible. As stated previously, if the Boiler Building is retained there is insufficient space to locate the energy storage elsewhere within Grayson. Placing energy storage within the Boiler Building carries with it significant complications that make retention of the building infeasible, including:

- It would necessitate a surgical demolition around and hazardous materials cleanup of the Boiler Building interior, which results in potentially significant impacts due to possible building damage, and a release of hazardous materials.
- Increased construction time and cost
- It would also drive a structural upgrade of the building adding additional cost to the project, that would create a potentially significant impact to the Building.
- Locating some types of energy storage technologies within the building may not be feasible.

While not a formal alternative, the possibility of relocating a portion of the energy storage system to another part of the Utility Operations Center (UOC) was also considered. No feasible space was identified because there is no spare space at the UOC. Additionally, relocating the batteries would require GWP to dislocate some other function that is essential to GWP's operation and maintenance of the electric and water systems.

For these reasons, retaining the Boiler Building would be a barrier to providing the full 75 MW/300 MWH of energy storage at Grayson.

5.3.6 Reconfigured Tesla/Wartsila Repowering Project (Alternative 6)

As mentioned previously, in Alternative 6 is identical to Alternative 7, but with a different configuration. As work progressed on considering this Alternative, it was determined to be infeasible because the design for Wartsila's structures requires that all the existing piles be removed and not be backfilled with anything that would impede driving new piles. Given the close proximity of existing and new piles, work on this Alternative was terminated. Alternative 6 was determined to be infeasible during the engineering phase and was eliminated from further consideration see Executive Summary).

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7.0 RESPONSE TO COMMENTS

7.1 SUMMARY OF VERBAL AND WRITTEN COMMENTS RECEIVED DURING THE PUBLIC REVIEW PROCESS FOR THE PARTIALLY RECIRCULATED DRAFT EIR

Written comment on the PR-DEIR received during the public review period are included in this section. The comment letters are provided at the end of the section, following all of the responses. When a comment is made by multiple parties, the response is provided the first time the comment is made, and all other similar comments are referred back to that response.

The format of the responses to all the comments is based on a unique letter and number code for each comment. The letter and number immediately following the letter refer to an individual agency, business, group, organization, or member of the general public comment letter. The number at the end of the code refers to a specific comment within the individual letter. Therefore, each comment has a unique code assignment. For example, comment L1-1 is the first comment in letter L1.

Comments were received on the PR-DEIR and they were reviewed to determine whether there is substantial disagreement about the potential significance of impacts. Any issues raised concerning potentially significant impacts were reviewed, addressed, and clarified.

Attachment A contains the Public Meeting and Individual Responses received and have been bracketed to match the comment codes as described above.

Written comments received from State Agencies:	1
Written comments received from Regional and Local Agencies:	2
Written comments received from Interest Groups:	5
Written comments received from the General Public:	28
Verbal comments received during September 9, 2021, Meeting:	96

Table 7-1 Individual Comment Letters

Name of Commenter	Date of Comment	Comment Letter No.
Larry Moorehouse	09/13/2021	1
Jennifer Pinkerton	09/28/2021	2
Calin Ursea	10/01/2021	3
Emily Griffin	10/03/2021	4
Vahan Barseghian	10/04/2021	5
Alin Lin on behalf of Caltrans	10/06/2021	6
Colin Fleming	10/06/2021	7
Henry Schlinger	10/06/2021	8
Alina Mullins on behalf of SCAQMD	10/07/2021	9
Randall and Nancy Wise	10/13/2021	10
Andre Sarkissian	10/03/2021	11
Emily Mirzakhan	10/03/2021	12
Melany Mirzakhan	10/03/2021	13
Candace Hodder	10/03/2021	14
David R. Diaz	10/03/2021	15
John Schwab-Sims on behalf of TGHS	10/10/2021	16
Alina Mullins on behalf of SCAQMD	10/12/2021	17
Zarah Patrinana on behalf of EarthJustice	10/12/2021	18
Jackie Gish	10/13/2021	19
Andrew Ellis	10/15/2021	20
Elise Kalfayan on behalf of Glendale Environmental Coalition	11/15/2021	21
Francesca Smith	11/15/2021	22
Lupe Ruelas on behalf of EarthJustice	11/15/2021	23
Webster McKinsey-Lea	11/10/2021	24
Rachel Ridgway	11/15/2021	25
Jennifer Pinkerton	09/13/2021	26
Larry Moorehouse	09/21/2021	27
Larry Moorehouse	09/21.2021	28
Daniel Brotman	09/26/2021	29
Larry Moorehouse	10/15/2021	30
Larry Moorehouse	10/26/2021	31
Larry Moorehouse	10/26/2021	32
Larry Moorehouse	11/02/2021	33
Hank Schlinger	11/02/2021	34
Larry Moorehouse	10/31/2021	35
Adrienne Griffin	08/15/2021	36

7.2 TOPICAL RESPONSES

A number of comments received on the PR-DEIR focused on several main issues and topics associated with the Project and the CEQA analysis of Project impacts. Because of this, the City of Glendale determined it would be appropriate, and would facilitate public review, to provide topical responses to address these comments and provide the necessary context for considering the issues raised. The main issues and topics warranting topical responses are provided in full, below, and include the following:

Table 7-2 Topical Responses

Topics	Topical Response No.
Project Purpose and Objectives	1
Cost Estimates	2
Historical Resources	3
Air Quality	4
GWP's Path to 100 Percent Clean Energy	5
Consideration of Alternatives	6
Partial Recirculation and Adequacy of the Partially Recirculated Draft EIR	7
Sufficiency of Alternative 2	8

7.2.1 Topical Response No. 1 Project Purpose and Objectives

Summary of Comments

Comments were received questioning the need to repower the Grayson Power Plant. Commenters asked why GWP has not increased import capacity as an alternative to repowering the Grayson Power Plant. Several comments also asserted that GWP has misstated or inflated its energy reserve obligation and is using third-party sales to justify the inclusion of fossil-fired generation in its reserve portfolio.

Summary of Responses

GWP has an obligation to ensure reliable electric service that meets anticipated energy demands referred to as its "load," as well as cope with contingency events, such as a transmission line outage or failure of a power generation facility, which disrupt supplies of energy. Glendale's current peak load is 346 MW and is forecasted to increase to 398 MW by 2027. See Response 1 below.

The City requires the continued operation of the Grayson Power Plant (Grayson), including at least some fully dispatchable (capable of starting any time of the day) generation, in order to ensure reliability of the electrical supply. If the Grayson units are available for operation (they need not be operating), they will free-up transmission capacity that would otherwise be needed to meet reserve obligations and allow these lines to be used to import more remote, renewable generation. If the Grayson units were to be shut down, then GWP would: (1) have to commit a significant amount of its transmission so that it can be used to import reserves during contingencies, thereby reducing the amount of renewable generation GWP could import into its system to serve its load[21]; and (2) at times need to initiate rolling blackouts and manually shed load to reduce demand to below available supply. See Response 1 below.

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[21] Manual load shedding involves turning off the power to blocks of customers to maintain the system load less than the available supply. Typically, this involves open distribution circuit feeder breakers interrupting supply to some customers, and then restoring their supply while another block of customers is turned off. Hence the term "rolling blackouts."

In order to maintain reliable service, GWP must cover both its load and its energy reserve obligations, namely the two largest contingencies, the N-1 and N-1-1 contingencies, which combined are 148 MW and could increase depending on Grayson's future configuration[22]. GWP currently meets its reserve obligations using the Balancing Authority Area Services Agreement (BAASA) it has with LADWP, which covers 80 MW of reserves for 60 minutes, and the other resources in GWP's portfolio, which includes Grayson. The BAASA has the following limitations which make it imprudent for GWP to rely upon to cover its long-term reserve needs: (1) it is limited in durability – it may be terminated by LADWP upon providing Glendale "eighteen (18) months prior written notice," (2) it is limited in size – it only covers 80 MW, so if GWP experiences a contingency above 80 MW it must obtain additional reserves, (3) it is limited in scope – it only covers GWP's N-1 contingency, but not its N-1-1 contingency, and (4) it is limited in duration – it only covers the first 60 minutes of an N-1 contingency. See Responses 2, 4, 7, and 8 below.

Glendale is also a NERC-registered Distribution Provider, and because LADWP only acts as its own Planning Coordinator, Planning Authority, or its Transmission Planner, GWP must fill that role and conform with the Transmission Planning or "TPL" Reliability Standards' obligations for Planning Coordinators, Planning Authorities, and Transmission Planners. Therefore, Glendale is obligated to comply with the applicable NERC Reliability Standards, which include reserve requirements, as well as operational, testing and maintenance responsibilities. See Response 4 below.

Glendale's reserve obligations are neither misstated, nor inflated. Glendale is contractually obligated to cover its system's reserve requirements, including the N-1 and N-1-1 contingencies. These obligations stem from longstanding contracts with LADWP that make Glendale solely responsible for covering system's reserve requirements and obligate Glendale to design, construct, operate, and maintain its system in conformance with Good Utility Practice and the applicable North American Electric Reliability Corporation's (NERC) Reliability Standards. For over 50 years, Glendale has fulfilled these obligations and maintained reserves sufficient to cover its N-1 and N-1-1 contingencies. This multi-decade course of performance under its contracts with LADWP would make it difficult for GWP to contend that it is not obliged to cover its contingencies, were a dispute to arise on this point. On multiple occasions, LADWP has confirmed that it too interprets these longstanding contracts to require Glendale to meet these contingency obligations. If Glendale were to cease cover its N-1 and N-1-1 contingencies, it would be exposed to litigation risks, as well as reliability risks. If Glendale's failure to meet is

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22 The N-1 contingency refers to the loss of one (the largest) element of the "N" number of elements in the electricity supply chain be it a generator or a transmission line. Currently, the N-1 for GWP is a loss of one of the two circuits on the Pacific Direct Current Intertie (PDCI) that brings power from the Pacific Northwest to Southern California Edison's (SCE) Sylmar Substation whereupon it traverses the SCE and LADWP transmission systems to GWP. There are two circuits, and GWP's share of each circuit is approximately 100 MW after accounting for transmission losses. The N-1-1 refers to the loss of the second largest element of the "N" elements in the electricity supply chain for GWP. Currently, the N-1-1 contingency for GWP is the loss of Grayson Unit 8BC. For the Proposed Project the N-1-1 contingency would be one of combined cycle units with a loss of 71 MW, Unit 9, with a loss of 48 MW for Alternative 7, and remain Unit 8BC for Alternative 8.

reserve obligations under its contracts with LADWP resulted in LADWP suffering damages and/or having penalties imposed upon it for violating the NERC Reliability Standards, it is likely LADWP would expect to pass those damages and penalties through to Glendale. Such penalties can be as much as $1 million per day. See Responses 4 and 5 below.

Because of the BAASA's limitations, GWP is responsible for providing energy (1) for any outages that are larger than 80 MW; (2) to cover an N-1-1 contingency; and (3) for any contingency that extends beyond one hour. Therefore, the BAASA does not fully cover Glendale's reserves' needs. Due to these limitations, LADWP has stated "that the BAASA arrangements do have 18-month termination provisions which were put in place to allow both parties to adapt to a changing environment and it would be imprudent to make very long-term decisions related to repowering of your generation resources relying on any agreement with such relatively short-term certainty." See Response 8 below.

GWP has previously, and again in 2021, asked LADWP (its Balancing Authority) if LADWP would assume and allow GWP to reduce its reserve obligations or offer to sell GWP additional reserves beyond the 80 MW under the BAASA. In LADWP's 2018 letter they refused to assume and allow GWP to reduce its reserve obligations. LADWP has also refused to sell GWP additional reserves. GWP engaged with LADWP again in 2021 at the General Manager level. While LADWP has yet to formally respond, there is no indication that their prior position will change. See Response 8 below.

Glendale is a "load pocket," which means it has insufficient transmission capacity to meet its peak load and cover its reserve obligations, using solely outside resources; Glendale must use local generation. While GWP actively seeks new opportunities for new transmission and to increase existing transmission capacity there are no new transmission lines or transmission upgrades being proposed that would allow GWP to import enough electricity into Glendale to meet its peak load. Glendale has acquired 72 MW of additional transmission rights on the Southern Transmission System (effective 2027) and has access to 25 MW of transmission which is only available to import its power from the Eland I Solar and Storage Project when it is providing power. The impact of these transmission rights on GWP's energy needs are demonstrated in the Tables set forth below. Although these additional assets will reduce the amount of local generation that Glendale needs to meet is peak load and reserve obligations, they unfortunately still are insufficient to enable Glendale to do so using solely outside resources. Therefore, while Glendale has attempted to increase import capacity as an alternative to repowering the Grayson Power Plant, it has been unable to do so sufficiently to meet all its needs. See Responses 4, 9, 11, and 12 below.

As stated in the PR-DEIR (Executive Summary page x), GWP has a regulatory deadline to bring the Grayson Power Plant Units into compliance with new SCAQMD requirements by December 31, 2023. See Response 11 below.

While GWP must sell off excess energy under specific circumstances, as described below, the Grayson repower is sized to meet Glendale's energy needs, not to sell excess energy into the market. See Response 4, 9, 11, and 12 below.

The annual fuel usage amounts contained in the air permit applications equate to a 15 percent capacity factor or less. This low a capacity is inconsistent with using Grayson to support local reliability and engage in wholesale market sales. Permitted fuel usage supporting a much higher capacity factor would have been needed to support wholesale market sales. See Response 11 and 13 below.

Response

1. Overview of GWP's Obligation to Ensure Reliability

GWP has the obligation to provide a reliable electric supply for Glendale residents and businesses at all times. If GWP could assure that it could reliably supply Glendale's electricity needs without thermal generation at the Grayson Power Plant, then new thermal generation would not be proposed.

GWP's main supply of electricity comes from electricity imported into Glendale over transmission lines[23] and supplemented by locally-produced renewable energy such as roof-top solar. That combination, along with energy efficiency and demand response measures, is sufficient to meet Glendale's current electricity demand on most days. However, it is not sufficient on days when GWP is experiencing high energy demand, such as on very hot days, or when there is an interruption or degradation (contingency event) affecting the transmission system (such as an equipment failure or wildfire induced shutdown of a transmission line) or the generation sources from which electricity is being imported.

Additionally, GWP must plan not only for what today's electrical demands are, but also for future demands for electricity. An important step in that process is GWP's Integrated Resource Plan (IRP). The 2019 IRP developed a probabilistic estimate of Glendale's electric demand with a range of forecasted loads. On the low end of the range was the P5 forecast which was a low estimate of peak demand that could be experienced during a cool summer. The mean peak (P50) was indicative of an average summer condition. The P95 forecast was a high estimate reflecting a hot summer. The P95 loads were used for planning purposes in the IRP recognizing that climate change is impacting Southern California and resulting in longer and hotter summers.

[23] GWP's imports today are a diversified mixture of resources including wind, solar, geothermal, hydroelectric, nuclear, natural gas, and coal generation. These imports come from the Pacific Northwest over the Pacific Direct Current Intertie (PDCI) and the southwest via the Southwest Transmission System (STS). Over time, particularly as the coal-fired Intermountain Power Project is replaced with a smaller natural gas-fired combined cycle plant that will be fueled with hydrogen (with the hydrogen produced using wind and solar powered hydrolysis), that mix will change to wind, solar, geothermal, hydroelectric, nuclear, hydrogen, and natural gas generation.

The 2019 IRP included and considered anticipated electrification of the transportation sector anticipating an increase in electricity demand due to the need to charge more electric vehicles during the day and overnight. (See 2019 IRP, Section 3). Since the 2019 IRP was released, Governor Gavin Newsom issued Executive Order No. 79-20, requiring that by 2035, all new cars and passenger trucks sold in California must be electric vehicles.

Recently, there has been a growing movement towards electrification of buildings as well. The 2019 IRP load projections models do not include potential load growth due to building electrification. Building electrification will reduce carbon dioxide emissions by replacing natural gas-fueled HVAC systems, water heaters, and cooking appliances with electric ones. While the winter heating season usage of electrically powered HVAC systems should not impact peak power demands, there is a potential for an increase in electricity demand from electric water heaters and cooking appliances, with load growing over time as gas-fueled appliances reach the end of their lives and are replaced with electric ones[24]. Additionally, new all electric construction will also contribute to electric demand.

A factor that the IRP did not contemplate was COVID-19. COVID resulted in a significant slowdown in economic activity due to the closure across every segment of the economy, and an increase in people working-from-home. While electric demand in 2020 and 2021 was less than the 2019 IRP forecast, the overall COVID impact is a short-term impact when viewed in the context of a 20-year IRP. The combination of recovery from the COVID pandemic, electric vehicle growth, and building electrification, will lead to electric demand recovering.

In accordance with California law, the 2019 IRP addressed system and local reliability[25]. Contingency[26] events can occur at any time. To address such events, and ensure Glendale has adequate and reliable power, Glendale needs locally dispatchable generation that can be started at any time that the combination of the following are insufficient to meet Glendale's load: (1) energy imported into Glendale's system from remote generation resources over transmission lines, (2) local renewables, (3) local energy efficiency programs, and (4) demand response measures. Local generation is necessary because Glendale is a "load pocket," which

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24 See Energy + Environmental Economics (E3) study, "Residential Building Electrification in California: Consumer economics, greenhouse gases, and grid impacts, prepared for SCE, LADWP, and SMUD, dated April 2019, available at https:/www.ethree.com/wp-content/uploads/2019/07/CA_Res_Building_Electrification_Final Presentation.pdf

25 See California Energy Commission - Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines (Second Edition), available at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=18-IRP-01

26 Glossary of Terms Used in NERC Reliability Standards (updated June 28, 2021) ("NERC Glossary") defines "Contingency" as "[t]he unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element." https://www.nerc.com/files/gosssary_of_terms.pdf

means that it has insufficient transmission capacity to meet its peak load and cover its reserve obligations using solely outside resources.

GWP is also required to provide a yearly update to LADWP (its Balancing Authority) of GWP's Load and Resources[27] (LAR) forecast, an obligation imposed on both LADWP and GWP by the Western Electric Coordinating Council (WECC). Additionally, as a load-serving entity and distribution provider, GWP must demonstrate to the State of California Energy Commission (CEC) that it has the requisite reserves and is able to handle contingency conditions[28]. The oversight provided by the WECC and the CEC speaks to the importance of ensuring electric reliability.

Glendale must size Grayson to enable it to sufficiently meet its peak load and reserve obligations. If Glendale fails to do this, it would be exposed to future reliability risks, which could include extended blackouts on its system, and to the risk of future legal liability arising from its failure to meet its reserve obligations. If Grayson is properly sized and the units are available for operation (they need not be operating), they will free-up transmission capacity that would otherwise be needed to meet reserve obligations and allow these lines to be used to import more remote, renewable generation. If the Grayson units were to be shut down, then GWP would: (1) have to commit a significant amount of its transmission so that it can be used to import reserves during contingencies, thereby reducing the amount of renewable generation GWP could import into its system to serve its load; and (2) at times need to initiate rolling blackouts and manually shed load[29] to reduce demand to below available supply. The proposed Project and Alternatives are designed to address these issues and avoid the aforementioned risks, so that Glendale's customers are protected from the dangers of an unreliable power supply, potential litigation, as well as price increases that occur during times of constrained supply.

2. Reserves and Other Ancillary Service Requirements

In addition to the need to maintain sufficient power to cover peak load, Glendale must also have available sufficient amounts of the following:

- **Spinning Reserves** – Generation operating at low load that is synchronized and ready to serve additional demand (i.e., the battery is charged and connected to the grid, the generator is synchronized to the grid). Spinning reserves are particularly important in the

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[27] 2020 Loads and Resources Data Collection Manual, December 2019, Western Electric Coordinating Council.

[28] *Refer to* California Public Resources Code 25216, 25216.5, and 25300-25323. *Also refer to* California Energy Commission Docket No. 17-IEPR-02.

[29] Manual load shedding involves turning off the power to blocks of customers to maintain the system load less than the available supply. Typically, this involves open distribution circuit feeder breakers interrupting supply to some customers, and then restoring their supply while another block of customers is turned off. Hence the term "rolling blackouts."

event of the sudden, unexpected, and sustained loss of a generating resource. The amount of spinning reserve may be spread over more than one resource.

- **Non-spinning or supplemental reserves** – A non-operating generating resource that is capable of starting and serving demand within a specified time (currently 10 minutes) (i.e., the unit is in standby and can be started and producing full power within 10 minutes). The amount of non-spinning reserves may be spread over more than one resource.

- **Regulation and frequency response services** – Capacity of adjusting generation output instantaneously up or down ("regulation up" and "regulation down") to meet swings in demand, resource capability, and frequency.

- **Replacement Reserves** that relieve the generators providing the spinning or non-spinning reserve and thus restore the **Operating Reserves** (composed of spinning and non-spinning/supplemental reserves) using generators that require a longer start-up time (typically thirty to sixty minutes).

"Spinning" reserves and "non-spinning" or "supplemental" reserves are referred to as "contingency reserves." Utilities use these contingency reserves to ensure that adequate generating capacity is available at all times to maintain scheduled frequency (to keep the generation and load in balance) and avoid power outages following the loss of a major generation or transmission resource (a contingency event). "Replacement" reserves are sometimes referred at "Planning" reserves and involve the use of resources that have a slightly slower start-up time but that are able to respond to the same types of contingencies addressed by spinning and supplemental reserves.

Utilities require regulation and frequency-response services to maintain voltage and frequency within narrow operating bands, ensuring the reliable and safe operation of the interconnected bulk electric system. The bulk electric system is a large network in which all of the components must operate at the proper voltages and within a very narrow range of frequency (60 Hz ±0.1 Hz). A complete collapse of the bulk electric system will occur if generation and load are not kept in balance and operated within acceptable limits.

To prevent such a collapse, NERC and WECC have issued a series of mandatory rules – i.e., the NERC Reliability Standards – that will keep the grid running reliably, predictably, and safely. "Regulation" is the ability of a generator to immediately and automatically match load with generation. As load increases (e.g., someone turns on a light), generation must immediately and automatically respond to that increased load; as load decreases (someone unplugs a toaster), generation must immediately and automatically decrease to match the change in load. Similarly, as loads increase, frequency decreases, so generators must increase output to ensure frequency is maintained at 60 Hertz (Hz). If generators do not respond to maintain system frequency, and frequency is allowed to stray beyond an acceptable amount, it can destabilize the grid leading to affected portions being separated from the rest of the grid by automatic protective relays and circuit breakers. If those separated portions have insufficient generation to serve load, they will collapse (generators trip off-line on low frequency) and go black. That this is a rare occurrence, is due to the defense in depth and provision of enough resources to cope with contingency events and ensure reliability.

3. NERC Reliability Standards that Address Reserve Obligations

NERC has several Reliability Standards that apply to different entities and establish reserve obligations. NERC's Resource and Demand Balancing or "BAL" Reliability Standards address certain contingency requirements that a "Balancing Authority" must meet. The NERC Glossary[30] defines "Balancing Authority" as "[t]he responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area[31], and supports Interconnection frequency in real time."

NERC Reliability Standard BAL-002-WECC-3 is one of the NERC Reliability Standards that addresses resource and demand balancing in WECC and ensures that adequate resources are available at all times to maintain scheduled frequency, and avoid loss of firm load (i.e., brown-outs[32] and black-outs) following transmission or generation contingencies. It labels all of the aforementioned reserves, except planning reserves, as "Contingency Reserves" and specifies the quantity and types of these contingency reserves that are required to ensure reliability under normal and abnormal conditions. This regional standard in WECC (the region in which Glendale is located) is slightly more stringent than the national standard because it requires more stringent minimum reserves and requires restoration of contingency reserves within 60 minutes following an event.

BAL-002-WECC-3 is applicable to any "Balancing Authority[33]" or "Reserve Sharing Group[34]." BAL-002-WECC-3's purpose is "to specify the quantity and types of Contingency Reserve required to

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30 Glossary of Terms Used in NERC Reliability Standards (updated June 28, 2021) ("NERC Glossary"); https://www.nerc.com/files/gosssary_of_terms.pdf

31 The NERC Glossary defines "Balancing Authority Area" as "The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area." The NERC Glossary defines "Balancing Authority" as "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time."

32 "Brownouts" refer to the electric system operating with degraded voltage conditions. This is not a desirable condition because it results in motors working harder and drawing more current to provide the required mechanical power to the connected load. Long-term operation can result in motor failures as the increased current draw results in excessive motor heating.

33 The NERC Glossary defines "Balancing Authority" as "[t]he responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time."

34 The NERC Glossary defines "Reserve Sharing Group" as "[a] group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required

ensure reliability under normal and abnormal conditions." This will ensure that a Balancing Authority is able to use its contingency reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. It requires:

R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is: [Violation Risk Factor: High] [Time Horizon: Real-time operations]

1.1 The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency [i.e., Single Largest Contingency];
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

1.2 Comprised of any combination of the reserve types specified below:

- Operating Reserve – Spinning
- Operating Reserve – Supplemental
- Interchange Transactions designated by the Source Balancing Authority as Operating Reserve – Supplemental
- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service
- A resource, other than generation or load, that can provide energy or reduce energy consumption
- Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.

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for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group."

- All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.

1.3 Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC[35] Order 464).

1.4 An amount of capacity from a resource that is deployable within ten minutes[36].

The NERC Glossary defines the "Most Severe Single Contingency" as:

> *The Balancing Contingency Event[37],] due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority)[38].*

Balancing Contingency Events include the sudden loss (full or partial) of transmission or generation capacity. The requirement to maintain "the amount of Contingency Reserve equal to the loss of the most severe single contingency [referred to in the PR-DEIR as the "single largest contingency"[39]," is also referred to in the industry as the "N minus 1" or "N-1 contingency."

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[35] Federal Energy Regulatory Commission (FERC).

[36] *See* NERC Reliability Standard BAL-002-WECC-2a (emphasis added).

[37] The NERC Glossary defines the "Balancing Contingency Event" as "Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.
A. Sudden loss of generation:
a. Due to i. unit tripping, or ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or iii. sudden unplanned outage of transmission Facility;
b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.
C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE."

[38] *See* NERC Glossary definition of "Most Severe Single Contingency" (emphasis added).

[39] WECC Standard BAL-002-WECC-2a – Contingency Reserves R1; *See also, Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators,* 153 FERC ¶ 61,221 at fn. 60 (2015) ("An N-1 contingency is the loss of a single generator or transmission element.").

Having reserves to meet an N-1 contingency means an entity has sufficient Contingency Reserves.

The NERC Reliability Standards require entities to hold reserves sufficient to meet their second largest contingency, which is referred to as the "N minus 1, minus 1" or "N-1-1 contingency[40]." Having reserves to cover an N-1-1 means an entity can respond to two contingencies happening consecutively[41]. An entity will establish a new N-1 reserve after the first contingency occurs. This is done since many times the first contingency results in a prolonged outage of that resource. An N-1-1 contingency is different from an N-2 contingency in that the latter involves the first and second largest contingencies happening simultaneously as opposed to consecutively.

The need to address an N-1-1 contingency under the NERC Reliability Standards is found in other "BAL" Reliability Standards, the Transmission Planning or "TPL" Reliability Standards, and the Transmission Operations or "TOP" Reliability Standards. NERC Reliability Standard BAL-002-WECC-3 part M1 requires entities to restore their contingency reserves within 60 minutes following an event. Therefore, if an entity has an N-1 contingency that lasts longer than 60 minutes, it must have the reserves necessary to cover its next single largest contingency (i.e., the N-1-1), to comply with this requirement. NERC Reliability Standard BAL-002-WECC-2a part M1 states in pertinent part:

> *Each Balancing Authority and each Reserve Sharing Group will have documentation demonstrating its Contingency Reserve was maintained, except within the first sixty minutes following an event requiring the activation of Contingency Reserve*[42].

NERC Reliability Standard TPL-001-4, which is entitled "Transmission System Planning Performance Requirements," is applicable to any "Planning Coordinators[43]" (also sometimes referred to as

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40 *See e.g., Price Formation in Energy and Ancillary Services Markets,* 153 FERC ¶ 61,221 at fn. 61 ("An N-1-1 contingency is a sequence of events consisting of an initial loss of a single generator or transmission element, followed by system adjustment, followed by another loss of a single generator or transmission element. An N-2 contingency is the simultaneous loss of two transmission elements or generators.").

41 In power system operations, a "contingency" is the unexpected failure of a system component (for example, a generator, a transmission line, or a circuit breaker). Contingency analysis simulates taking one or more components out of service to determine how the system is affected. A first contingency ("N-1") analysis asks what the effect on the system would be if a single power line (for example) were to trip. A second contingency ("N-1-1") analysis asks what the effect on the system would be if a subsequent power line (for example) were to trip. Second contingency analysis assumes that, following the first contingency, "operator action" takes place to ameliorate (to the extent possible) the effects of the first outage before the second outage occurs.

42 *See* NERC Reliability Standard BAL-002-WECC-2a Part M1 (emphasis added).

43 The NERC Glossary defines a "Planning Coordinator" as having the same definition as a "Planning Authority," and defines a "Planning Authority" as "[t]he responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems."

"Planning Authorities") and "Transmission Planners[44]." TPL-001-4's purpose is "[e]stablish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." TPL-001-4 requires systematic and diligent contingency analysis, including exhaustive N-2 contingency analysis (loss of two elements simultaneously), N-1-1 contingency analysis (loss of two elements consecutively within specific time frames[45]), and assessment of cascading outages[46]. Specifically, TPL-001-4 defines a set of system performance requirements that the electric system must meet under N-1, N-1-1, and N-2 contingency conditions. TPL-001-4 includes a table entitled "Table 1 – Steady State & Stability Performance," which categorizes these contingencies and how they are to be addressed. Categories P1-P2 address N-1 contingencies and Categories P3-P7 address N-1-1, N-2 and beyond.

Each Transmission Planner and Planning Coordinator in North America is required to perform the studies necessary to assess system performance under these contingency conditions and ensure that the system complies with these TPL requirements. In the context of the TPL standards, an entity meeting its N-1-1 contingency is referred to as meeting its Planning Reserve obligations.

The need to address N-1-1 contingencies has also been "driven by [other] requirements of the NERC Reliability Standards.[47]" For example, BAL-003-2, which addresses "Frequency Response and Frequency Bias Setting," includes a requirement obligating entities to have the requisite capacity to provide Frequency Response reserves to maintain the Interconnection Frequency, between their system and neighboring systems, within predefined bounds. BAL-001-2, which

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44 The NERC Glossary defines a "Transmission Planner" as "[t]he entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area."

45 N-1-1 contingency analysis considers the consecutive loss of two elements in a power system, with intervening time for operator adjustments as is required under NERC Standard TPL-001-4. *See also* 18 CFR Part 40 Mandatory Reliability Standards for the Bulk Power System, 118 FERC ¶ 61,218 (2007) ("The Commission agrees with MidAmerican that for Category C contingencies of TPL-003-0, the worst N-1-1 contingency would be a single element outage followed by a multiple element outage, provided that following the first N-1 contingency, capability exists to switch the unfaulted elements back into service promptly, *i.e.,* within 30 minutes, as part of the adjustments the Reliability Standard allows.").

46 Generally, utilities will do an Assessment Study, which will test their systems to determine if they have the requisite reserves to maintain system reliability. These studies will look at the system in N-0 (normal operations prior to any contingency), N-1 (to show the system can withstand the first contingency, which may involve the loss of one or more system components, without affecting service to customers), and N-1-1 (the system must be able to withstand the most severe single outage on its system without the occurrence of instability, and within 30 minutes of the first outage, the system must be prepared for the next most severe outage).

47 *See e.g., Price Formation in Energy and Ancillary Services Markets,* 153 FERC ¶ 61,221 at PP 31-65 (describing how because BAAs are required to meet N-1-1 or N-2 contingencies under the NERC Reliability Standards they may charge uplift charges to meet these obligations, *citing* "Reliability Standard TOP-007-WECC-1a" and "Reliability Standard TOP-004-2."); *See also* NERC Reliability Standard TPL-001-4.

addresses “Real Power Balancing Control Performance,” has requirements that obligate entities to meet the Control Performance Standard 1 (CPS1) requirements, which involves making sure its Area Control Error (ACE), which measures imbalances between it and other entities, is low such that entities are not leaning on neighboring systems (e.g., neighboring BAs) for balancing services.

Reliability Standard TOP-007-WECC-1a, was a Western Electricity Coordinating Council regional standard requiring, among other things that “at no time shall the power flow for a Transmission path exceed the System Operating Limit for more than 30 minutes.” NERC Reliability Standard TOP-004-2, was a Continent-wide standard that required each Transmission Operator[48] shall operate within Interconnection Reliability Operating Limits and System Operating Limits.[49]” Reliability Standard TOP-001-5, which is entitled “Transmission Operations,” which superseded the aforementioned and maintained the obligations, is applicable to Balancing Authorities, Transmission Operators, Generator Operators[50] and Distribution Providers[51]. Its stated purpose is “to prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.” TOP-001-5 R12, requires that “[e]ach Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL Tv[52].”).

NERC’s Protection and Control or “PRC” Reliability Standards also include requirements that obligate entities to have programs and systems in place to address Contingencies and events that cause frequency reductions. The PRC Reliability Standards require entities to perform the necessary maintenance and testing to ensure these programs and systems are ready to respond to such events. NERC Reliability Standard PRC-005-1.1b, which is entitled “Transmission and Generation Protection System Maintenance and Testing,” applies to Transmission Owners, Generator Owners and Distribution Providers that owns a transmission Protection System[53]. The

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48 The NERC Glossary defines a “Transmission Operator” as “[t]he entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission Facilities.”

49 *Price Formation in Energy and Ancillary Services Markets,* 153 FERC ¶ 61,221 at fn. 62.

50 The NERC Glossary defines a “Generation Operator” as “[t]he entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.”

51 The NERC Glossary defines a “Distribution Provider” as entity that “[p]rovides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.”

52 The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit’s Tv shall be less than or equal to 30 minutes.

53 The NERC Glossary defines a “Protection System” to include any of the following:
• Protective relays which respond to electrical quantities,

purpose of PRC-005-1.1b is "to ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested." It requires that "[e]ach Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation or generator interconnection Facility Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES[54]."

NERC Reliability Standard PRC-005-6, which is entitled "Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance," applies to Transmission Owners, Generator Owners and Distribution Providers. The purpose of PRC- PRC-005-6 is to require entities "to document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System … so that they are kept in working order."

NERC Reliability Standard PRC-006-5, which is entitled "Automatic Underfrequency Load Shedding," applies to Transmission Owners, Generator Owners, Distribution Providers, and UFLS-Only Distribution Providers. Its purpose is "to establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures."

In addition to the NERC Reliability Standards' requirements, the need for a system to be able to address N-1 and N-1-1 contingencies is also required by "Good Utility Practice", which is sometimes referred to as "Prudent Utility Practice," and FERC precedent[55]. LADWP, the CAISO[56],

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- Communications systems necessary for correct operation of protective functions• Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

[54] Bulk Electric System.

[55] *See e.g., Cal. Indep. Sys. Oper. Corp.,* 116 FERC ¶61,274 at P 1169 (2006) ("We [FERC] find that the N-1-1 local reliability criteria is good utility practice. . . .").

[56] *See e.g., Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators,* 153 FERC ¶ 61,221 at P 34 (2015) ("CAISO currently uses the Minimum Online Commitment constraint, which ensures that, in a given geographic region (e.g., the Los Angeles Basin), there is sufficient generation on-line to prevent voltage collapse after a series of transmission (often N-1-1) contingencies.").

ID[57], other California Balancing Authority Areas (BAA)s, NYISO[58][59], ISO-NE[60][61], and virtually every other BA, ISO and RTO maintain the reserves necessary to meet these contingencies and avoid outages. The procurement of reserves to meet N-1 and N-1-1 contingencies predates the NERC Reliability Standards, which were born out of the Energy Policy Action of 2005. Utilities have done this for over 80 years because Good Utility Practice requires that a system operator be able to handle more than just the loss of one contingency[62]. This is especially true for entities that are Metered Subsystems[63], or sub-BAAs that are load pockets, such as Glendale, – i.e., entities that, due to transmission constraints, cannot meet their load and reserve obligations using solely outside resources. For example, FERC has found that the City of Santa Clara (aka Silicon Valley Power or SVP), a Metered Subsystem that is also a load pocket, must maintain sufficient local capacity area resources to ensure the reliability of their systems:

> Local capacity area resources are needed within load pockets in order to ensure reliability of the CAISO-controlled grid, because transmission capability available to import energy to meet load in the load pocket is limited. A local capacity area resource requirement is calculated as the amount of capacity that cannot be met with capacity outside the load pocket due to transmission limitations. Grid reliability benefits all participants, and no LSE should be excluded from the responsibility to procure these local capacity area resources. Accordingly, all LSEs will be responsible for their allocated amount of local capacity area resource requirements in order to maintain the reliability of the CAISO-controlled grid.
>
> We find that Santa Clara's general obligation to serve its own load does not result in a reduction in local capacity requirements to meet grid reliability. The development of local capacity area resource requirements is part of the resource adequacy planning process that is separate and distinct from real-time energy balancing issues or penalties[64].

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[57] Imperial Irrigation District ("IID").

[58] New York Independent System Operator ("NYISO").

[59] *Id* at P 35 ("NYISO states that its network model currently includes certain N-1-1 constraints, including local N-1-1 thermal requirements in New York City. NYISO states that the New York City load pockets of the day-ahead market ensure sufficient generation capacity is available in those load pockets to be able to meet N-1-1 criteria. NYISO also states that it has established two operating reserve zones (East of Central-East and Long Island) and is in the process of establishing a third (southeastern New York) to address N-1-1 contingencies.").

[60] Independent System Operator-New England (ISO-NE).

[61] *Id* at P 38 ("ISO-NE purchases operating reserves to address multiple contingencies on a forward basis.").

[62] *See e.g., Cal. Indep. Sys. Oper. Corp.,* 116 FERC ¶61,274 at P 1169.

[63] A metered subsystem is a geographically contiguous system located within a BAA (usually a load serving entity), "which is responsible for balancing its own load and resources within its territory." *See e.g., N. Am. Elec. Reliability Corp.,* 153 FERC ¶61,024 at P 8 (2015).

[64] *California Indep. Sys. Oper. Corp.,* 119 FERC ¶61,076 at PP 580-581 (2007).

4. NERC Reliability Standards Applicable to Glendale and LADWP

LADWP is a power system operator (i.e., the BA) that operates the LADWP BAA and is responsible for balancing its BAA under federal the NERC Reliability Standards. This means LADWP must strictly adhere to the NERC Standards that govern how it must meet these reserve obligations within the LADWP BA. For example, NERC Reliability Standard BAL-003-1.1 – Frequency Response and Frequency Bias Setting, requires LADWP to have the requisite capacity to provide Frequency Response reserves to maintain the Interconnection Frequency – between it and its neighboring systems – within predefined bounds. BAL-001-2 – Real Power Balancing Control Performance, requires LADWP to meet the Control Performance Standard 1 (CPS1) requirements, which involves making sure its Area Control Error (ACE), which measures imbalances between it and other entities, is low such that it is not leaning on neighboring systems for balancing services.

Under NERC Reliability Standard BAL-002-WECC-2a – Contingency Reserves R1.1, LADWP must maintain "the amount of Contingency Reserve equal to the loss of the most severe single contingency [referred to in the PR-DEIR as the "single largest contingency"]," which is the N-1 contingency[65]. In compliance with NERC Reliability Standards BAL-002-WECC-2a part M1, TPL-001-4, and TOP-001-3 and for the reasons detailed above, LADWP also carries reserves sufficient to meet its BAA's second largest contingency (i.e., the N-1-1 contingency)[66].

LADWP does not include Glendale's load or its reserves obligations in the calculations of LADWP's reserve obligations. LADWP also does not act as GWP's Planning Coordinator or Planning Authority under the NERC Reliability Standards, and therefore, does not meet any of the TPL Reliability Standard's requirements for Glendale.

Glendale operates as a Metered Subsystem[67] or sub-BAA within the LADWP BAA. As such, like other Metered Subsystems that have remained vertically integrated (as opposed to functional separate and centrally dispatched by and ISO or RTO like CAISO)[68], Glendale meets its Metered

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[65] WECC Standard BAL-002-WECC-2a – Contingency Reserves R1; *See also, Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators,* 153 FERC ¶ 61,221 at fn. 60 (2015) ("An N-1 contingency is the loss of a single generator or transmission element.")

[66] *See e.g.,* NERC Reliability Standards BAL-002-WECC-2a part M1, TPL-001-4 and TOP-001-3.

[67] A metered subsystem is a geographically contiguous system located within a BAA (usually a load serving entity), "which is responsible for balancing its own load and resources within its territory." See e.g., N. Am. Elec. Reliability Corp., 153 FERC ¶61,024 at P 8 (2015).

[68] *See e.g., Id.; See also Cal. Indep. Sys. Oper.,* 153 FERC ¶ 61,002 at PP 1 and 14 (2015) (order accepting a BA's (California Independent System Operator (CAISO)) transmission tariff amendment that requires metered subsystems to "identify any variable energy resources [*i.e.,* renewable generators] outside their resource portfolios they intend to rely on" and "include in their resource adequacy plans [*i.e.,* reserve plans] additional flexible adequacy capacity [*i.e,* their reserves]" sufficient to handle the intermittence these renewable cause because these metered subsystems are "required to balance load and generation resources in their portfolio")

Subsystem's reserve obligations and balance its loads and resources within its Metered Subsystem. Therefore, for the past 50-plus years, and continuing to this day, Glendale has maintained reserves sufficient to meet both its system's N-1 and N-1-1 contingencies. Glendale uses its own generation and generation it purchased from others to meet these contingencies.

GWP is also a NERC-registered Distribution Provider – Under-Frequency Load Shed (DP-UFLS) entity, that is required to comply with all applicable NERC Reliability Standards. Of relevance here, is that Glendale is required to comply with NERC's PRC Reliability Standards. This has meant that Glendale must have the requisite programs and systems in place to address contingencies and events that cause frequency reductions. Therefore, Glendale performs the necessary maintenance and testing this standard requires to ensure its programs and systems are ready and able to respond to such events in the time frames required.

Glendale is a "load pocket," which means it has insufficient transmission capacity to meet its peak load and cover its reserve obligations, using solely outside resources; Glendale must use local generation. As such it is critically important for it to be able to cover its N-1 and N-1-1 contingencies. A failure to do so, could result in FERC ordering Glendale to maintain sufficient local capacity area resources to ensure the reliability of its system, like FERC did in the City of Santa Clara case[69].

Because LADWP only acts as its own Transmission Planner, Planning Coordinator, or Planning Authority, Glendale acts in this capacity on its behalf[70]. Therefore, Glendale is responsible for compliance with the TPL Reliability Standards, including TPL-001-4. As such, Glendale has established system planning performance requirements that will enable it to operate reliably during the broad spectrum of system conditions and wide range of probable contingencies identified in TPL-001-4, including N-1-1 contingencies.

5. Glendale's Reserve Obligations Under its Agreements with LADWP

Prior to the enactment of the Energy Policy Act of 2005, which established the NERC Reliability Standards detailed above, Glendale entered into a variety of agreements with LADWP and others, under which it agreed to be responsible for providing the reserves necessary to facilitate the transactions under these agreements. Glendale agreed to these responsibilities because, at the time, there were no BAs or BAAs, or BAL Reliability Standards, there were just "Control Areas" whose operators had conform to rules established by the Western Systems Coordinating Council (WSCC), Good Utility Practice and agreements governing the Control Areas' interconnected operations. At this time, Glendale was a Control Area Operator that operated a Metered Subsystem within LADWP's Control Area. As such, Glendale, along with Burbank, was expected

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69 *California Indep. Sys. Oper. Corp.,* 119 FERC ¶61,076 at PP 580-581.

70 See http://www.oasis.oati.com/woa/docs/LDWP/LDWPdocs/Pending_Attachment_K.pdf, which states: "*LADWP has provided and continues to provide wheeling services to the Cities of Burbank and Glendale (which are in the LADWP control area), however, these cities perform their own transmission and resource planning.")*

to balance its loads and resources and maintain the necessary reserves to ensure it did not cause problems with LADWP. It is in this context that Glendale entered into agreements requiring it to meet its system's reserve requirements. For example, Article 15(a) of Glendale-LADWP PDCI Agreement requires that "[e]ach Participant shall at all times maintain on its system, or have available by arrangement with others, spinning reserve capacity sufficient to immediately replace at least the amount of power scheduled to be received by it over the D-C Transmission facilities and additions and betterments thereto[71]." Glendale is a "Participant[72]" under this Agreement and is obligated to carry reserves sufficient to cover each MW of power it schedules over Pacific-DC Intertie. Because Glendale can schedule up to 100 MW over its share of the Pacific-DC Intertie, Article 15(a) requires it carry 100 MW of reserves to cover such a schedule. Glendale has been carrying reserves to cover its share of PDCI since 1967[73].

Similarly, Section 7.4 of the VIC-LA TSA[74], Section 8.3 of the Hoover TSA[75], and Section 6.3 of the IPP TSA[76] each state that "Glendale will provide for its own spinning reserve requirements, and Los Angeles shall not be required to maintain any spinning reserve requirements for Glendale under this Agreement." Thus, under each of the agreements governing the transmission paths Glendale uses to import power into its system, Glendale, not LADWP, is obligated to carry reserves to respond to any contingencies that arise on these paths.

In addition to requiring Glendale to carry reserves, its agreements with LADWP also require it and LADWP to operate their respective systems in a manner that is consistent with Good Utility Practice and with the reliability standards established by the WSCC, which is the entity that preceded and was replaced by WECC in 2002. For example, Sections 13.1 and 13.2 of the Interchange Agreement state:

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71 City-Glendale Pacific-Intertie D-C Transmission Facilities Agreement, between LADWP and Glendale, executed on or about March 16, 1967 (LADWP Contract No. 10128) ("PDCI Agreement").

72 PDCI Agreement at p. 1, Recital E ("City, Glendale and each of the entities mentioned in Recital D, which acquires an undivided interest in the D-C Transmission Facilities, is herein referred to, individually, as a 'Participant', and collectively as 'Participants.'")

73 The LADWP-Glendale 1999 Interchange Agreement ("Interchange Agreement"), Section 8.1.1 incorporates the DC Facilities Agreement's reserve requirements, it states "Spinning reserve requirements for energy transmitted pursuant to Section 6 shall be in accordance to Article 15 of the DC Facilities Agreement."

74 Los Angeles-Glendale Victorville-Airway Receiving Station Transmission Service Agreement (LADWP Contract No. 10932) ("VIC-LA TSA").

75 Los Angeles-Glendale Hoover Transmission Service Agreement, (LADWP Contract No. 10932) ("Hoover TSA").

76 Los Angeles-Glendale IPP Transmission Service Agreement (LADWP Contract No. 10007) ("IPP TSA").

> **13.1** Each party hereto shall design, construct, operate, and maintain its system in conformance with Good Utility Practice[77]:
>
> 13.1.1 To minimize electric disturbances that may damage or interfere with the system or customers of the other Party hereto or the system of any third party connected with the system of the other Party, and
>
> 13.1.2 To minimize the effect on its system, and on its customers, of such electric disturbances from the system of the other Party or third party.
>
> **13.2** Each Party shall operate its system in accordance with the WSCC's Reliability Criteria, to the extent applicable, as they may be revised from time to time. (Emphasis added)[78].

LADWP, CAISO, the other BAs in California, and other system operators in WECC and throughout the country, maintain reserves sufficient to cover at least their N-1-1 contingencies. Consistent with this generally accepted practice and longstanding FERC precedent, which indicates it is Good Utility Practice to cover N-1-1 contingencies[79] Glendale and LADWP, have interpreted the above referenced contract provisions to mean that Glendale is obligated to maintain reserves sufficient to cover up to at least an N-1-1 contingency. That is why Glendale covered its N-1 and N-1-1 contingencies for over 50 years.

Glendale and LADWP have for decades interpreted Glendale's reserve obligations under these agreements to require that Glendale meet all its system's reserve obligations (including both N-1 and N-1-1). This course of performance shows that for over five decades Glendale – not LADWP – was responsible for carrying reserves sufficient to meet both its N-1 and N-1-1 contingencies. Therefore, any failure of Glendale to meet its reserve obligations under its agreements with LADWP would expose Glendale to the risk of a breach of contract lawsuit by LADWP and potentially other lawsuits from third parties harmed by any blackouts or similar outages resulting from Glendale failing to meet its reserve obligations. Such lawsuits would pose significant challenges for Glendale considering the contracts' language, the course of performance under

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77 Section 4.12 of the Interchange Agreement defines Good Utility Practice as: "Any of the practices, methods and acts engaged in by a significant portion of the electrical utility industry in the WSCC region during the relevant time period; or any of the practices, methods, and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be any one of a number of the optimum practices, methods, or acts to the exclusion of all others, but rather to be practices, methods, or acts generally accepted in the WSCC [now WECC] region."

78 Sections 13.1 and 13.2 of the Interchange Agreement.

79 *See e.g., Cal. Indep. Sys. Oper. Corp.,* 116 FERC ¶61,274 at P 1169 (holding that the N-1-1 local reliability criteria is good utility practice).

these contracts, and California courts' reliance on course of performance to interpret parties' contractual obligations[80].

If such a LADWP lawsuit involved Glendale's breach of its reserve obligation that caused a large, long-term blackout, the damages claims Glendale would face could be significant because such an event would require LADWP to take costly emergency actions and would almost certainly result in NERC imposing penalties on LADWP that LADWP would expect Glendale to pay. Such penalties can be as high as $1 million per day. On the later point regarding NERC penalties, because Glendale is not registered with NERC as a BA, such a breach likely would not lead to a direct action by NERC/WECC against Glendale for a violation of the NERC Reliability Standards. Rather, the penalties would likely be imposed on LADWP. LADWP would then include these penalties as part of the damages it would be request in a breach of contract lawsuit brought against Glendale. To avoid this litigation exposure, Glendale must maintain reserves sufficient to meet both its system's N-1 and N-1-1 contingencies.

6. Glendale's Current N-1 and N-1-1 Reserve Obligations

Glendale's current single largest contingency (N-1) is an outage of the Pacific-DC Intertie (i.e., the 100 MW Glendale share of the Intertie). Under the PDCI Agreement and BAL-002-WECC-2a, if Glendale is fully utilizing its share of the Pacific-DC Intertie, Glendale must maintain 100 MW of reserves to respond to this outage scenario. The PDCI Agreement requires this 100 MW to be all spinning reserves, but NERC Reliability Standard BAL-002-WECC-2a allows Glendale to cover this

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80 *Emp'rs Reinsurance Co. v. Superior Ct.,* 161 Cal. App. 4th 906, 921, 74 Cal. Rptr. 3d 733 (2008) (holding "the most reliable evidence of the parties' intentions" is their conduct after the contract is signed and before any controversy has arisen and that where the parties to a contract have, for years, harmoniously performed under the contract in a way that reflects a particular, reasonable understanding of the terms of the contract, that performance is relevant to determining the meaning of the contract); *Crestview Cemetery Assn. v. Dieden,* 54 Cal. 2d 744, 754, 8 Ca. Rptr. 427, 356 P.2d 171 (1960) (holding "[t]his rule of practical construction is predicated on the commonsense concept that 'actions speak louder than words.' Words are frequently but an imperfect medium to convey thought and intention. When the parties to a contract perform under it and demonstrate by their conduct that they knew what they were talking about the courts should enforce that intent."); *Lennar Mare Island, LLC v. Steadfast Ins. Co.,* 176 F. Supp. 3d 949, 966 (E.D. Cal. 2016) (holding "course of performance evidence [is] admissible to explain or supplement but not to contradict the terms of an *integrated* agreement, *even when the agreement's written terms are unambiguous*."); *Kuitems v. Covell,* 104 Ca. App. 2d 484, 485, 231 P.2d 552 (1951) (holding may introduce course of performance evidence to explain or supplement the agreement); *Eggert v. Pacific States Sav. & Loan*, 57 Cal. App. 2d 239, 242, 136 P.2d 822 (1943). ("Where uncertainty arises concerning a provision of an agreement, a trial court may ask how the parties themselves understood the language; when the parties have acted upon that understanding before the dispute arose, a finding that the agreement should be construed as acted upon will not be disturbed by the reviewing tribunal."); *See also, Southern Pacific Transportation Co. v. Santa Fe Pacific Pipelines, Inc.,* 74 Cal. App. 4th 1232, 1241, 88 Cal. Rptr. 2d 777 (1999) (holding that extrinsic evidence can be offered not only "where it is obvious that a contract term is ambiguous, but also to expose a latent ambiguity" and that such evidence is admissible when relevant to prove a meaning to which the language of the instrument is reasonably susceptible).

obligation with 50 MW of spinning reserves and 50 MW of non-spinning reserves[81]. If Glendale fails to maintain these reserves, LADWP would be required balance Glendale's system on an emergency basis. This would result in Glendale breaching its contractual obligations under the PDCI Agreement.

The Pacific-DC Intertie experiences frequent de-rates or outages, which often last for more than 60 minutes. In fact, they can last for several hours, days, weeks or even months. Glendale's above discussed contracts and Good Utility Practice require it to have reserves sufficient to cover the loss of this N-1 contingency and its N-1-1 contingencies. If Glendale does not carry reserves to cover its N-1-1 contingency, even though it is aware of the frequency at which it experiences a de-rate or loss of the Pacific-DC Intertie – its N-1 contingency – Glendale would spend significant periods of the year taking the risk of an N-1-1 event that it is not prepared to cover. If this second contingency were to occur in these circumstances, Glendale would be required to scramble to find energy to cover its load. If the energy cannot be procured, Glendale would face brownouts or blackouts. In addition, Glendale would be exposed to the litigation risks detailed above. To avoid these risks, Glendale must meet these reserve obligations.

Glendale's next single largest contingency (N-1-1), after loss of the Pacific-DC Intertie, is the loss of an operating unit or another transmission link. This could vary from 48-75 MW depending on the system configuration. If an N-1 event (the 100 MW loss of the Pacific-DC Intertie) occurs, Glendale must plan and prepare for the loss of a unit at the power plant (i.e., Glendale's N-1-1 contingency) requiring Glendale to have replacement power available within 10 minutes of the loss of the N-1-1 contingency generator[82]. In this scenario, Glendale has lost 100 MW of import capability on the Pacific-DC Intertie and has subsequently lost 48-75 MW of local generation (before the 100 MW on the Pacific-DC Intertie is restored). Therefore, Glendale must replace up to 175 MW of "lost" power supply on a potentially on-going basis (i.e., longer than one hour).

To meet the NERC Reliability Standards' requirements, which Glendale agreed to satisfy under its agreements with LADWP, and to comport with Good Utility Practice, Glendale must plan in advance for both the N-1 and the N-1-1 scenarios because by the time the N-1 event occurs, Glendale's options to purchase reserves from outside of Glendale would be limited due to its

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81 WECC Standard BAL-002-WECC-2a – Contingency Reserves R1.1.

82 See, e.g., Schedule 5, Section 6 of the BAASA ("If Glendale makes such sales of Spinning Reserves it shall provide said Spinning Reserves from its resources or resources that it contracts for that are separate and distinct from the purchase of reserves from LADWP under this Agreement."); See also Schedule 6, Section 6 of the BAASA ("If Supplemental Reserves made available by Glendale fail to respond within 10 minutes of the time the reserves are requested by LADWP, Glendale will pay to LADWP a fee equal to 3 x [Monthly OATT Rate] x [MW Short] per reserve activation."); See also NERC Reliability Standard BAL-002-WECC-2a R1, which describes the need for "Contingency Reserve equal to the loss of the most severe single contingency" and BAL-002-WECC-2a R2 which describes Contingency Reserves as a "[r]eserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system" or a "[r]eserve that is capable of fully responding within ten minutes."

limited transmission import capability[83]. For example, if the Pacific-DC Intertie transmission line fails (due to equipment failure, wildfires, or other natural disasters) or is taken out of service for maintenance, Glendale loses 100 MW of transmission capacity and, for as long as the transmission line is unavailable. Glendale will not be able to bring energy over that line to serve 100 MW per hour of its residents' energy needs. LADWP and Burbank also rely on the Pacific-DC Intertie line to bring energy into the LA Basin. Therefore, if the Pacific-DC Intertie line is down, LADWP, Burbank, and Glendale will all have fewer resources available to serve their residents' energy needs and will all be forced to rely on local generation or imports over other, operating transmission lines. This will mean the supply of local generation and alternate transmission routes available to Glendale will be dramatically reduced as the owners of that generation and transmission will be using it first to meet their own needs before they offer it to Glendale. Moreover, in these circumstances, if generation is available, Glendale will be forced to pay a premium for it.

7. Glendale Meets its N-1 and N-1-1 Reserve Obligations Using the BAASA and Internal and External Generation

To meet the reserve requirements of its Metered Subsystem, Glendale must either self-provide reserves from its own resources, purchase them from LADWP or from third parties[84]. Glendale currently meets its subsystem balancing obligations using its own generation and generation it purchases from others, including from LADWP under the BAASA. However, because the BAASA is only intended to cover the first 60 minutes of a contingency event[85] and may be terminated by LADWP upon providing Glendale "eighteen (18) months prior written notice[86]," Glendale's ability

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83 This is what all Regional Transmission Operators (RTOs) and Independent System Operators (ISOs) do to maintain the reliable operations of their systems. *Price Formation in Energy and Ancillary Services Markets,* 153 FERC ¶ 61,221 at PP 30-46 (describing how RTOs and ISOs determine and charge their customers for N-1-1 or N-2 contingencies under the NERC Reliability Standards).

84 *See e.g., N. Am. Elec. Reliability Corp*., 153 FERC ¶61,024 at P 8; *See also* LADWP's Business Practice entitled "Contingency Reserves Requirement" Version No. 1, Effective Date: 10/1/2015, if Contingency Reserves are not covered contractually in other agreements with LADWP then LADWP's OATT Customers must provide Contingency Reserves via one of the following methods: Self-Supply; Supply from a Third Party; or Purchase from LADWP.

85 *See e.g.,* BAASA Schedules 5 and 6, Section 8 ("Glendale may draw energy from the BAA following a contingency event causing a resource reduction for Glendale *up to 60 minutes from the time of the event*.") (Emphasis added); *See also* Schedules 5 and 6 Section 10 ("If Glendale fails to return CE to zero within 60 minutes, it will pay an additional charge to LADWP of 3 x [LADWP Energy Rate] x MWh for the energy received from 60 minutes after the time of the event until Glendale's CE returns to zero.")

86 BAASA Section 6. ("Termination For Convenience by Party (ies). *Either Party may seek to terminate this Agreement at any time with at least eighteen (18) months prior written notice to the nonterminating Party*. Such written notice shall specify a Termination Date. Upon request, the Parties shall make reasonable efforts to extend the Termination Date for up to an additional eighteen (18) month period, or a longer period with the mutual agreement of the Parties, if necessary to implement the provisions of Section 6.4.") (Emphasis added).

to rely on the BAASA is limited. Put simply, the BAASA is insufficient to meet Glendale's long-term obligations under contract, and national/regional reliability standards.

8. Glendale's Balancing Authority Area Services Agreement with LADWP

As discussed above, Glendale has entered into a BAASA with LADWP, under which it purchases certain balancing services from LADWP because Glendale does not currently have the resources available to fully self-supply them. Specifically, the City purchases Regulation and Frequency Response Service (Schedule 3), Energy Imbalance Service (Schedule 4), Operating Reserve – Spinning Reserve Service (Schedule 5), and Operating Reserve – Supplemental Reserve Service (Schedule 6) from LADWP.

With regard to the spinning reserves (Schedule 5) and non-spinning/supplemental reserves (Schedule 6), under the terms of the BAASA, LADWP has agreed to sell Glendale 40 MW of spinning reserves and 40 MW of non-spinning/supplemental reserves (a total purchase of 80 MW) to cover Glendale's first-hour reserve obligations, and has agreed that this 80 MW purchase will be sufficient to cover Glendale's Spinning and Supplemental obligation to cover the first hour of its single largest contingency[87]. Specifically, with the reserve services provided under the BAASA, LADWP has agreed to cover Glendale's single largest contingency for only the first 60 minutes of a contingency event using Spinning and Supplemental Reserves[88]. Any outages that extend beyond the hour require Glendale to self-supply or purchase from others additional generation capacity to cover the extended outage[89]. Therefore, even with the BAASA, and even if Glendale pays LADWP to cover its first hour single largest contingency, Glendale needs to have access to generation that will cover an extended outage of its single largest contingency.

If Glendale experiences an N-1 contingency and loses the Pacific-DC Intertie line, Glendale has up to 60 minutes to replace the resource as LADWP will cover only 80 MW of Glendale's load for up to 60 minutes. Section 4.c of Schedules 5 and 6 of the BAASA describe the limit on the amount of reserves that LADWP will supply GWP in the context of transactions over the Pacific-DC Intertie. Schedule 5, Section 4.c. of the BAASA states:

> If GWP schedules more than 86 MW (at Nevada Oregon Border ("NOB")) on the PDCI sinking in the BAA, ***GWP shall self-supply or purchase additional Spinning Reserves from a third-party***

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[87] Glendale has transmission rights to 119 MW on the upper segment of the Pacific DC line, and 100 MW on the lower segment into Glendale. However, because Glendale is unable to self-supply 100 MW of reserves, Glendale has contractually agreed that it will not use all of its available transmission capacity on the Pacific DC Intertie.

[88] Schedules 5 and 6, Section 8 of the BAASA state: "GWP may draw energy from the BAA following a contingency event causing a resource reduction for GWP up to 60 minutes from the time of the event."

[89] *Id*.

> ***to support the schedules greater than 86 MW***. For such schedules, GWP must notify LADWP no less than one hour prior to scheduling more than 86 MW on the Pacific HVDC[90] Intertie.

Schedule 6, Section 4.c states:

> If GWP schedules more than 86 MW (at Nevada Oregon Border ("NOB")) on the PDCI sinking in the BAA***, GWP shall self-supply or purchase additional Supplemental Reserves from a third-party to support the greater than 86 MW***. For such schedules, GWP must notify LADWP no less than one hour prior to scheduling more than 86 MW on the Pacific HVDC Intertie.

Under Section 4.c of Schedules 5 and 6 of the BAASA, Glendale must use local generation to cover reserves or purchase reserve to cover any outage above 80 MW. These sections reference 86 MW because LADWP has agreed to provide an additional 6 MW to address transmission losses, but this is not intended to increase the reserves available to Glendale above the 80 MW. So, if Glendale loses 100 MW of transmission over the Pacific-DC Intertie, it would have to use local generation to cover the 20 MW not covered by the BAASA (100 MW – 80 MW=20 MW). In addition, if the loss of the Pacific-DC Intertie line exceeds 60 minutes, Glendale must also demonstrate that it can cover its next largest or N-1-1 contingency beginning at minute 61, which would then become its new, single largest contingency until the Pacific-DC Intertie line is restored. Glendale must have this replacement resource in place within 60 minutes. Thus, Glendale cannot rely on the BAASA for reserves above 80 MW, after the N-1 contingency's 60-minute period has run, or to address N-1-1 contingencies.

In addition, LADWP has taken the position that, although Article 2.2.2 of the BAASA states that "[f]or the term of this Agreement, this Agreement shall satisfy GWP's obligations under the Existing Agreements to provide spinning reserves, supplemental reserves (sometimes referred to as "non-spinning reserves") or any other contingency reserves," LADWP is not responsible for covering Glendale's N-1-1 contingency under the BAASA[91]. LADWP has indicated that the BAASA (1) is limited in size and only includes 80 MW of reserves, so GWP will need to obtain additional reserves for contingencies above 80 MW; (2) has a limited duration of only 60-minutes, so contingencies that extend beyond that require GWP to procure additional reserves, (3) does not include other ancillary service beyond those identified in the BAASA (i.e., Glendale must provide those), (4) does not cover Glendale's N-1-1, which LADWP refers to as "planning reserves," and (5) should not be relied on by Glendale when making long-term decisions relating to repowering of generation. Specifically, LADWP stated:

> *This is in response to our brief conversation last Friday and to confirm that LADWP is not responsible for Glendale's planning reserves or ancillary services. Per the BAASA, LADWP is responsible for contingency reserves which are only good for 1 hour. After that Glendale is*

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[90] The references to "Pacific HVDC Intertie," mean the Pacific-DC Intertie.

[91] *See e.g.*, Email from Jan Lukjaniec, the Manager of Fuel and Purchased Power at LADWP to Mark Young at Glendale Water & Power, dated April 10, 2018 ("LADWP April 10, 2018 Email").

> *responsible to cover the lost generation to serve its load whether self-provided or self-procured. The BA also has to replace the reserves after 1 hour to remain compliant. However, LADWP does not include Glendale in its planning horizon and in its planning reserves and LADWP is not responsible for planning for Glendale's load. Also, I would point out that the BAASA arrangements do have 18-month termination provisions which were put in place to allow both parties to adapt to a changing environment and it would be imprudent to make very long term decisions related to repowering of your generation resources relying on any agreement with such relatively short term certainty. (Emphasis added)*[92].

LADWP has taken similar positions in follow-up correspondence between the Parties[93]. For example, on September 25, 2018, after Glendale received the foregoing email, Mr. Zurn (Glendale's former General Manager) sent a letter to Reiko Kerr, LADWP's Senior Assistant General Manager, Power Systems ("Glendale's September 2018 Letter"), asking for LADWP's position regarding Glendale's reserve obligations under Glendale's contracts with LADWP as in light of LADWP's role as Glendale's BA. Glendale's September 2018 Letter set forth a list of Glendale's interpretations of: (a) LADWP's legal obligations as its BAA, and (b) LADWP's and Glendale's contractual rights and duties under the Glendale-LADWP contracts. The letter then asked LADWP to confirm whether it agreed with the following statements:

1. Glendale operates as a metered subsystem within the LADWP BAA that is responsible for balancing its own loads and resources.

2. Under the intertie agreement, interchange agreement, TSAs and LADWP Open Access Transmission Tariff, LADWP and Glendale are responsible for providing their respective reserves either by self-provision or purchase from third parties.

3. Under the BAASA, LADWP and Glendale have agreed to the following:

    a. Operate their systems to minimize disturbances on one another's systems. (BAASA Section 3.5.2).

    b. LADWP will sell Glendale 80 MW of spinning and supplemental reserves (i.e., N-1 reserves) (plus 6 MW of transmission losses) for a period of up to 60 minutes. (BAASA Schedules 5 and 6, Section 4).

    c. The 80 MW of reserves was sufficient for GWP to meet its N-1 obligation (even though Glendale's single largest contingency, the loss of the Pacific DC Intertie Line is a 100 MW contingency), but only on the condition that Glendale agrees to limit its

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92 *Id.*

93 Letter from Reiko Kerr to Steve Zurn, the form General Manager at GWP, dated October 12, 2018 ("LADWP October 12, 2018 Letter").

transmission on the Pacific DC Intertie Line to 80 MW (plus 6 MW of transmission losses). Therefore, if Glendale increases its use of the Pacific DC Intertie above the 86 MW, Glendale will have to acquire additional reserves. (BAASA Schedules 5 and 6, Section 4).

d. Glendale's total transmission rights on the Pacific DC Intertie are 119 MW but Glendale only has 100 MW of corresponding transmission from Sylmar to Airway under TSA LADWP Contract No. 10135.

e. At the end of the 60 minutes, if Glendale's N-1 is not back in service, Glendale LADWP would only continue to supply Glendale the 80 MW of energy after the 60 minutes if LADWP has access to, and can deliver, the generation necessary to do so without violating "safety, equipment, or regulatory or statutory requirements." See e.g., BAASA Section 3.6.1. But LADWP is not required to do so if it cannot access said generation. (BAASA Schedules 5 and 6, Sections 8 and 10; See also Schedule 4 Introduction and Section 3).

f. The rate Glendale will pay for this post 60-minute period energy is three times LADWP's Tariff energy rate. Glendale must also return to LADWP all of energy that LADWP provides during this post 60-minute period, at a future time. (BAASA Schedules 5 and 6, Section 10(a)).

g. The BAASA can be cancelled on 18 months' notice. (BAASA Section 6.0).

4. The BAASA does not require LADWP to cover Glendale's second largest contingency (the N-1-1 contingency) or any other Glendale reserves (e.g., planning reserves).
5. LADWP does not need to suffer blackouts before LADWP can stop supplying Glendale the power Glendale needs to avoid blackouts.
6. LADWP's Integrated Resource Plan ("IRP") does not account for or set aside generation to specifically cover Glendale's reserve obligations.
7. LADWP does not plan its system to accommodate Glendale's reserve needs.
8. "Good Utility Practice" requires system operators to maintain reserves sufficient to cover their system's N-1 and N-1-1 contingencies, in order to avoid outages[94].

On October 12, 2018, LADWP responded ("LADWP's October 2018 Letter") and addressed each of the items listed above. In its response, LADWP indicated that it agreed with the statements in items 2, 3(a) thru 3(g), 5, 6, 7, and 8 and provided a slight clarification regarding items 1 and 4 but indicated that it generally agreed with their content as well. Specifically, regarding the

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[94] Glendale's September 2018 Letter at pp. 1-3.

statement in item 1, LADWP indicated that "while the phrase 'metered subsystem' is neither defined nor used in the BAASA, the metered boundary and the requirements described in the BAASA effectively treat Glendale as a metered subsystem within LADWP's BAA.[95]" Regarding item 4, you indicated that "LADWP generally agrees that the BAASA does not specifically require LADWP to cover Glendale's second largest contingency (the N-1-1 contingency).[96]" Thus, LADWP clearly believes that the BAASA only covers 80 MW of an N-1 contingency even, this coverage only lasts for a limited 60-minute duration, and does not cover Glendale's N-1-1 at all.

It is also important to note that LADWP's provision of reserves and other ancillary services, under the BAASA, is highly dependent on the availability of excess LADWP generation that it can set aside and make available to Glendale during emergency conditions. If LADWP does not have excess generation, it cannot provide these services to Glendale. Similarly, the prices for these services are subject to change as the demand for LADWP's generation changes and as the LADWP Open Access Transmission Tariff (OATT) rates change. LADWP now actively participates in the CAISO Energy Imbalance Market (EIM)[97]. As a result, LADWP has less excess generation available to sell. As the supply of excess energy goes down, whatever excess LADWP has is likely to be offered at increased rates. It is possible that LADWP will not have any excess generation available to provide these services.

Additionally, as a load-serving entity and distribution provider, GWP also must demonstrate to the State of California Energy Commission that it has the requisite planning reserve margin and is able to handle contingency conditions[98].

The foregoing demonstrates that the BAASA does not meet all of Glendale's reserve obligations and since LADWP can terminate the BAASA, upon 18-months' notice, is not a long-term tool to demonstrate compliance with contractual obligations, state law, and reliability standards. It is at best an interim stopgap measure that allows Glendale to meet only a part of its N-1 contingency reserve obligations and none of its N-1-1 planning reserve obligations. Therefore, as LADWP correctly advises, it would be imprudent for Glendale to make its resource planning decisions based on the BAASA.

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95 LADWP's October 2018 Letter at p. 1.

96 Id.

97 *Id*. An Energy Imbalance Market ("EIM") is a real time, wholesale energy trading market that enables participants anywhere in the west to buy and sell energy when needed. https://www.westerneim.com; also refer to https://www.nrel.gov/docs/fy12osti/56236.pdf ("In the proposed Western EIM, BAAs would pool their variable and conventional generation resources to improve operational efficiency over a wider area. This sub-hourly, real-time energy market would provide centralized, automated, and region-wide generation dispatch for imbalances.") Glendale cannot participate in the Energy Imbalance Market because it is not a Balancing Authority.

98 *Refer to* California Public Resources Code 25216, 25216.5, and 25300-25323. A*lso refer to* California Energy Commission Docket No. 17-IEPR-02.

To ensure Glendale can meet its future balancing obligations and avoid future reliability risks and dramatic price increases for reserves and other balancing services, Glendale will need to adequately size the repowered Grayson plant so that Glendale can meet its peak load and reserve obligations. If Glendale fails to do this, it will be exposed to the aforementioned future reliability and litigation risks and would be completely dependent on the market to meet its reserve obligations. The proposed Project and Alternatives 7 and 8 are designed to avoid those risks so that GWP customers are protected from unreliable power supply as well as price increases that occur during times of constrained supply.

9. Why Hasn't GWP Added More Transmission Import Capacity Instead of Proposing to Repower Grayson

The only electric transmission system that is wholly owned and controlled by GWP is the short run from the Utility Operations Center to the LADWP Airway Substation. All of GWP's other transmission assets are partial minority capacity/ownership shares of existing transmission lines or the purchase of transmission services from others under Transmission Service Agreements (TSA) or Open Access Transmission Tariffs. When opportunities have presented themselves for GWP to increase its share of transmission rights, it has done so. These opportunities are generally not available and are infrequent as transmission capacity is a precious and limited commodity.

GWP has been a long-term participant in the repower of the Intermountain Power Project and was recently able to purchase an additional 72 Megawatts (MW) (gross) in the Southwest Transmission System when some other owners of the Intermountain Power Project chose not to continue with the repower, and thus their share of the associated transmission capacity became available for purchase. This additional transmission capacity becomes available in 2027.

In 2019, GWP signed contracts for a share of the Southern California Public Power Authority's (SCPPA) Eland I Solar and Storage project. GWP has a minority interest of 25 MW of solar energy on a must-take, non-dispatchable basis. GWP has access to the solar portion whenever it is producing power; however, GWP only has access to the energy storage portion when the majority participant, LADWP dispatches it. For these reasons, Eland counts only for energy supply but not for dispatchable reserves.

In 2018, Glendale issued a Clean Energy RFP that required clean energy to be generated locally or delivered to Glendale without reliance on Glendale's existing transmission, since GWP's existing transmission capacity is fully utilized. If GWP had received a proposal that delivered renewable energy via a new transmission line to Glendale, it would have received serious interest, but GWP did not receive any such proposals. Offers for remote renewables were submitted either without a secured transmission path or were subject to the proposer's application for future transmission rights, or were reliant on GWP to acquire transmission[99].

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[99] GWP received one proposal that entailed daily deliveries of charged battery containers from a remote solar PV project using freeways to circumvent the lack of transmission. Given concerns with feasibility, reliability of delivery, traffic, among other reasons, this proposal was not selected for implementation.

Proposers recognized that building new transmission is a long-term, capital-intensive task that is not feasible in the foreseeable future.

The approach that GWP took with respect to the Clean Energy RFP is consistent with what California's Community Choice Aggregators have done when they issue Requests for Offers (RFOs); both sought to have energy delivered to their customers. California's Community Choice Aggregators serve some existing investor-owned utility customers. The territory of a Community Choice Aggregator overlaps the territory of the investor-owned utility, such as Southern California Edison, within which it operates using the same investor-owned utility transmission and distribution poles and wires. Instead of a customer having their energy supplied by their local investor-owned utility, a customer can choose to have it procured by the Community Choice Aggregator. A Community Choice Aggregator may source the replacement electricity differently, typically offering a greener mix of power; however, they still use the same utility's poles and wires – transmission and distribution – to deliver their replacement energy to customers. Thus, when a Community Choice Aggregator issues an RFO, the typical requirement is that the energy be delivered to the California Independent System Operator (CAISO) grid. Once delivered to the grid, the energy flows over the utility's existing transmission and distribution system to the customer as it was doing before. Because GWP is not part of CAISO, GWP asked for any imported energy to be delivered to the GWP system.

GWP is always interested in any opportunity for new transmission lines and is in regular communication with neighboring jurisdictions. GWP also participates in transmission planning meetings. However, there are no new transmission lines being proposed that would bring energy into Glendale. As described in the 2018 FEIR Topical Response No. 2 and response to individual comment L298-80, building a new Glendale-owned transmission line will require traversing the dense urban environment across the Los Angeles basin. New transmission line corridor(s) (like any other transportation corridor such as a High Speed Rail, or a freeway system) will require acquisition of large linear pieces of property either through purchase agreements or condemnation. Environmental studies will be required and the environmental impacts of a new transmission corridor project would need to be analyzed under CEQA. The public will need to be informed and public participation will be required. It is reasonable to expect that many public and private property owners would be impacted by a new transmission project and that there would be opposition to constructing a new transmission line corridor based on the permanent impacts, which could be significant. New transmission would need to not only traverse Glendale, but probably many other jurisdictions because most solar/wind renewable resources are located either some distance outside of Los Angeles County or, in the case of potential future development of offshore wind resources, off of the Southern California coast.

Some increases in transmission capacity that do occur are not always available to GWP. Oftentimes the transmission line owner needs the capacity themselves. Additional transmission capacity within the LA Basin is largely within the control of LADWP and Southern California Edison. Additional transmission into the LA Basin itself from the east is another major constraint. In April 2019, GWP requested 75 MW of firm, bi-directional transmission from the Mead 230 substation to Glendale. On June 19, 2019, LADWP provided Glendale with a study showing available transmission capacity into the Los Angeles basin is severely constrained, with negative available transmission capacity numbers. In January 2022, GWP staff reviewed LADWP's Open Access Same-time Information System (OASIS) system[100] and confirmed that there is no available transmission capacity into GWP's Airway Receiving Station, and along other pathways that would assist Glendale with its transmission needs.

10. Existing Grayson Capacity and Proposed Repowering Capacity

The existing Grayson Units 1 through 8 have a power generating capacity of 238 MW_{gross} and 219 MW_{net}.

Unit	Gross Capacity (MW)	Net Capacity (MW)
1 (steam turbine only, steam supplied by 8A and 8BC)	20	18
2 (steam turbine only, steam supplied by 8A and 8BC)	20	18
3 (boiler and dedicated steam turbine)	20	18
4 (boiler and dedicated steam turbine)	44	42
5 (boiler and dedicated steam turbine)	44	42
8A (gas turbine only, steam supplied to Units 1 and 2 steam turbines)	30	26
8BC (gas turbines only, steam supplied to Units 1 and 2 steam turbines)	60	55
Total of Units 1-8	238	219
9 (gas turbine not being replaced)	50	48

The proposed Project consists of two simple cycle units and two combined cycle units with a generating capacity of 270 MW_{gross} and 262 MW_{net}. Alternative 7 is comprised of a battery energy storage system with a power capacity of 75 MW_{net} and 300 MWH of energy, and a thermal power generating capacity of 93 MW_{net} provided by five Wartsila reciprocating engines. Alternative 8 is similar and is also comprised of a battery energy storage system with a power capacity of 75 MW_{net} and 300 MWH of energy, and thermal power generating capacity of 101 MW_{net} provided by refurbishing Units 8A and 8BC. Alternatives 7 and 8 both provide less power generation capacity than the existing Grayson units they replace. These alternatives represent a net reduction of at least 43 MW and 118 MW after the batteries are discharged.

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[100] Open access same-time information system, (OASIS), is an Internet-based tool for sharing information on transmission prices and product availability in North American on a non-discriminatory basis. It is the primary means by which high-voltage transmission lines are reserved for moving wholesale quantities of electricity. This enables transmission customers to purchase available transmission capacity from transmission providers based on a FERC approved Open Access Transmission Tariff. FERC Order No. 889 restricts communication between power marketing and transmission operation employees within any one organization. Utilities can obtain information about their own transmission system for their own wholesale power transactions only through OASIS. Customers can view Available Transmission Capability; submit transmission service requests, etc. on the applicable region's OASIS site(s).

11. Regulatory Constraints: Units 1-9 Must Comply with Newly Amended SCAQMD Rules by December 31, 2023

The South Coast Air Quality Management District (SCAQMD) is the regulatory body for everything related to air emissions in Glendale and the surrounding areas. SCAQMD amended Rule 1135, "Emissions of Oxides of Nitrogen from Electricity Generating Facilities," on November 2, 2018, to require older power generating units to reduce emissions to meet current day limits. This change affects Grayson Power Plant Units 1-9.

All units must comply with current requirements before January 1, 2024. For units that are not already in compliance, the owner must submit their plan for what they intend to do with the unit prior to June 30, 2022. At the time the PR-DEIR was published, Glendale's deadline to submit its application for its plan to bring the Grayson Power Plant into compliance was June 30, 2022. Given that Glendale is still deciding how it will proceed, on January 7, 2022, SCAQMD adopted a modification to Rule 1135 to extend the application deadline for non-RECLAIM facilities such as the Grayson Power Plant to submit its plan to SCAQMD, to December 31, 2022. However, this six-month extension of the application deadline does not extend the deadline to bring the Units into compliance. This deadline December 31, 2023, remains unchanged.

For the units at Grayson:

- Units 1-5 cannot be feasibly modified to meet future emissions requirements and support future operational requirements because none of the existing emissions control system technologies in place have the capability of achieving the emissions control levels required by SCAQMD Rule 1135. To reduce the original levels of emissions from Boilers 3, 4 and 5, they have been retrofitted with Low NOx burners and flue gas recirculation. Additionally, Unit 5 has been retrofitted with a rotating over-fire air and non-catalytic SCR, in order to meet their current air permit limits of approximately 40 to 80 ppm NOx. To further reduce the boiler emissions down to the 5 ppm Rule 1135 requirement for boilers, GWP would need to add selective catalytic reduction systems. Further, even if those modifications were successful, the boilers would still be slow start units requiring the burning of gas to keep them warm and ready for startup (adding to emissions) and even then, could not react quickly enough to system demands.

- Units 8A and 8BC can feasibly be modified to meet future emissions requirements and support future operational requirements. This would require tuning changes to the water injection system, replacement of the selective catalytic reduction catalyst, and upgrades of the Continuous Emissions Monitoring Systems.

- Unit 9 can meet future emissions but may require some tuning changes to the emissions control system.

There are three options for the existing Grayson units:

- Option 1: Retire existing units that are not upgraded before 2024
- Option 2: Replace with new generation that meets SCAQMD requirements
- Option 3: Modify units to meet current SCAQMD requirements before 2024

Both the Proposed Project and Alternative 7 achieve the first and second options by replacing Units 1 through 8.

Alternative 8 achieves the first and third options by retiring Units 1-5 and modifying Units 8A and 8BC to include current day emissions controls as well as modifying these units to make them faster starting and more efficient to better meet today's functional needs.

12. Glendale's Resource Needs

The following three tables illustrate whether GWP will be able to meet reliability criteria based upon GWP's historic and forecasted peak power demand (peak load) with and without repowering the Grayson Power Plant. The tables provide an instantaneous snapshot and presumes that all resources are fully available ignoring time of day or other capacity constraints. Thus, the table maximizes the contribution of resources (particularly non-thermal resources) and minimizes the need for Grayson thermal resources. It is important to note that actual results will be different and the available margins that exceed reliability criteria will be less (with the implication that Grayson may need more capacity) for the following reasons:

- <u>Transmission Capacity Utilization</u> – The ability to import electricity is dependent on the combination of the resource producing electricity and having available transmission capacity. The "space" or share of the transmission capacity for that resource must be allocated on a full-time basis in order to have a firm commitment to transport the electricity from the resource any time it is available. Unless the resource also has a firming component (energy storage or thermal generation that provides electricity when the primary resource does not) GWP may not receive the full output on a continuous basis. Thus, even though GWP may have contracted for a 100 MW generation resource and contracted for the associated 100 MW of transmission capacity, this does not completely ensure that 100 MW of imported power is available on a continuous basis. GWP's existing strategy to mitigate this risk is to over-procure renewable generation in order to maximize utilization of the contracted transmission capacity.
- <u>Time of Day</u> – Peak electricity demand occurs later in the day after the solar peak. Thus, the full output from rooftop or imported utility scale solar resources will likely not be available during peak load unless coupled with energy storage. Also, based on the geographic location of the utility scale solar resources east of Glendale, their peak output occurs earlier in the day as compared to when Glendale's peak demand occurs.
- <u>Weather Factors</u> – Extreme heat waves (such as 10-20 degrees above normal) could significantly increase demand beyond forecasted levels. This happened in August 2020

prompting California shed load which resulted in multiple rolling blackouts. Additionally, cloudy or raining day scenarios can potentially reduce rooftop PV solar generation, shifting the demand served by behind-the-meter resources back to the utility that must be covered by reserves. Maintaining a diverse portfolio of resources, that includes generation resources that are weather-resilient and not dependent upon the sun, are essential to ensure reliability.

- Customer Choice – The capacity of local energy efficiency, demand response, and the virtual power plant depend on voluntary customer participation.

- Capacity Limitations – Some resources are limited due to design (batteries have finite energy capacity and then need to be recharged), customer action (there are a limited number of times that GWP is able to call upon demand response reductions), or contract limits (the proposed virtual power plant would produce a maximum of 50.5 MWH per day).

- Peak Load is Underestimated – The 2019 IRP did consider vehicle electrification but did not include a projection for building electrification. (2019 IRP Section 3). Accordingly, if the state or the city adopt building electrification requirements the demand for electricity may exceed the 2019 IRP projections.

In the Tables below, the 2024 column reflects the post-2023 shutdown of Units 1-8 with no further action at Grayson. The 2027 column in the Tables below reflects the post-2027 addition of 72 MW transmission import capacity through the Southwest Transmission System associated with the Intermountain Power Project repower.

- The "Presumed Non-Thermal Resources" are the expected power from clean resources that will be available both via transmission lines and from local renewable energy, energy storage, energy efficiency, and demand response. Transmission assets are included in the "Presumed Non-Thermal Resources" because, even though today the resources which are imported over the transmission system are a mix of thermal and carbon-free resources, imported generation resources will transition to 100 percent carbon-free over time.

- Existing local solar/energy efficiency/demand response resources whose development GWP has supported over the past 20 years are not explicitly shown as they are already in use and past peak loads reflect their contribution.

- Once hydrogen becomes available to Grayson, and the thermal generation equipment modified for hydrogen, then the carbon footprint of the thermal generation would be eliminated. There would be some reduction in output due to the lower volumetric energy density of hydrogen as compared to natural gas[101].

The calculation in the Table below shows that prior to 2027, without repowering the Grayson Power Plant (but still relying on 50 MW of local new Distributed Energy Resources/ Virtual Power Plant, 75 MW of Battery Energy Storage, 25 MW from Eland, Magnolia Power Plant and Grayson Unit 9), GWP cannot meet peak load. After 2027, when an additional 72 MW of transmission will become available, GWP would be able to meet the City's peak load without repowering Grayson, but would not be able to meet all contingency reserve requirements. Note that while the table indicates Alternatives 7 and 8 are only operating for contingency events, they could also operate in place of Grayson Unit 9 or the Magnolia Power Plant which are relied upon to meet peak load in the following table. Similarly, if the Tesla batteries are discharged or not available, the thermal generation from Alternatives 7 or 8 would operate in their place.

The following tables show:

1. In the column labeled 2024, the resources that GWP expects to have available in 2024 after Units 1-8 are shut down at the end of 2023 in accordance with SCAQMD Rule 1135. If no further action were taken with respect to Grayson, this would be equivalent to the No Project Alternative.

2. In the column labeled 2027, the resources that are expected to be available after the addition of 72 MW through the Southwest Transmission System and with either Alternatives 7 or 8 being implemented.

Presumed Non-Thermal Resources			
Item	All values are in MW	2024	2027
1A	Existing Transmission (100 MW Pacific DC, 112 MW Southwest Transmission System)	212	212
1B	Post-2027 Transmission addition on Southwest Transmission System[102]	0	72
1C	Reduction due to transmission losses on Southwest Transmission System (losses are 5.8 percent)	-12	-16
1D	Eland I Solar and Storage Project (the full 25 MW capacity was assumed for this analysis; actual performance may be less)	0	25
1E	Local new Distributed Energy Resources/ Virtual Power Plant (Franklin, Lime/Willdan[103], and Sunrun from the Clean Energy RFP, plus future additional	0	50

[101] Please see Response to Comment L5 for a fuller discussion of hydrogen. Local production of hydrogen is considered infeasible at this time due to the additional power demands it would impose on the GWP system; thus, hydrogen would need to be imported via pipeline as natural gas is now.

[102] This added transmission capacity is tied to the repower of the Intermountain Power Project. With the repower, this asset will transition from coal-fired generation to natural gas and then to hydrogen. Thus, this resource will always be a thermal resource but transition to carbon-free.

[103] Since the time of the PR-DEIR being published, Lime Energy has changed its name to Willdan.

Presumed Non-Thermal Resources			
Item	All values are in MW	2024	2027
	programs). There are limits as to time of day and/or number of times these resources can be called upon.		
1F	Battery Energy Storage System (BESS) contribution for peak load. This is a 4-hour resource and some energy capacity must be reserved to provide sufficient spinning reserve. This table assumes that the full 75 MW/300 MWH of BESS capacity will be installed earlier than the 2019 IRP contemplated, as the 2019 IRP contemplated that the 93 MW of Wartsila engines would be available.	0	75
1G	Scholl Canyon Biogas	0	11
1T	Total of Presumed Non-Thermal Resources	200	429
Remaining Thermal Resources (Assumes Units 1-8 Retired)			
2A	Magnolia Power Plant (summer net)	35	35
2B	Grayson Unit 9	48	48
2T	Total of Thermal Resources	83	83
3	Alternative 7 Repower	0	93
4	Alternative 8 Repower	0	101
	Grayson Generation to be Retired	219	0
Available Resources Summary			
Line 1T, above (transmission imports plus local green)		200	429
Lines 1T + 2T (adds remaining thermal)		283	512
Lines 1T + 2T + 3 (adds Alternative 7)		283	605
Lines 1T + 2T + 4 (adds Alternative 8)		283	613

This second table shows the peak load and how large the N-1 and N-1-1 contingencies are for 2024 and 2027. It then adds them together to show much generation is required to cover peak load plus contingencies.

How Much Generating Capacity Must be Provided?			
Item	All values are in MW	2024	2027
5	Historical Peak Load and Forecasted Peak Load from 2019 IRP (the value of 346 MW is a historical peak; the value of 398 MW was interpolated from the values published in the 2019 IRP[104])	346	398
Contingency Requirements N-1 = based on the capacity of the largest resource N-1-1 = based on the capacity of second largest resource			
6A	N-1 (loss of 100 MW of transmission)	100	100
6B	N-1-1 (No Repower)	48	64
6C	N-1-1 (Alternative 7) • loss of 48 MW from Unit 9 through 2026 • loss of 64 MW of Southwest Transmission System post-2027 • Due to the modular design and redundancies within the control system, the 75 MW BESS creates contingencies that are smaller than the ones shown here	48	64
6D	N-1-1 (Alternative 8) • loss of 48 MW from Unit 9 through 2026 • loss of 75 MW from Unit 8BC post-2027	48	75
Required Resources Summary			
Lines 5 + 6A (peak plus N-1 contingency with no repower)		446	498
Lines 5 + 6A + 6B (peak plus contingencies with no repower)		494	562
Lines 5 + 6A + 6C (peak plus contingencies with Alternative 7)		494	562
Lines 5 + 6A + 6D (peak plus contingencies with Alternative 8)		494	573

[104] Note that the 2019 IRP did not include a forecast for building electrification load. With that inclusion, the predicted load of 398 MW may be higher.

This third table checks whether there are enough resources (lines 1T, 2T, 3, and 4 in the first table) to cover the peak load and contingencies (lines 5, 6A, 6B, 6C, and 6D in the second table).

Are Reliability Criteria Met (Are Available Resources > Required Resources)?			
Item	All values are in MW	2024	2027
Grayson Units 1-8 Shut Down, Existing and Forecast Resources with Peak Load and No Contingencies			
Are Presumed Non-Thermal Resources greater than Peak Load? [Is 1T > 5?] [Is 200>346?] [Is 429>398?]		No	Yes
Are Presumed Non-Thermal + Remaining Thermal Resources greater than Peak Load? [Is (1T+2T) > 5?] [Is 283>346?] [Is 512>398?]		No	Yes
Grayson Units 1-8 Shut Down, Existing and Forecast Resources with Peak Load and No Contingencies			
Are Presumed Non-Thermal + Remaining Thermal Resources greater than Peak Load + N-1 Contingency Requirements? [Is (1T+2T)>(5+6A)?] [Is 283>446?] [Is 512>498?]		No	Yes[105]
Are Presumed Non-Thermal + Remaining Thermal Resources greater than Peak Load + (N-1) + (N-1-1) Contingency Requirements? [Is (1T+2T)>(5+6A+6B)?] [Is 283>494?] [Is 512>562?]		No	No
Grayson Units 1-8 Shut Down, Alternative 7 or 8, Existing and Forecast Resources with Peak Load and Contingencies			
Are Presumed Non-Thermal + Remaining Thermal Resources + Alternative 7 greater than Peak Load + (N-1) Contingency Requirements? [Is (1T+2T+3)>(5+6A)?] [Is 605>498?]		N/A	Yes
Are Presumed Non-Thermal + Remaining Thermal Resources + Alternative 7 greater than Peak Load + (N-1) + (N-1-1) Contingency Requirements? [Is (1T+2T+3)>(5+6A+6C)?] [Is 605>562?]		N/A	Yes
Are Presumed Non-Thermal + Remaining Thermal Resources + Alternative 8 greater than Peak Load + (N-1) Contingency Requirements? [Is (1T+2T+4)>(5+6A)?] [Is 613>498?]		N/A	Yes
Are Presumed Non-Thermal + Remaining Thermal Resources + Alternative 8 greater than Peak Load + (N-1) + (N-1-1) Contingency Requirements? [Is (1T+2T+4)>(5+6A+6D)?] [Is 613>573?]		N/A	Yes

105 Note that there is a 14 MW margin which does not include a forecast for building electrification and is relying on the full output of Eland (the solar peak and load peak are not coincident), the full 50 MW of Distributed Energy Resources/ Virtual Power Plant (that 100 percent is available and fully responds), and the full 75 MW from the Battery Energy Storage System is available. Thus, the 14 MW margin (3 percent) may not be as large as indicated.

13. Third Party Sales of Energy

As stated in the 2018 FEIR, Section 2.4, GWP has not sized the proposed Project to sell energy to other parties. As shown in the above tables Alternatives 7 and 8 are sized to cover the City's peak demands plus contingencies to ensure a reliable supply to GWP customers. Alternatives 7 and 8 are not sized or designed for GWP to be able to sell energy to third parties. Indeed, on July 23, 2019, the Glendale City Council adopted a motion that specified:

"if Gas engines are installed at the Grayson Power Plant, the use of such Gas engines shall occur during situations such as peak weather or adverse system conditions."

The thermal generation at Grayson will allow GWP to manage and balance the intermittency of increasing amounts of renewable energy, to cover its customers' energy needs during peak weather events, to cover contingencies, and ensure that GWP can reliably supply power even in adverse system conditions.

The repower is not sized for GWP to become a merchant power plant. Merchant power plants are permitted such that they can operate at higher capacity factors so they have ample opportunity to sell their electricity. The Grayson thermal unit's operation are constrained by the fuel burn limits proposed in the SCAQMD air permit application. Those fuel limits in turn were derived from the anticipated operating hours, around 1,200 hours for both Alternatives 7 and 8, or only approximately a 14 percent capacity factor (1200/8760 = 0.137 or 13.7 percent). Further to this point one need only look at Unit 9. Unit 9 is permitted with a fuel burn limit that allows for operation at a higher capacity factor. However, Unit 9's historical capacity factor is 5 percent, a value in line with its usage to assure Glendale electric reliability – not merchant energy sales.

It must be noted that GWP does, and would continue to, engage in third party sales of energy under specified circumstances:

- Off System sales of excess imported energy: GWP over-procures renewable energy as a strategy to compensate for the intermittency of renewable energy sources, and to maximize its available transmission capacity (to keep the transmission lines full). If GWP's electric demand is less than the supplies GWP has contracted for, or if there is a transmission constraint that prevents that contracted energy from being delivered, then GWP will try to sell the excess energy to third parties. This saves GWP customers money by avoiding taking a loss on electricity that has already been purchased.

- Sales of in-system generation/ procurement not from Grayson. In the long term, when efforts to develop local generation have fully matured, it is possible that local renewable generation sources may exceed local demand and the capacity of the Battery Energy Storage System to accept more energy (the battery is fully charged). If this were to occur, GWP would either have to sell the energy to third parties and export it, or curtail one of the resources. Curtailing distributed or local renewables is not always possible.

- Sales of energy from Grayson thermal generation would generally not occur as the City Council has adopted a motion restricting the use of those gas engines to situations such as peak weather or adverse system conditions. Limited sales may occur in the following circumstance: if a Grayson thermal unit is started and the minimum emissions-compliant load on that unit was larger than the need, then GWP must do something with the excess electricity because the generation and demand must always be in balance. Because of the need to maintain balance, the extra electricity would need to either be used to charge the Battery Energy Storage System or sold into the market. Given the low permitted levels of operation proposed for the Grayson Units, even without the City Council's restrictions on the running of the gas units, GWP will need to save its permitted operating hours to cope with contingencies.

7.2.2 Topical Response No. 2 Cost Estimates

Summary of Comments

Several commenters asked for information regarding the cost of Alternatives 7 and 8. Several commenters also recommended that the funds spent on a repower would be better spent on cleaner energy sources.

Summary of Responses

- The proposed Project has an estimated cost of $514 million including contingency. A new switchyard was not part of the proposed Project.
- Alternative 7 has an estimated cost of $389 million including contingency but excluding the Glendale Switching Station and financing costs.
- Alternative 8 has an estimated cost of $330 million including contingency but excluding the Glendale Switching Station and financing costs.
- While specific values are expected to evolve as firm bid pricing becomes available, the overall conclusions that: 1) Alternative 7 is the more costly of the two alternatives, and 2) that Alternatives 7 and 8 are less expensive than the Proposed Project, are not expected to change.
- GWP is also investing in clean and renewable energy sources and will continue to do so to meet the Senate Bill 100 (100 percent clean by 2045) goals. A comparison of the costs of recent clean energy projects to Alternatives 7, 8 and the proposed Project is included below.
- CEQA requires an analysis of physical impacts to the environment; it does not require analysis of costs or of social and economic impacts.

Response

The Alternative 7 and Alternative 8 cost estimates were developed by GWP in conjunction with GWP's Owner's Engineer (Black & Veatch). Black & Veatch is a US-based internationally recognized employee-owned consulting, engineering, procurement, and construction firm with a 100-year legacy of performing energy, sustainable infrastructure, and other projects worldwide. Through Black & Veatch's many years of experience on a variety of energy projects, they are well qualified to have developed this estimate. The updated cost estimate for the proposed Project was calculated by GWP in conjunction with Dave Tateosian, a Professional Engineer with over 40 years of power generation experience including project development, permitting, design, construction, and commissioning with a range of technologies. Please refer to Individual Response L33-1 for resumes of the lead individuals.

Cost of Alternatives 7 and 8

Alternative 7 has an estimated cost of $389 million and Alternative 8 has an estimated cost of $330 million, including contingency, but excluding the Glendale Switching Station and financing costs. Alternative 8 is lower cost, as compared to Alternative 7, predominantly because it would reuse the existing Units 8A and 8BC gas turbine-generators (which would be refurbished) and their foundations. While the project cost estimate will evolve as the Tesla and Wartsila contracts are finalized and other construction bids are received, the overall conclusion that 1) Alternative 7 is more costly (and also more flexible resource) than Alternative 8, and 2) that Alternatives 7 and 8 are less costly than the proposed Project, are not expected to change.

Engineering, procurement, and construction costs of the Glendale Switching Station were not included in the above estimated costs for the following reasons:

- The work scope is the same for both Alternatives 7 and 8 and thus does not impact their comparative cost; and

- Construction of the Glendale Switching Station cannot start until after the repower is completed because the Glendale Switching Station will occupy land that is needed for repower construction laydown. Thus, the start of construction is not expected until 2026 at the earliest and a cost estimate performed now would not be reliable or accurate at this time.

Alternative 7 Cost Estimate

Approximately 4 percent of the Alternative 7 cost estimate represents development costs that have been or will be incurred through readiness to issue Full Notice to Proceed to the various contractors. This includes the Limited Notice to Proceed costs, conceptual engineering, design studies, environmental studies including site surveys and geotechnical work, legal services, and the work of Stantec, Black & Veatch, Clean Power Consulting Partners, and other consultants.

The bulk of the project cost estimate for Alternative 7, about 65 percent, is tied to the Tesla and Wartsila power island engineering, procurement, and construction contracts. As noted above, these contracts are under negotiation and the values will be updated after contract negotiations have been completed

An allowance (monies that may or may not be spent) of $6 million, or approximately 2 percent, is included for emissions offsets in the Alternative 7 cost estimate. The emissions offset quantity and cost estimate was developed by GWP’s air permitting consultants (refer to Individual Response L33-1 for resumes of the lead individuals). The actual amount may be less as offsets may not be needed for Alternative 7 (see Individual Response L25-3 for further discussion on need for emission offsets and estimated costs).

An allowance (some or all of which may be spent) of $6 million, or approximately 2 percent, is included as an allowance for long-lead spare parts that GWP would purchase and maintain on site.

The balance of the Alternative 7 work scope includes the following estimates, which represent approximately 27 percent of the Alternative 7 cost estimate:

- Project management, Owner's Engineering, confirmatory geotechnical work, and environmental monitoring

- Separation of Unit 9 from the rest of the Grayson power plant so it can operate independently during the demolition, site improvement, and construction phases (Unit 9 currently shares makeup water, control room, water drains, and other ancillary functions with Units 1-8)

- Balance of Site Engineering, Procurement, and Construction (BOS-EPC) to integrate the Tesla and Wartsila power islands into the Grayson site (interconnections for electricity, communication, water, gas, etc.), site paving, and other improvements

- Contingency to cover underground risks[106], escalation in commodity and shipping prices (lithium and shipping in particular experienced significant increases in 2021) currency/exchange risks, inflation, escalation in commodity prices, as well as normal contingencies

These estimates were developed by GWP in conjunction with GWP's Owner's Engineer (Black & Veatch). Black & Veatch is a US-based internationally recognized employee-owned consulting, engineering, procurement, and construction firm with a 100-year legacy of performing energy, sustainable infrastructure, and other projects worldwide. Through Black & Veatch's many years of experience on a variety of energy projects, they are well qualified to have developed this estimate. Please refer to Individual Response L33-1 for resumes of the lead individuals.

Alternative 8 Cost Estimate

Alternative 8 is lower cost, as compared to Alternative 7 or the proposed Project, predominantly because it would reuse the existing Units 8A and 8BC gas turbine-generators (which would be refurbished) and their foundations.

For the Alternative 8 cost estimate, many elements were similar to Alternative 7:

- Project development costs that have been or will be incurred in the near-term

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106 Extensive research and field work was performed to understand what may be encountered during excavation work. However, a contingency for subsurface risk is included because of the possibility that items or contamination may be found in a site that has been in use for almost 100 years.

- Tesla power island

The following costs were reduced compared to Alternative 7:

- The Wartsila engine component of Alternative 7 was removed.
- Emissions offsets (Units 8A, and 8BC are already existing and operating and thus do not require offsets)
- Spare parts (GWP already has a spare parts inventory for the Units 8A and 8BC gas turbines)

The following costs were increased compared to Alternative 7:

- For Alternative 8, the cost estimate for the Alternative 8 Balance of Site Engineer, Procure Construction-(BOS-EPC) work scope increased due to the Wartsila power island being replaced by refurbishing Units 8A and 8BC. The refurbishment work, as well as the other work to replace the balance of plant equipment is within the BOS-EPC work scope. Thus, the cost estimate for the Alternative 8 BOS-EPC work scope increased.

Cost of the Proposed Project

A cost estimate was prepared for the Proposed Project in February 2018. The estimated cost at the time was $479 million. That estimate was based on:

1. A negotiated contract (with escalation provisions) for the Power Island Equipment (PIE) representing 33 percent of the estimate

2. A firm price proposal for the Engineering Procurement and Construction (EPC) contract representing 51 percent of the estimate

3. Engineering estimates for the balance (demolition, emissions offsets, contingency, other costs) representing 16 percent of the estimate.

Thus, 84 percent of the Proposed Project estimate was tied to either a negotiated contract or firm price proposal.

An updated cost estimated for the proposed Project, taking the following factors into account:

- There has been inflation of about 12 percent. Using data from the US Bureau of Labor Statistics, $1 in February 2018 has the same buying power as $1.12 in November 2021.

- The US dollar to Euro exchange rate has improved slightly ($1 USD = 0.82 Euro in February 2018, $1 USD = 0.88 Euro on January 7, 2022, a 7 percent decrease

Applying a 12 percent increase due to inflation to the EPC proposal and balance of work, a 12 percent increase to 25 percent[107] of the PIE contract, a 7 percent decrease to 75 percent of the PIE contract results in a revised estimate of $514 million, an increase of 7 percent.

Comparative Cost Estimates with Other GWP Projects

The Grayson Repower is one of several projects under consideration or approved by Glendale to assure reliable, environmentally sustainable sources of electricity and energy and capacity savings for Glendale, including:

- Franklin Energy Demand Response and Smart Thermostat Program. This four-year, residential and commercial demand response program and online store for the purchase of rebated energy efficient products was approved by the Glendale City Council on October 13, 2020 (with an amendment to add funding for rebates, approved on December 15, 2020) and is underway.

- Lime Energy Commercial Energy Efficiency Program. This commercial direct install energy efficiency program was approved by the Glendale City Council on October 13, 2020 and amended in February 2021 is underway.

- Sunrun, Inc. Virtual Power Plant Program (See PR-DEIR, Section 5.2.3.1). This proposed, 25-year virtual power plant program is in the final stages of contract negotiation and is expected to be presented to the Glendale City Council in early 2022.

- Eland I Solar and Storage Project. The Glendale City Council approved Glendale's participation in this solar and storage project on December 10, 2019, and approved Glendale's execution of a Firm Point to Point Transmission Agreement for the purchase of 25 MW of transmission under the LADWP Open Access Transmission Tariff for the project on August 24, 2021. The guaranteed commercial operation date for this project is December 31, 2023.

- Star Peak and Whitegrass Geothermal Projects. The Glendale City Council approved contracts for this project on February 25, 2020. The Whitegrass Geothermal Project is in operation producing 4 MW_{gross} and 3 MW_{net}. The Star Peak Geothermal Project is currently expected to achieve commercial operation in April 2022. It is expected to produce 14.5 MW_{gross} and 12.5 MW_{net}.

- Scholl Canyon LFG Plant will provide 11 MW_{net} on a continuous basis for several years following commencement of operations. Output will eventually begin to decline once

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107 Most of the equipment in the PIE contract would be being supplied from Europe, however some major components and equipment would be sourced from the United States.

landfill gas production drops below full production capacity of the engines (initially, more gas is produced than the engines can use).

The following table provides some comparative capacity and cost information for the different resources that GWP is pursuing.

Comparison of Various GWP Resource Development Efforts – Non-Grayson					
Program or Project	Franklin Energy	Lime	Sunrun	Eland 1	Star Peak Whitegrass
Technology Type	Demand Response	Energy Efficiency	Front of the Meter Solar with Storage (Virtual Power Plant)	Utility Scale Solar with Storage	Geothermal
Capacity, MW/MWH	Up to 10 MW[108] Up to 600 MWH	Up to 8.32 MW Up to 35,500 MWH[109]	Up to 37 MW of PV Up to 25.25 MW/50.5 MWH of Battery Energy Storage[110] 34,581 MWH[111]	25 MW PV with 18.75 MW/75 MWH BESS 100,329 MWH[112]	Star Peak: 12.5 MW 100,000 MWH Whitegrass: 3 MW 23,000 MWH
Starts/Cycles per Year	15[113]	N/A	N/A	N/A	N/A
Hours per Year	60[114]	N/A	N/A[115]	N/A[116]	N/A
Fully Dispatchable?	No	No	No[117]	No[118]	No[119]
Estimated Contract Cost, $ million	$7.8	$18	$219.4[120]	$126.7[121]	$216.7

108 Depending on customer participation, this is the capacity by year four of the four-year Franklin Energy Demand Response program. GWP estimates that the average annual maximum peak power available over the life of the program at 7.0 MW.

109 The Lime Energy Efficiency program delivers energy savings, not capacity that is dispatchable. Depending on customer participation, the Lime program is expected to reach 35,500 megawatt-hours per year of energy savings by year 7 of the Program. Those energy saving are expected to last 12.5 years.

110 With full customer participation, Sunrun provides up to 37 MW of rooftop solar which is used to charge a 25.25 MW/50.5 MWH battery, which can be dispatched with 15 minutes notice up to the maximum of 50.5 MWH per day.

111 Estimate Total annual energy delivered to Glendale.

112 Average annual energy delivered to Glendale.

113 Franklin can be called upon fifteen times per year, but not more than 3 consecutive days. Customers have the option to opt out.

114 Franklin demand response events can last up to 4 hours per event.

115 Sunrun should be available on a daily basis. How many hours it operates depends on over how many hours the battery is discharged. Excess PV (after the storage has been fully charge) will be directly delivered to Glendale as its being generated.

116 Eland 1 should be available on a daily basis. How many hours it operates depends on how many hours the PV component generates, and the battery component is discharged.

117 The Sunrun battery system requires 15-minute advance notice before the event. To qualify as operating reserve, it must be dispatchable within 10 minutes.

118 The Eland BESS is dispatched by LADWP and GWP takes the energy.

119 100 percent of generation is used for baseload demand.

Comparison of Various GWP Resource Development Efforts – Grayson				
Program or Project	**Proposed Project**	**Grayson BESS Alt 7/8**	**Grayson Thermal Alt 7**	**Grayson Thermal Alt 8**
Technology Type	Generation	Utility Scale Storage	Generation	Generation
Capacity, MW/MWH	Unit 10: 71 MW Unit 11: 71 MW Unit 12: 60 MW Unit 13: 60 MW Unit 10: 539,316 MWH Unit 11: 539,316 MWH Unit 12: 102,000 MWH Unit 13: 102,000 MWH	50 MW/200 MWH 50,000 MWH[122]	93 MW 104,160 MWH[123]	Unit 8A: 27 MW Unit 8BC: 74 MW Unit 8A: 32,400 MWH Unit 8BC: 88,800 MWH
Starts/Cycles per Year	Unit 10: 67 Unit 11: 67 Unit 12: 621 Unit 13: 621	250	280/unit	Unit 8A: 125 Unit 8BC: 200
Hours per Year	Unit 10: 7,596 Unit 11: 7,596 Unit 12: 1,700 Unit 13: 1,700	8,412	1,120/unit[124]	Unit 8A: 1200 Unit 8BC: 1200
Fully Dispatchable?	Yes	Yes	Yes	Yes
Estimated Contract Cost, $ million	$514	$129	$260	$201

The Proposed Project and Alternatives 7 and 8 have operational value in that they are fully dispatchable, i.e., can provide full capacity at any time of the day to help meet the City's energy needs when called upon to do so within the constraints of its air permit. Other resources are limited by their inability to be dispatched within 10 minutes, time of day, stored energy, customer ability to opt out, or the number of times the resource can be called upon annually.

There are operating and maintenance costs associated with operating Grayson:

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120 Estimate includes costs for energy, capacity, renewable energy credits, customer incentives, as well as marketing and other project implementation costs.

121 Includes PPA cost and incremental transmission cost through LADWP Open Access Transmission Tariff (OATT) Rate.

122 Assumes 250 discharge cycles of 200 MWH each.

123 Assumes all five engines operate 1,120 hours per year at full load.

124 Each unit will operate approximately 1,120 hours up to its annual air permit fuel limit. Engines may operate singly or in combination with others.

- Grayson Battery Energy Storage System – The City would incur transmission losses of approximately 5.86 percent for the imported energy to charge the battery, round trip efficiency losses within the battery (meaning that all the energy delivered to the battery cannot be recovered, typically a 15 percent loss), plus annual capacity maintenance payments which have a floor and increase based on usage.

- Grayson Thermal – Each of the proposed Project and Alternatives 7 and 8 have fuel and ammonia consumption costs, plus annual long-term service agreement payments.

While not a complete cost comparison, the following provides additional perspective on fuel costs, which are a major component of operating costs:

> *The wholesale trading price for natural gas is currently about $5/MMBTU, and since 1 kWH is 3,414 BTU, that is equivalent to about 1.7 cents/kWH for fuel. The Wartsila engines are about 41 percent efficient, so they can be thought of having a variable operating fuel cost of 4.16 cents/kWH. There are additional variable operating costs for ammonia and lubricating oil which is a very small component. Additional fixed operating costs, primarily plant staff and the long-term service agreement, as well as capital cost, must also be considered. This cents/kWH impact depends on how much electricity the engines produce.*
>
> *Assuming that all battery charging is performed off-peak when electricity is more available, off-peak wholesale electric rates run about $40/MWH or 4 cents/kWH. As there is about a 5 percent energy loss in importing the energy, and the round-trip efficiency of the BESS is about 85 percent, about 20 percent of the purchased energy is lost while 80 percent can be used from the battery. So, the variable operating "fuel" cost for the BESS is about 5 cents/kWH. Additional fixed operating costs, primarily plant staff and the long-term service agreement, as well as capital cost, must also be considered. This cents/kWH impact depends on how much the batteries are cycled.*

CEQA Does Not Require Analysis of Economic Impacts or Costs

Finally, analysis of costs is not a required part of an EIR analysis pursuant to CEQA. CEQA requires an analysis of physical impacts to the environment; it does not require analysis of social and economic impacts. Under CEQA, "[a]n economic or social change by itself shall not be considered a significant effect on the environment." (CEQA Guidelines, Sections 15131 and 15382) Effects analyzed under CEQA must be related to a physical change. (CEQA Guidelines, Section 15358(b)). The cost of the alternatives is an important factor for consideration in the evaluation of the proposed Project and alternatives, but it is not a required component of the EIR analysis.

7.2.3 Topical Response No. 3 Historical Resources

Summary of Comments

A few commenters (including Individual Response L16 Sims on behalf of The Glendale Historical Society (TGHS), and Individual Response L22 Smith) commented on the PR-DEIR analysis of cultural resources, on the proposed demolition of the historic Boiler Building for the Project, on the adequacy of the PR-DEIR alternatives analysis and include contention that an updated cultural resources technical report should have been completed.

The Glendale Historical Society contends there was an "incomplete discussion of consultation with TGHS [The Glendale Historical Society]", that the consideration of the Project's cumulative impact on historical resource impacts was flawed, and that the EIR should have included an alternative that would retain historical resources. TGHS also resubmitted their 2017 comment letter (L16A-1), to which a response was provided in the 2018 FEIR, and to which further responses are provided in the 2018 FEIR. The bulk of the commentary in TGHS's 2017 letter pertained to whether the Grayson Power Plant is an historical resource. The PR-DEIR treats Grayson's Boiler Building as an historical resource, and therefore, addresses TGHS's comments concerning the characterization of the Boiler Building as an historical resource.

A Summary and Timeline of Historical Resources Evaluation is included as **Attachment B.**

Response

Need to Demolish the Boiler Building

Comments were received which question whether the Boiler Building needs to be demolished in order to accommodate the Project or any of the Alternatives.

The Boiler Building houses the boilers for Units 1-5 as well as the steam turbines on a deck on the east side. The Boiler Building occupies about 1.2 acres (20 percent of the approximately 6 acres of the Grayson Power Plant to be affected by the repowering[125]. As such, the Boiler Building represents a sizable portion of the available space for the repower. In looking at the General Arrangements for the proposed Project, Alternative 7, and Alternative 8 (attached to this Topical Response No. 3 as **Attachment C**), the Boiler Building footprint is indicated by the gray areas. The

[125] As stated in the 2018 FEIR, Section 3.0, 10 acres will be disturbed by the proposed Project. The 10 acres includes Units 1-8 and the "Glendale Rack", but excludes existing Unit 9, which will continue to operate. The Boiler Building represents 12 percent of the 10-acres. Six acres is the footprint of the Boiler Building, plus cooling towers, Unit 8A and 8BC, and all areas west of the Glendale Rack. The "Glendale Rack" is defined in the PR-DEIR; this facility has also been referred to at various times in the PR-DEIR as the "Glendale Switchyard". The "Glendale Rack" connects the existing Grayson Units 1-5 to the GWP electrical system. The "Glendale Rack" is located on the Project site and is distinct from the existing "Kellogg GIS" switching station which is not located on the Project site and is not a part of the Project or Alternatives. Existing Grayson Units 8A, 8BC, and 9 currently connect to the existing Kellogg GIS.

Boiler Building is located within the Utility Operations Center (UOC) and does not border any of the sides of the UOC. Due to security and safety protocols, there is not now, nor would there ever be, public access to the Boiler Building.

As demonstrated by the General Arrangements, and due to technical feasibility, the Wartsila engines could not be installed over the old Boiler Building foundation. The Boiler Building foundation and the underlying piles were built to codes and standards that have long been superseded, and the new Wartsila engine foundation design is predicated on an underlying foundation built to current standards. Thus, the Wartsila engines could not be located within the Boiler Building footprint and are required to be located where foundation piles could be driven into the native soils. Alternative 8 is similarly constrained because that Alternative involves re-using the existing Units 8A and 8BC gas turbine foundations. Similar to the Wartsila engines, the new heavy rotating equipment foundations (steam turbine) for Alternative 8 must stay off of the Boiler Building foundation, which will be removed to a few feet below grade and backfilled.

Because the Alternative 7 Wartsila engines or the Alternative 8 steam turbine cannot be located on the Boiler Building site, that location must be used to accommodate the remaining project components. Specifically, the proposed Project and both Alternatives 7 and 8 include a new control room and workshop/warehouse/office space. Alternatives 7 and 8 also include a 75 MW/300 MWH Battery Energy Storage System (BESS) and a new Glendale Switching Station. As illustrated in the General Arrangement, the required components of the proposed Project and the Alternatives have a large site footprint which leaves no space to accommodate retention of the Boiler Building. In addition, during Project construction, on-site laydown space is required. In post-construction GWP will need additional remaining spaces to support routine operation and maintenance.

As part of the City's development and evaluation of the proposed Project and Project Alternatives, the Boiler Building was studied to understand its potential for re-use. Specifically, the City had its Owner's Engineer, Black & Veatch, perform a structural review of the Boiler Building. The Boiler Building was designed to older codes and does not meet current Building & Safety codes for seismic safety and would not be acceptable under today's building standards. For example, the structural design uses steel connection design elements that are no longer allowed. Building and safety codes are frequently updated based on observations of how buildings fare under seismic and other stresses. The Boiler Building is an old building, and as such bears the scars of an old building including larger than hairline cracks in the foundation as well as outdated structural design elements.

Similarly, with respect to hazardous materials, Stantec also performed a hazardous materials review of the Boiler Building. The building uses "Transite" siding, which contains asbestos. In addition, there are significant quantities of asbestos within the building itself in the form of thermal insulation on the piping and boilers as well as insulation on electrical cabling. Lead-based paints are also prevalent within the building as well as heavy metal contaminants in the Boiler Building fire brick. Equipment that contains PCBs has also been identified in the building. All of these hazardous materials will need to be (and can be) safely mitigated and remediated pursuant to proper hazardous materials protocols. This abatement work would be necessary whether the Boiler Building is retained or demolished. However, hazardous material removal and remediation is a more complex task in an intact building. If the Boiler Building were to be reused as opposed to a more straight-forward demolition, that would complicate the process because everything inside would need to be remediated and then removed in smaller pieces through existing doorways. Demolition of the building would allow a more efficient process using cranes to reach in through open sides and top of the Boiler Building to remove equipment. Thus, retaining the Boiler Building would lead to a more extensive, time consuming and expensive process.

After 2024, space at the site is expected to be further constrained when GWP materials currently stored under the adjacent Highway 134 will be required to be moved onto the Grayson site because the City's lease for this space expires and is not expected to be renewed due in that Metro has planned a Doran Street Grade Separation improvements project.

Further space allocation and site layout considerations are as follows:

1. The new Glendale Switching Station must be located where the existing Glendale Rack is located, because of the space that is needed for that facility, as well as because the selected location will minimize impacts to the public. GWP no longer installs new sulfur hexafluoride (SF6) gas insulated substations because, even though they are compact (an important consideration), the insulating gas that they use (SF6) has a global warming potential greater than CO2. As a result, an open air insulated design will be used. The open-air design that will be used for the new Glendale Switching Station requires more space. Additionally, the location for proposed Glendale Switching Station was selected because it is closed to the public and it operates quietly, minimizing noise impacts to the community.

2. Consideration was given to locating the Battery Energy Storage System, and the building elements of the proposed Project and Alternatives 7 and 8, away from the Boiler Building to the extent possible. These are all static elements that do not require piles and thus could be located over the backfilled Boiler Building. However, there is insufficient space for all of these elements and to also retain the Boiler Building. See Exhibits A, B, and C to this Topical Response.

3. The site layout was developed with a goal to locate the noise sources near the center of the site in order to help mitigate noise impacts to a less than significant level.

4. Exhaust stacks also have been located near the center of the site.

Taken together, the Boiler Building's lack of structural integrity, the Boiler Building's hazardous materials, and the physical constraints on locating the elements of the repowered facility, all render re-use of the Boiler Building for a modern energy facility infeasible. For these reasons, the proposed Project and Alternatives 7 and 8 all require the Boiler Building demolition to provide sufficient space for the new facilities, to retain Unit 9, and to retain other essential facilities at the Utility Operations Center (UOC).

Historic Preservation Commission Review

TGHS contends that the City as the Lead Agency has not complied with Glendale Municipal Code (GMC) Chapter 15.20 Historic Preservation with respect to Historic Preservation Commission review of the proposed Project. Pursuant to the powers and duties of the Historic Preservation Commission (HPC) under GMC Title 2 (Chapter 2.76), any permit for demolition of an historic resource will be reviewed by the HPC prior to demolition permit issuance as required by GMC Chapter 15.22. The PR-DEIR has determined that the proposed demolition of the historic Boiler Building will have a significant impact on an historical resource for which a statement of overriding considerations will be required for the Project to receive PR-DEIR certification. The City has not yet applied for a demolition clearance permit because the City Council first needs to award contracts for demolition and take action on Project funding for such demolition to proceed. Nonetheless, per GMC section 2.76.100.L the Project is being brought before the HPC at its regular January 20, 2022 meeting to provide information on the PR-DEIR, and the application for a demolition permit will be brought to the HPC for review as required by GMC Chapter 15.22.

Alternatives Analysis

Commenters contend that the PR-DEIR alternatives analysis should have included an alternative that would retain the Boiler Building.

- Selection of alternatives is based on the alternative feasibly being able to meet most of the Project objectives while reducing or avoiding one or more of the Project's significant impacts. CEQA does not require alternatives be selected on the basis of reducing or eliminating all significant project impacts. There are four threshold tests for suitable alternatives. Potential alternatives are reviewed to determine whether they:
    - Can substantially reduce significant environmental impacts;
    - Can attain most of the basic project objectives;
    - Are potentially feasible; and
    - Are reasonable and realistic.
- Candidate alternatives that do not satisfy all four criteria may be excluded from the EIR. 14 Cal Code Regs §15126.6(c). These criteria are not exhaustive, and other appropriate factors may be considered as well. 14 Cal Code Regs §15126.6(c).
- Here, as evaluated in the PR-DEIR, none of the alternatives selected for analysis that meet the four criteria can feasibly retain the Boiler Building. Commenters have not

recommended an alternative that can both achieve the Project goals and objectives and retain the Boiler Building. Disagreement with the PR-DEIR conclusions is not sufficient. The PR-DEIR demonstrates (Sections 5.1.4.1, 5.2.2.2, 5.2.4.2, 5.2.5.2, 5.2.6.1, and 5.2.7.1) that the Project and selected alternatives cannot accommodate retention of the Boiler Building and meet the Project Objectives.

- Commenters have not shown that the range of alternative selected in unreasonable. Under the CEQA Guidelines, an EIR need discuss only a range of reasonable alternatives. 14 Cal Code Regs §15126.6(a), (c). An EIR that discusses a reasonable range of alternatives is not deficient simply because it excludes other potential alternatives from its analysis. There are many court cases that discuss this principle. (*South of Market Community Action Network v City & County of San Francisco (2019) 33 CA5th 321, 345; City of Maywood v Los Angeles Unified Sch. Dist. (2012) 208 CA4th 362; Cherry Valley Pass Acres & Neighbors v City of Beaumont (2010) 190 CA4th 316). With respect to the interpretation of CEQA law, the courts have been clear that each case must be reviewed on the facts, and the facts must, in turn, be reviewed in light of the purpose of CEQA's alternatives requirement. (Citizens of Goleta Valley v Board of Supervisors (1990) 52 C3d 553, 566; Sierra Club v City of Orange (2008) 163 CA4th 523, 546*). See Topical Response No. 6 for a discussion of the adequacy of the 2018 FEIR and PR-DEIR Alternatives analysis.

Cumulative Impact on Historical Resources

Commenters contend that the PR-DEIR's consideration of cumulative impact on historical resources is flawed.

- The CEQA Guidelines define cumulative impacts as "two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts." 14 Cal Code Regs §15355. The individual effects may be changes resulting from a single project or more than one project. 14 Cal Code Regs §15355(a). Cumulative impacts may result from individually minor but collectively significant projects taking place over a period of time. 14 Cal Code Regs §15355(b). A cumulative impact is an impact created by the combination of the project reviewed in the EIR together with other projects causing related impacts. 14 Cal Code Regs §15130(a)(1). (Emphasis added) The cumulative impact from several projects is the change in the environment that results from the incremental effect of the project when added to other past, present, and probable future projects. 14 Cal Code Regs §§15065(a)(3), 15130(b)(1)(A), 15355(b). Commenters contend that the Project impact on historical resources is cumulatively significant, but they provide no credible evidence to support this contention.

- An EIR must discuss cumulative impacts when the project will make a "cumulatively considerable" incremental contribution to a significant cumulative effect. 14 Cal Code Regs §15130(a). A project's incremental contribution is cumulatively considerable if it is significant when viewed in connection with the effects of other past, current, and probable future projects. 14 Cal Code Regs §15065(a)(3). Under these provisions of the CEQA Guidelines, a lead agency may determine that the project will not have a significant cumulative impact because its incremental contribution to a cumulative effect is not cumulatively considerable. 14 Cal Code Regs §15130(a).

- An EIR need not discuss cumulative impacts that do not result in part from the project. 14 Cal Code Regs §15130(a)(1). *Santa Monica Baykeeper v City of Malibu (2011) 193 CA4th 1538, 1559. In Sierra Club v West Side Irrig. Dist. (2005) 128 CA4th 690, 700*, the court explained that if a project does not make some contribution to a cumulative environmental effect, the cumulative effect cannot be characterized as a cumulative impact of that project (citing this text).

- Section 15130(b)(1)(A) of the CEQA Guidelines stipulates that consideration of cumulative impacts should include past, present, and probable future projects producing related or cumulative impacts. The PD-DEIR is consistent with this requirement and Section 4.11.12 of the PR-DEIR recognizes and states that development of related projects can affect historical resources if such projects adversely alter and/or demolish historical resources that may be interrelated, such as historical resources that are part of a historic district or examples of the same property type as those within the Project site.

- Neither the Boiler Building nor Grayson Power Plant were identified as contributors to a historic district; however, there are other extant properties within Glendale associated with the same property type. The Boiler Building represents a property type associated with municipal power generation within the City of Glendale. Research conducted as part of this analysis identified the following three properties that were previously identified as historical resources and are examples of the municipal power property type.

Previously Identified Historical Resources of the Same Property Type

Name	Address	OHP Status Code(s)
Municipal Light & Power Building	620 E. Wilson Street (formerly 145 N. Howard Street)	3S; 5S1
Municipal Light & Power Building	6135 San Fernando Road	2S2
Water Power Light Building/ Municipal Services Building	119 N. Glendale Avenue/ 633 E. Broadway	3S; 5S1

- There are no known related projects that impact other previously identified historical resources which are examples of the municipal power property type in Glendale. The three properties listed are not impacted by the Project or the Alternatives and therefore there is no cumulative impact on historic resources on related projects. While the Project would have a direct impact on a discretionary historical resource, it would not contribute a cumulatively considerable impact, and cumulative impacts on historical resources as a whole would be less than significant. The City's approach and evaluation of potential cumulative impacts meets the requirements of CEQA Guidelines Section 15130(b)(1)(A) for consideration of projects that would produce related impacts.

- A commenter stated that the Western Reservoir & Bel Aire Electric Substation Improvements should be considered as a project in the evaluation of cumulative impacts of the proposed Project. Those projects include slope repair, erosion control measures, site drainage improvements, access road repairs, retaining wall repairs, fence replacement, landscape and irrigation improvements. Activities potentially affecting the Pump House would involve reconfiguring the stairway to avoid a blower, flattening of the driveway, and modifying the driveway approach to allow better vehicle access. The Western Reservoir & Bel Aire Electric Substation Improvements are located more than 1.5 miles north of the Grayson Power Plant would not result in demolition of buildings and would therefore not have the potential to contribute to a cumulative impact of the proposed Project or Alternatives 7 and 8.

- A commenter stated that the Los Angeles Zoo Vision Plan should be considered _as a project in the evaluation of cumulative impacts of the proposed Project. The Los Angeles Zoo Vision Plan would guide future development and modernization of the zoo for the next 20 years. It would include comprehensive redesign and redevelopment of the zoo to replace outdated buildings and infrastructure and upgrade animal care and guest amenities through the 133-acre zoo. Improvements would include new and revitalized immersive exhibit space and animal habitats, new visitor-serving buildings, expanded and modernized administrative and services facilities, circulation improvements for access roads, pedestrian walkways and paths, an enhanced entry way and plaza, and new parking facilities. The Los Angeles Zoo Vision Plan EIR considers the cumulative impacts of the Grayson Repowering Project and concludes that there would be no cumulative impacts to historical resources. Comparatively, the Grayson Repowering Project or Alternatives 7 and 8 would not result in cumulative historical resources impacts when considered in combination with the Los Angeles Zoo Vision Plan. Please refer to Individual Response L21-24 for a more detailed discuss of the Los Angeles Zoo Vision Plan and its relationship to the Project and the Alternatives.

- Here, the commenter has not established that there are any related projects causing similar impacts (e.g. removal of a municipal building from a power plant site) to which the Project makes a cumulatively considerable incremental contribution. There is no evidence that the Project contributes to any cumulatively considerable impact on historical resources in connection with past, current and probably future projects.

History of Consultation with TGHS

Commenters (L16 and L22) contend that City is not properly accounting for all its interactions with TGHS concerning the Project and that not doing so is somehow improper. The City did consult with TGHS although such consultation with TGHS is not mandatory under CEQA. CEQA Guidelines section 15064.5(b)(5) requires consultation when a project will affect state-owned historical resources, as described in Public Resources Code Section 5024, and the lead agency is a state agency, then the lead agency shall consult with the State Historic Preservation Officer as provided in Public Resources Code Section 5024.5. Consultation with Responsible Agencies and Trustee Agencies is also required (CEQA Guidelines section 15063 (g). Here, the Project is not a state-owned historical resource, the Lead Agency is not a state agency, and TGHS is a private non-profit organization and is not a Responsible or Trustee Agency. Accordingly, the City has no mandatory duty to consult with TGHS. CEQA Guidelines section 15083 and 15086 indicate that a Lead Agency has the discretion to (may) consult directly with any person or organization concerning the draft EIR, and in this case the City has consulted with TGHS. To this point, the commenter (L22-4) admits that the lead agency undertook more than six months of discussions with TGHS. The commenter (see L22-6) alleges there was "…meager coordination that took place with TGHS", yet based on those discussions, the City elected to treat the Boiler Building as an historical resource and agreed to implement reasonable mitigation measures based on measures proposed by TGHS. The City elected to treat the Boiler Building as an historical resource despite substantial evidence that the building is not a resource as reflected in the 2018 FEIR. The Cultural Resources Program Manager for California High-Speed Rail and the State Historic Preservation Office (SHPO) also concurred that the Boiler Building is not eligible for listing in the National Register of Historic Places (See Response to L-22C attachment, December 3, 2020 letter to Brett Rushing, Cultural Resources Program Manager, California HSR, from Juliette Polanco, State Historic Preservation officer, Department of Parks and Recreation Office of Historic Preservation, wherein SHPO concurs that the Grayson Power Plant is ineligible for listing on the NRHP under all criteria).

The City agreed to implement concepts from three of the four mitigation measures requested by TGHS. (See discussion of mitigation measures below re why the City chose not to implement the fourth mitigation measure requested by TGHS).

Specifically, the City responded to TGHS's November 19, 2017 Comment Letter in the 2018 FEIR, after which, and in consideration of TGHS's comments and concerns, the City elected to treat the Boiler Building located on the Project site as a discretionary historical resource although the 2018 FEIR had previously determined that the Boiler Building had undergone significant modifications since it was constructed. The proposed demolition of the Boiler Building for the Project was analyzed in the PR-DIER and was also examined in connection with all Project Alternatives that were selected for further analysis. The PR-DEIR is not required to provide dates, times or content of all emails, discussions, draft agreements and mitigation measures the City discussed with TGHS concerning treatment of the Boiler Building as an historical resource in the PR-DEIR.

- Mitigation Measures. The Lead Agency is not required to include every mitigation measure proposed by commenters. The Lead Agency has incorporated the concepts of three of the four mitigation measures recommended by TGHS. Attachment 4 to L-22 is the TGHS's initial version of the mitigation measures which version was further discussed and negotiated with TGHS and from which refined concepts for three Cultural Resource Mitigation Measures were included in the PR-DEIR. The Lead Agency did not include

TGHS's fourth mitigation measure that would have required the City to survey all City-owned properties. As the commenter admits, (See L22-6), the TGHS provided that mitigation measures not for purposes of mitigating the Project's impacts but as a punitive measure to ensure "…that the problems of this magnitude related to City-owned historic properties were not repeated in the future." TGHS recommendation the City should perform a survey of all City-owned historic resources in Glendale as mitigation for the demolition of the Boiler Building is neither reasonably related to the Project impacts, nor does it in any way necessitate a survey of all City-owned properties in the City of Glendale. As with project conditions imposed in connection with issuance of a permit, mitigation measures must mitigate the environmental impact of the Project and cannot be used to as mitigation for other issues not reasonably related to the Project's impacts.

- The Constitution requires mitigation measures bear "reasonable relationship" or "nexus" exist between the project's impacts and an exaction, fee, or condition imposed by the agency. There is long-standing US Supreme Court case law that sets the legal parameters for appropriate mitigation. (*Nollan v California Coastal Comm'n (1987) 483 US 825, 107 S Ct 3141*.) In Nollan, the court held that it is an unconstitutional taking of property for a government entity to require dedication of an easement as a condition of granting a development permit unless a substantial relationship exists between the impact of the proposed construction and the permit condition. The court held that the required public easement along the beach was not substantially related to the burden created by rebuilding a residence, because the project would not interfere with public use of the beach. See also *Surfside Colony, Ltd. v California Coastal Comm'n (1991) 226 CA3d 1260* (study showing generally that seawalls cause erosion was insufficient to justify dedication of public easement along beach required for seawall project because study acknowledged that results vary locally and no showing was made of potential erosion damage from this seawall); *Rohn v City of Visalia (1989) 214 CA3d 1463* (condition of site plan approval and building permit requiring that portion of property be dedicated to city for street widening project was invalid under substantial relationship test because project would not increase traffic).

- A development exaction must bear a reasonable relationship to the burden created by the development. See *Dolan v City of Tigard (1994) 512 US 374, 114 S Ct 2309; Nollan, 483 US at 835 n4*. In Dolan, the U.S. Supreme Court adopted a "rough proportionality" standard for the relationship between a project's impacts and a dedication requirement imposed by the approving agency. Based on an individualized determination relating to the project, the agency must demonstrate that both the nature and extent of the required dedication are reasonably related to the impact of the proposed Project. Under Nollan and Dolan the government may choose whether and how a permit applicant is required to mitigate the impacts of a proposed development, but it may not leverage its legitimate interest in mitigation to pursue governmental ends that lack an essential nexus and rough proportionality to those impacts. Here, the commenters' suggestion that the proposed demolition of the Boiler Building requires preparation of a City-wide historic survey is TGHS's attempt to leverage its desired interest in obtaining a City-wide survey of historical buildings based on demolition of one historic building. Such a mitigation is not reasonably related to the demolition of a single historical building and lacks the required essential nexus and rough proportionality tests of Nollan/Dolan. Prior to the publication of the PR-DEIR for public comment, the City apprised TGHS in writing of its position concerning the proposed City-wide survey. The City's rejection of TGHS's proposed mitigation measure as violation of the Constitution was appropriate.

Inclusion in an Historic District

Commenters contend that the Grayson property as a whole should be considered as a potential "historic district". Historic districts are created through overlay zones (GMC 30.25.020) and are created at the discretion of the City Council (here the Lead Agency) through a legislative amendment to the Zoning Map. The amendment of the City's zoning code to create an historic district overlay zone is a commenter recommendation and does not provide a basis for creating an historic district for, or including the Project site in, an existing historic district. Historic district generally are areas or neighborhoods with a number of contributing historical resources, as opposed to a single building or facility. See Historic District Handbook, City of Glendale Historic Preservation Commission (undated). The commenter appears to be basing their contention that the whole site should be a historic district on the unsupported premise that additional buildings on the Grayson site are also historic.

Proposed Need to Re-evaluate the Entire Project Site/Need for a Supplemental or Updated Cultural Resources Technical Report

This response is to comments regarding a commenter's contention that the City should have re-evaluated the entire Project Site, e.g. "intensively re-evaluate the entire property for local and California Register eligibility to understand its significance" as part of the PR-DEIR, and to also prepare a supplemental or updated Cultural Resources Technical Report.

- The City prepared an intensive-level analysis of the Project impacts which is included in the 2018 FEIR and which is also shown in the DPR (evaluated in 2017 and again in 2019), included in attachment 1 to the commenter's own letter (L22), and reference Appendix A to the 2018 FEIR.

- As part of the City prepared intensive-level analysis, all existing buildings and infrastructure on the Grayson Power Plant site were considered as part of its evaluation for eligibility as a historical resource. Buildings and features considered include the Boiler Building, Switching Yards, Cooling Towers, Boiler Units, as well as five ancillary buildings such as offices and storage sheds.

The commenter specifically contends the "Glendale Switch Rack" connected to the Boiler Building is part of the historical resource, and that identification of it and of other features, which the commenter does not identify, are historical resources. (See Response immediately below). The commenter characterizes its contention that the PR-DEIR should have provided an updated cultural resources technical report that identified all historical resources associated with the independent power source in Glendale as well as their character-defining features is a "serious omission". (See Response immediately above).

The feature the commenter refers to as the "Glendale Switch Rack" is identified in the 2018 FEIR as the "Glendale Switching Yard." (See footnote 1 herein above for further clarification). The 2018 FEIR notes that while the Glendale Switching Yard was constructed around the same period as the Boiler Building, it has been substantially altered over time. Alterations include the expansion of the Glendale Switching Yard circa 1953, 1958, and 1964, the addition, and interconnection with the Glendale Switching Yard, of a new Kellogg Switching Yard circa 1973, expansion of the Kellogg Switching Yard circa 1975, and the construction of a third addition in the 2000s that replaced the Kellogg Switching Yard. Other alterations to the Glendale Switching Yard include the removal and replacement of original equipment, such as electrical utility boxes to the east of the transformers and replacement of individual transformers, bus structures, and lines. The entire facility has been essentially replaced over time, and consequently the 2018 FEIR concluded that the Glendale Switching Yard no longer retains architectural integrity. (See 2018 FEIR Appendix A, Architectural Resource Evaluation, Section 4.5 of Appendix A, Initial Study and Notice of Preparation).

A commenter also contends, without substantial evidence, or identification of what is meant by "all historical resources associated with the independent power source…" that there are more historical resources on the Project site, besides the Boiler Building, that were omitted from evaluation, and on that basis an updated cultural resources technical report was required.

The PR-DEIR is a supplemental cultural resources analysis to the cultural resources analysis prepared for the 2018 FEIR. In the 2018 FEIR, all existing buildings and infrastructure on the Grayson Power Plant site were considered as part of its evaluation for eligibility as a historical resource. (See response immediately above). The 2018 FEIR concluded that the Grayson Power Plant is not a historical resource, including the Boiler Building, Switching Yards, Cooling Towers, Boiler Units, as well as five ancillary buildings such as offices and storage sheds. After discussion with TGHS, the City elected to treat the Boiler Building as a discretionary historical resource; however, there is no evidence to support mandatory or discretionary treatment of any other buildings or infrastructure at Grayson as historic (more about the distinction between a discretionary resource and a mandatory resource is included below).

A commenter also contends the updated cultural resources section in the PR-DEIR wherein the Boiler Building is treated as an historical resource and wherein the Project impact on cultural resources is evaluated, is not adequate. The Project (and all Project Alternatives except for the No Project Alternative, and Alternative 3, which was found to be infeasible), involves demolition of all existing facilities on the Project site, except for Unit 9. (See Need to Demolition the Boiler Building at the beginning of this Topical Response). The Project involves replacing the existing aging, inefficient Grayson Power Plant with a newer, more efficient, reliable and operationally flexible facility that will meet Glendale's on-going and growing need for electricity. The PR-DEIR concludes that the demolition of the Boiler Building, which TGHS identified as potentially historic, will result in a significant and unavoidable impact on historical resources. The Lead Agency will be required to make findings in support of a statement of overriding considerations (SOC) in order certify the FEIR for this Project. A SOC is required because there are no feasible mitigation measures that will reduce Project impacts on historical resources to a less than significant level.

- CEQA does not require that an agency conduct every recommended test and perform all recommended research in evaluating a project's environmental impacts. 14 Cal Code Regs §15204(a). The lead agency is charged with designing the EIR and has broad discretion to determine how environmental issues should be studied, and assertions that they might be analyzed a different way or that other studies might shed additional light on the subject do not provide a basis for challenging the EIR. Although further investigation might be helpful, that does not make it necessary. There are many court cases that support the position that lead agencies are not required to perform all recommended tests or studies. (Laurel Heights Improvement *Ass'n v Regents of Univ. of Cal. (1988) 47 C3d 376, 410, 415; Save Panoche Valley v San Benito County (2013) 217 CA4th 503, 524.; Bay Area Citizens v Association of Bay Area Gov'ts (2016) 248 CA4th 966, 1017; Society for Cal. Archaeology v County of Butte (1977) 65 CA3d 832. See also Association of Irritated Residents v County of Madera (2003) 107 CA4th 1383, 1396; Cadiz Land Co. v Rail Cycle (2000) 83 CA4th 74, 102; Riverwatch v County of San Diego (1999) 76 CA4th 1428, 1447). The fact that additional testing is feasible does not mean that it is required. (Gray v County of Madera (2008) 167 CA4th 1099, 1115)*.

- Here, a commenter has asserted preferences about what the Lead Agency should study, but short of speculation, the commenter has not provided a substantial evidence basis that demonstrates further investigations would yield any benefit, change any result, or which shows that any further investigations or mitigations would be either feasible or required. Since 2018, the Project (and now the feasible Project Alternatives as studied in the PR-DEIR) all necessitate demolition of the Grayson Power Plant facilities, except for Unit 9. (See above for a more detailed response concerning the need for demolition). There is no evidence that further study would change the result. Although there are no Project or Project Alternative iterations that could feasibly preserve the Boiler Building, or other facilities other than Unit 9, based on several months of discussions with TGHS, including a site visit to the Grayson Power Plant, the Lead Agency is nonetheless including mitigation measures (CR 1, 2 and 3) that are designed to preserve the history of the Boiler Building in a HAER survey, archival quality photographs, installation of a plaque at the Project entrance, and in a display of salvaged equipment and photos with Grayson Power Plant historic context information to be located at a publicly accessible location on City Hall campus.

- Evidence supporting the conclusion that further studies would not provide information essential to an adequate impact assessment is sufficient to support reliance on the EIR's analysis even if there is a difference of expert opinion on the usefulness of further studies. For more information about court guidance on whether additional study is necessary, see *National Parks & Conserv. Ass'n v County of Riverside (1999) 71 CA4th 1341, 1361*. A lead agency may also reject further study as infeasible for economic or planning reasons. *71 CA4th at 1364; Chaparral Greens v City of Chula Vista (1996) 50 CA4th 1134, 1146 n8; Riverwatch v County of San Diego, supra; Society for Cal. Archaeology v County of Butte (1977) 65 CA3d 832.*

- Here, not only is there evidence that detailed study of the entire Grayson site was completed, there is also no evidence that further study would provide information essential to an adequate impact assessment. In addition, there are significant economic and planning reasons why further delay is harmful (See Topical Response Nos. 1 and 2).

- The commenter has not provided new significant information that would necessitate another recirculation of the PR-DEIR. (See Topical Response No. 7 for discussion of why re-circulation is not required). The critical issue in determining whether recirculation is required is whether any new information added to the EIR is significant. The purpose of recirculation is to give the public and other agencies an opportunity to evaluate the new data and the validity of conclusions drawn from it. *Spring Valley Lake Ass'n v City of Victorville (2016) 248 CA4th 91, 108; Silverado Modjeska Recreation & Park Dist. v County of Orange (2011) 197 CA4th 282, 305; Save Our Peninsula Comm. v Monterey County Bd. of Supervisors (2001) 87 CA4th 99, 131; Sutter Sensible Planning, Inc. v Board of Supervisors (1981) 122 CA3d 813, 822. The CEQA Guidelines, 14 Cal Code Regs §15088.5(a),* establish when recirculation is required:

  - When the new information shows a new, substantial environmental impact resulting either from the project or from a mitigation measure;

  - When the new information shows a substantial increase in the severity of an environmental impact, except that recirculation would not be required if mitigation that reduces the impact to insignificance is adopted;

  - When the new information shows a feasible alternative or mitigation measure, considerably different from those considered in the EIR, that clearly would lessen the significant environmental impacts of a project and the project proponent declines to adopt it; and

  - When the draft EIR was "so fundamentally and basically inadequate and conclusory in nature" that public comment on the draft EIR was essentially meaningless.

- When an agency certifies an EIR, it is not required to make an express finding that there is no significant new information that would require the EIR to be recirculated. Such a finding is implied from the agency's decision to certify the EIR without recirculating it. *South County Citizens for Smart Growth v County of Nevada (2013) 221 CA4th 316, 333; Western Placer Citizens for an Agric. & Rural Env't v County of Placer (2006) 144 CA4th 890, 904.*

Cumulative Impacts re Loss of Embodied Energy/Consideration of Embodied Energy

There are comments that contend that the DEIR should have considered expected loss of embodied energy. The commenter further contends that the EIR should have evaluated cumulative impacts from the "expected loss of embodied energy that would be caused by the Project." CEQA does not require an analysis of "loss of embodied energy"; it is not one of the twenty resource categories for which CEQA requires analysis; there is no LORS addressing a threshold for expected loss of embodied energy. Accordingly, since there is no project level impact to evaluate there is no cumulative impact to analyze.

Review by the City's Sustainability Commission:

The Project was brought to the Sustainability Commission and Glendale Water and Power Commission for review and recommendation in Fall 2021, and the 2022 Final EIR will be brought back to these commissions for their review and recommendation on the 2022 Final EIR in January 2022 prior to the City Council's consideration of the Project 2022 Final EIR for certification.

Historical Resource Eligibility

Comments about issues related to Boiler Building historical resource eligibility determination have been considered and resolved as the PR-DEIR treats the Boiler Building as an historical resource.

Distinction between a Mandatory and a Discretionary Historical Resource

CEQA Guidelines define when a Lead Agency has discretion to treat a resource as an historical resource. CEQA Guidelines section 15064.5(b) states:

"The fact that a resource is not listed in, or determined to be eligible for listing in the California Register of Historical Resources, not included in a local register of historical resources (pursuant to section 5020.1(k) of the Public Resources Code), or identified in an historical resources survey (meeting the criteria in section 5024.1(g) of the Public Resources Code) does not preclude a lead agency from determining that the resource may be an historical resource as defined in Public Resources Code sections 5020.1(j) or 5024.1."

A mandatory historical resource is one that is listed in or determined to be eligible by the State Historical Resources Commission for listing in the California Register of Historical Resources. (CEQA Guidelines section 15064.5(a)(1).

Here, at the time the Lead Agency elected to treat the Boiler Building as an historical resource the building was not listed in or determined to be eligible for listing in the California Register of Historical Resources, was not listed in Glendale's register of historical resources or identified in an historical resources survey. Accordingly, the Lead Agency's decision to treat the Boiler Building as historic was discretionary. The distinction between mandatory and discretionary resources notwithstanding, the net result is that the resource is treated as historic.

7.2.4 Topical Response No. 4 Air Quality

Alternative 8 AQIA Model Input and Results can be found as **Attachments E and F**, respectively, and the Alternative 8 SCAQMD Permit Application Report as **Attachment G**.

Summary of Comments

Operating Capacity and Enforceability: Several commenters questioned how operating capacity of the units will be enforced and expressed concern that the Units would be operated at full capacity, noting a statement in the PR-DEIR describing the inputs to Glendale's SCAQMD permit applications for Alternative 7 and Alternative 8 stating that the operating assumptions were not intended as permit limitations.

Baselines: Commenters expressed concern regarding air emission baselines in the PR-DEIR. Specifically, they noted that while the 2018 FEIR utilized a 2015-2016 baseline, PR-DEIR Appendices C-1 and C-2 suggested that an alternative 2018 baseline was selected, while Appendix C-1 of the PR-DEIR references a 2016-2017 emission baseline. Other commenters suggested that an updated baseline should be used.

Air Quality Impact Analysis: Several commenters indicated that although air quality impact analysis results were included in the PR-DEIR for the proposed Project, similar analysis results were not included or easily located for Alternatives 7 and 8. One commenter also indicated concerns that while some ambient air quality impacts were expressed in terms of ug/m3 (micrograms per cubic meter), others were expressed as PPM (parts per million).

Greenhouse Gas Emissions: Commenters shared concerns about GHG data being in various locations through the document. One commenter also noted a discrepancy between mass GHG emissions in an appendix to the SCAQMD application and data contained in the body of the PR-DEIR and also that mass GHG emissions were reflected but identified as carbon dioxide equivalent (CO2e) emissions. One commenter also expressed concern about showing a 2018 historic baseline net of landfill gas emissions for GHG emissions, but without adjusting accordingly for criteria pollutant emissions.

Summary of Responses

Operating Capacity and Enforceability: The SCAQMD will enforce fuel usage and mass emissions limits on the operation of the units. To develop these limits, GWP compiled operating schedules for the units (number of startups and operating hours), and from that information in turn established expected fuel use and resultant emissions. The SCAQMD permits will be based upon those emission inventories and operating schedules that GWP has submitted in its permit application packages. That information is contained in application appendices, rather than application forms. Those annual operating schedules and emission inventories provided by GWP to the SCAQMD reflect the utilization schedules used for the emissions analysis in the PR-DEIR. The statement in the SCAQMD permit application regarding operating assumptions and permit limitations was directed only to the discussion regarding annual operating hours and does not mean that Glendale can operate the units to exceed permit limitations.

Baselines: The 2016-2017 inventory that is included in Appendix C-1 of the PR-DEIR is part of the SCAQMD permit application and reflects a demonstration made in accordance with SCAQMD Regulation XIII to aid the SCAQMD in determining which emissions from Alternative 7 are to be offset by concurrent emission reductions versus emissions to be offset through the acquisition of emission reduction credits. It was not intended as an emission baseline for the CEQA analysis. In response to comments suggesting an updated baseline, Glendale has prepared an updated average annual emission inventory for the years 2019 and 2020, shown in Table 1 through 3 below. These Tables show that regardless of whether one uses the 2015-2016 EIR baseline or an alternative 2019 -2020 baseline, the air emission impacts, with offsets, are less than significant for the Proposed Project, and for Alternatives 7 and 8.

Air Quality Impact Analysis: To express the relevance of Alternatives 7 and 8 in the PR-DEIR, only their net emissions (tons/year) were compared with emissions of the proposed Project. Net emissions from Alternatives 7 and 8 are generally lower than emissions that were attributed to the Proposed Project, so air quality impacts would reasonably be expected to be similar or lower than the Project impacts. Additionally, the air quality impact analyses that were conducted for the Proposed Project and Alternatives incorporate state and federal air quality standards. Some standards are expressed as ug/m3 (micrograms per cubic meter), others are expressed as PPM (parts per million). The analysis for the proposed Project reflects these units of measurement set forth in the respective standards. The analysis contained in the PR-DEIR Appendix C-1 (Alternative 7) was conducted for SCAQMD and model baselines and net results were expressed as ug/m3 for all pollutants, without conversion to the official state or federal standard of measurement.

Greenhouse Gas Emissions: The updated 2018 historic GHG inventory, excluding emissions from landfill combustion, was developed at the request of prior commenters to more conservatively assess impacts of Alternatives 7 and 8. Table 5, below, compares the proposed Project and Alternatives 7 and 8 annual GHG emissions to average 2019 – 2020 annual GHG emissions. The comparison shows that air quality impacts of the Alternatives 7 and 8 continue to be less than significant, even when compared with 2019-2020 historic emissions because potential GHG emissions of Alternatives 7 and 8 are lower than the 2019-2020 annual average historic emissions.

Operating Capacity and Enforceability

Several commenters observed that the proposed annual operating capacity of Alternatives 7 and 8 are lower than the physical capacity of the equipment. They questioned how the utilization specified in the PR-DEIR would be enforced once the equipment is installed. Commenters also noted a statement made on Page 392 of the PR-DEIR PDF file suggesting that operating assumptions are not intended as permit limitations. There were also comments regarding operating schedules (24/7/365) contained on SCAQMD application forms that were interpreted to mean that the engines would operate at full capacity.

The statement regarding permit limits on Page 392 of the PR-DEIR at the end of the first paragraph of Section 4.3 was directed only to the discussion regarding annual operating hours. SCAQMD's permit will contain limits on the number of starts, the amount of fuel burned, and mass emissions rather than total operating hours. Accordingly, plant operations cannot exceed these permit limits. Operating hours, fuel consumption rate, emission rate and number of startups are the primary factors that drive emissions. Hence the fuel consumption (operating hours x fuel consumption rate) and mass emissions (operating hours x emissions rates plus startup emissions) proposed to SCAQMD reflects the operating profile and emission inventory contained in the PR-DEIR.

The (24/7/365) data contained on SCAQMD application forms is intended to advise the SCAQMD that the equipment can be operated at any time on any given day of the year. It is not intended to reflect actual 24/7/365 operations or utilization in low use applications such as peaking power plants; nor is it used by SCAQMD to calculate emissions or specify utilization limits in permits. SCAQMD will issue and enforce permits based upon emission inventories and operating schedules that GWP has submitted in its permit application packages; that information is contained in application appendices, rather than application forms. The annual operating schedules and emission inventories presented to SCAQMD reflect the utilization schedules that were used for the PR-DEIR and the Project description contained in the PR-DEIR.

For Alternative 7, permit applications to SCAQMD reflect emissions from an operating schedule of up to 250 hours per month and 1,260 hours per year, including 50 maximum startups per month and 280 maximum startups per year, and up to 203,616 MMBtu of fuel throughput per year for each of the five engines[126] (PR-DEIR Appendix C Updated Air Quality Technical Report, Section C.1 Alternative 7, Revised Application to the South Coast for a Permit to Construct for the Grayson Repowering dated June 2021, Appendix B, Table B-4, page 483 of the PDF file).

Alternative 8 permit applications to SCAQMD reflect an operating schedule of up to 250 hours per month and 1,200 hours per year, including 25 startups per month and 125 startups per year, and an annual fuel throughput limit of 420,000 MMBtu for each of the three turbines[127] (PR-DEIR Appendix C Updated Air Quality Technical Report, Section C.2 Alternative 8, Criteria Pollutant Emission Inventory dated July 2021, page 597 of the PDF file).

Maximum allowable utilization will be reflected in SCAQMD permit limits in accordance with SCAQMD Regulation XIII – New Source Review. SCAQMD will incorporate the following types of operating or emission limits into the permit for each generating device to ensure consistency with the application and the EIR:

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126 For clarity, the five engines would burn approximately 1 million MMBTU per year if operated to their permit limits.

127 For clarity, the three turbines would burn approximately 1.26 million MMBTU per year if operated to their permit limits.

- Maximum monthly and annual emissions of NOx, CO, VOC, PM10 and SOx
- Maximum annual fuel consumption
- Permitted emission concentrations (PPMV) or emission factors for NOx, CO, VOC, PM10 and SOx
- Maximum number of daily and annual startups, shutdowns and maintenance hours, as well as duration and emission concentrations or emission factors for those events

Additionally, SCAQMD enforces a robust compliance management program that includes continuous emissions monitoring of NOx and CO, as well as metered fuel consumption and start/stop sequences. Periodic testing of VOC, SOx and PM10 will also be required in accordance with various SCAQMD regulations. The compliance program also includes quality assurance measures relative to continuance emissions monitoring equipment, fuel meters, and recordkeeping practices.

Emission Baseline Period

Several commenters expressed concern regarding the treatment of baseline periods when addressing Alternatives 7 and 8. Specifically, they noted that while the 2015-2016 baseline that existed at the time of the Notice of Preparation was published for the proposed Project, the inclusion of alternative data in PR-DEIR Appendix C-2 suggests that an alternative 2018 baseline was selected, while PR-DEIR Appendix C-1 of the PR-DEIR references a 2016-2017 emission baseline.

First, it is important to understand how CEQA requires baselines to be measured. In determining whether a project's impacts are significant, an EIR ordinarily compares those impacts with existing environmental conditions, which are referred to as the "baseline" for the impact analysis. The provisions of the CEQA Guidelines on setting the environmental baseline are included in the guideline governing the environmental setting (14 Cal Code Regs §15125(a)) and the guideline governing analysis of environmental impacts (14 Cal Code Regs §15126.2(a)). These guidelines specify that the baseline generally should be described as the physical conditions that exist in the area affected by the project at the time the EIR process begins (14 Cal Code Regs §15125(a)(1)). They also provide that an EIR's assessment of the project's impacts should normally be limited to changes in those existing physical conditions (14 Cal Code Regs §15126.2(a)). Under 14 Cal Code Regs §15125(a), an EIR must describe "the physical environmental conditions in the vicinity of the project" and this setting will normally be used as the baseline for determining "whether an impact is significant." These conditions should be described "from both a local and regional perspective" (14 Cal Code Regs §15125(a)(1)). This requirement (that existing physical environmental conditions be described) is intended to provide the public and decision-makers with "the most accurate picture practically possible of the project's impacts" (14 Cal Code Regs §15125(a)(1)).

As a general rule, physical environmental conditions should be described as they exist at the time the notice of preparation is published or, if no notice of preparation is published, at the time the environmental analysis begins (14 Cal Code Regs §§15125(a)(1), 15126.2(a)). An EIR's analysis should, however, employ a realistic baseline, such as when existing physical conditions change or fluctuate over time, then the lead agency may define existing conditions by taking account of historic conditions, or conditions expected when the project becomes operational, or both (14 Cal Code Regs §15125(a)(1)). That is basis for the adjusted baseline for air quality analysis provided in the PR-DEIR for which the NOP was issued after the proposed Project NOP.

Commenters have expressed concern that the City is inappropriately using different base lines. However, a lead agency may use one baseline to evaluate certain impacts and another baseline to evaluate other impacts if each baseline is legally adequate and provides the most realistic basis for the environmental analysis. An EIR can existing conditions baseline for most impacts and future baseline for traffic and air quality, so long as use of a future baseline is sufficiently justify future baseline. The justifications for using an adjusted baseline for air quality is provided below and in the PR-DEIR. A lead agency also may elect to use two baselines for analyzing an impact, which was done here, where one is defined by existing conditions and another defined by expected future conditions, as long as the description of future conditions is supported by reliable predictions based on substantial evidence in the record (14 Cal Code Regs §15125(a)(1)).

An EIR's assessment of a project's environmental impacts examines changes to physical conditions expected to result from the project (14 Cal Code Regs §15126.2(a)). An EIR must focus on the project's impacts on the environment, not its impacts on hypothetical situations, such as conditions that might be allowed under existing permits or plans (14 Cal Code Regs §15126.2(a)(3)). This is why the air impact analysis in the PR-DEIR is different from the air permit data required by SCAQMD as that permit has not been issued and does not reflect the existing environmental conditions.

Specifically, the 2016-2017 inventory that is included in PR-DEIR Appendix C-1 of the PR-DEIR is part of the SCAQMD permit application and reflects a demonstration made in accordance with SCAQMD Regulation XIII to aid the SCAQMD in determining which emissions from Alternative 7 are to be offset by concurrent emission reductions versus emissions to be offset through the acquisition of emission reduction credits. It was not intended as an emission baseline for the CEQA analysis. The 2018 annual emission inventory that was included in PR-DEIR Appendix C-2 of the PR-DEIR was intended to demonstrate, based upon validated data available at the time, the degree to which historic facility emissions changed as landfill gas combustion was being discontinued as well as the degree to which future potential emissions may be higher or lower from the more recent 2018 historic emissions. This is the updated baseline for air quality that is allowed by CEQA based on changes in emissions due to the elimination of landfill gas combustion.

Alternatives 7 and 8 were measured against the emission inventories of the proposed Project to demonstrate the relative emissions footprint of each alternative, and also measured the annual average 2015/2016 baseline in the PR-DEIR and also compared with more recent information for 2018. Because emissions attributed to Alternatives 7 and 8 are less than emissions attributed to the Project, and because the Project impacts are shown to be less than significant, it is reasonable to conclude that the impacts of Alternatives 7 and 8 would also be less than significant.

Several commenters suggested that an updated baseline is warranted (see discussion above). They proposed a baseline emission inventory that was taken from the SCAQMD Annual Emissions Report for 2019 from the SCAQMD website. However, it is not appropriate to use a report produced by another agency that did not specifically analyze the air quality impacts from the Project and Alternatives. An EIR must focus on the project's impacts on the environment, not its impacts on hypothetical situations, such as conditions that might be allowed under existing permits or plans (14 Cal Code Regs §15126.2(a)(3)). The City compiled the following updated average annual emission inventory for the years 2019 and 2020 to reflect emissions from Grayson Boilers 3, 4 and 5 as well as the Units 8A and 8BC gas turbines. The following inventory excludes emissions from Unit 9 and other miscellaneous emission sources that exist at the facility but are not affected by the proposed Project.

The subsequent tables compare emissions from Alternatives 7 and 8 with the proposed Project, and also compare those emissions with 2015/2016 and 2018 historic emissions that were shown in the PR-DEIR as well as the updated 2019/2020 average historic emissions. In 2019, Unit 4 was out-service nearly year-round primarily due equipment failure; Units 8A and 8BC were out-service for more than half the year primarily due equipment/system failures; and Unit 5 was out-service for more than 1,000 hours (albeit not in the summertime) due to unplanned outages. As result of these equipment issues impacting operations, 2019 operations and emissions were substantially lower than a typical "average year." in 2019, power generated from the boilers was approximately 50 percent of that generated in the preceding years and approximately 66 percent of 2020 operations.

Table 1 - Comparative Baselines and Emissions - Proposed Project and Alternatives 7 and 8

Annual Historic Baseline Emissions	NOX (tons/year)	CO (tons/year)	VOC (tons/year)	PM (tons/year)	SOX (tons/year)
2015/2016 Average Emissions	29.9	67.0	12.0	15.4	2.2
2018 Emissions (LFG Transition Year)	28.5	56.9	6.1	8.6	1.0
2019/2020 Average Emissions	9.2	55.6	4.5	5.0	0.4
Net Future Maximum Potential Annual Emissions	NOX (tons/year)	CO (tons/year)	VOC (tons/year)	PM (tons/year)	SOX (tons/year)
Proposed Project	51.5	37.6	13.1	15.1	3.0
Tesla/Wartsila Alternative 7	8.2	13.9	8.4	5.0	0.4
Unit 8 Refurbishment Alternative 8	10.9	53.9	7.6	2.0	0.5
Proposed Project Increase or Decrease from Historic Baseline	NOX (tons/year)	CO (tons/year)	VOC (tons/year)	PM (tons/year)	SOX (tons/year)
2015-2016	21.6	-29.4	1.1	-0.3	0.8
2018	23.0	-19.3	7.0	6.5	2.0
2019-2020	42.3	-18.0	8.6	10.1	2.6
Alternative 7 Increase or Decrease from Historic Baseline	NOX (tons/year)	CO (tons/year)	VOC (tons/year)	PM (tons/year)	SOX (tons/year)
2015-2016	-21.7	-53.1	-3.6	-10.4	-1.8
2018	-20.3	-43.0	2.3	-3.6	-0.6
2019-2020	-1.0	-41.7	3.9	0.0	0.0
Unit 8 Refurbishment Alternative 8 Increase or Decrease from Historic Baseline	NOX (tons/year)	CO (tons/year)	VOC (tons/year)	PM (tons/year)	SOX (tons/year)
2015-2016	-19.0	-13.1	-4.4	-13.4	-1.7
2018	-17.6	-3.0	1.5	-6.6	-0.5
2019-2020	1.7	-1.7	3.1	-3.0	0.1

Notes:

1. Increases over historic actual emissions do not reflect emission offsets that will be applied for NOx, VOC, PM10 and SOx. Offsets ensure that no net emission increase will exist.
2. Net Differences reflect future maximum emissions, versus historic actual emissions and do not reflect annual variations that could occur with existing permitted Unit 8 Turbines as base-load boiler operations decrease.
3. VOC, PM and SOx emissions for Unit 8 Turbines (Alternative 8) reflect existed permitted emission rates without the benefit of guarantees that exist for Alternative 7 and the Project from new vendors.

Several commenters suggested that the potential future emissions should be compared with an updated daily emissions baseline. As indicated above, a lead agency may use two baselines for analyzing an impact where one is defined by existing conditions and another defined by expected future conditions, as long as the description of future conditions is supported by reliable predictions based on substantial evidence in the record (14 Cal Code Regs §15125(a)(1)).

Specifically, the following table reflects average daily emissions from the facility during 2019 and 2020. The historic emissions reflect SCAQMD Regulation XIII calculation methods. As such, emissions from Boiler 3 and Units 8A and 8BC turbines were excluded from the inventory due to low annual utilization. Additionally, emissions from Boiler 4 in 2019 were discounted by 50 percent because of the unusually low operations during that year in accordance with SCAQMD Rule 1306(c)(3) calculation methods.

Alternative 8's CO and VOC potential emissions reflect existing permitted emission concentrations without consideration of the effectiveness of the new oxidization catalyst that would be installed and without the benefit of vendor guarantees for PM emissions. Historic emissions, however, reflect actual measured emissions. As such, the impacts of Alternative 8 may be overestimated. Alternative 8 does not include a new emission source. It is a strategy to reduce NOx emissions from the existing Units 8A and 8BC turbines pursuant to SCAQMD regulations.

Potential future emissions of CO, PM and SOx attributed to the proposed Project as well as Alternatives 7 and 8 are below SCAQMD daily mass emissions significance thresholds, without consideration of emission offsets. NOx and VOC emissions are below significance levels when SCAQMD offsets are applied.

Table 2 - Historic and Potential Future Daily Emissions

	NOX (lbs./day)	CO (lbs./day)	VOC (lbs./day)	PM10 (lbs./day)	SOX (lbs./day)
2019-2020 Historic Emissions[1] (SCAQMD AER)	29.4	358.4	25.0	34.6	2.7
Proposed Project Emissions (EIR)	648.0	623.0	179.0	173.0	35.0
Net Increase	618.6	264.6	154.0	138.4	32.3
Significance Threshold	55	550	55	150	150
Exceed Threshold?	Y	N	Y	N	N
Exceed Threshold after New Source Review Offsets?	N	N	N	N	N
Tesla/Wartsila Alternative 7 Emissions (SCAQMD Application, 30-day average)	101.0	176	107.9	64.5	5.9
Net Increase	71.6	-182.4	82.9	29.9	3.2
Significance Threshold	55	550	55	150	150
Exceed Threshold?	Y	N	Y	N	N
Tesla/Units 8A and 8BC Refurbishment Alternative 8 Emissions [2] (PR-DEIR, 30-day average)	166.8	836.2	105.3	27.4	6.2
Net Increase	137.3	477.7	80.3	-7.17	3.5
Significance Threshold	55	550	55	150	150
Exceed Threshold?	Y	N	Y	N	N
Exceed Threshold after New Source Review Offsets?	N	N	N	N	N

Notes:
1. Baselines reflect average of Boilers 4 and 5 with SCAQMD discount factor.
2. Unit 8 historic emissions reflect measured, rather than permitted concentrations. Future historic CO, VOC, PM and SOx emissions reflect existing maximum permitted concentrations without consideration of emission reductions attributed to the new oxidization catalyst (CO, VOC) or vendor guarantees (PM10).

The following tables reflect reported annual emissions in 2019 and 2020 and adjustment to derive historic baselines in accordance with SCAQMD Regulation XIII.

Table 3 – Calculated Average 2019 and 2020 Baseline Daily Emissions

Year	Device	Fuel Usage, MMCF/year	Op. Days	AER Emissions, lbs./year				
				NO_X	CO	VOC	PM10	SO_X
2019	Boiler Unit 3	0.00	0	0	0	0	0	0
2019	Boiler Unit 4	44.77	1	575	3,761	246	340	27
2019	Boiler Unit 5	944.99	158	22,085	79,379	5,197	7,182	567
2019	Gas Turbine 8A	12.86	9	877	974	537	184	8
2019	Gas Turbine 8BC	32.15	12	1,613	2,595	1,341	460	19
2019	Boiler Unit 3	0.00	0	0	0	0	0	0
2019	Boiler Unit 4	1,197.16	196	5,986	100,562	6,584	9,098	718
2019	Boiler Unit 5	240.60	5	3,481	20,210	1,323	1,829	144
2019	Gas Turbine 8A	53.53	19	1,748	11,199	2,233	766	32
2019	Gas Turbine 8BC	9.17	3	449	3,734	383	131	6
2019	Boiler Unit 3	0.00	0	0	0	0	0	0

Year	Device	BACT Adjusted Emissions, lbs./year				
		NO_X	CO	VOC	PM10	SO_X
2019	Boiler Unit 3	0	0	0	0	0
2019	Boiler Unit 4	290	3,527	246	340	290
2019	Boiler Unit 5	6,114	74,456	5,197	7,182	6,114
2019	Gas Turbine 8A	101	46	35	184	101
2019	Gas Turbine 8BC	252	115	88	460	252
2020	Boiler Unit 3	0	0	0	0	0
2020	Boiler Unit 4	7,746	94,324	6,584	9,098	7,746
2020	Boiler Unit 5	1,557	18,957	1,323	1,829	1,557
2020	Gas Turbine 8A	420	192	146	766	420
2020	Gas Turbine 8BC	72	33	25	131	72

Year	Device	Usage Factor	Usage Adjusted Emissions, lbs./day				
			NO_X	CO	VOC	PM10	SO_X
2019	Boiler Unit 3	0	0.0	0.0	0.0	0.0	0.0
2019	Boiler Unit 4	0	0.0	0.0	0.0	0.0	0.0
2019	Boiler Unit 5	0.5	19.3	235.6	16.4	22.7	1.8
2019	Gas Turbine 8A	0	0.0	0.0	0.0	0.0	0.0
2019	Gas Turbine 8BC	0	0.0	0.0	0.0	0.0	0.0
2020	Boiler Unit 3	0	0.0	0.0	0.0	0.0	0.0
2020	Boiler Unit 4	1	39.5	481.2	33.6	46.4	3.7
2020	Boiler Unit 5	0	0.0	0.0	0.0	0.0	0.0
2020	Gas Turbine 8A	0	0.0	0.0	0.0	0.0	0.0
2020	Gas Turbine 8BC	0	0.0	0.0	0.0	0.0	0.0

Device	Average Historic 2019-2020 Emissions, lbs./year				
	NO_X	CO	VOC	PM10	SO_X
Boiler Unit 3	0.0	0.0	0.0	0.0	0.0
Boiler Unit 4	19.8	240.6	16.8	23.2	1.8
Boiler Unit 5	9.7	117.8	8.2	11.4	0.9
Gas Turbine 8A	0.0	0.0	0.0	0.0	0.0
Gas Turbine 8BC	0.0	0.0	0.0	0.0	0.0
Total Emissions	29.4	358.4	25.0	34.6	2.7

Air Quality Impact Analysis

Several commenters indicated that although air quality impact analysis results were included in the PR-DEIR for the proposed Project, similar analysis results were not included or easily located for Alternatives 7 and 8. One commenter also indicated concerns that while some ambient air quality impacts were expressed in terms of ug/m3, others were expressed as PPM.

To express the relevance of Alternatives 7 and 8 in the PR-DEIR, only their net emissions (tons/year) were compared with emissions of the proposed Project. Net emissions from Alternatives 7 and 8 are generally lower or similar to emissions that were attributed to the Project.

The air quality impact analyses that were conducted for the proposed Project and Alternatives incorporate state and federal air quality standards. Some standards are expressed as ug/m3, others were expressed as PPM. The analysis for the proposed Project reflects these units of measurement set forth in the respective standards. The analysis contained in PR-DEIR Appendix C-1 (Alternative 7) was conducted for SCAQMD and model baselines and net results were expressed as ug/m3 for some pollutants, without conversion to the official state or federal standard of measurement.

The following table contains the results of the ambient air quality analysis that was conducted for Alternatives 7 and 8. For consistency with the proposed Project, results are expressed in terms of measurements that reflect applicable state and federal ambient air quality standards. The relative impacts of Alternatives 7 and 8 are not notably different and all the potential air quality impacts would be less than significant when compared with state and federal ambient air quality standards. The same can be said for the proposed Project as reflected in the 2018 FEIR and PR-DEIR. Supporting data for the Alternative 7 analysis are included in PR-DEIR Appendix C-1 of the PR-DEIR (SCAQMD Application). Supporting data for the Alternative 8 analysis are included in Attachment G to this response.

Table 4 - Air Quality Impact Analysis Results - Alternatives 7 and 8

Pollutant	Unit	Avg. period	Background	Alt. 7 Project Increase	Alt 7. Overall Impact	Alt. 8 Project Increase	Alt 8. Overall Impact	Limiting Standard	Type of Standard
NO2	ppm	1-HR	0.0719	0.0211	0.093	0.0080	0.08	0.18	CAAQS
NO2	ppm	1-HR (98th percent)	0.0593	0.0175	0.077	0.0069	0.066	0.1	NAAQS
NO2	ppm	Annual	0.0154	0.0001	0.016	0.0001	0.016	0.03	CAAQS
CO	ppm	1-HR	2.6	0.04	2.64	0.06	2.66	20	CAAQS
CO	ppm	8-HR	1.6	0.03	1.63	0.03	1.63	9	CAAQS
PM10	ug/m3	24-HR		1.25	1.25	0.21	0.21	Increase of 2.5	CAAQS
PM10	ug/m3	24-HR (6th highest)	96	1.25	97.25	0.19	96.19	150	NAAQS
PM10	ug/m3	Annual		0.07		0.07		Increase of 1.0	CAAQS
PM2.5	ug/m3	24-HR		1.25		0.21		Increase of 2.5	CAAQS
PM2.5	ug/m3	24-HR (8th highest)	30.5	1.20	31.70	0.19	30.69	35	NAAQS
PM2.5	ug/m3	Annual		0.07		0.07		Increase of 1.0	CAAQS
SO2	ppm	1-HR	0.018	0.0002	0.0182	0.0001	0.0181	0.25	CAAQS
SO2	ppm	1-HR (99th percent)	0.0094	0.0002	0.01	0.0001	0.01	0.075	NAAQS
SO2	ppm	3-HR	0.002	0.0002	0.002	0.0001	0.002	0.04	CAAQS
SO2	ppm	24-HR	0.002	0.0000	0.002	0.0000	0.002	0.04	CAAQS

Greenhouse Gas Emissions

Commenters shared concerns about GHG data being in various locations through the document. One commenter also noted a discrepancy between mass GHG emissions in an appendix to the SCAQMD application and data contained in the body of the PR-DEIR and also that mass GHG emissions were reflected but identified as carbon dioxide equivalent (CO2e) emissions. One commenter also expressed concern about showing a 2018 historic baseline net of landfill gas emissions for GHG emissions, but without adjusting accordingly for criteria pollutant emissions.

The updated 2018 historic GHG inventory, excluding emissions from landfill combustion, was developed at the request of prior commenters to more conservatively assess impacts of Alternatives 7 and 8. Table 5 compares the proposed Project and Alternatives 7 and 8 annual GHG emissions to average 2019 – 2020 annual GHG emissions. Table 6 shows the average annual 2019 and 2020 GHG emissions calculated based on the 2019 - 2020 baseline operations that were also used to estimate 2019-2020 baseline criteria pollutant emissions. For consistency, CO2e emissions are shown in all operating scenarios. Occupancy-related GHG emissions (270 metric tons per year) are assumed for baseline as well as future potential emissions. Maximum potential emissions of both Alternatives 7 and 8 reflect a reduction from the 2019-2020 baseline.

Table 5 - Comparison of CO2e Emissions to 2019-2020 Average Emissions

2019-2020 Updated Baseline	**Metric Tons (CO2e)**
Generating Units	69,029
Occupancy	270
Total	69,299
Proposed Project (FEIR)	
Generating Units	476,040
Occupancy	270
Total	476,310
Net Increase	407,011
Alternative 7 (PR-DEIR)	
Generating Units	59,608
Occupancy	270
Total	59,878
Net Increase	-9,421
Alternative 8 (PR-DEIR)	
Generating Units	66,925
Occupancy	270
Total	67,195
Net Increase	-2,104

Table 6 - 2019-2020 Average Annual CO2e Emissions

Device/Activity	Fuel Usage, MMCF/year	CO_2, MT/year	CH_4, MT/year	N_2O, MT/year	Total CO_2e, MT/year
Boiler 3	0	0	0	0	0
Boiler 4	621	33,781	0.640	0.062	33,815
Boiler 5	593	32,248	0.611	0.059	32,281
Gas Turbine 8A	33	1,806	0.034	0.003	1,808
Gas Turbine 8BC	21	1,124	0.021	0.002	1,125
Facility Occupants	N/A				270
				Total Project GHG Emissions:	69,299

7.2.5 Topical Response No. 5 GWP's Path to 100 Percent Clean Energy

Summary of Comments

- Comments were received that GWP is not doing enough to use clean energy in Glendale.

Summary of Responses

- GWP has a long history of using and increasing clean energy in Glendale and is continuing to grow local demand response, energy efficiency, and rooftop solar PV as part of its clean energy strategy. GWP has been using and increasing clean energy for the past 20 years and in 2020 64 percent of the energy provided came from carbon-free sources.
- GWP has already performed a 100 percent Clean Energy by 2030 study and presented the results to the City Council in March 2021. The study concluded that GWP can reach 89 percent clean around-the-clock (24x7) by 2030 with a portfolio which includes only commercialized technologies
- Technological advancements in long-duration storage and increased availability of alternative fuels such as renewable natural gas and green hydrogen will have a vital role in GWP's goal to reach 100 percent by 2045 or earlier
- Transitioning GWP's thermal generation to a renewable fuel such as green hydrogen, when it becomes available, and/or increasing access to transmission is required for Glendale to achieve 100 percent clean energy just as LADWP determined in their LA100 study (which includes approximately 2,600 MW worth of in-basin renewably fueled thermal generation). One of the LA100study scenarios assumes replacing LADWP's existing in-basin natural gas burning power plants with renewably fueled combustion turbines without the use of biofuels by 2035.
- Alternatives 7 and 8 provide a pathway to transition to hydrogen gas (in particular green hydrogen, when it becomes available) as fuel to the combustion engines/turbines.

Response

GWP Has a Long History of Using and Increasing Clean Energy in Glendale

GWP has a long history of developing clean energy resources. Beginning in 2002, GWP became one of the first municipal utilities to provide solar rebates to its customers to encourage new solar installations within the City. Since 2002, over 1,900 solar PV systems have been installed within the City with a capacity of 20 MW. Of those amounts, 1,300 systems and 9 MW benefited from GWP solar rebates. GWP continues to offer a Net Energy Metering program, including aggregate Net Energy Metering program, as well as a Feed-in-Tariff program and an array of customer energy efficiency and demand reduction programs. (See 2018 FEIR at Topical Response Nos. 5 Alternative Energy and Demand Response No. 7 Demand Response) and [https://www.glendaleca.gov/government/departments/glendale-water-and-power/residential-customers/residential-programsfor GWP's residential energy efficiency and demand response programs].

Building on this earlier work, GWP is continuing to make significant investments in Clean Energy programs. The Franklin Energy Demand Response and Lime Energy Efficiency programs are now in place and once fully implemented will offer 10 MW (Franklin) in demand response during peak energy demand events and 35,500 MWH (Lime Energy) in energy savings on an annual basis. The proposed Sunrun Virtual Power Plant (VPP) is in the final phase of contract negotiations and GWP expects to take contracts to City Council for consideration in early 2022. At GWP's request, Sunrun has increased the amount of VPP capacity that would be included in the program from 13 MW to 25.25 MW. (Please refer to Topical Response No. 2 for a table that provides various parameters for each of GWP's clean energy efforts). Although commercial solar is not part of Sunrun's proposal, this Environmental Impact Report, and the capacity needs analysis contained herein, assumes that the City will be adding additional distributed energy and solar from commercial facilities for a total of 50 MW of Distributed Energy Resources.

Separately, the City also owns a 0.261 MW solar photovoltaic system at the Glendale Community College (GCC) and is exploring additional opportunities to partner with GCC on local solar and distributed generation projects. GWP has retained an owner's engineer who is currently evaluating all City owned property for additional deployment of local solar and storage, as well as a separate study of necessary distribution system upgrades to accommodate more local distributed generation. Furthermore, GWP is currently evaluating the viability of installing distributed energy resource storage for customers with existing solar system (i.e., batteries on customer sites).

Another local renewable resource available to the City of Glendale is the landfill gas that is produced as a byproduct of the Scholl Canyon Landfill, which can generate up to 11 MWnet of renewable energy. The City certified the EIR and approved the required land use permits for the Scholl Canyon Biogas Renewable Generation Project in November 2021.

Some renewable resources, such as geothermal and hydroelectric energy, are not available within Glendale. Wind is a potential renewable energy resource; however, the City does not own land that is either suitable or of sufficient size to support wind development. Moreover, wind generally does not produce significant energy during the time that GWP experiences peak power demands (summer afternoons). (See Topical Response No. 5 to the 2018 FEIR).

In 2020, 64 percent of the energy provided by GWP came from carbon-free sources such as wind, solar, hydro, geothermal, biomass & biowaste, and nuclear. (See GWP's 2020 Portfolio Content Label Report, available at https://www.glendaleca.gov/home/showpublisheddocument/64139/637685994997330000).

100 percent Clean Energy by 2030 Study

In 2020, GWP conducted a study of plans for goals or methods to achieve 100 percent Clean Energy by 2030, as requested by the City Council. The study, undertaken by Ascend Analytics. This report was presented to the City Council in March 2021 and is discussed on page xii of the PR-DEIR.

The study was designed to develop a "best case" pathway towards 100 percent clean while maintaining reliability. The primary objective was to maximize clean energy around-the-clock (24x7) using a realistic plan. Only commercially available technologies were assessed in this study, including solar, wind, geothermal, and lithium-ion batteries. New large- and small-scale hydro, nuclear, green hydrogen and long duration storage were not considered in modeling the "best case" scenario because 1) development of new hydro and nuclear capacity for Glendale to procure is considered speculative, 2) green hydrogen as a fuel alternative is in its early stages, lack of available cost/performance data for meaningful evaluation, and the challenge to make hydrogen available at Grayson (see Individual Response L5 Vahan Baseghian for further discussion on hydrogen), and 3) commercial utility scale long-duration storage system (with greater than 200 hours of storage duration) technology is still under development. In addition, cost was not considered a limiting factor but was taken into account.

The study was performed on an hourly basis and showed that Glendale can satisfy SB100's target with 100 percent "Net Clean" and can plausibly reach 89 percent clean energy around-the-clock by 2030, with significant up-front investments. Availability of transmission and technological change will play a significant role in achieving the remaining 11 percent. Potential future resources beneficial to GWP include renewable natural gas, carbon neutral fuels to replace natural gas, hydrogen produced from renewable sources for use in thermal power plants, and long duration storage.

Closing the 11 percent Gap

At least 93 MW of local dispatchable combustion engines was included in the portfolio model for the 100 percent Clean by 2030 Study to maintain reliability of the system. Similar to the LA100 report, GWP also recognizes the necessity for local thermal generation that can use renewably derived fuels to mitigate the intermittency of renewable resources, transmission limitations, high load demand with low solar or wind production, and contingency events such as transmission and/or clean energy resource outages or derates spanning several days or weeks. In all of the LA100 scenarios, LADWP utilizes significant amounts of infrequently used in-basin renewably fueled thermal generation as "they form an insurance policy to keep the lights on when things go wrong, including bad weather, hot weather, and fires that take down transmission lines". (https://www.nrel.gov/docs/fy21osti/79444-ES.pdf page 29)

The thermal generation included in the proposed Project and in both Alternatives 7 and 8 provides a pathway to transition to hydrogen gas. The Proposed Project utilizes Siemens gas turbines. Siemens is also enhancing their turbine's ability to burn high concentrations of

Hydrogen. For example, the Siemens SGT-800, the turbine used for the combined cycle units, is currently capable of operating on a 75 percent hydrogen/25 percent natural gas mixture on a volume basis. With Alternative 7, the Wartsila units are already capable of operating on 30 percent hydrogen mix upon commissioning with plans to achieve 100 percent by 2025. The units in Alternative 8 can be retrofitted to operate on 30 percent hydrogen mix by 2025, with plans to achieve 100 percent hydrogen by 2035. Additionally, Unit 9 can be upgraded to operate on a blend of 35 percent hydrogen/65 percent natural gas with the potential for further upgrades to 100 percent hydrogen. However, these upgrades are all dependent on the availability of green hydrogen at Glendale. (See also Individual Response L5 Vahan Barseghian).

7.2.6 Topical Response No. 6 Consideration of Alternatives

Summary of Comments

Comments were received that the Draft EIR inadequately identified and analyzed Project alternatives.

Summary of Responses

The alternatives analysis meets CEQA requirements for selection of a reasonable range of feasible alternatives. Additional alternatives included in the PR-DEIR were added based on discussion and comments on the 2018 FEIR alternatives analysis and results of the City's "Clean Energy RFP" discussed in the Executive Summary of the PR-DEIR. The Clean Energy RFP has additionally resulted in the City planning for at least 50 MW of clean distributed energy resources, such as demand response and energy efficiency and distributed energy resources. The 50 MW of clean distributed energy resources is the result of actions the City has taken during CEQA review of the proposed Project to promote energy efficiency and maximize use of clean energy sources, which in part, led to consideration of Alternatives 7 and 8 in the PR-DEIR which both include less natural gas-fueled electricity generation than the proposed Project.

The alternatives selected for analysis in the EIR were evaluated in sufficient detail to provide meaningful information in order to compare the environmental impacts of alternatives to those of the Project. In addition, as required by CEQA, an environmentally superior alternative was selected.

Response

Background – CEQA Requirements for Selection of Alternatives

CEQA requires that a Lead Agency describe a range of reasonable alternatives for evaluation, which would feasibly attain most of the basic project objectives but would avoid or substantially lessen any of the significant effects of the project. CEQA Guidelines Section 15126.6(a). The nature and scope of the alternatives studied in an EIR is governed by a rule of reason. CEQA Guidelines Section 15126.6(f). An EIR need not consider every conceivable alternative to a project. Rather it must consider a reasonable range of potentially feasible alternatives that will foster informed decision-making and public participation. CEQA Guidelines Section 15126.6(a). The EIR should briefly describe the rationale for selecting the alternatives to be discussed. CEQA Guidelines Section 15126.6(c).

There is no ironclad rule governing the nature or scope of the alternatives to be discussed other than the rule of reason. *Citizens of Goleta Valley v. Board of Supervisors (1990) 52 Cal.3d 553; Laurel Heights Improvement Association v. Regents of the University of California (1988) 47 Cal.3d 376.* Because the primary purpose of an EIR is to mitigate or avoid significant environmental effects, the alternatives discussion is focused on alternatives to the project that are capable of avoiding or substantially lessening any significant effects of the project, even if those alternatives would impede to some degree the attainment of the project objectives or would be more costly. CEQA Guidelines Section 15126.6(b).

Of the alternatives that fit the above criteria, the EIR need examine in detail only those alternatives that the Lead Agency determines could feasibly attain most of the basic objectives of the project. CEQA Guidelines Section 15126.6(f). An EIR need not present alternatives that are incompatible with the project's fundamental purpose. *Bay-Delta Programmatic Envt'l Impact Report Coordinated Proceedings (2008) 43 Cal.4th 1143, 1164; Bay Area Citizens v. City of Oceanside (2004) 119 Cal.App.4th 477; Jones v. Regents of Univ. of Cal. (2010) 183 Cal.App.4th 818.*

No set number of alternatives is necessary to constitute a legally adequate range of alternatives. The scope will vary from case to case depending on the nature of the project and the Lead Agency has discretion to determine how many alternatives constitute a reasonable range. *Citizens of Goleta Valley v. Board of Supervisors (1990) 52 Cal.3d 553, 566.*

Further, neither CEQA nor the CEQA Guidelines require that an EIR include studies comparing the project's environmental costs with its benefits. See *San Francisco Ecology Ctr. v City & County of San Francisco (1975) 48 CA3d 584, 595.* The only direct comparison required in an EIR is the comparison of project alternatives, and a cost-benefit analysis is not required in making that comparison. 14 Cal Code Regs §15126.6(d).

The Draft EIR complies with CEQA Requirements Regarding Selection of Alternatives

The City's selection of alternatives meets the requirements of CEQA. Section 5.0 of the Final EIR evaluated the No Project Alternative (Alternative 1), Energy Storage Project Alternative (Alternative 2), Alternative Energy Project Alternative (Alternative 3), 150 MW Project Alternative (Alternative 4), and 200 MW Project Alternative (Alternative 5). City Council elected not to certify the Final EIR in April 2018, and instead directed GWP to consider greener alternatives.

In response, GWP issued a Clean Energy Request for Proposals (RFP), evaluated, and modeled the proposals received through the Clean Energy RFP, and identified a cleaner portfolio to meet the City's energy needs. That portfolio was presented to the City Council in GWP's 2019 Integrated Resource Plan in July 2019 and as a result, the PR-DEIR included two additional alternatives with less natural gas fueled electrical generation compared to the Project. Sections 5.2.6 And 5.2.7 of the PR-DEIR includes evaluation of Tesla/Wartsila Repowering Project Alternative (Alternative 7) and Unit 8 Refurbishment Project Alternative (Alternative 8).

Alternatives 7 and 8 were selected for evaluation in the PR-EIR because both could feasibly attain the Project objectives while reducing environmental impacts compared to the Proposed Project. An alternative that was considered but determined not to be feasible is Alternative 6, the Tesla/Wartsila Repowering Project, which is identical to Alternative 7, but with a different physical layout configuration that would have replaced the existing units with the exception of Unit 9 with the same equipment proposed in Alternative 7, but in a different arrangement.

Alternative 6 was determined to be infeasible from a practical and technical standpoint because of insufficient space in the east-west direction between the belowground edge of Boiler Building foundation and the west edge of the site for Wartsila power island, the close proximity of existing and new building support piles required to implement Alternative 6, as well as the poorer geotechnical conditions. As a result, Alternative 7 was developed, which is functionally identical and uses the same equipment but in a different arrangement. Alternative 7 placed the Wartsila power island on a geotechnically superior portion of the site and avoided the pile interaction issues while having enough space for the Wartsila power island. The Tesla equipment, which is lighter than and does not involve rotating equipment like the Wartsila engines do, does not require piles.

A variation of Alternative 7, which included preservation of the Boiler Building was also considered by the City during preparation of the PR-DEIR. The Alternative 7 variation would reduce the electrical capacity of the battery energy storage system to reduce the physical size and allow the Boiler Building to be retained. The retained Boiler Building would be upgraded for continued use as a control room and warehouse/workshop space. City Council determined during its December 2020 meeting that the cost and benefits of this variant of Alternative 7 and preservation of the Boiler Building did not warrant further study and evaluation in the PR-DEIR. Specifically, in order to retain the Boiler Building it would be necessary to reduce the amount of energy storage possible to 50 MW/200 MWH[128]. (Please refer to Topical Response 3 for a detailed discussion of the need to demolish the Boiler Building). Given the importance of utility scale energy storage for GWP's efforts to continue increasing their use of clean energy, and the lack of space elsewhere within Glendale for utility scale energy storage (also see Topical Response No. 8), further consideration of this variant was halted.

Environmentally Superior Alternative

The CEQA Guidelines state that if the No Project Alternative is the environmentally superior alternative, the EIR must also identify "an environmentally superior alternative" from among the other alternatives. CEQA Guidelines Section 15126.6(e)(2). When none of the alternatives is clearly environmentally superior, it is sufficient for the EIR to explain the environmental advantages and disadvantages of each alternative.

The discussion of the comparative environmental impacts of the Project alternatives complies with the requirements of CEQA. The PR-EIR includes a detailed description of the potential environmental impacts of each Project alternative as compared to the proposed Project in

[128] The battery energy storage system and building elements of Alternative 7 that could be located away from the Boiler Building footprint were planned to do so, however, there is insufficient space for all of these elements and to also retain the Boiler Building. As these are static elements that do not require piles, they could be located over the backfilled Boiler Building making removal of the Boiler Building and re-use of its footprint a key element of Alternative 7. The Alternative 7 variation retaining the Boiler Building would have meant reducing the size of the battery energy storage system. See Topical Response 3.

Sections 5.2.1 through 5.2.7. In addition, Table 5-15 describes the environmental advantages and disadvantages of each alternative. As a result of this analysis, the proposed Tesla/Wartsila Project Alternative and Tesla/Unit 8 Refurbishment Project Alternative would meet the project objectives while resulting in the fewest impacts when compared to the feasible alternatives evaluated. While the potential environmental impacts between these two alternatives are very similar, the Tesla/Wartsila Project Alternative would have slightly lower noise impacts and is therefore considered the environmentally superior alternative.

The No Project Alternative would avoid demolition of the Boiler Building and a significant impact to a discretionary historic resource associated with the proposed Project but would not meet any of the Project objectives. While the Alternative Energy Project Alternative would also avoid demolition of the Boiler Building and a significant impact to a discretionary historic resource associated with the proposed Project, the Alternative Energy Project Alternative would result in greater offsite impacts to aesthetics, agriculture and forestry resources, biological resources, environmental justice, geology and soils, land use and planning, population and housing, tribal cultural resources, and wildfire compared to the proposed Project due to the need for new transmission into the City. Additionally, the 2019 IRP determined that new transmission into the City is not feasible.

Methodology Employed and Level of Detail

Potential environmental impacts of alternatives and the proposed Project are compared for each environmental topic area. Where, based on objective criteria, the impact of the alternative would clearly be less than the impact of the proposed Project, the comparative impact is said to be "less." Where the alternative's net impact would clearly be more than the proposed Project, the comparative impact is said to be "greater." Where the impacts of the alternative and Project would be roughly equivalent, the comparative impact is said to be "similar". Section 15126.6(d) of the State CEQA Guidelines states that alternatives analysis need not be presented in the same level of detail as the assessment of the proposed Project. Rather, the EIR is required to provide sufficient information to allow for meaningful evaluation, analysis, and comparison with the proposed Project. If an alternative would cause one or more significant impacts in addition to those of the proposed Project, analysis of those impacts is to be discussed, but in less detail than for the proposed Project.

7.2.7 Topical Response No. 7 Partial Recirculation and Adequacy of the Partially Recirculated Draft EIR

Summary of Comments

Comments were received that a new Environmental Impact Report (EIR) should have been prepared and that the Partially Recirculated Draft EIR evades a full-scale review of environmental issues and is misleading because the original Project is treated as viable. Commenters stated that the City had rejected the Project or otherwise taken final action on the Project, and that the Partially Recirculated Draft EIR does not provide a full analysis of Project impacts. Commenters claim that the City should use the subsequent environmental review standards in CEQA because the original Draft EIR is outdated.

Summary of Responses

- The City has not taken any final action on the Project or any alternatives. The City Council directed that additional alternatives be evaluated, and that is the primary reason that the Partially Recirculated Draft EIR was prepared and circulated for public review.

- The City has followed the requirements of the CEQA Guidelines by recirculating portions of the Draft EIR where significant new information was added to the environmental analysis prior to certification of a Final EIR. The Partially Recirculated Draft EIR needs to be considered and reviewed together with the original EIR.

- The City Council directed GWP to consider additional alternatives to repowering the Grayson Power Plant that would incorporate more renewable energy opportunities. GWP did as directed by soliciting and analyzing proposals, selecting two proposals as feasible, and adding analysis of the two potential alternatives to the Draft EIR. In accordance with CEQA Guidelines Section 15088.5, GWP determined it was appropriate to recirculate portions of the Draft EIR for additional public review and comment rather than incorporate the changes into a revised 2018 Final EIR. The 2022 Final EIR includes a comprehensive, updated analysis of the Project impacts for all resource areas, including analysis of two new alternatives that are less impactful than the Project analyzed in the 2018 Final EIR.

Response

The Grayson Repowering Project is a power plant repowering project that removes 238 megawatts (MW) gross (219 MW net) of aging and inefficient generation equipment and replaces it with approximately 270 MW gross (262 MW net), state-of-the-art modern equipment ("Repowering Project," "Project," or the "proposed Project"). A Draft EIR for the Project was prepared and circulated for public review and comment on September 18, 2017 to November 20, 2017. The City responded to all comments received on the Draft EIR and prepared a Final EIR that was considered by the Glendale City Council on April 10, 2018 (the “2018 FEIR”). The City did not certify the 2018 FEIR or approve the Project at that time, instead directing GWP to consider greener alternatives as part of the Project and continuing the hearing on the Project to a future date. At the direction of the City Council to consider additional alternatives to the proposed Project, GWP issued a Clean Energy Request for Proposals, evaluated, and modeled the proposals received, and identified two cleaner portfolio alternatives to the Project.

Some commenters mischaracterize the City’s prior action as rejecting the Project as originally proposed. The City did not take any final action on the proposed Project or any alternatives, but instead directed that additional alternatives be considered. The Partially Recirculated Draft EIR is thus a continuation of the ongoing CEQA review for the Grayson Repowering Project, and the Partially Recirculated Draft EIR needs to be reviewed and considered together with the 2018 FEIR in evaluating the impacts of the proposed Project and alternatives. In the City’s view, many of the comments that the EIR does not fully evaluate Project impacts are based on a fundamental misunderstanding or mischaracterization of the City’s action in 2018 – the City directed that additional alternatives be considered but did not take final action on any alternatives, including the originally proposed Project.

When a Draft EIR has been circulated for a project and new alternatives are proposed, CEQA Guidelines Section 15088.5 applies to determine whether the Draft EIR, or a portion of the Draft EIR, must be recirculated for additional public review and comment or whether the new information can be included in a revised Final EIR without recirculating any of the environmental analysis. CEQA Guidelines Section 15088.5 provides that a lead agency is required to recirculate an EIR when significant new information is added after public review of the Draft EIR, but before certification of the Final EIR. New information is not “significant” unless the EIR is changed in a way that deprives the public of a meaningful opportunity to comment upon a substantial adverse impact or a feasible way to mitigate or avoid such an impact (including a feasible project alternative) that the project proponents have declined to implement. “Significant new information” requiring recirculation includes, for example, a disclosure showing that:

1. A new significant environmental impact would result from the project or from a new mitigation measure proposed to be implemented.

2. A substantial increase in the severity of an environmental impact would result unless mitigation measures are adopted that reduce the impact to a level of insignificance.

3. A feasible project alternative or mitigation measure considerably different from others previously analyzed would clearly lessen the environmental impacts of the project, but the project’s proponents decline to adopt it.

4. The Draft EIR was so fundamentally and basically inadequate and conclusory in nature that meaningful public review and comment were precluded.

Recirculation is not required where the new information added to the EIR merely clarifies or amplifies or makes insignificant modifications in an adequate EIR. If the revision is limited to a few chapters or portions of the EIR, CEQA Guideline Section 15088.5 provides that the lead agency need only recirculate the chapters or portions that have been modified.

Following the requirements of CEQA Guidelines Section 15088.5, GWP determined that significant new information is being added to the Draft EIR with respect to alternatives and cultural and paleontological resources, and therefore recirculation of a portion of the Draft EIR was required. In addition to an updated analysis of cultural and paleontological resources and analysis of two new alternatives, the Partially Recirculated Draft EIR includes two new chapters, Energy and Wildfire, which previously were not required to be analyzed as separate chapters under CEQA.

Recirculation of the portions of the Draft EIR where significant new information is being added is appropriate and required by CEQA. Accordingly, the City followed the procedures required by CEQA in recirculating the Partially Recirculated Draft EIR for additional public review. The Project has been subjected to a full-scale review of the environmental issues, including: (a) the Draft EIR; (b) Responses to Comments for the 1,133 comment letters and public testimony received on the Draft EIR; (c) the 2018 FEIR; (d) the Partially Recirculated Draft EIR; (e) Responses to Comments received on the Partially Recirculated Draft EIR; and (f) the 2022 Final EIR (including any clarifications, amplifications, or insignificant modifications or updates to the Draft EIR and Partially Recirculated Draft EIR). The environmental analysis and public review for the Project has been extensive, comprehensive, and compliant with CEQA.

A number of commenters suggested that CEQA's standards for subsequent review should be applied in determining the content of the Partially Recirculated Draft EIR. These standards are set forth in Public Resources Code section 21166 and CEQA Guidelines 15162 through 15164, and they apply to subsequent actions after an EIR has been certified for a project. They do not apply now, because the City has not yet certified the EIR for the Project; instead the City directed that additional alternatives be considered. The CEQA standards for recirculation were properly applied here, and there is no basis for claims based on CEQA's subsequent review standards.

7.2.8 Topical Response No. 8 Sufficiency of Alternative 2

Summary of Comments

Comments were received questioning the size of the Alternative 2 Energy Storage option and whether the 75 MW/ 300 MWH energy storage system that is being proposed is large enough.

Summary of Responses

- GWP performed an hourly evaluation of the same four-day peak load period in August 2017 that was discussed in the 2018 FEIR and PR-DEIR and concluded that, to meet that same four-day peak load, an energy storage system with a minimum power capacity of at least 155 MW and an energy capacity of greater than 2,400 MWH would be required to serve electric demand and meet reliability requirements.
- There is an insufficient charging capacity available to recharge the energy storage system on a daily basis, which means that long-duration energy storage would be required.
- At this time there are no large capacity long-duration energy storage systems available that could reasonably be sited within Glendale.

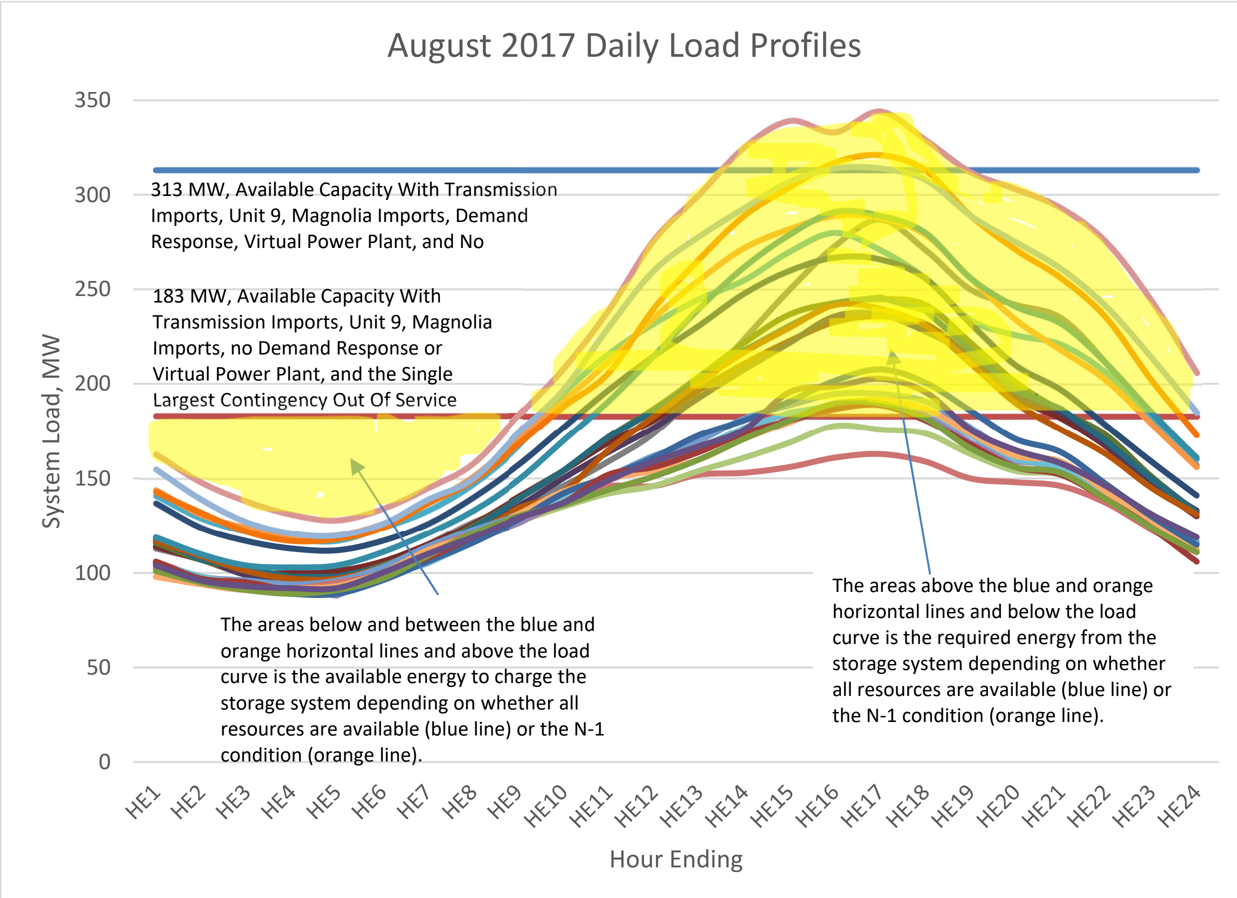
Response

Alternative 2 was selected to explore the alternative of using local utility scale energy storage alone to meet Glendale's energy and power needs. This energy storage system would need to be larger than the battery energy storage system proposed as part of Alternative 7 or 8 as it would need to supply the energy that was to be supplied by the local thermal generation component as well as the energy storage component.

Because the construction of new transmission lines through the LA Basin is considered infeasible (see PR-DEIR Topical Response No. 1 and 2018 FEIR Topical Response Nos. 2, 3, and 4, and 2018 FEIR Response to Comments L298-80 and L925-2) for further discussion), the energy storage system would need to be charged using available transmission capacity (the difference between available transmission imports and what is being used to serve load) as well as imports from the Magnolia Power Plant and local generation, including Unit 9 at Grayson.

Section 5.2.2.1 of the PR-DEIR describes how the energy storage power and energy requirements for Alternative 2 were determined based on past peak load days. It concluded that a system with a peak power capacity of 161 MW and an energy storage capacity of 2,940 MWH would be needed when considering the peak load and the loss of the single largest contingency (N-1).

Inadvertently Figure 5-1 of the PR-DEIR used the same figure that was used in the 2018 FEIR for the proposed Project. The corrected figure is shown below.



The 313 MW and 183 MW thresholds shown in the chart are based on the following:

313 MW Available Resources	Power
Imported Energy	200 MW
Grayson Unit 9	48 MW
Magnolia Power Plant	35 MW
Demand Response and Virtual Power Plant	30 MW
Total Resources	313 MW

183 MW Available Resources with N-1	Power
Imported Energy	200 MW
Grayson Unit 9	48 MW
Magnolia Power Plant	35 MW
Demand Response and Virtual Power Plant	0 MW
Loss of N-1	-100 MW
Total Resources	183 MW

The Scholl Canyon Biogas Project was not included in the 2017 Daily Load Profiles because it had not yet been approved. However, the Scholl Canyon Biogas Project has since been approved and is included in Tables 1 and 3 herein below. Demand response and the Virtual Power Plant were not included as they are not dispatchable within the required timeframe (10 minutes) to meet operating reserve criteria[129].

The peak power capacity need of 161 MW from Section 5.2.2.1 of the PR-DEIR was based upon the largest hourly shortfall which occurred in hour ending 17 (HE17, 5:00 PM or 1700 hours) of the last of the four days when the average load over the hour was 344 MWH and hence the average power was 344 MW (344 MW - 183 MW = 161 MW). The energy capacity need was determined by adding the net difference (plus or minus) between the load and a 183 MW supply on an hourly basis. Thus, when the load was higher than 183 MW for an hour, this resulted in energy (MWH) that would have needed to have been supplied by the energy storage system. When demand was lower than the 183 MW, this resulted in energy (MWH) being available to charge (add to) the energy storage system. Using that method over the four-day peak load period resulted in the following daily energy shortfalls listed in footnote 12 of the PR-DEIR:

August 28	-165 MWH
August 29	-688 MWH
August 30	-825 MWH
August 31	-1,262 MWH
Total	-2,940 MWH

In the Tables below, the Alternative 2 power/energy requirements were updated to align with Topical Response No. 1 and establish a lower bound by including the Scholl Canyon Biogas project, additional STS transmission capacity, the Eland I Solar and Storage project, and new Distributed Energy Resource programs. In Topical Response No. 1, it was assumed that all resources were available at the same coincident time as the peak load to demonstrate the minimum requirement for local Grayson thermal generation while still meeting contingency reserve requirements. Topical Response No. 1 also discusses the factors that in reality would preclude all resources being available at maximum capacity at the same time. When considering the time-of-day availability of resources, the required capacity of Grayson may be greater in order to meet the contingency requirements.

To fully address the public comments regarding Alternative 2, in the Tables below, an analysis of the available resources was performed using the same resources included in Topical Response No. 1 (i.e., including Scholl Canyon Biogas, additional STS transmission, etc.) as well as their time-of-day availability. An hourly evaluation was performed for the same 4-day period as in the FEIR and PR-DEIR using the same 2024 and 2027 assumptions as Topical Response No. 1 (the major ones being Grayson Units 1-8 shutdown at the end of 2023 and 72 additional MW of transmission imports becoming available in 2027). This evaluation demonstrates the minimum power and energy that would be required from an energy storage only alternative.

[129] See WECC-0114 Posting 1 BAL-002-WECC-2a Request for Interpretation - Clean - 5-4-2015 through 6-18-2015 (nerc.com), Section B, R1, 1.2 (includes Operating Reserve – Spinning) and 1.4 (states the 10 minute deployment)

Table 1, below, presents an hourly projection of electric energy production for each resource between Hour Ending 1 (HE1, 12:00A-1:00 AM) and Hour Ending 24 (HE24, 11:00 PM-12:00A):

- Transmission imports were assumed to be at 100 percent capacity for the entire 24-hour period. As explained in Topical Report No. 1., this may be a non-conservative assumption, i.e., real performance may be less than 100 percent at times of the day, particularly at night when solar resources are unavailable. The Pacific DC Intertie was included for all years, and the additional 72 MW of Southwest Transmission System capacity associated with the Intermountain Power Project repower was included for 2027. Transmission losses were modeled at 5.8636 percent.

- Eland Solar and Storage was modeled as a 25 MW solar PV resource plus 18.75 MW/75 MWH from GWP's share of the energy storage portion of the project. GWP is a minority share participant, and LADWP dispatches the plant. All electrical output was assumed to occur during the day when the sun is available, and loads are highest. A total energy production of 358 MWH was used for the day using a high solar capacity factor (24 hours x 25 MW solar component x 47 percent capacity factor + 75 MWH from storage = 358 MWH). This energy was spread between HE7 and HE23 with energy storage used to extend maximum generation through the after peak demand period.

- Local new Virtual Power Plant was also modeled as a variable resource. The Virtual Power Plant would produce solar energy during the day combined with energy storage. Up to 37 MW from the solar PV component would be used to charge the 25.25 MW/50.5 MWH battery energy storage component, with the storage component then being used to serve electric demand. For August, Sunrun was modeled as providing between 0 and 9 MW for a total of 58 MWH in 2024, and between 0 and 22 MW for a total of 143 MWH in 2027. This modeling recognizes the time required to build out the rooftop solar and batteries, as well as recognizing that the solar PV energy is used first to charge the batteries and then any excess flows to GWP as well as energy discharged later in the day (allowing contribution through Hour Ending 20 ("HE20"), or 8 p.m.

- Local new Demand Response was modeled, with the assumption that the four-year program would be extended through 2027. Energy efficiency and demand response have the least impact during nighttime hours when most residents are sleeping, and energy use is reduced. Thus, demand response was modeled as contributing 10 MW for Hour Ending 16 (HE16), or 4 p.m., through Hour Ending 19 (HE19), or 7 p.m. The actual contribution may be less depending on how many customers participate and whether some choose to opt out of demand reduction when called upon to reduce their usage (participation is voluntary). (Demand response doesn't actually produce energy, it saves energy. But whether it is counted as adding energy on the supply side or counted as reducing demand on the load side, when looking at the difference between supply and demand the effect is mathematically the same).

- Scholl Canyon Biogas was modeled at 11 MW_{net} for all hours.

- Magnolia Power Plant and Grayson Unit 9 were modeled at maximum output for all hours.

Table 2 presents the hourly energy consumption for August 28-31, 2017, the same days that were included in the 2018 FEIR and PR-DEIR. This was used as a proxy for August 28-31, 2024. As these are MWH energy values for one hour, the average power for one hour is the same as the MWH value. Actual power may be higher or lower during the hour. That is why the peak energy hour is 344 MWH but the peak historical power is 346 MW (peak is instantaneous so the average over the hour will be a little less).

Table 1 – August 2024 Energy Resources, MWH

Resource Capacity	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24	Total Daily MWH Produced
Existing PDCI+STS Transmission	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	5,088
Post-2027 STS Transmission Addition	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission Losses	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-12	-298
Eland Solar and Storage	0	0	0	0	0	0	2	20	23	23	24	24	24	24	24	25	25	25	25	20	19	19	12	0	358
Local DER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	10	10	10	0	0	0	0	0	40
Local VPP	0	0	0	0	0	0	0	2	0	2	3	3	3	7	6	9	8	6	5	4	0	0	0	0	58
Scholl Canyon Biogas	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	264
Magnolia (summer net)	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	840
Unit 9	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	1,152
Loss of N-1 (PDCI)	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-2,400
Reduction in Transmission Losses	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	141
Loss of N-1-1 (Unit 9)	-48	-48	-48	-48	-48	-48	-48	-48	-48	-48	-48	-48	-48	-48	-48	-48	-48	-48	-48	-48	-48	-48	-48	-48	-1,152
Available Resources	151	151	151	151	151	151	153	173	174	176	178	178	178	182	181	195	194	192	191	175	170	170	163	151	4,090

Table 2 – August 2024 Energy Demand, MWH

Used 2017 data for 2024	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24	Total Energy Demand	Net Short
8/28/2024	119	110	104	103	104	111	121	133	149	170	191	215	240	262	279	291	289	280	256	241	232	211	185	161	4,557	-467
8/29/2024	143	132	122	117	118	124	137	149	168	188	206	240	266	289	304	317	321	313	289	271	256	235	202	173	5,080	-990
8/30/2024	155	139	127	121	120	126	139	150	174	197	230	260	278	293	307	314	314	308	289	275	261	241	214	185	5,217	-1,127
8/31/2024	163	148	138	131	128	134	145	158	183	208	239	276	300	325	339	333	344	329	312	303	293	275	244	206	5,654	-1,564

Cells shaded in green are hours where supply exceeded demand and power was available to charge the energy storage system ranging from 0 to 48 MW depending on the hour. Cells shaded in yellow are where demand exceeds supply, and the energy storage system would need to discharge energy to make up the shortfall with the required power ranging from 0 to 158 MW. The total energy shortfall over the four days is 4,146 MWH (the sum of the daily net short).

Table 3 presents the same information as Table 1 except updated for 2027. The primary change is the additional 72 MW of STS transmission capacity as well as growth in the proposed Sunrun virtual power plant. The 72 MW was not included in the Alternative 2 evaluation in the PR-DEIR as it was not considered firm at the time the evaluation was performed.

Table 4 presents the same information as Table 2 except updated for 2027. The 2017 load data was scaled up by the ratio of the peak loads.

By 2027, Tables 3 and 4 show that daily available energy has increased by approximately 1,200 MWH and daily load has grown by approximately 800 MWH. The increase in resources compared to load allows more of the cells (hours) to turn green; however, there is still a net shortage for three of the four days (not enough nighttime energy to cover the next day).

Table 3 – August 2027 Energy Resources, MWH

Resource Capacity	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24	Total Daily MWH Produced
Existing PDCI+STS Transmission	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	212	5,088
Post-2027 STS Transmission Addition	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	1,728
Transmission Losses	-10	-17	-17	-17	-17	-17	-17	-17	-17	-17	-17	-17	-17	-17	-17	-17	-17	-17	-17	-17	-17	-17	-17	-17	-393
Eland Solar and Storage	0	0	0	0	0	0	2	20	23	23	24	24	24	24	24	25	25	25	25	20	19	19	12	0	358
Local DER	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	10	10	10	0	0	0	0	0	40
Local VPP	0	0	0	0	0	0	0	6	0	4	7	8	8	17	15	22	19	15	12	10	0	0	0	0	143
Scholl Canyon Biogas	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	264
Magnolia (summer net)	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	840
Unit 9	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	1,152
Loss of N-1 (PDCI)	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-100	-2,400
Loss of N-1-1 (STS)	-64	-64	-64	-64	-64	-64	-64	-64	-64	-64	-64	-64	-64	-64	-64	-64	-64	-64	-64	-64	-64	-64	-64	-64	-1,536
Reduction in Transmission Losses	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	231
Available Resources	214	197	197	197	197	197	199	223	220	224	228	229	229	238	236	254	251	247	244	227	216	216	209	197	5,294

Table 4 – August 2027 Energy Demand, MWH

2027 Load Data Ratioed by 398/344	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24	Total Energy Demand	Net Short
8/28/2027	137	127	120	118	120	128	139	153	171	196	220	247	276	301	321	335	332	322	294	277	267	243	213	185	5,242	52
8/29/2027	164	152	140	135	136	143	158	171	193	216	237	276	306	332	350	365	369	360	332	312	294	270	232	199	5,843	-549
8/30/2027	178	160	146	139	138	145	160	173	200	227	265	299	320	337	353	361	361	354	332	316	300	277	246	213	6,001	-707
8/31/2027	187	170	159	151	147	154	167	182	211	239	275	317	345	374	390	383	396	378	359	349	337	316	281	237	6,504	-1,210

The maximum difference in power between demand and available supply is 154 MW. The maximum available charging power is 79 MW. The total energy shortfall over the four days is 2,414 MWH.

It is also worth noting that all mechanical and electrical systems have inefficiencies. In the case of battery energy storage, Tesla's contract minimum performance guarantee is a roundtrip efficiency (RTE) of approximately 85 percent, i.e., 15 percent of the energy supplied to the battery is lost. Thus, about 18 percent more energy must be supplied than stated (1.18 MW charged x 0.85 RTE = 1 MWH delivered).

The 154-158 MW power capacity needed from the energy storage system is independent of the energy capacity need. The 154-158 MW is the amount of power that must be supplied to close the gap between demand and supply. The required energy is the result of the size of the power gap (which varies by hour) and the hours over which the power must be supplied. Given the limited amount of charging power available, Ascend Analytics concluded in its analysis for the City's 2019 IRP that energy storage alone was infeasible. Given the finite capacity of an energy storage system, it is prudent to size the system such that it can handle all planning contingencies so that the City is not short of power and that reliability is not compromised. Therefore, Alternative 2 reflects an energy storage system that is sized to handle contingencies.

Options for locating utility scale energy storage within Glendale are constrained by several considerations:

- Need to seasonally shift energy - given the inadequate amounts of charging power during a sustained heat wave, which means that the energy storage system must gather and store energy well in advance, store it for some time (months), and then be available to release it when needed.

- Commercially available and demonstrated technologies - the one widely deployed technology today that routinely handles seasonal shifts in energy is hydroelectricity (both seasonally stored and pumped hydro). Local hydroelectricity is not feasible for Glendale, leaving battery energy storage as the other widely deployed energy storage technology. While there are other technologies that have potential and are in initial commercial deployment such as flow batteries and liquid air systems, nothing has been proposed or built to date approaching the size that Glendale would need.

- Adequate interconnection capability – the energy storage system should be connected to the GWP 69 kV backbone where it can be delivered at or to the Kellogg Switching Station at Grayson for distribution throughout Glendale. The Kellogg Switching Station is the nexus for the GWP system to which all substations are connected and through which incoming power flows.

- Available space – the only GWP property with sufficient space for a utility scale system is Grayson. None of GWP's other substations within Glendale have in total the available space that can accommodate utility scale systems comparable to what is proposed at Grayson. There is only space at some for small systems such as the 2 MW/1 MWH system installed at Grandview.

For the reasons stated above, there were no better alternatives identified other than siting the energy storage facility proposed as part of Alternatives 7 and 8 at Grayson. For the reasons discussed here and, in the PR-DEIR, lithium-ion batteries were also considered the best choice for Glendale given the urban setting, siting constraints, and available technologies[130].

It is typical for procurement contracts that extend over years to contain escalation clauses tied to globally recognized price indexes. That would be the case with the Tesla contract (and Wartsila as well). Given the growth in demand for energy storage and electric vehicles, the demand and accordingly the price of lithium is escalating. The price of lithium has the potential to escalate the cost of the project.

The current cost of the Tesla power island is approaching $400/kWH. That cost includes the battery systems, foundations, transformers, and installation. It does not include any demolition or site improvement costs. The price has increased driven by current market conditions, and the escalating price of Lithium. The price of Lithium Carbonate as tracked on the Shanghai Metals Exchange. The price on December 10, 2020, was 53,000 Renminbi (RMB)/metric ton. Since the time of the last Tesla cost update, has risen from 219,500 RMB/metric ton on December 10, 2021, to 275,000 RMB/metric ton on December 30, 2021.

Comment L21-88 cites a Bloomberg New Energy Finance (BloombergNEF) report from May 2021 that is based upon a 2019 Battery Price Survey that showed a projected 2020 cost of $137/kWH. The underlying data is two years old and does not fully reflect today's current market conditions or the escalation in lithium pricing. One can also look at Lazard's more recent Levelized Cost of Storage Analysis Version 6.0 study from 2020. Use Cases 1 and 2 are most applicable. Use Case 1 is based on 4 hour storage (like what is proposed for Alternatives 7 and 8) but is for a system twice as large and thus enjoys greater economy of scale. It has an expected cost range of $183-340/kWH. Use Case 2 is for a smaller 10 MW/60 MWH system with an expected cost range of $301-412/kWH. In both cases the projected price has risen compared to what was in the BloombergNEF report. Since 2019, there has been increasing demand for lithium batteries, both

[130] Three other thermal energy storage technologies were also offered. One required a companion steam power cycle (thermal generation) and was intended to work with the Proposed Project combined cycle units. That proposed system could provide additional power when the combined cycle units were in operation, and up to 12 hours of stored energy at reduced output when the combined cycle unit was not in operation. The second proposal offered long duration 10 MW/100 MWH and short-duration 10 MW10 MWH systems using molten salt. A third proposal offered distributed thermal energy storage. All three proposals were evaluated but not selected for short listing because the proposers did not meet RFP criteria and requirements and did not meet GWP's needs as greener alternatives to the proposed Project were being sought and GWP needed more capacity than was being offered.

for commercial and utility scale energy storage, as well as transportation, and hence the increasing upward pressure on price.

Using a cost of 298 $/kWH (the midpoint of the $183-412/kWH range in Lazard report) and 2,414 MWH from the 2027 information above, results in an energy system cost of approximately $719 million. That is a significant capital investment for a system that can only store energy and is dependent on energy that must be imported for charging.

GWP would also be paying an annual capacity maintenance fee to maintain the batteries' power and energy over the course of the 20-year agreement. At the end of that period, energy capacity would begin to decay without further battery upgrades or replacement.

7.3 RESPONSE TO COMMENTS DURING PUBLIC MEETING

7.3.1 September 9, 2021, Special Joint Meeting of the Glendale Water and Power and Glendale Sustainability Commission

A special joint meeting of the Glendale Water & Power and Glendale Sustainability Commissions was held on September 9, 2021. Both Commissioners (in person and virtually) and members of the public (by phone) were able to make comments. The following page and line numbers refer to the transcript of the September 9 meeting. A video recording of the meeting is also available through the City of Glendale website.

MC - Response to Comments received from President Flanigan during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-1 President Flanigan asked if the purpose of the meeting was to make a recommendation or to receive public comment. This comment was addressed during the meeting on September 9, 2021. Please refer to page 35 line 25 and page 36 lines 1 through 18, where it is confirmed the purpose of the hearing was to receive comments.

MC-2 President Flanigan asked about the certification of the EIR, whether it would include the proposed Project and alternatives. This comment was addressed during the meeting on September 9, 2021, where staff confirmed the EIR would be coming back later to the Commission for a recommendation. Please refer to page 36 lines 19 through 25 and page 37 lines 1 through 11 for details.

MC - Response to Comments received from Commissioner Jazmadarian during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-3 Commissioner Jazmadarian asked about contingency needs, and Mr. Tateosian responded at the meeting and described the contingencies. Please refer to page 38 lines 1 through 25 for details.

MC - Response to Comments received from Commissioner Kedikian during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-4 Commissioner Kedikian first asked about participation in the Intermountain Power Project (IPP), and why some other agencies did not participate, and Mr. Young, GWP General Manager, responded that it was primarily CAISO members that did not participate. Please refer to page 39 lines 9 through 25 and page 40 lines 1 through 15 for details.

MC-5 Commissioner Kedikian asked a follow-up question about the IPP, and Mr. Young responded. Please refer to page 40 lines 16 through 25 and page 41 lines 1 through 6 for details.

MC-6 Commissioner Kedikian asked what type of event might cause the loss of the transmission from the IPP, and Mr. Young responded, noting that wildfire was one example. Please refer to page 41 lines 7 through 21 for details.

MC-7 Commissioner Kedikian asked about the costs of alternatives 7 and 8, and Mr. Tateosian responded that cost estimates were underway. Please refer to page 41 lines 22 through 25 and page 42 lines 1 through 15 for details. See also Topical Response No. 2.

MC-8 Commissioner Kedikian asked a follow-up question about cost, and Mr. Tateosian responded to this question during the meeting. Please refer to page 42 lines 17 through 25 and page 43 lines 1 through 8 for details. See also Topical Response No. 2.

MC - Response to Comments received from Commissioner Peterson during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-9 Commissioner Peterson asked about visual discharges from the stacks, and Mr. Young responded there would be no visible discharge. Please refer to page 43 lines 17 through 25 and page 44 lines 1 through 2 for details.

MC-10 Commissioner Peterson asked whether it would be more efficient to just use renewables rather than generating hydrogen, and Mr. Young responded that excess power from renewables during the day would be used to generate hydrogen that could be used during the night. Please refer to page 44 lines 4 through 25 and page 45 lines 1 through 22 for details.

MC-11 Commissioner Peterson then summarized the discussion, and Mr. Young confirmed his summary. Please refer to page 45 lines 23 through 25 and page 46 lines 1 through 8 for details.

MC - Response to Comments received from President Flanigan during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-12 President Flanigan made a number of introductory comments about energy efficiency, the experience of other jurisdictions, and the status of the Sunrun project. With respect to energy efficiency and clean energy, see Topical Response No. 5. With respect to the Sunrun project, that project is on the agenda for City Council action this year. President Flanigan also asked about the need for the proposed Project. This comment was addressed in response to a similar question asked by Chairperson Bartrosouf during the meeting. Please refer to page 49 lines 4 through 12, page 80 lines 22 through 25, and page 81 lines 1 through 16 for details. Please also see Topical Response No. 1.

MC-13 President Flanigan asked about the cost of alternatives 7 and 8. Please refer to Topical Response No. 2.

MC-14 President Flanigan asked about the run time of the units, and Mr. Young responded that it was determined by run hours and was anticipated to be a long time; Mr. Tateosian also provided a further response. Please refer to page 50 lines 7 through 15, page 52 lines 13 through 25, and page 53 lines 1 through 2 for details.

MC-15 President Flanigan asked if refurbished units would have a similar run time to the Wartsila units, and Mr. Young confirmed that is the case. Please refer to page 50 lines 16 through 24 for details.

MC-16 President Flanigan asked whether hours were the basis for the BTU comparisons, and Mr. Tateosian confirmed hours of run time was the basis. Please refer to page 51 lines 8 through 15 for details.

MC-17 President Flanigan asked if the run time would be for the specified amount or more, and Mr. Tateosian responded that the specified amount was in the EIR and in the permit application to SCAQMD. Please refer to page 51 lines 16 through 25 for details. Also please see Topical Response No. 4.

MC-18 President Flanigan asked if the run time would increase, and Mr. Tateosian responded that it would be limited by the permit. Please refer to page 52 lines 8 through 11 for details.

MC-19 President Flanigan stated that he hoped the refurbished units would have a short life, limiting the use of gas technology, and Mr. Tateosian stated the useful life of a refurbished unit would be over 10 years. Please refer to page 53 lines 10 through 18 for details.

MC-20 President Flanigan asked about hydrogen purchases, and Mr. Young and Mr. Tateosian confirmed the initial hydrogen use would be for the Intermountain Power Project. Please refer to page 54 lines 2 through 9 for details.

MC-21 President Flanigan asked if the engines can run partially on hydrogen, and Mr. Tateosian confirmed that they can. Please refer to page 54 lines 10 through 19 for details as well as Individual Response L5.

MC-22 In response to President Flanigan's question, Mr. Tateosian confirmed the units could take renewable natural gas meeting California standards. Please refer to page 54 lines 20 through 25 and page 55 lines 1 through 4 for details.

MC-23 President Flanigan noted it may be possible to transition the units first to renewable natural gas and then to hydrogen. Mr. Tateosian agreed, noting that both Alternative 7 and Alternative 8 could run on renewable natural gas when available, that Alternative 7 could also run on a blend of RNG and hydrogen, and that Alternative 8 probably could not run on hydrogen. Please refer to page 55 lines 5 through 24 for details.

MC-24 President Flanigan asked if Alternatives 7 and 8 alone could carry the City, and Mr. Tateosian confirmed that neither alternative in itself can carry the City's capacity if the City were separated from the grid. Please refer to page 56 lines 1 through 25 and page 57 lines 1 through 3 for details.

MC-25 President Flanigan asked if this was in contrast to the ability of the proposed Project to carry the city, and Mr. Tateosian and Mr. Young confirmed that was correct. Please refer to page 57 lines 4 through 25 and page 58 lines 1 through 5 for details.

MC - Response to Comments received from Commissioner Pinkerton during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-26 Commissioner Pinkerton reiterated prior comments about costs. See Topical Response No. 2.

MC-27 Commissioner Pinkerton stated her opinion that the City is too wedded to gas through the proposals. Please see Topical Response No. 1. Please refer to page 58 lines 23 through 25 for details. Currently fast starting thermal generation and battery energy storage systems are the two predominant technologies for providing dispatchable generation any time of the day. That capability is of paramount importance to Glendale because of the extent to which the City relies upon external sources of generation. Battery energy storage is included as part of project Alternatives 7 and 8 up to a capacity that the 2019 IRP indicated that GWP would have capability to recharge without going to seasonal long-duration storage (which is currently infeasible locally as discussed in Topical Response No. 8) on a recurring basis. Battery energy storage also has a finite capacity. While thermal generation also has a finite capability as defined by its air permit; it has the capability to generation for several days if needed.

MC-28 Commissioner Pinkerton raised questions about the reliability of transmission lines, and losses of power through transmission lines. Please refer to page 59 lines 1 through 15 for details.

The risks to transmission, as Commissioner Pinkerton correctly points out, are why GWP must plan for and have local resources to cope with contingency events such as the loss of a transmission line. Please also see Topical Response No. 1.

Electric power losses through the transmission system were taken into consideration. Please see Topical Response Nos. 1 and 8. GWP has long relied upon transmission imports to access a technologically diverse mix of resources such as geothermal, hydro, nuclear, and wind resources that could not be achieved within Glendale itself. Given the urban nature and intensive level of land use within Glendale, that will continue to be the case for the foreseeable future. Within Glendale, pragmatic options are limited to solar PV coupled with energy storage for generation. The proposed Virtual Power Plant would provide up to 50.5 MWh of firm energy per day from the energy storage component[131], On a winter day, when electric demand and solar PV production is typically at its lowest, GWP provides about 2,000 MWH on a daily basis.

MC-29 Commissioner Pinkerton asked if the 3 per cent coal shown on the power content label was all from the Intermountain Power Plant, and Mr. Young confirmed that was correct. Please refer to page 59 lines 18 through 24 for details.

MC-30 Commissioner Pinkerton referred to the repowering of the Intermountain Power Plant and the transition to more gas, and Mr. Young confirmed that IPP will be repowered by 2025, at which time there will be hydrogen and gas usage, and no coal. Please refer to page 59 line 25, page 60 lines 1 through 25, and page 61 line 1 for details.

MC-31 Commissioner Pinkerton stated his concern about not using local resources, and being wedded to natural gas, and stated she would like to see the funding for School Canyon used for PV and other renewables. In response, Mr. Young

[131] The Sunrun Virtual Power Plant at full buildout would consists of up to 37 MW of rooftop solar PV coupled with up to 25.25 MW/50.5 MWH battery energy storage system. The energy from the solar PV system would be used to charge the batteries. Any excess solar PV power after the batteries are charged would be fed back onto the grid and provided to GWP.

confirmed that IPP will be transitioning to 100 percent hydrogen. Please refer to page 61 lines 2 through 20 for details and MC-27, above.

MC - Response to Comments received from Vice Chairperson Werner during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-32 Vice Chair Werner asked if the possible influx of all-electric buildings was taken into account, and Mr. Young responded addressing both electric vehicles and buildings and some informal rules of thumb. The Integrated Resource Plan did take electric vehicles into account. Please refer to page 62 lines 1 through 22 for details.

MC-33 Vice Chair Werner asked about visual impacts, and this comment was partially addressed during the meeting on September 9, 2021. Please refer to page 62 lines 24 through 25 and page 63 lines 1 through 15 for details. There are trees on the south end next to the Verdugo Wash. However, on the east and west sides, the site extends up to the railroad and roadway respectively, leaving very little clearance for trees while still maintaining safe working clearances.

MC - Response to Comments received from Commissioner Khanjian during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-34 Commissioner Khanjian asked about construction timelines and whether they vary between Alternative 7 and Alternative 8, and Mr. Tateosian discussed the timelines and stated they were similar. Please refer to page 63 lines 23 through 25 and page 64 lines 1 through 15 for details.

MC - Response to Comments received from Chairperson Bartrosouf during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-35 Chair Bartrosouf asked if the timeline provided was for both alternatives 7 and 8, and Mr. Tateosian confirmed that was correct. Please refer to page 64 lines 18 through 24 for details.

MC - Response to Comments received from Commissioner Kartounian during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-36 Commissioner Kartounian asked how much thermal generation would be needed beyond 2045, and whether Unit 9 might become an orphaned asset. Mr. Young responded that the expectation is that load will expand, that GWP will be looking for renewable gas, either renewable natural gas or hydrogen, so the unit would continue to be viable, and that the unit is not expected to become a stranded asset. Please refer to page 65 lines 7 through 23 for details.

MC-37 Commissioner Kartounian asked how much thermal generation would be needed after 2045, and Mr. Young stated that twenty years from now was far away. In addition to this response given at the meeting, given Glendale's reliance on limited transmission and imported power, having some form of local, dispatchable generation would be prudent and necessary for reliability purposes. Thermal generation fueled with green hydrogen would be an optimum solution as it would be a fully dispatchable, offer high energy density (requiring less space than alternatives) and carbon free (green hydrogen fueled) local resource. Please refer to Topical Response No. 1.

MC-38 Commissioner Kartounian asked about cancer risk associated with Alternatives 7 and 8, noting that 8 had a lower cancer risk, even though its CO2 emissions are higher than Alternative 7. Mr. Tateosian responded that the differences were due to dispersion and the efficiency of the equipment, and Mr. Tateosian noted that the risk numbers for both alternatives were very low. Please refer to page 66 lines 8 through 25, page 67 lines 1 through 25, and page 68 lines 1 through 2 for the full response.

MC - Response to Comments received from Chairperson Bartrosouf during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-39 Chair Bartrosouf asked whether the additional 73 megawatts coming into the City by 2027 made a difference in the EIR calculations. Mr. Tateosian responded that the 72 megawatts was not available with the original project proposal, but with the reduction in the proposed Project, 72 megawatts of transmission became available Please refer to page 68 lines 13 through 25 and page 69 lines 1 through 14 for details. Also, please refer to the tables in Topical Response Nos. 1 and 8 .

MC-40 Chair Bartrosouf asked whether another 25 megawatts becoming available in 2024 was factored into calculations. Mr. Tateosian and Mr. Young both responded, clarifying that the 25 megawatts reflects new imported energy from the Eland project that will displace thermal energy. For the full response, please refer to page 69 lines 17 through 25 and page 70 lines 1 through 21. Also, please refer to Topical Response Nos. 1 and 8 .

MC-41 Chair Bartrosouf asked whether the additional capacity would change the calculations about the ability to recharge batteries. In response, Mr. Tateosian explained how the additional transmission capacity contributes to battery storage. Please refer to page 70 lines 23 through 25, page 71 lines 1 through 25, and page 72 lines 1 through 6 for details as well as Topical Response No. 8.

MC-42 Chair Bartrosouf asked about the use of hydrogen in Alternative 8, and whether RICE units and the refurbished units can use hydrogen. Mr. Tateosian responded that the units currently can operate with a mix of natural gas and hydrogen, and the goal is that they will be able to operate with 100 percent hydrogen. Please refer to page 72 lines 9 through 25, page 73 lines 1 through 8, page 74 lines 16 through 25, and page 75 lines 1 through 4 for details, as well as Response to L5.

MC-43 Chair Bartrosouf asked if the units are being purchased with an understanding they can run on 100 percent hydrogen, and Mr. Tateosian responded that they cannot do that yet, but that is their goal. Please refer to page 73 lines 9 through 18, lines 23 through 25, and page 74 lines 1 through 12 for details, as well as Response to L5.

MC-44 This comment is a continuation of the comment and response set forth in MC-43 above.

MC-45 Chair Bartrosouf asked about the low-use exemption for carbon dioxide emissions. Mr. Lany[132] of Montrose Environmental Group responded that the low-use exemption is very stringent, and would apply to older unit emissions, not the emissions from the new compliant units. The SCAQMD Ruel 1135, as amended, also allows gas turbines and boilers installed prior to November 2, 2018, to take a low-use exemption and therefore not be subject to the rule's new emission limits. To qualify for the exemption, gas turbines and boilers must:

- Maintain an annual capacity factor of less than twenty-five percent for gas turbines, each calendar year
- Maintain an annual capacity factor of less than two-and-one-half percent for boilers, each calendar year
- Maintain an annual capacity factor of less than ten percent for gas turbines averaged over three consecutive calendar years on a rolling basis
- Maintain an annual capacity factor of less than one percent averaged over three consecutive calendar years on a rolling basis
- Retain the NOx and ammonia limits, averaging times, and startup, shutdown, and, if applicable, tuning requirements specified in the SCAQMD Permit to Operate as of November 2, 2018.

If a low-use exempted gas turbine or boiler exceeds the annual or three year average annual capacity factor limits, the owner/operator is subject to:

1) a notice of violation each year there is an exceedance, and

[132] The transcript misspells the speaker's name as "Laney" instead of "Lany."

2) shall submit within six months of the reported exceedance complete permit applications to repower, retrofit, or retire the subject gas turbine or boiler;

3) submit a continuous emissions monitoring (CEMS) Plan within six months from the date of complete permit application submittal; and,

4) not operate the subject gas turbine or boiler in a manner that exceeds the rule's emission compliance limits after two years of the reported exceedance.

GWP chose not to pursue the low use exemption path because the long start-up times of the boilers in particular (~36-48 hours), and the existing Unit 8A and 8BC gas turbines to a lesser extent (~6 hours), would result in significant operating hours for the units to startup and remain in standby mode so they could be able to react quickly. Those hours would consume a substantial portion of the allowed ten percent (876 hours) and one percent (87 hours) 3 year rolling average capacity factor limits. This approach would also not do anything to mitigate the age of the units or ensure Grayson being a reliable resource to ensure reliability. Lastly, retaining the existing units precludes the addition of the battery energy storage system at Grayson.

MC-46 Chair Bartrosouf asked if the older units could be used at ten percent under the low use exemption, and Mr. Lany confirmed that is correct, if a turbine is useful to the City at that level. Please refer to the response to MC-45.

MC-47 Chair Bartrosouf asked what the difference was between operation of old units at 10 per cent versus new units at 15 per cent. Mr. Lany responded that emissions from newer units at 15 per cent should be lower in terms of criteria pollutant and NOx emissions. Mr. Tateosian added that startup time makes a difference also. Due to the lengthy startup time of the boilers and Units 8A and 8BC combined cycle units, the truly available capacity is diminished. A startup of the boilers from a cold condition takes 36-48 hours and power production only begins during the second day after steam lines and the steam turbine have been warmed. A startup of Units 8A and 8BC from cold conditions takes about 6 hours with power production from the gas turbines beginning quickly at low levels, and from the steam turbine at the end of the process after the steam lines and turbine have been warmed. These startup hours consume fuel and create emissions that count against the air permit limits. With Alternative 7, the Wartsila engines can start and achieve full load within 10 minutes. With Alternative 8, Unit 8A will also be able to start and achieve full load within 10 minutes. Unit 8BC gas turbine will also be able to start and reach full load within 10 minutes, with the steam turbine following within a couple of hours. These faster startups allow the units to reach full load more quickly, which results in the emissions control systems warming up more quickly, and allowing the units to reach the operating emissions levels more quickly reducing overall emissions. Please refer to page 76 lines 10 through 25 and page 77 lines 1 through 22 for the full response.

MC-48 Chair Bartrosouf asked for more information about the 15 per cent utilization, and whether it factored in the various different programs being deployed by the City. In response, Mr. Tateosian explained the calculations were done for the EIR analysis and reflected in the air permits. Please refer to Topical Response No.s 1 and 8 R-DEIR..

MC-49 Please refer to the response to MC-48.

MC-50 Chair Bartrosouf questioned a comment by Mr. Young that the system may use less, and Mr. Young confirmed that this could occur for example during a cool summer. Please refer to page 79 lines 12 through 25 for details.

MC-51 Chair Bartrosouf asked whether the project could be phased in with fewer than five units. Mr. Tateosian responded that the number of units is driven by the power need. The number of units needed driven by the gap between forecasted demand and the power available from other resources. As shown in the hourly modeling included in Topical Response No. 8, there is a shortfall of about 155 MW in 2027. Subtracting 75 MW from the proposed battery energy storage system, leaves an 80 MW gap. Five units are needed to cover an 80 MW shortfall. The amount of energy that is needed over the course of a year drives the operating profile (starts, hours).

MC-52 Chair Bartrosouf asked whether the 72 megawatts was factored in post-IRP. In response, Mr. Young and Mr. Tateosian confirmed the 72 megawatts was not factored into the IRP analysis but was factored into the modeling for the EIR. (See page 81 lines 21 through 25 and page 82 lines 1 through 4). As additional information, 35 MW of IPP generation was factored into the 2019 IRP. The 2019 IRP discussed the possibility of an additional 50 MW from the IPP repower (see pages 18 and 109 of the 2019 IRP). The 50 MW amount was based on the original size of the IPP repower, 1200 MW. When the IPP repower size was reduced to 840 MW, Glendale's percentage share remained the same, but our megawatt share of the project was reduced to 35 MW. The 100 percent Clean by 2030 Study factored in the 72 MW of additional STS transmission.

MC-53 Chair Bartrosouf asked whether the 25 MW Eland project was also factored into the IRP or the EIR. Mr. Young responded that it was not factored into the IRP, because the Eland contract was recently entered into and the IRP was two years ago. Please refer to page 82 lines 9 through 17 for details; please refer also to response MC-54.

MC-54 Chair Bartrosouf asked whether the 25 MW Eland project was reflected in the EIR. Mr. Tateosian responded that it was, implicitly. Eland provides energy and is not generation that is dispatched by GWP. It is dispatched by LADWP and GWP takes it as received. Please refer to Topical Response Nos. 1 and 8.

MC-55 Chair Bartrosouf stated that we are getting the same amount of power, but from different sources, and Mr. Tateosian confirmed this was correct. Please refer to page 83 lines 10 through 17 for details. In addition, GWP has 200 MW of transmission capacity that it can use to contract for imported energy. This will grow by 72 MW in 2027. When the Eland project comes online in 2024, Glendale's share of the Eland output, 25 MW, will be transported by LADWP on LADWP's transmission lines when Eland is producing electricity. As such this transmission capacity acts like local generation because GWP has no rights to use that transport capacity to import any other imported generation sources. See Topical Response No. 1.

MC-56 Chair Bartrosouf referred to the LA 100 study and asked why isn't Glendale starting with a study of getting to 100 per cent renewable and working backward from there; instead Glendale is considering heavy investment in two natural gas plants. During some back and forth follow up discussion, Mr. Young noted that the Scholl Canyon project is a renewable gas project, not a natural gas project. (See page 85, lines 2 to 25). Also, the 100 percent Clean Energy study showed that GWP is able to achieve 89 percent clean energy by 2030. To green the last 11 percent, each percent increase will be more expensive. Topical Response No. 8 provides some indication of how large (and expensive) an energy storage solution would be. Thermal generation fueled by renewable natural gas or green hydrogen can be a more cost-effective approach. Please also refer to Topical Response 5.

MC - Response to Comments received from Stephanie McGreevy during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-57 Ms. McGreevy criticized the Wartsila engines and stated that cleaner technologies exist. The Wartsila engines meet current SCAQMD emissions requirements. Please refer to the PR-DEIR and Topical Response No. 4 for further discussion of how the Wartsila engines perform.

MC-58 Ms. McGreevy advocated the use of renewable natural gas. The proposed Project, Alternative 7, and Alternative 8 can all operate on renewable natural gas. As discussed in the response to Public Comment L5-1, there is also a path to burn hydrogen as well.

MC-59 Ms. McGreevy noted the fire risk associated with lithium ion batteries, and advocated other battery technologies. The Victoria Big Battery fire that occurred in Australia involving a Tesla Megapack was the first fire of a Tesla Megapack stationary battery other than for testing and qualification purposes. The Victoria Big Battery fire was discussed in Section 5.2.6.1 of the PR-DEIR and the relevant portions are included here.

> "As the PR-DEIR was being finalized for release, information became available regarding a fire incident on Friday July 30, 2021, in which a Tesla Megapack caught fire during testing at the Victorian Big Battery Project in Victoria, Australia. Following the incident, visible flames had subsided by approximately 5.5 hours later and the Country Fire Association (CFA) with assistance from Fire Rescue Victoria have remained on site to continue to monitor the temperature decline of the two battery packs impacted by the fire. The EPA's air monitoring has shown there has been good air quality in the local community. There were no injuries, the site was disconnected from the grid and there has been no impact to electricity supply. Investigation preparations are underway and physical inspections will commence once the CFA have completed their procedures. This is the first Megapack fire that has occurred other than those started artificially for testing purposes.
>
> "Tesla is still in the process of investigating what occurred, what actions need to be taken to prevent reoccurrence, and whether any changes may be needed to avoid or combat a Megapack fire. Installation of the battery energy storage system at Grayson is not anticipated to begin until the first quarter of 2023. If the results of the investigation into the Tesla fire find that changes in design, testing, or other factors impact the technical studies supporting the PR-DEIR, they will be re-assessed to determine whether any changes in the conclusions of the PR-DEIR are warranted."

Tesla now has over 1,000 Megapacks in operation and has over 10,000 MWH of energy storage products safely operating in over 50 countries for the past 8 years prior to the fire in Victoria. While there was a large fire response at VBB, other than spraying water on the surrounding Megapacks and neighboring equipment, the fire was allowed to burn itself out as per Tesla's recommended guidelines in its Emergency Response Guide, publicly available on the Tesla website. The cause of the fire was due to a series of highly unlikely events and a procedural mistake in the commissioning procedure, all of which have been addressed and mitigated at VBB and the rest of Tesla's Megapack project fleet to further reduce the likelihood of a similar type of event to occur again.

A Megapack fire was an event analyzed within the PD-DEIR and the offsite releases were all below acceptable limits. The analysis and results are discussed in Section 5.2.6.2 of the PR-DEIR and are summarized in Table 5-6 on pages 5.50 and 5.51.

Tesla has continued to advance their technology since GWP's interaction began with Tesla through the Clean Energy RFP in 2018. The original Megapack design proposed for Grayson utilized Li-ion Nickel-Manganese-Cobalt (NMC) battery chemistry. Through the current contract negotiations with Tesla, they are offering their new Megapack 2 design that utilizes Lithium-Iron-Phosphate (LFP) technology which is more resistant to thermal runaway further reducing the fire risk. This technology is currently under development. As is the case with Tesla, many battery system vendors are moving from Lithium Nickel Manganese Cobalt Oxide (NMC) to Lithium Iron Phosphate (LFP) battery chemistry to further enhance fire resistance of Li-ion batteries.

MC-60 Ms. McGreevy concluded by stating that these alternate technologies are commercially available. Please refer to the responses to MC-57, 58, and 59.

MC - Response to Comments received from David Dennick during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-61 Mr. Dennick stated that Glendale should prioritize clean energy. Please refer to Topical Response Nos. 5 and 8.

MC - Response to Comments received from Roberta Medford during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-62 Ms. Medford criticized the City and GWP for proposing more fossil fuel spending and doing very little to promote clean energy.

As indicated in GWP's PowerEnergy Content Label[133] for 2020, the most recent reporting year, the City achieved 64.2 percent clean energy. Glendale's current clean energy resources include: the High Winds Project (wind), the Pleasant Valley project (wind), the Pebble Springs project (wind), Tieton (small hydroelectric), the Star Peak project (geothermal), the Whitegrass project (Geothermal, Eland 1 (solar and storage), Townsite Renewables (various renewable sources.), Hoover, and Palo Verde. Please also refer to Topical Response Nos. 5 and 8.

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[133] https://www.glendaleca.gov/government/departments/glendale-water-and-power/about-us/power-content-label

MC - Response to Comments received from Kate Unger during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-63 Ms. Unger stated that no new fossil fuel energy should be approved and advocated clean energy. Please refer to Topical Response No. 5.

MC-64 Ms. Unger criticized the analysis of alternatives and stated that cost information was needed. Please refer to Topical Response Nos. 2, 6 and 7.

MC - Response to Comments received from Burt Culver[134] during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-65 Mr. Culver asked why the Wartsila 50DS, which uses gas and biodiesel, was not studied.

Wartsila proposed the 18V50SG engine for the Grayson repowering. This engine is a spark ignited engine similar to the engine in a car. Wartsila has demonstrated on two prior projects – Port Westward and Denton – that the 18V50SG engine with the "West Coast" exhaust emissions equipment package can meet SCAQMD air emissions requirements while still being able to start quickly and accept load changes.

The Wartsila engines that burn biodiesel are compression ignition engines (such as the 18V50DF), the same as a diesel engine. As they do not have a spark plug, they inject a small amount of diesel or biodiesel as a pilot fuel (about 1 percent after startup) which ignites at the end of the compression stroke and in turn ignites the natural gas air-fuel mixture. When running on only biodiesel, it operates like a diesel engine. Wartsila has stated that the 18V50DF cannot meet the SCAQMD Rule 1110.20.07 LB/MWH NOx standard.

MC-66 Mr. Culver asked why new transmission lines were not studied. Please refer to Topical Response Nos. 1, 5, and 6.

MC-67 Mr. Culver referred to the City of Los Angeles' 100 percent renewable goal, suggesting they may be proposing new transmission lines that Glendale could also use. Please see Topical Response No. 1 regarding GWP's efforts to obtain more transmission capacity. As to clean energy goals, please refer to Topical Response No. 5.

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[134] The transcript misspells the commenter's name as "Culbert" instead of "Culver."

MC-68 Mr. Culver advocated vanadium battery technology instead of lithium. Vanadium is typically used in flow batteries. None of the proposals received in response to the Clean Energy RFP utilized flow battery technology.

MC-69 The commenter suggests that converting the existing AC (alternating current) transmission lines into DC (direct current) transmission lines like the Pacific DC Intertie might allow more power to be imported into Glendale.

Converting transmission lines outside of Airway is not feasible because LADWP owns and operates the transmission lines connecting to Airway (Sylmar – Airway and Victorville/ Adelanto – Airway). Setting aside physical constraints (such as the space needed for converter stations, and the impact on LADWP's distribution system) and the cost, Glendale does not have the ability to convert those lines to DC transmission lines.

MC-70 Mr. Culver stated that no new gas should be approved. The commenter's statement on the merits of the project is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

MC-71 Mr. Culver stated that hydrogen would reduce maximum peak power and asked if this had been considered. Yes, it is recognized when one switches from 100 percent natural gas to 100 percent hydrogen that there will be some loss of power output due to the lower volumetric energy density of hydrogen as compared to natural gas. Please also refer to Individual Response to L5.

MC-72 Mr. Culver asked why the Kellogg switching station was added to the Project. The Kellogg Switching Station is an existing asset that was modernized in 2002 and is not part of this project.

MC-73 Mr. Culver asked why the Scholl Canyon project was considered separately. Please refer to 2018 FEIR Topical Response No. 11 and Individual Response L21-82.

MC - Response to Comments received from Cat Tilardi during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-74 Ms. Tilardi expressed concern about the severity of air quality issues. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. On air quality impacts and analysis, please refer to Topical Response No. 4.

MC - Response to Comments received from Monica Campagna during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-75 Ms. Campagna recommended that the Commissioners reject the project and support less gas and 100 percent clean energy. On these issues, please refer to Topical Response Nos. 1, 5, and 8. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

MC - Response to Comments received from Elise Kalfayan during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-76 Ms. Kalfayan spoke of the emergency nature of the climate crisis and stated that this project is not enough to reduce emissions. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. Please see Topical Response No. 4.

MC-77 Ms. Kalfayan asked why Glendale is not committing to 100 percent clean energy. Please refer to Topical Response Nos. 1 and 5.

MC-78 Ms. Kalfayan stated that air quality was a huge issue to sensitive receptors near the project. Please refer to Topical Response No. 4.

MC-79 Ms. Kalfayan stated that Glendale is not doing enough to pursue clean energy. Please refer to Topical Response Nos. 5 and 8.

MC-80 Ms. Kalfayan stated that the project should be rejected in favor of a project with more local solar with storage. This comment is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

MC - Response to Comments received from David Eisenberg during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-81 Mr. Eisenberg asked for an explanation of the 15 per cent capacity utilization, suggesting that it led to a substantial understatement of actual emissions and impacts. In response, the operating hours were stated in the PR-DEIR and not the 15 percent capacity factor number, so there is not a specific page number to provided. The capacity factor is calculated by dividing the actual energy produced in a year (8,760 hours) by the maximum possible amount of energy produced in a year. Thus, the expected capacity factor for Alternative 7, assuming all operating hours are full power operating hours, is (1,120 hours x 93 MW (all five units))/ (8,760 hours x 93 MW (plant capacity)) = 12.8 percent. For Alternative 8, the expected capacity factor is (1,200 hours x 27 MW (Unit 8A) + 1,200 hours x 74 MW (Unit 8BC))/(8,760 hours x 101 MW (plant capacity)) = 13.7

percent. Note that in both cases, the air permit limits on the number of starts, fuel usage, and mass emissions are what limits plant operations. This is also discussed in Topical Response No. 4.

MC - Response to Comments received from Francesca Smith during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-82 Ms. Smith criticizes the EIR analysis of historic resources. Most of the issues raised in this comment are addressed in Topical Response Nos. 3 and 7. Ms. Smith criticizes the use of the term "presumptive historical resource," arguing that this term is intended to lead nonprofessionals to believe the significance is in doubt. This comment is incorrect, the EIR treats the power plant as a discretionary historic resource, and mandatory, presumptive, and discretionary historic resources are categories based on the specific wording of the CEQA Guidelines on historic resources, Guideline 15064.5(a)(1), (2), and (3). Notably Guideline 15064.5(a)(2) refers to resources as "presumed to be" historically significant.

MC-83 Ms. Smith states that analysis of additional alternatives is required. Please refer to Topical Response Nos. 3, 6 and 7.

MC-84 Ms. Smith states that meetings are not fully described. Please refer to Topical Response No. 3.

MC-85 Ms. Smith states that the EIR should have considered adaptive reuse of the power plant. Please refer to Topical Response No. 3.

MC-86 Ms. Smith criticized the EIR analysis of alternatives and cumulative impacts. Please refer to Topical Response No. 3.

MC - Response to Comments received from Diana Matsushima during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-87 Ms. Matsushita stated the EIR should be rejected in favor of evaluating more solar generation and storage. Please refer to Topical Response Nos. 5 and 8.

MC - Response to Comments received from Commissioner Kedikian during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-88 Commissioner Kedikian asked if a decision had been made regarding the type or chemical composition of the batteries to be used, noting that the lithium phosphate battery seems more reliable. Mr. Tateosian responded that the project would probably use the lithium phosphate battery.

Tesla has continued to advance their technology and if a project with Tesla battery energy storage is approved, will be offering GWP with their Megapack2, the next generation of the Megapack instead of the originally-proposed Megapack. The original Megapack design proposed for Grayson utilized Li-ion Nickel-Manganese-Cobalt (NMC) battery chemistry. The Megapack 2 design that utilizes Lithium-Iron-Phosphate (LFP) technology which is more resistant to thermal runaway further reducing the fire risk.[135]

MC - Response to Comments received from Vice Chairperson Werner during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-89 Vice Chair Werner commented that it was difficult to find the Peak Savings program on the GWP website and information on which thermostats are eligible, and asked when the commenter's thermostat brand, Honeywell, would be eligible for participation in the program. Mr. Young responded at the meeting, noting that getting additional thermostats into the program was a priority and they were focusing on the most widespread thermostat brands first. Please refer to page 113 line 25, page 114 lines 1 through 25, and page 115 lines 1 through 16 for details.

In addition, with regard to the website, customers can find information and sign up for the program at the program website: http://www.GWPpeaksavings.com. Alternatively, the Peak Savings Program can be found from the GWP website in two ways:

- First, one can go to the GWP home page, scroll down, and click on the "For Your Home" link under the "Programs & Services" section. The Peak Savings Program is the first program that appears.
- Second, when on the GWP home page, one can scroll to the "Highlights" section and scroll to the second slide, and click on the "Peak Savings Program" link or image.

GWP will be working with the Information Services Department to make this and other programs more easily accessible from the GWP website. With regard to the thermostats that are eligible for the program, the program's approach is to support all thermostats with the highest market penetration. Nest and Ecobee thermostats are currently compatible and integrated with the Peak Savings Program. The following thermostat brands are on track to be integrated and supported by the Peaks Saving Program in the first quarter of 2022: Honeywell, Emerson, Energate, and Carrier. In addition, the Energate and Carrier thermostats

135 Soltaro - The Advantages & Disadvantages of chemistry. NMC vs LFP

are offered through GWP's CEIVA In-Home Display/ Thermostat Program. If a customer does not see their thermostat brand listed on the Program's website the customer may sign up to get notified when their thermostat will be supported. The list of upcoming, supported thermostats is listed on the website.

MC-90 Vice Chair Werner asked how a customer would find out when their thermostat will be supported by the Peak Savings program. Mr. Young responded that he would check the website and make sure the information is as easy to find as possible, and that he would respond on when the Honeywell thermostat would be eligible. See page 115 lines 17 through 25 and page 116 lines 1 through 4 for details. In addition, see response to comment MC-89, immediately above.

MC - Response to Comments received from Commissioner Pinkerton during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-91 Mr. Pinkerton asked about the 15 per cent utilization rate issue raised by one of the commenters and asked that someone respond with a specific page number. Mr. Young responded this would be an action item.

In response, see response to MC-81.

MC - Response to Comments received from Chairperson Bartrosouf during the *Special Meeting of Glendale Water & Power Commission*, held on September 9, 2021

MC-92 Chair Bartrosouf asked if the 25 megawatts from Eland was included as part of this analysis, and Mr. Young confirmed that was correct. Please refer to page 117 lines 7 through 19 for details and Topical Response No. 1.

MC-93 Chair Bartrosouf asked if we knew the costs associated with moving to hydrogen or a hydrogen mix, and if those costs were incorporated into the analysis. Mr. Young said they were not incorporated, but the project would purchase the most advanced technology available and changing to add hydrogen would involve things like changing nozzles or changing the firing mechanism. Please refer to page 117 lines 20 through 25 and page 118 lines 1 through 11 for details and Individual Response to L5.

MC-94 Chair Bartrosouf asked about the cost of alternatives. Mr. Young stated it was a goal to provide the best numbers to the Council and Commissioners before the decision is made on alternatives. Please refer to page 118 lines 12 through 25 and page 119 line 1, and please also refer to Topical Response No. 2.

MC-95 Chair Bartrosouf asked about maximizing the various elements of the Clean Energy RFP to further reduce the megawatts needed from the project. Mr. Young stated that the City was doing as much as it could, and that the City worked very hard to get down to 93 megawatts. Please refer to page 119 lines 2 through 25, page 120 lines 1 through 25, and page 121 lines 1 through 22 for the full response.

MC-96 Chair Bartrosouf asked how commercial properties play into this analysis. Mr. Young responded that initiating commercial use had been slower, noting the pandemic, and noted that Sunrun is starting to penetrate commercial multifamily uses. Please refer to page 121 lines 23 through 25 and page 122 lines 1 through 22 for details.

7.4 INDIVIDUAL RESPONSES TO COMMENTS

L1 - Responses to Comments from Larry Moorehouse, received September 13, 2021

L1-1 This is a general statement stating that the commenter has submitted two separate letters with questions and ideas about the Project. The commenter actually submitted several comment letters, and responses have been prepared to all of those letters. See Individual Responses to L27, L28, L30 through L33, and L35.

L2 - Responses to Comments from Jennifer Pinkerton, received September 28, 2021

L2-1 A permit has not yet been issued by the South Coast Air Quality Management District (SCAQMD) for the proposed Project or a project alternative. SCAQMD will not issue an air permit unless and until the 2022 Final EIR is certified and a project or project alternative is selected.

The air permit applications for Alternative 7 is contained in the PR-DEIR in Appendix C. The air permit application for Alternative 8 is attached to Topical Response No. 4. The air permit application for the proposed Project has been rendered inactive at the request of SCAQMD pending future consideration by the City Council of the proposed Project and Project Alternatives. The air permit for the proposed Project can be resubmitted at any time for SCAQMD's consideration.

PR-DEIR Appendix C-1 Section C.1 addresses air permitting for Alternative 7. Tables B-4 and B-5 (pages 483 and 484 of the PDF file) within PR-DEIR Appendix C-1 provide the starts, hours, and fuel use limits.

PR-DEIR Appendix C-1 Section C.2 contains the information for Alternative 8. The table on page 597 of the PDF file contains the starts and operating hours in the lower left corner. The maximum annual fuel use is not stated but it can be calculated from the stated heat input value of 350 MMBTU/turbine multiplied by the turbine operating hours of 1,200 hours per year. In that Alternative 8 there are three turbines (8A, 8BC) and the maximum fuel use is 350 x1200 x 3 = 1,260,000 MMBTU.

Within each application there is a SCAQMD Form 400-E-5 Section C - Operating Information (there is one for each engine and turbine emissions control system) The forms provide, along with other data, the window of time, i.e., all year, within which the engines/turbines may operate up to the maximum number of hours and starts that are stated elsewhere in the application. So, for example, one of the Wartsila engines may operate during any of the 8,760 hours in a year as long as it stays within its air permit limits.

The air permits that will be issued by SCAQMD would reflect the operating limits – starts, fuel usage, and mass emissions contained within the applications and the emission profile calculations contained in PR-DEIR Appendix C-1. In addition to the applications, on October 13, 2021, the City also supplied SCAQMD with supporting data engineering files.

L3 - Responses to Comments from Calin Ursea, received October 1, 2021

L3-1 The comment is a general statement expressing the commenter's pinion on (or preference about) the Project. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L4 - Responses to Comments from Emily Griffin, received October 3, 2021

L4-1 The comment is a general statement about the commenter's opinion of (or preference about) the Project. The comment expresses support for Alternative 7 and does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L5 - Responses to Comments from Vahan Barseghian, received October 4, 2021

L5-1 The proposed Project, Alternative 7, and Alternative 8 all have the capability to operate using renewable natural gas with no modifications. The use of hydrogen is a potential pathway for GWP to reduce the carbon footprint from thermal generation in the future.

The use of hydrogen is similar to the plan presented by NREL in Los Angeles' LA100 Renewable Study (LA100). In the LA100 study, LADWP will continue to rely on significant amounts (approximately 2,600 MW) of in-basin thermal generation for reliability purposes. The LA100 study relies on retrofits or repowers of these in-basin facilities with combustion turbines fueled by renewable fuel such as green hydrogen[136]. (See Topical Response No. 5).

Both Alternatives 7 and 8, as well as the proposed Project, have upgrade paths that would allow the use of hydrogen when it becomes available for use at the power plant. For Alternative 7, the Wartsila engines would have the ability to run on a mix of 30 percent hydrogen and 70 percent natural gas with minor modification. Wartsila is further developing their technology to allow the engines to run on 100 percent hydrogen by 2025. Thus, once a hydrogen supply becomes available, the Wartsila engines could be modified to operate on 100 percent green hydrogen.

Alternative 8 relies on continued operation of the existing Unit 8A and 8BC FT4 gas turbines. Due to the vintage of the FT4 model gas turbine, there is no work underway to explore the capability to operate on hydrogen. However, work is underway to develop that capability for the next generation of the FT4 gas turbine, the FT8® gas turbine. The FT8® gas turbine has been in operation for over 20 years and continues to be available to customers. Mitsubishi[137] is further developing its FT8® gas turbine to run on 30 percent hydrogen by 2025 and 100 percent hydrogen by 2035. The FT8® gas turbine is physically smaller than the FT4 and thus, once a hydrogen supply becomes available at Grayson, the FT8® gas turbine could be retrofitted into the existing FT4 enclosures.

The proposed Project utilizes Siemens gas turbines. Siemens is also enhancing their turbines' ability to burn high concentrations of hydrogen. For example, the Siemens SGT-800, the turbine used for the combined cycle units, is currently capable of operating on a 75 percent hydrogen/25 percent natural gas mixture on a volume basis.

With some upgrades, the existing Unit 9 (a General Electric LM6000[138] PC SPRINT gas turbine which is not being replaced) also has the capability to operate on a

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136 Brown, grey, blue, and green are used to denote the carbon footprint of the source of hydrogen. Brown hydrogen is the most carbon intensive and is produced from coal gasification. Grey hydrogen is produced from natural gas. Blue hydrogen is produced from fossil fuels with carbon capture. Green hydrogen is produced using carbon free energy. GWP will be endeavoring to procure green hydrogen to the maximum extent possible.

137 Mitsubishi Power Aero is the current owner of the power generation FT8® gas turbine product line. The FT4 and FT8® aero-derivative gas turbines for power generation applications were derived by Pratt & Whitney from their J75/JT4 and JT8D gas turbines for aircraft applications respectively.

138 General Electric's LM6000 is also an aero-derivative gas turbine developed for power generation applications from General Electric's CF6-80C2 gas turbine for aircraft applications.

mixture of 35 percent hydrogen/65 percent natural gas. General Electric is also developing the technology to increase the hydrogen capability of the LM6000.

In all cases there would be some loss of power when operating on high concentrations of hydrogen as it is a less energy dense fuel volumetrically as compared to natural gas.

GWP is dependent on a supply of hydrogen being delivered via a pipeline. Currently GWP does not have an expected timeframe for when a pipeline supply of hydrogen will become available.

Local production of hydrogen would require a source of water to produce hydrogen through electrolysis, which involves breaking water down into its hydrogen and oxygen constituents. While there are environmental considerations in doing so, using recycled water from the Los Angeles-Glendale Water Reclamation Plant is a potential source, which water source would be subject to other uses and demand. Electrolysis also requires electricity to break down the water which would further increase the electrical load that GWP must have to serve the residents of Glendale.

Additionally, because GWP would only operate thermal generation when needed, the hydrogen would need to be stored locally until it is needed. Storing hydrogen, or hydrogen in the form of ammonia, at Grayson, or anywhere in Glendale, requires storage space. Obtaining sufficient space for storage presents an additional challenge given the dense urban environment. For these reasons, GWP believes it is prudent to wait for a pipeline supply of hydrogen to become available.

L6 - Responses to Comments from Alin Lin on behalf of State of California Department of Transportation (Caltrans), received October 6, 2021

L6-1 This is a general statement regarding the commenter's letter found in the pages below. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L6-2 This is a general statement summarizing the scope of the Project and content of the PR-DEIR. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L6-3 The comment states Vehicle Miles Traveled (VMT) should be the standard transportation analysis metric in CEQA for land use projects after July 1, 2020. Baseline conditions for evaluating a project's potential environmental impacts pursuant to CEQA are established at the time of Notice of Preparation issuance. The Notice of Preparation (NOP) for the proposed Project was issued in December 2016, prior to the state requirement to evaluate VMT and prior to the City's adoption of a VMT standard. Further, the intent of the PR-DEIR was to evaluate additional alternatives that could reduce environmental impacts of the proposed Project rather than re-evaluate the proposed Project's impacts. Section 5 of the PR-DEIR includes a discussion that demonstrates the proposed Project, Alternative 7, and Alternative 8 would have similar construction scenarios and result in similar vehicle trips. Operation of the proposed Project, Alternative 7, and Alternative 8 would have similar personnel and operation/ maintenance requirements and result in similar vehicle trips. The PR-DEIR therefore accurately concludes that the proposed Project, Alternative 7, and Alternative 8 would have similar potential transportation impacts regardless of the level of service or VMT criteria applied.

L6-4 This is a general statement identifying a contact point for the commenter. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L6A - Responses to Comments Caltrans, received October 23, 2017, submitted with the 2018 FEIR

Please refer to Individual Response L44- Response to Comments from Miya Edmonson, dated October 23, 2017, in the 2018 FEIR.

L7 - Responses to Comments from Colin Fleming, received October 6, 2021

L7-1 The commenter expresses opposition to the repowering and encourages GWP to exclusively pursue renewable energy systems. A 100 percent clean energy alternative was analyzed in the 2018 FEIR as Alternative No. 3. This alternative would not meet the project objectives because there is insufficient land available within Glendale for utility scale renewable energy production, and additional imported renewable energy is dependent on new transmission capacity. Please see Topical Response No. 1, regarding the infeasibility of building new transmission. GWP is working towards a 100 percent clean energy supply and in 2020, 64 percent of the supplied energy came from carbon-free sources. This is addressed in detail in Topical Response No. 5. The need for Grayson until such time that GWP can achieve 100 percent clean is addressed in Topical Response No. 1.

Please also refer to Topical Response No. 5 for a description of GWP's path to 100 percent clean energy.

L8 - Responses to Comments from Henry Schlinger, received October 6, 2021

L8-1 GWP is working towards a 100 percent green energy supply. This is addressed in detail in Topical Response No. 5. The need for Grayson until such time that GWP can achieve 100 percent green is addressed in Topical Response No. 1.

Please refer to Topical Response No. 6.

L9 - Responses to Comments from Alina Mullins on behalf of South Coast Air Quality Management District (SCAQMD), received October 7, 2021

L9-1 This is a general statement summarizing the commenter's successful receipt of the PR-DEIR. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L9-2 The commenter requested an electronic copy of any live modeling and emission calculation files used to quantify air quality impacts from construction and/or operation of the Project. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L9-3 The commenter provided a submission point and contact point of the previously requested air quality analyses. The commenter expresses concern that without the requested documentation, the SCAQMD would be unable to conduct a complete review of the air quality analyses in a timely manner. GWP sent the requested files to the SCAQMD on October 13, 2021, and the SCAQMD acknowledged receipt on October 15, 2021. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L10 - Responses to Comments from Randall and Nancy Wise, received October 13, 2021

L10-1 The commenter expresses opposition to locating a repowering facility at the Scholl Canyon Landfill and recommends relocating a repowering facility at the site of the existing Grayson Power Plant. To clarify, the Grayson Repowering project and the additional alternatives analyzed in the PR-DEIR is to determine the best method to repower the Grayson power plants. The Project and Alternative 7 propose to replace Units 1 through 8 (and in the case of Alternative, to replace Units 1 through 5 and modernize and upgrade Units 8A and 8BC) with a combination of energy storage and thermal generation which together will have a combined output less than the existing units they will replace. The pipeline discussed in this comment letter was used prior to April 2018 to transport landfill gas from the Scholl Canyon landfill to Grayson. Landfill gas has not been transported to Grayson since then and the pipeline is in the process of being formally abandoned in place. The City approved the Biogas Renewable Generation Project at the Scholl Canyon Landfill in November 2021 which project will use the collected landfill gas to generate renewable power of the Scholl Canyon landfill for distribution to Glendale.

The commenter comments on the closure of the Scholl Canyon landfill. The comment does not pertain to the proposed Project nor identify a specific environmental analysis or CEQA issue relative to the Final EIR and compliance with CEQA. The commenter's statement is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L11 - Responses to Comments from Andre Sarkissian, received November 3, 2021

L11-1 This is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L11-2 GWP is working towards a 100 percent clean energy supply. This is addressed in detail in Topical Response No. 5. The need for Grayson until such time that GWP can achieve 100 percent clean energy is addressed in Topical Response No. 1. Air quality impacts of the proposed Project and Alternatives 7 and 8 are addressed in Topical Response No. 4.

L11-3 Please refer to Topical Response No. 5.

L12 - Responses to Comments from Emily Mirzakhan, received November 3, 2021

L12-1 The comments within this letter were originally submitted by Andre Sarkissian on November 3, 2021. Please refer to comment letter L11.

L13 - Responses to Comments from Melany Mirzakhan, received November 3, 2021

L13-1 The comments within this letter were originally submitted by Andre Sarkissian on November 3, 2021. Please refer to responses to comment letter L11.

L14 - Responses to Comments from Candace Hodder, received November 8, 2021

L14-1 As reflected in GWP's 2019 Integrated Resource Plan and many clean energy initiatives, clean energy programs and alternatives have been and will continue to be an integral part of GWP's energy portfolio, not a standalone option. Please refer to Topical Response Nos. 5, 6, and 8.

L14-2 A Health Risk Assessment ("HRA") was conducted for the proposed Project as part of the 2018 FEIR (See Section 4.3, page 4.3.43 through 4.3.47) and for Alternatives 7 and 8 as part of the PR-DEIR (See Tables 5-3 and 5-9). The HRA examines health impacts on people and also specifically examines potential health impacts on children. The HRA model output accounts for residential receptors, which are assumed to include children and other sensitive people that are assumed to have greater exposure to emissions (24 hours per day for 30 years). Additionally, the State of California Office of Environmental Health Hazard Assessment (OEHHA) modeling tools also account for the greater breathing rates of children, relative to adults in order to more accurately assess exposure. The HRA concluded the health risks (cancer and non-cancer) for the proposed Project, Alternative 7, and Alternative 8 are below the significance thresholds.

L14-3 See Individual Response L14-2, above, and refer to Topical Response No. 4.

L15 - Responses to Comments from David R. Diaz, received November 10, 2021

L15-1 This is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L15-2 Please refer to Topical Response No. 2.

L15-3 Please refer to Topical Response Nos. 2 and 7.

L15-4 Please refer to Topical Response No. 2.

L15-5 Please refer to Topical Response Nos. 2 and 7.

L15-6 Please refer to Topical Response No. 2.

L15-7 A refined health risk assessment ("HRA") was conducted for the proposed Project as part of the 2018 FEIR (See Section 4.3, page 4.3.43 through 4.3.47) and was updated for Alternatives 7 and 8 for the PR-DEIR (See Tables 5-4 and 5-9). The HRA examines health impacts on people and also specifically examines potential health impacts on children. The HRA model output accounts for residential receptors, which are assumed to include children and other sensitive people that are assumed to have greater exposure to emissions (24 hours a day for 30 years). Additionally, the State of California Office of Environmental Health Hazard

Assessment (OEHHA) modeling tools also account for the greater breathing rates of children, relative to adults, in order to more accurately assess exposure. The results of the assessments indicate that health risks attributed to the Project as well as the Alternatives 7 and 8 would be well below significance thresholds.

L15-8 Please refer to Topical Response No. 7.

L15-9 This is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L15-10 This comments states that an economic impact analysis is required. CEQA does not require an economic impact analysis. Information about the costs of alternatives is included in Topical Response No. 2. Please refer to Topical Response Nos. 2 and 7.

L15-11 Please refer to Individual Response L21-10.

L15-12 GWP is working towards a 100 percent clean energy supply. This is addressed in detail in Topical Response No. 5. Glendale delivered 64 percent clean energy in 2020 and can potentially reach 89 percent clean energy with approximately 80 percent renewable around the clock by 2030 using commercially available technologies.

L15-13 Please refer to Topical Response No. 7.

L15-14 The City's General Plan Elements do not expire. By statute, the general plan is required to be updated "periodically." Other than the Housing Element, there is no requirement for how often to update the general plan. The housing element is the only portion of the general plan that is on a mandated update schedule- 4, 5, or 8 years, as listed by the Housing and Community Development agency (HCD). The City is in the process of completing its update to the Housing Element as required by law. Please refer to Topical Response No. 7.

L15-15 Please refer to Topical Response No. 7.

L15-16 Please refer to Topical Responses Nos. 2 and 7.

L16 - Responses to Comments from John Schwab-Sims and Greg Grammar on behalf of The Glendale Historical Society, received November 10, 2021

L16-1 This comment is an email which references an attached letter from TGHS on the Project.

L16-2 This comment is an introductory statement concerning the propose of the letter and describing TGHS as an organization. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L16-3 This comment generally identifies problems with the PR-DEIR's discussion of historical resources which includes the alternatives analysis (see Topical Response No. 3 on Historical Resources, alleged failure to prepare an updated cultural resources technical report, alleged incomplete discussion of consultation with TGHS, alleged omission of coordination with the City's Historic Preservation Commission, and alleged flawed consideration of cumulative historical resources impacts).

L16-4 This comment states there is no alternative that would retain historical resources. The comment also poses questions related to why the Boiler Building and the Glendale Switch Yard cannot be reused, and the comment also makes statements concerning CEQA law. See Topical Response No. 3 for a comprehensive response to these comments.

L16-5 See Topical Response No. 3 for a comprehensive response to these comments which include responses to the commenter's unsupported assertions about the Lead Agency's decision to treat the Boiler Building as a discretionary resource as well as assertions concerning eligibility for listing on the California and National Registers.

L16-6 This comment quotes from TGHS's 2017 comment letter on prior DEIR, which letter was responded to in the 2018 FEIR. The comment provides characterizations of the City's discussion with TGHS in Spring and early Summer 2021, and characterizations concerning the City's response to TGHS's proposed mitigation measure that would have required the City to prepare an intensive level historic survey of all City-owned property as proposed mitigation for the demolition of the Boiler Building. See Topical Response No. 3 for a comprehensive response to these comments.

L16-7 Please refer to Topical Response No. 3 for a comprehensive response to comments about the Historic Preservation Commission and its role in the review process.

L16-8 This comment alleges the City used an "overly narrow lens" for cumulative impacts to municipal power property types in Glendale and attempts to link their proposed mitigation measure requiring a City-wide survey of City-owned historic resources to the cumulative impacts analysis. Please refer to Topical Response No. 3 for a comprehensive response to these comments.

L16-9 This comment expresses an opinion about the Project and desire that the Project fully consider and mitigate impacts to historical resources. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. Please refer to Topical Response No. 3 for a comprehensive response to these comments.

L16A - Responses to Comments from Greg Grammar on behalf of The Glendale Historical Society, received November 19, 2017

L16A-1 This comment references an attachment which is The Glendale Historical Society's (TGHS) November 19, 2017, comments letter on the 2017 DEIR submitted by Greg Grammer (the "2017 TGHS Letter") during the public comment period on the 2017 DEIR. All of the comments in the 2017 TGHS Letter were responded to in detail in the 2018 FEIR. Please refer to the March 1, 2018, Final EIR Response to Comments to the 2017 TGHS Letter, L781-1 through 29. No further amplification or clarification of these prior responses is required as the comments on the 2018 FEIR do not address the updated Cultural Resources Section of the PR-DEIR. See also Topical Response No. 3.

L17 - Responses to Comments from Alina Mullins and Lijin Sun on behalf of SCAQMD, received November 12, 2021

L17-1 This is a general statement expressing the commenter's comments are found in the pages below. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L17-2 This is a general statement and summary of the Project EIR process. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L17-3 This is a general statement and summary of the PR-DEIR. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L17-4 This is a general statement describing SCAQMD's role as a Responsible Agency under CEQA. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L17-5 This comment describes SCAQMD's review of the PR-DEIR and technical appendices. SCAQMD requested that the City provide additional information in the FEIR as substantial evidence to support the operating hours used in the air quality analysis for the Alternatives. SCAQMD has since confirmed that GWP's air permit applications are based on the operating profile provided in the PR-DEIR.

L17-6 This comment requests that the City provide written responses to SCAQMD's comments prior to certification of the Final EIR. Subsequent to this comment, on November 14, 2021, the City provided the requested information to SCAQMD and had conversations and exchanged emails with SCAQMD to respond to their concerns. On November 16, 2021, SCAQMD recognized and accepted the City's clarifications to their concerns.

L18 - Responses to Comments from Zarah Patriana on behalf of Earthjustice, received November 12, 2021

L18-1 This comment is an introductory statement and a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L18-2 Please refer to Topical Responses Nos. 5 and 6.

L18-3 The proposed Project and Alternatives 7 and 8 were analyzed in the 2018 FEIR and the PR-DEIR, respectively, to determine the degree of air quality and public health impacts. In each case, those impacts have been shown to be less than significant. Please see Topical Response No. 4.

L18-4 Please refer to Topical Responses Nos. 1 and 2.

L18-5 This is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L18-6 This comment reiterates the comments made in comment L18-2 through L18-5. Please refer to Individual Response L18-2 through L18-5.

L18-7 This comment includes a list of twenty-two Glendale residents that have signed onto the letter and have reiterated the comments made in L18-2 through L18-5. It is noted that the "message text" column that was received with the list of names was cut off and does not fit to the .pdf page. However, it is apparent that all comments submitted are the same. Please refer to Individual Response L18-2 through L18-5.

L19 - Responses to Comments from Jackie Gish, received November 13, 2021

L19-1 This comment is a general statement expressing the commenter's concerns within the letter. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L19-2 The comment poses questions concerning the air quality baseline in the PR-DEIR. Please refer to Topical Response No. 4.

The emissions shown in AQMD FIND database (https://xappprod.aqmd.gov/find) are facility-wide emissions, which include other emissions sources not affected by the project, such as those from Unit 9, small unpermitted sources, emergency engines, etc.

Unit 9 emissions reported in 2018 SCAQMD AER are as follows:

- NOx: 2.64 tons
- CO: 0.28 tons
- VOC: 0.19 tons
- SOx: 0.05 tons
- PM: 0.60 tons

L19-3 Unit 9 emissions reported in 2019 SCAQMD AER are as follows:

- NOx: 2.98 tons
- CO: 0.40 tons
- VOC: 0.20 tons
- SOx: 0.05 tons
- PM: 0.62 tons

L19-4 Please refer to Topical Response No. 4.

L19-5 Please refer to Topical Response No. 4.

L19-6 Please refer to Topical Response No. 4.

L19-7 Please refer to Topical Response No. 4. A project's baseline is defined by CEQA Guidelines Section 15125, which provides the following guidance for establishing the baseline. "An EIR must include a description of the physical environmental conditions in the vicinity of the project, as they exist at the time the notice of preparation is published, or if no notice of preparation is published, at the time environmental analysis is commenced, from both a local and regional perspective. This environmental setting will normally constitute the baseline physical conditions by which a lead agency determines whether an impact is significant."

The baselines the Commenter uses are not in fact CEQA baselines and are therefore not appropriate to use for purposes of determining significance as required by CEQA. The proposed Project was analyzed in the 2018 FEIR and was shown to have less than significant air quality impacts based upon net emissions and upon a complex air quality impact analysis that complied with National and State of California Ambient Air Quality Standards requirements. (See 2018 FEIR, Appendices D1 through D5). The air quality emissions of both Alternative 7 and Alternative 8 were analyzed in the PR-DEIR and are lower than the -proposed Project. (See PR-DEIR Appendix C).

L19-8 Please refer to Topical Response No. 4.

L19-9 Please refer to Topical Response No. 4.

L19-10 The example presented by the commentor on page 573 of the PR-DEIR reflects a difference of 1.3 percent in NOx. While it is not clear if the differences are due to truncation or rounding within the SCAQMD application spreadsheet, the calculations are part of the SCAQMD application and intended to be used for SCAQMD New Source Review calculations, rather than a CEQA demonstration. They are used to determine what future emissions would be offset by concurrent emission reductions at the facility and what future emissions would be offset through the use of emission reduction credits. SCAQMD will conduct its own assessment and if the noted difference of 0.16 ton per year exists, SCAQMD will adjust offsets accordingly to ensure no net emission increase from Alternative 7. In all instances, however, the CEQA air quality analysis reflects less than significant air quality impacts for the proposed Project and Alternatives 7 and 8.

L19-11 The GHG emissions on Page 623 of the PR-DEIR reflect the 2018 Air Emissions Reporting (AER) for the affected sources.

L19-12 Please refer to Topical Response No. 4.

L19-13 Please refer to Topical Response No. 4.

L19-14 Please refer to Topical Response No. 4.

L20 - Responses to Comments from Andrew Ellis, received November 15, 2021

L20-1 This is a general statement introducing the commenter and expressing the commenter's concerns included in the comment letter. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L20-2 This is a general statement which describes the commenter's concerns but does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L20-3 Please refer to Topical Response No. 7. In addition, the commenter expressed concern that once the public comment period closed the public is "forever foreclosed" from participation in the CEQA or project review process. This statement is incorrect. While the public comment period is provided on the Draft EIR so that the lead agency has an opportunity to respond to comments, the public is not foreclosed from commenting on a project or the EIR at any public meeting or hearing prior to approval.

L20-4 Please refer to Topical Response No. 7.

L20-5 Please refer to Topical Response No. 7.

L20-6 Specific details and mitigation activities for paleontological resources will be provided for in the Paleontological Monitoring and Mitigation Plan that Mitigation Measure PAL-2 stipulates a qualified paleontologist will draft for the project prior to the start of work. This level of detail is beyond what can be drafted at this time, as specific monitoring plans need to be tailored to project activities and construction schedule. The ultimate preservation of significant paleontological resources at an accredited repository is provided for in PAL-3, which stipulates significant fossils be curated in an accredited repository.

L20-7 This comment incorrectly describes the paleontological potential of the site as high. The results of the paleontological resources assessment indicated that the upper ten feet of undisturbed sediments have low paleontological potential, as they are too young to preserve fossils, while from depths of around ten feet and deeper, undisturbed sediments have high paleontological potential. This comment also incorrectly equates the assessment of high potential with a "likely" significant impact on paleontological resources. The potential of a geologic unit[139] to preserve fossils is assessed as high when significant fossils are known from that unit (as per the Society of Vertebrate Paleontology guidelines). This only applies to the change of fossil being in the unit and is not a reflection on whether a project might impact fossils, should they be present. The impacts assessment presented in the PR-DEIR indicated that there was a chance paleontological resources could be encountered, and therefore prescribed mitigation measures designed to reduce impacts to a less than significant level.

L20-8 See Individual Response L20-7 above for response to observation 1 and 2 in the list contained within this comment. Observation 3 the commentor states the PR-DEIR correctly analyzes the relationship with INCREASING PALEONTOLOGICAL POTENTIAL as they excavate deeper into the undisturbed sediments. Observation 4 indicates that additional detail is needed for the Paleontological Worker Training. The overall goal of the training – to communicate requirements and procedures in the event of a fossil discovery – is specified. Further, PAL-3 provides additional information on these steps, including a work stoppage, assessment of the resource, and treatment of significant specimens.

Item 5 of this comment states that "The PALEONTOLOGICAL MONITORING PROGRAM to mitigate the environmental impacts in the event of an `inadvertent discovery' of fossil material . . .". This is not a correct summary of the monitoring program. PAL-2 calls for full-time monitoring of ground disturbance over ten feet in depth; this monitoring is not triggered by a find; it happens regardless. This is an important distinction, as it means all work into high potential sediments is monitored, thus reducing potential impacts to less than significant. Item 5 also states that the monitoring program is not described in sufficient detail; however,

[139] A geological unit is a volume of rock or ice of identifiable origin and age range that is defined by the distinctive and dominant, easily mapped and recognizable petrographic, lithologic or palaeontologic features (facies) that characterize it.

as addressed in Individual Response L20-6 above, PAL-2 calls for a project specific Paleontological Monitoring and Mitigation Plan that would address all of the details and specifics of the monitoring program that are beyond the scope of the PR-DEIR.

L20-9 The commenter suggests that the wildfire impact analysis and mitigation are inadequate because they do not recognize or evaluate a designated high fire hazard risk area located 0.1 mile from the proposed Project site. While the proposed Project site is not within a high fire hazard risk area, the eastern extent of a high fire hazard risk area near and including Griffith Park is located west of the proposed Project site and across the Los Angeles River. The high fire risk area nearest the Project site includes the John Ferraro Athletic Fields, Interstate 5, and State Highway 134 which do not include substantial wildlands. The proposed Project would be required to adhere to all applicable fire code requirements and does not introduce elements that have the potential to result in greater wildfire risks compared to baseline conditions associated with existing power plant operation. The presence of a developed area at the boundary of a designated high fire hazard risk area within 0.1 mile of the proposed Project site does not, nor does the commenter provide substantive evidence that the proposed Project would have the potential to result in a significant wildfire impact. The City's determination of less than significant wildfire impacts, even when considering the location of the adjacent high fire hazard risk area, would remain less than significant and not require mitigation pursuant to CEQA.

L20-10 Please refer to Individual Response to L20-9, immediately above.

L20-11 The off-site consequence analyses performed for the proposed Project and Alternatives 7 and 8 are consistent with U.S. Environmental Protection Agency guidance for conducting off-site consequence analysis. This guidance identifies a worst-case scenario as a complete release of the volume contained in the single largest storage vessel or process, unless administrative controls are present to reduce potential release volumes or rates. The City's analyses of accidental worst-case aqueous ammonia releases were consistent with U.S. Environmental Protection Agency guidance for conducting off-site consequence analyses and assumed the complete release of the tank contents of the aqueous ammonia storage tank. While a worst-case release is never anticipated, the City considered additional protective measures in the Project design should such a release occur. These measures included constructing a concrete-reinforced contaminant structure surrounding each aqueous ammonia storage tank and placing 3-inch diameter high-density polyethylene (HDPE) balls inside the containment structures. The surrounding containment would serve the purpose of secondary containment for more than the maximum volume of the storage tank should a worst-case release per U.S. Environmental Protection Agency guidance for conducting off-site consequence analyses occur. The presence of the floating HDPE balls inside the containment reduces the free surface area in contact with the atmosphere and would serve to reduce emissions rates from the containment structure even if the worst-case scenario occurred. A scenario evaluating a worst-case release beyond that defined by U.S. Environmental Protection Agency for off-site consequence analyses is not required or necessary for evaluating potential hazards and hazardous materials impacts of the proposed Project pursuant to CEQA.

L20-12 The commenter suggests the PR-DEIR fails to adequately describe the environmental impacts relating to the storage and use of hazardous materials. Please refer to Individual Response L20-11. The commenter does not provide any substantive evidence to their opinion that the PR-DEIR fails to adequately describe the environmental impacts relating to the storage and use of hazardous materials. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L20-13 The commenter expressed concern for noise related to siting power plants near sensitive noise receptors such as residences, schools, and medical facilities. The commenter specifically suggests that the 15- to 20-minute duration measurements used for evaluating noise impacts in the PR-DEIR are not adequate for establishing ambient noise levels. However, the duration of these noise measurements exceeds the 5-minute-long durations identified in Section 8.36.030 (decibel measurement criteria) of the City's Noise Ordinance used for establishing ambient noise levels and reflects a more accurate and conservative assessment of ambient noise. In addition, noise measurements were collected both during day and nighttime hours when noise can be more noticeable. The noise impact analysis concluded that noise produced by the Project would result in less than significant potential increases in ambient noise at nearby sensitive receptors estimated in the 2108 FEIR. The noise study applied "presumed" ambient noise levels that by City code are more conservative and protective of community noise exposure than were measured "actual" for purposes of a noise study to comply with CEQA. Potential noise impacts of the proposed Project are analyzed in Section 4.8 of the 2022 Final EIR and Appendix E of the PR-DEIR. These analyses include modeling of demolition, construction, and operation noise.

Sections 5.2.6.2 and 5.2.7.2 of the PR-DEIR notes that Alternatives 7 and 8 would involve the same or similar demolition and construction activities as the proposed Project. They would further occur on the same site, have an equivalent disturbance footprint, involve similar construction equipment, and have similar durations. It is therefore reasonable to assume construction noise from Alternatives 7 and 8 would be similar to the proposed Project which were disclosed in Section 4.8 of the 2018 FEIR and Appendix E of the PR-DEIR and determined not to result in a significant noise impact.

Sections 5.2.6.2 and 5.2.7.2 of the PR-DEIR include a summary of predicted operation phase noise modeling for Alternatives 7 and 8. Tables 5-5 and 5-12 in the PR-DEIR specifically show the predicted noise levels and increases in noise levels above baseline ambient noise levels that would result at nearby sensitive receptors. These data show operation noise from the proposed Project, Alternative 7, and Alternative 8 would not result in a significant noise impact.

The commenter does not provide any substantive evidence to their opinion that the PR-DEIR fails to adequately describe noise impacts. The commenter' statement is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L20-14 Please refer to Individual Response L20-13 and Topical Response No. 7.

L20-15 Several geotechnical investigations of the Grayson site have been performed. Subsurface investigations were performed by URS in 2002 in order to evaluate the Grayson site prior to the addition of Unit 9 to Grayson. In 2016, Stantec performed a geotechnical study of the site, including borings and laboratory testing for the Draft Environmental Impact Report review of the proposed Project. The Stantec geotechnical report conformed with the then current and applicable 2016 California Building Code which incorporated the requirements of ASCE 7-10 "Minimum Design Loads for Buildings and Other Structures." As discussed further in Individual Response L20-16, additional geotechnical work was performed for Alternatives 7 and 8 and the PR-DEIR.

The results of site-specific geotechnical studies and their conformance with the California Building Code provides an adequate basis for evaluating the proposed Project's potential impacts pursuant to CEQA. The commenter while suggesting the information provided in the PR-DEIR is not adequate, does not provide substantive evidence as to what details the PR-DEIR lacks and how those details would alter the findings of the PR-DEIR. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L20-16 The original geotechnical work for the Grayson repowering was performed by Stantec in accordance with the requirements of then in effect California Building Code 2016 edition and ASCE 7-10 "Minimum Design Loads for Buildings and Other Structures." Following adoption of the 2019 California Building Code and ASCE 7-16 "Minimum Design Loads and Associated Criteria for Buildings and Other Structures," Black & Veatch and their geotechnical consultants, Terracon and Kehoe Testing & Engineering, performed additional site borings, cone penetration testing, seismic measurements, and laboratory work in September 2020 and May 2021 to address the added requirements with regards to soil liquefaction. Black & Veatch developed site-specific seismic response spectra and a site-specific soil liquefaction evaluation. Further, Black & Veatch also developed geotechnical recommendations to improve the site through the use of stone columns, wicking columns drains, and replacement/backfill soils. These requirements were included in the Grayson Demolition/Site Improvement Request for Proposal. The Grayson Demolition/Site Improvement Request for Proposal also requires as part of the site improvement work and prior to the start of construction that a confirmatory geotechnical study will be performed to ensure that the work improved the site to meet the required site characteristics.

The geotechnical work was performed by registered geotechnical engineers and meets the professional l standard of care required to provide a thorough environmental site assessment and detailed design of the proposed Project and Alternatives 7 and 8.

L21 - Responses to Comments from Elise Kalfayan on behalf of Glendale Environmental Coalition, received November 15, 2021

L21-1 This comment is an introductory statement to the comment letter and attachments thereto. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L21-2 This comment is a general statement about the commenter's purpose for submitting comments on the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L21-3 This comment is a general statement introducing the commenter. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L21-4 This comment is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. Also, see generally Topical Response Nos. 5 and 6 to the PR-DEIR, and Topical Response Nos. 1 and 5 to the 2018 FEIR.

L21-5 This is a general statement about the commenter's opinion of (or preference about) the Project and general environmental concerns related to investments in "climate-altering infrastructure" and investments in natural gas power equipment. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. In response to the comment that every investment in natural gas equipment locks in harmful emissions, that is not necessarily correct; as noted in Topical Response No. 5, the equipment being installed as part of this project can serve as a transition to later use of hydrogen fuel. This comment incorrectly asserts that the City Council rejected the original project in 2018. The City Council did not take an action to approve or disapprove the Project, but instead directed staff to explore clean energy alternatives to the Project.

L21-6 This comment expresses the commenter's concerns and opinions about the repowering at Grayson. Please refer to Topical Response Nos. 5 and 6, and Individual Responses L21-5 above and L21-10, below.

L21-7 This is a general statement about the history of the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L21-8 This is a general statement about the City's 2019 Integrated Resource Plan. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L21-9 This is a general statement about the history of the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L21-10 This comment incorrectly states that the proposed Project is no longer under consideration. The City Council did not take an action to approve or disapprove the Project, but instead directed staff to explore clean energy alternatives to the Project. The PR-DEIR contains the review of additional clean energy alternatives to the Project for the City Council to consider in addition to the proposed Project. In addition, the comment is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L21-11 This comment is a general statement about the commenter's opinion of (or preference about) the Project and commenter's summary of Project Alternatives 7 and 8. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L21-12 Please refer to Topical Response No. 7.

L21-13 Please refer to Individual Response L21-10 regarding the status of the Project. This comment contains a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L21-14 Please refer to Topical Responses Nos. 6 and 7 and Individual Response L21-10.

L21-15 Please refer to Topical Responses Nos. 6 and 7.

L21-16 Please refer to Topical Response No. 7 and Individual Response L21-10.

L21-17 Please refer to Topical Response No. 7.

L21-18 Please refer to Topical Response No. 7.

L21-19 Please refer to Topical Response No. 7.

L21-20 Please refer to Topical Response No. 7.

L21-21 Please see Topical Response No. 11 to the 2018 FEIR. Baseline conditions for evaluating a project's potential environmental impacts pursuant to CEQA are established at the time of Notice of Preparation issuance. The NOP for the proposed Project was issued in December 2016, prior to release of the commenter's noted data in 2017 and 2018. While the proposed Project was determined to have less than significant environmental justice impacts during the Initial Study, the City recognizes the Disadvantaged Community designation and has taken steps to reduce impacts such as discontinuing the combustion of landfill gas in old boilers. The purpose of the PR-DEIR was to evaluate additional alternatives that could reduce environmental impacts of the proposed Project rather than re-evaluate the proposed Project's impacts. The PR-DEIR concludes that in all resource categories analyzed, Alternatives 7 and 8 would result in less environmental impacts and as such it can reasonably be concluded that further environmental justice analysis of the Alternatives is not warranted because the Alternatives would, overall, have less than significant environmental justice impacts that are even lower than the proposed Project. As demonstrated in the PR-DEIR analysis, the Alternatives involve less natural gas-fueled electricity generation and lower mass emissions of criteria and hazardous air pollutant emissions within a disadvantaged community.

L21-22 The commenter questions the selection of related projects for the cumulative impact analysis and suggests additional projects should have been considered in the PR-DEIR. The PR-DEIR includes information on potential cumulative impacts to cultural and paleontological resources, energy, and wildfire which were updated or added as new resource categories considered in updates to the CEQA Guidelines. Cumulative impacts to all other environmental resource categories were previously addressed in the Initial Study, Draft EIR, and/or final EIR. The City did consider and evaluate the potential impacts to Confluence Park which was proposed after release of the 2018 FEIR (See PR-DEIR Executive Summary and Sections 1.1.1.1, 1.1.3.4, 1.1.4.2, 4.12.1, 5.2.6.2, and 5.2.7.2). The commenter does not provide any evidence that the Los Angeles Zoo Vision Plan or any of the projects identified in attachments B and C of comment letter L21-22 are changed circumstances that would increase the impacts of the proposed Project or Alternatives. Please refer to Individual Response L22-24 for further information related to the proposed Project's potential to result in cumulative impacts when considered in combination with the Los Angeles Zoo Vision Plan project. The commenter's statement is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. Generally, a cumulative impact is an impact created by the combination of the project reviewed in the EIR together with other projects causing related impacts. CEQA Guideline 15065(a)(3), 15130(b)(1)(A), and 15355(b). An EIR need not discuss cumulative impacts that do not result in part from the Project CEQA Guideline 15130(a)(1); *Santa Monica Baykeeper v City of Malibu (2011) 193 Cal App 4th 1538, 1539. Also, in Sierra Club v West Side Irrig. Dist. (2005) 128 Cal App 4th 690, 700,* the court explained that if a project does not make some contribution to a cumulative environmental effect, the cumulative environmental effect cannot be characterized as a cumulative impact of that project. Accordingly, the projects chosen for determining a cumulative impact are those that create a "related" impact; otherwise, the impact is not characterized as cumulative.

The commenter does not provide any evidence that any of the projects identified in attachments B and C of comment letter L21-22 are changed circumstances that would increase the impacts of the proposed Project or Alternatives. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L21-23 The commenter suggests the cumulative impacts analysis was constrained to other power generating projects and must additionally consider the cumulative impacts from other project types. The City did consider non-power generating projects in its review of related projects.

As referenced in Individual Response L21-22, the purpose of the PR-DEIR was to evaluate additional alternatives that could reduce environmental impacts of the proposed Project rather than re-evaluate the proposed Project and the related projects that were considered in the cumulative impact analysis. However, Section 4.11.2 of the Draft EIR (page 4.11.3) states "the listing of projects for the cumulative analysis includes projects of a similar nature, but in some cases (such as aesthetics) additional nearby projects that are not of a similar nature that could combine with the project impacts to make a more significant cumulative impact were considered for specific issue areas". Section 4.11.3 through 4.11.11 of the Draft EIR further evaluate the proposed Project's potential to result in significant cumulative effects when considering the specifically identified related projects and others that may occur in the area beyond power generating projects.

L21-24 The commenter suggests that the City did not consider related projects outside the City of Glendale and should have identified the Los Angeles Zoo Vision Plan as a cumulative project. See Individual Response L21-23 above; the Los Angeles Zoo Plan is not a related project. As noted in Section 4.11.2 (page 4.11.2) of the Draft EIR, the City consulted with representatives from the Cities of Los Angeles, Burbank, and Pasadena when considering related projects outside of Glendale. Further the EIR for the Los Angeles Zoo Vision Plan was only recently released in June 2021, several years after release of the NOP and Draft EIR for the proposed Project. As referenced in Individual Response L21-22, the purpose of the PR-DEIR was to evaluate additional alternatives that could reduce environmental impacts of the proposed Project rather than re-evaluate the proposed Project and the related projects that were considered in the cumulative impact analysis. The commenter additionally does not provide substantive evidence as to how or why the proposed Project when considered along with the Los Angeles Zoo Vision Plan would result in significant cumulative impacts. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

The Los Angeles Zoo Vision Plan Final EIR (Zoo EIR) analyzes potential environmental impacts associated with future development and modernization of the Zoo for the next 20 years. It would include comprehensive redesign and redevelopment of the Zoo to replace outdated buildings and infrastructure and upgrade animal care and guest amenities through the 133-acre Zoo. Improvements would include new and revitalized immersive exhibit space and animal habitats, new visitor-serving buildings, expanded and modernized administrative and services facilities, circulation improvements for access roads, pedestrian walkways and paths, an enhanced entry way and plaza, and new parking facilities. Annual visitation is projected to increase by approximately 1.2 million visitors per year.

The Zoo EIR considers the cumulative impacts of the Grayson Repowering Project to air quality and hazardous materials. The Zoo EIR further concludes that a cumulatively considerable air quality impact could result because the Zoo project's construction emissions would exceed the SCAQMD regional daily mass emissions thresholds of significance for NOX. The Zoo EIR further concludes that use of Tier 4 standard engines during Zoo construction would reduce construction emissions below applicable significance criteria. SCAQMD has in part established these mass emissions thresholds to ensure that any one project's contribution of air pollutants emissions do not result in cumulatively considerable adverse air quality and public health impacts. Because the Zoo project construction emissions would be below the applicable mass emissions thresholds with mitigation, they were determined to have a less than significant cumulative air quality impact when considered with the Grayson Repowering Project. Correspondingly, Tables 4-12 and 4-13 of the Final EIR for the proposed Project show that construction emissions from the proposed Project would not exceed SCAQMD regional and localized daily mass emissions thresholds of significance and would therefore also not result in a cumulatively considerable air quality impact when considered in combination with construction of the Zoo project.

The Zoo EIR determined the potential for exposure to hazardous materials and contaminated soil from the Zoo construction in combination with potential similar exposures from construction and operation of the Grayson Repowering Project could result in cumulative impacts. The Zoo EIR notes transport, use, and storage of hazardous materials at Grayson Power Plant, ground disturbing activities on or in proximity to a Superfund cleanup site, and demolition of structures with asbestos containing materials and lead based paint. The Zoo EIR notes that cumulative projects would also be required to comply with federal, state, and local regulations regarding the handling, use, transport, and disposal of hazardous materials. The Zoo EIR determined that with implementation of mitigation, the Zoo project's contribution to cumulative impacts from exposure to hazards or hazardous materials would not be considerable and cumulative impacts from hazards and hazardous materials would be less than significant. Section 4.6 of the Final EIR for the proposed Project describes the potential impacts that could result from the above activities considered in the Zoo EIR. The City of Glendale's CEQA analysis of the Grayson Repowering Project included Phase 1 and 2 Environmental Site Assessments and Lead and Asbestos Surveys. As a result, the presence, locations, and concentrations of these hazardous materials was available to the City when analyzing potential hazardous and hazardous materials impacts of the proposed Project pursuant with CEQA. The Grayson Repowering Project EIR additionally includes the following mitigation measures to reduce the potential for off-site hazards and hazardous materials impacts during demolition and construction:

- HAZ-1: Prior to demolition of facilities associated with the Grayson Repowering Project, hazardous materials stored onsite and not required for continued operation of the facility shall be inventoried, packaged, removed, and disposed in accordance with a Hazardous Materials Management Plan prepared by the demolition contractor and submitted to the City for review and approval prior to initiating demolition activities.

- HAZ-2: Buildings or equipment to be demolished containing lead-based paint or asbestos shall be either decontaminated or encapsulated prior to removal from the Project site and disposed in accordance with an Asbestos and Lead Paint Management Plan prepared by the demolition contractor and submitted to the City for review and approval prior to initiating demolition activities.

- HAZ-3: Contaminated soil encountered during demolition activities shall be handled, removed, and disposed in accordance with regulatory requirements and the Project's Soil Management Plan.

- HAZ-4: Hazardous materials used during construction shall be limited to the quantities required for construction and shall be stored and handled in accordance with regulatory requirements.

- HAZ-5: Utility trucks and refueling trucks operating onsite shall have a spill kit onboard at all times. Small spills of petroleum products or other hazardous materials during construction operations shall be reported to the Construction Supervisor and a Spill Response form completed with a description of the type and quantity of the spill accompanied by photographs and a description of the disposition of the spill material. Hazardous spill material shall be disposed according to regulatory requirements. In the event of a large spill of hazardous materials equal to or above reportable quantities federal, state, and local reporting requirements shall be followed.

The Grayson Repowering Project EIR also evaluated the potential off-site consequences of a worst-case release of aqueous ammonia during operation that would be used in support of equipment emissions control systems. That analyses included in Appendix G of the Final EIR demonstrates that by incorporating mitigation to reduce the surface area available for ammonia evaporation should a release occur, concentrations of concern that exceed public health criteria would not impact receptors off-site Grayson Power Plant.

Considering the above, it is unlikely that the proposed Project would result in off-site hazards and hazardous materials impacts during construction and operation and would not have the potential to result in cumulative impacts when considered in combination with the Zoo project. The PR-DEIR additionally evaluates hazards and hazardous materials impacts of Alternatives 7 and 8 which have similar demolition and construction components as the proposed Project and would therefore have similar potential impacts. Alternatives 7 and 8 would also involve storage and use of aqueous ammonia which Appendix D of the PR-DEIR shows that similar to the proposed Project, by incorporating mitigation to reduce the surface area available for ammonia evaporation should a release occur, concentrations of concern that exceed public health criteria would not impact receptors off-site Grayson Power Plant.

The Grayson Repowering Project or alternative considered in the EIR would therefore result in less than significant cumulative environmental impacts when considered in combination with the Zoo project.

L21-25 Please refer to Individual Response L-21-10 regarding the Project. This is a general statement about the commenter's opinion of (or preference about) the Project. Please refer also to Topical Response No. 7.

L21-26 Please refer to Topical Response No. 6.

L21-27 The specific amount of non-renewable energy that may be imported to charge the BESS component of the project is not known at this time. Generally, any such energy will be generated by existing sources, and not new sources of generation that are a component of this project. Please also refer to the Individual Response L21-28.

If imported resources are not available to charge the batteries and it is necessary to operate local generation (Alternative 7 or 8 or Unit 9), those emissions have been addressed because the units will have to be operated within the limits of their air permit. The air emissions for Alternatives 7 and 8 are addressed in the PR-DEIR and emissions for Unit 9 when it was permitted. All Units must comply with Rule 1135 going forward. (See Topical Response No. 1).

L21-28 The specific amount of non-renewable energy that may be required to charge the BESS component of the project is not known at this time. Generally, any such energy will be generated by existing sources, and not new sources of generation that are a component of this project, so this aspect of the project does not involve new sources of energy that would require evaluation.

In addition, in addressing the extent to which EIRs must evaluate this type of energy usage impact, the State Office of Planning and Research in its explanation for the current text of CEQA Guideline 15126.2(b), stated as follows: "Finally, new subdivision (b) cautions that the analysis of energy impacts is subject to the rule of reason, and must focus on energy demand caused by the project. This sentence is necessary to place reasonable limits on the analysis. Specifically, it signals that a full 'lifecycle' analysis that would account for energy used in building materials and consumer products will generally not be required." OPR, November 2018 Final Statement of Reasons, pp.41-42. This aspect of the project (recharging storage) does not cause new energy demand, but instead uses storage technology to more efficiently satisfy existing demand.

L21-29 This comment identifies questions about impacts pertaining to the location of off-site staging for construction associated with the project or project alternative the Council selects. As provided in the 2018 FEIR, the Project site encompasses approximately ten acres within the City's Utility Operations Center. In addition, the Project would utilize space within the Utility Operations Center and underneath adjacent Highway 134 partially owned by the City and partially leased by the City from the State Caltrans division to provide construction parking, and an approximate two-acre off-site construction laydown area located north of the Project site at 1625 Flower Street adjacent to the Griffith Manor Park and owned by Disney These laydown locations were evaluated within the 2018 FEIR for the proposed Project or any Alternative selected. (See 2018 FEIR Section 3.1.1 Site Location).

L21-30 This comment concerns replacement of battery systems in Alternatives 7 and 8. The Tesla battery energy storage system will be operated under a Capacity Maintenance Agreement. Under this agreement Tesla will add battery augmentation units into predefined space in the project layout included as part of the design, and when necessary, replace battery modules to maintain the full power and energy output of the system over the term of the agreement subject to the system being operated within the defined limits (number of cycles, etc.) Battery modules would come from and be returned to Tesla's existing

Gigafactory in Reno, NV where they may be remanufactured or recycled. Periodic maintenance is a necessary activity for any energy storage system and the associated impacts are a small fraction of the original construction impact.

L21-31 Section 5 of the PR-DEIR compares Alternatives 7 and 8 with the historic baseline as well as an updated baseline. The proposed Project was shown to have less than significant air quality impacts, and the PR-DEIR shows that emissions from Alternatives 7 and 8 are lower than the emissions from the proposed Project. For further clarification regarding the air quality analysis, please refer to Topical Response No. 4. In addition, it is appropriate to evaluate alternatives in less detail than the proposed Project, per CEQA Guideline 15126.6(d). This makes particular sense here, where the impacts of the two additional alternatives are reduced compared to the proposed Project. See Topical Response No. 7.

L21-32 The degree to which alternatives present impacts is not dependent upon the length of the analysis contained in the PR-DEIR. Appendix C.1 to the PR-DEIR contains the permit application for Alternatives 7 and provides a detailed narrative of Alternatives 7 and 8. The permit application for Alternative 8 is attached to Topical Response No. 4. Please refer to Topical Response Nos. 4 and 7.

L21-33 This comment concerns the SCAQMD air quality permit package for Alternative 8. All the SCAQMD permit application for Alternative 8 is attached to Topical Response No. 4.

L21-34 This comment concerns the adequacy of the air quality analysis for compared to the proposed Project air quality analysis in the 2018 FEIR. Please refer to Topical Response Nos. 4 and 7. Please refer to the PR-DEIR Sections 5.2.6.2 (Tables 5-2 and 5-4) and 5.2.7.2 (Tables 5-8 and 5-10), which show that air emissions from Alternatives 7 and 8 are lower than emissions from the Proposed Project. The Proposed Project's air quality impacts were also determined to be less than significant with the exception of CO for Alternative 8. (2018 FEIR, Appendices D1 through D5). Alternative 8 is an emission reduction strategy to comply with SCAQMD Rule 1135.

The comment contends that there is no analysis of construction-related air quality impacts for Alternatives 7 and 8. Tables 4-12 and 4-13 of the 2018 FEIR include estimates of construction emissions for the proposed Project. Tables 4-12 and 4-13 also demonstrate that demolition and construction emissions of the proposed Project would be below applicable SCAQMD mass daily significance criteria and would result in a less than significant air quality impact. Sections 5.2.6.2 and 5.2.7.2 of the PR-DEIR notes that Alternatives 7 and 8 would involve the same or similar demolition and construction activities as the proposed Project. They would further occur on the same site, have an equivalent disturbance footprint, involve similar construction equipment, and have similar durations. It is there therefore reasonable to assume construction emissions of Alternatives 7 and 8 would be similar to the proposed Project which were disclosed in the EIR.

The comment contends that there is no analysis of air quality impacts from facility occupancy. This analysis is shown in Topical Response No. 4. It should also be noted that while facility occupancy emissions were noted for the Project, the facility is presently occupied, and occupancy emissions noted in the 2018 FEIR would not necessarily reflect an increase in emissions.

The comment contends that there is no analysis of air quality impacts from off-road equipment and vehicle trips. The project descriptions for Alternatives 7 and 9 indicate that the scope of construction activities would be similar, regardless of the selected alternative or the proposed Project. See PR-DEIR Sections 5.2.6.1 and 5.2.7.1). Construction and off-road equipment emissions that would be attributed to the proposed Project were shown to be less than significant (2018, Final EIR, Section 4.3). Likewise, construction and off-road vehicle impacts of Alternatives 7 and 8 would be less than significant. (PR-DEIR Sections 5.2.6.2 and 5.2.7.2).

The comment contends there is no ambient air quality impact analysis comparable to the FEIR and that there is no discussion of impacts under the threshold related to conflicts with or the obstruction of the implementation of the applicable air quality plan. Topical Response No. 4 addresses air quality impacts of Alternatives 7 and 8, relative to daily emissions, air quality impact analyses and GHG emissions and whether the Alternatives conflict or obstruct an applicable air quality plan (See Sections 5.2.6.2 and 5.2.7.2 of the PR-DEIR).

L21-35 The proposed Project and Alternatives 7 and 8, construction activities, including demolition and grading activities would be similar across all three projects because all the same above-ground and below-ground structures must be removed for all three, and the same soil improvement work is required for all three. Additionally, Alternatives 7 and 8 have smaller capacity, less equipment, and lower fuel consumption.. Offroad equipment utilization and other vehicle trips would also be similar for the Project and Alternatives 7 and 8. The emissions reflected in the EIR for the Project would therefore also be similar to emissions attributed to Alternatives 7 and 8. Air quality impacts attributed to Project construction activities were shown to be less than significant.

Facility occupancy for the Project would be similar to occupancy under Alternatives 7 and 8 because Alternatives 7 and 8 have smaller capacity, less equipment, and lower fuel consumption. The facility occupancy (e.g., operational emissions) reflected in the FEIR for the Project would likewise be similar to occupancy emissions of Alternatives 7 and 8. It should also be noted that while facility occupancy emissions were noted for the Project, the facility is presently occupied and occupancy emissions noted in the FEIR would not reflect an increase in emissions because there is no planned increase in staffing, and Alternatives 7 and 8 have smaller capacity, less equipment, and lower fuel consumption.

L21-36 Please refer to Topical Response No. 4.

L21-37 Please refer to Topical Response No. 4.

L21-38 Please refer to Topical Response No. 4.

L21-39 This comment concerns alleged difficulty in comparing impacts of the Project options because the data are shown in two separate tables. The impact analysis was completed, and the data provided for the Alternatives as required by CEQA. Health impacts of Alternative 7 are presented in Table 5-3 of the PR-DEIR and show that impacts are well below significance thresholds. For example, the maximum increase in cancer risk (MICR) attributed to Alternative 7 is 0.5 in one million versus a threshold of 10.0 in one million. Health impact of Alternative 8 are shown in Table 5-9 of the PR-DEIR. They are also shown to be well below significance thresholds, with a MICR of 0.014 in one million.

L21-40 Please refer to Topical Response No. 4.

L21-41 The updated 2018 baseline values reflected in the PR-DEIR reflect annual emissions reported to SCAQMD for Boilers 3, 4 and 5, and Turbines 8A, BC. Please refer to Topical Response No. 4 for further clarification.

L21-42 Please refer to Topical Response No. 4.

L21-43 PR-DEIR Table 5-2 shows impacts relative to an updated emission baseline. The footnote to PR-DEIR Table 5-3 clarifies that the 2018 information was extracted from SCAQMD annual emission reports for the facility. Please refer to Topical Response No. 4 for more discussion about the appropriateness of the air quality baselines chosen as well as the factual basis supporting the use of the updated baselines for air quality.

L21-44 At the time that the PR-DEIR was drafted and Notice of Preparation issued for the PR-DEIR, the 2018 emissions data was the most recent verified data available. Please refer to Topical Response No. 4. The City has updated the baseline analysis by including years 2019 and 2020 in which there was no landfill gas combustion in the Grayson Power Plant (See Topical Response No. 4).

L21-45 Please refer to Topical Response No. 4. See Individual Response L-21-44, immediately above.

L21-46 Please refer to Topical Response No. 4. Alternative 8 reflects an emission reduction strategy pursuant to SCAQMD Rule 1135. It does not reflect the installation of new emission sources. As such, the consideration of baseline emissions and potential emission increases under CEQA is somewhat out of context. Regardless, for the sake of comparison, Alternative 8 emissions were measured against baseline emissions in the PR-DEIR and the impacts of Alternative 8 are less than significant. (See PR-DEIR Table 5-9 page 5.66).

L21-47 Discussions of baselines contained in Appendix C.1 of the PR-DEIR refer to baseline consideration for the purpose of determining compliance with SCAQMD Regulation XIII. The discontinuation of LFG combustion created an exception to operating trends at the facility that warranted consideration of an older baseline in accordance with SCAQMD regulations and policy. Please refer to Topical Response No. 4.

L21-48 Please refer to Topical Response No. 4.

L21-49 BACT adjustments reflect current technology standards for the equipment being removed. Because BACT for turbines is different than BACT for boilers, the adjustments would not be the same for the two types of equipment. Additionally, there are not new BACT standards for PM and SOx, so BACT adjustments for these pollutants would not apply. The substantial evidence basis for providing adjustments to the baselines is provided in the PR-DEIR and in Topical Response No. 4.

L21-50 BACT adjustments reflect current technology standards for the equipment being removed. Because BACT for turbines is different than BACT for boilers, the adjustments would not be the same for the two types of equipment. Additionally, there are not new BACT standards for PM and SOx, so BACT adjustments for these pollutants would not apply. See Topical Response No. 4.

L21-51 Historic baselines were discounted in accordance with SCAQMD Regulation XIII in an effort to maintain consistency between CEQA demonstrations and SCAQMD permitting practices. Doing so also helps to ensure that the CEQA environmental analysis will not understate impacts (the approach is conservative, not illusory or hypothetical, and is permitted by CEQA). Without the baseline adjustments, the net increase in emissions portrayed in a CEQA analysis would be less significant. For example, without the baseline emission discounts taken pursuant to Regulation XIII for Boiler 5, the 2019 – 2020 NOx baseline would be 85.2 pounds per day, versus the 29.4 pound per day value. Please refer to Topical Response No. 4.

L21-52 Please refer to Topical Response No. 4, especially the baseline discussion.

L21-53 Please refer to Topical Response No. 4.

L21-54 Discussions of Alternative 7 baselines contained in Appendix C.1 to the PR-DEIR refer to baseline consideration for the purpose of SCAQMD Regulation XIII. The discontinuation of LFG combustion is a fact that had to be considered in the formulation of the baseline to measure air quality impacts; it created an exception to operating trends at the facility that warranted consideration of an older baseline in accordance with SCAQMD regulations and policy. Please refer to Topical Response 4.

L21-55 Please refer to Topical Response No. 4.

L21-56 Please refer to Topical Response No. 4.

L21-57 Please refer to Topical Response No. 4.

L21-58 Please refer to Topical Response Nos. 4 and 6. Alternative 8 is an emission reduction strategy – modifying the plant to reduce the existing Units 8A and 8BC emissions to lower levels - that is specified in SCAQMD Rule 1135. The environmental analysis for those reduced emissions are contained within the PR-DEIR at Section 5.2.7, page 5.65 through 5.68 and Appendix C-2 to the PR-DEIR. Units 8A and 8BC already being in operation, the existing potential emissions for Units 8A and 8BC have already been offset. SCAQMD Regulations mandate that any modification to an emission source, and any new emission source, not result in an overall increase in the basin. All emissions from either alternative will be offset.

L21-59 This comment pertains to sensitive receptors. Sensitive receptors are people that have an increased sensitivity to air pollution or environmental contaminants. Sensitive receptor locations include schools, parks, and playgrounds, daycare centers, nursing homes, hospitals, and residential dwelling unit(s). The location of sensitive receptors is needed to assess toxic impacts on public health.

The health risk assessment conducted for the proposed Project, Alternative 7, and Alternative 8 analyze the potential health risks for all known potential sensitive receptors surrounding the Project location. Table 25 of Appendix C.1. (page 411-412 of the PR-DEIR) simply lists the nearby schools and childcare facilities as required by SCAQMD for permitting purposes; and explains the maximum health risks from Alternative 7 do not extend to any of these nearby schools and childcare facilities. Additionally, page 411 of the PR-DEIR explains the nearby sensitive receptor is a residential dwelling unit located within 694 feet from the emissions sources and also identifies the nearest worker/commercial receptor at approximately 572 feet. The PR-DEIR analyzes the potential health risks and demonstrates that the maximum health risk from Alternative 7 is well below the significance thresholds. See Topical Response No. 4.

L21-60 The health risk values reflected in Appendix C.1 to the PR-DEIR reflect an emission inventory that did not account for reductions in organic hazardous air pollutants that will be achieved with the oxidization catalysts that will be installed as part of Alternative 7. A subsequent emission inventory and health risk assessment was completed to account for the emission control system after the SCAQMD application was prepared. The result of the newer, more accurate, risk assessment for Alternative 7 are contained in Table 5-3 of the PR-DEIR (page 5.47). The updated HRA shows cancer risk, non-cancer chronic risk, and non-cancer acute risk from Alternative 7 are well below the significance thresholds.

Information contained in on pages 527 and 564 of the PR-DEIR reflects health impacts attributed to the abandoned Alternative 6 without consideration for emission controls.

L21-61 Differences in results for Acute and Chronic Health risks also reflect differences between Alternatives 7 and 8, as well as the consideration of emission control systems for CEQA.

The health risk assessment analyzes the health risks for surrounding receptors within 16 kilometers radius of the emission sources. The maps on page 614 to 621 of the PR-DEIR show the locations of the maximum (cancer, acute, and chronic) health risks. Depending on the type of health risks being analyzed, the model shows various locations where the maximum values are present.

Since Alternative 7 contains different emission sources and parameters, the location showing the maximum values of health risks are expected to be different than Alternative 8.

L21-62 Please refer to Topical Response No. 4.

L21-63 Please refer to Topical Response No. 4.

L21-64 Please refer to Topical Response No. 4.

L21-65 This comment seeks clarification regarding whether startup/shutdown mode hours are overcounted as in the analysis. The total operations for Alternative 7 are 1,120 hours per year plus 280 startups (30 minutes each) for a total of1,260 hours per year per engine. To clarify Footnote B, there are 280 startups of 30 minutes duration each. Therefore, there are 280 hours, a portion of which (30 minutes) is affected by a startup. Therefore, the total startup time is 140 hours. (280 starts x 30 minutes per start). The total of 1,260 hours per engine per year is correct (1120 hours + 280 x 0.5). The startup hours are not "double that in Appendix C.1 in the PR-DEIR," as suggested by the commenter, because each startup hour is only 30 minutes.

L21-66 This comment concerns whether there are inconsistencies in the assumed operating hours. The table on page 598 of the PR-DEIR applies to Alternative 8 and references 1035.4 normal operating hours, 156 hours of startup / shutdown operations and 8.6 hours of maintenance operations, for a total of 1200 hours for Alternative 8. Maintenance hours are differentiated because of assumed higher emissions under that operating condition. The value of 1120 hours applies to Alternative 7, not Alternative 8. There is no inconsistency.

L21-67 Please see Individual Responses L21-65 and L21-66.

L21-68 Please refer to Topical Response No. 4.

L21-69 Please refer to Topical Response No. 4.

L21-70 Please refer to Topical Response No. 4.

L21-71 The commenter correctly noted an error. The difference in generating capacity between Alternative 8 and the proposed Project is 161 MW. This does not affect the comparison of Alternative 7 and Alternative 8 because the value of 161 MW is not used in any analysis comparing Alternatives 7 and 8.

L21-72 The commenter correctly noted that the Title of Table 5-8 incorrectly references Tesla / Wartsila Alternative 7, rather than the Unit 8 Reconfiguration Alternative 8.

L21-73 The 2018 FEIR includes a GHG analysis for the Project and indicates that GHG emissions attributed to the project are less than significant because they would be mitigated in the same manner that emissions are currently mitigated at the Grayson facility. That mitigation occurs through the CARB GHG Cap and Trade program. GHG emissions from Alternative 7 and Alternative 8 are approximately 11 percent and 14 percent of the emissions of the Project, respectively. Both Alternatives 7 and 8 are also less than significant. Please refer to Topical Response No. 4 and PR-DEIR page 5.48.

L21-74 An updated 2018 GHG baseline was included in the PR-DEIR (Appendix C Alternative 8 Attachments "GHG Emissions Inventory"). Please refer to Topical Response No. 4 regarding updated baseline information.

L21-75 Please refer to Topical Response No. 4.

L21-76 Please refer to Topical Response No. 4.

L21-77 The commenter notes a discrepancy in GHG emissions between the body of the PR-DEIR and the Alternative 7 application that was submitted to SCAQMD. The commenter is correct that the emissions numbers are different. Please refer to Topical Response No. 4 for a complete response.

L21-78 Alternative 8 emissions from power generating sources is 66,925 Metric Tons of CO $_{equivalent}$ (MTCO2e) and excludes 270 MTCO2e that results from facility occupancy. Emissions due to facility occupancy exist now with the current power plant staff and operations. These same staff would exist for the proposed Project, and Alternatives 7 and 8. Since the facility occupancy emissions existed in the past, exist now, and will exist in the future for a lower capacity facility that burns less natural gas, the 270 MTCO2e, was excluded because it does not represent an increase over existing conditions. Please refer to Topical Response No. 4.

L21-79 Please refer to Topical Response No. 4.

L21-80 Please refer to Topical Response No. 4.

L21-81 The commenter claims that some emissions sources are improperly omitted from the GHG analysis.

First, the commenter states that Alternative 7 does not include emissions from facility occupants. This analysis is show in Topical Response No. 4. Please also see Individual Response to L21-34.

Second, the commenter states that for both Alternatives 7 and 8, the analysis does not mention or disclose whether there would be emissions from the switching station and Tesla BESS. The Glendale Switching Station and the Tesla BESS do not produce any GHG emissions since they do not utilize combustion processes nor use SF_6 (sodium hexaflouride) electrical equipment.

The third bullet of the comment asserts that construction emissions of Alternatives 7 and 8 were not disclosed. Tables 4-12 and 4-13 of the 2018 FEIR include estimates of construction emissions for the proposed Project. Tables 4-12 and 4-13 also demonstrate that demolition and construction emissions of the proposed Project would be below applicable SCAQMD mass daily significance criteria and would result in a less than significant air quality impact. Sections 5.2.6.2 and 5.2.7.2 of the PR-DEIR notes that Alternatives 7 and 8 would involve the same or similar demolition and construction activities as the proposed Project. They would further occur on the same site, have an equivalent disturbance footprint, involve similar construction equipment, and have similar durations. It is there therefore reasonable to assume construction emissions of Alternatives 7 and 8 would be similar to the proposed Project which were disclosed in the EIR.

Fourth, the commenter notes that there is no analysis of GHG emissions from project-related use of off-road equipment and vehicle trips. The project descriptions for Alternatives 7 and 8 indicate that the scope of construction activities would be similar, regardless of the selected alternative or the proposed Project. (See PR-DEIR, Sections 5.2.6.1 and 5.2.7.1). Construction and off-road equipment emissions that would be attributed to the proposed Project were shown to be less than significant. Likewise, construction and off-road vehicle impacts of Alternatives 7 and 8 would less than significant.

Fifth, the commenter asserts that the PR-DEIR does not analyze GHG emissions related to energy produced outside of Glendale and used to charge the BESS. Please refer to the response to Individual Responses L21-27 and L21-28 regarding emissions related to energy used to charge the battery energy storage system.

Please refer to Topical Response No. 4.

L21-82 The Biogas Renewable Generation Project is not a part of, or the same as, or a direct or reasonably foreseeable consequence of, the Grayson Project. The Scholl Canyon Landfill has an existing Air Quality Management District-issued permit to burn the biogas emitted by the landfill regardless of whether it is burned at Grayson, flared on-site, or captured and converted to energy on-site by other means. The Biogas Renewable Generation Project is an entirely separate project with independent utility, meaning that regardless of the Project, the Biogas Renewable Generation Project is viable. The Biogas Renewable Generation Project is designed to efficiently capture existing landfill gas and convert that gas into energy which is fed into existing transmission lines at Scholl Canyon that connect with Glendale’s energy grid. Biogas from Scholl Canyon Landfill, which is a natural consequence of the decomposition of landfill materials, must, pursuant to the SCAQMD permit, either be flared off on-site or captured and converted to energy. Capturing and converting Scholl Canyon biogas is not a requirement of or prerequisite to the Grayson Project. The existing Grayson Plant and the Project are not dependent on biogas from the Scholl Canyon Landfill. Similarly, the Biogas Renewable Generation Project is not dependent on the approval or implementation of the Grayson Project; the gas can be flared off if the Grayson Project is approved and implemented. Also, please refer to 2018 FEIR Topical Response No. 11.

Additionally, the City has updated the baseline emissions in the air quality analysis to reflect the period which no landfill combustions occur at the Grayson Power plant. For more detailed discussion of the City's analysis of air quality impacts, see Topical Response No. 4.

L21-83 The comment pertains to the source of energy to charge the battery energy storage system and offsite storage of construction equipment and staging areas.

The preferential source of energy to charge the energy storage system is imported energy from renewable or other non-carbon resources. Local renewable energy (solar) will not be available as it will be used to serve electric demand during the day and is not available at night. The environmental impacts of the thermal resources that may be used when renewable and clean resources are insufficient were evaluated when those thermal resources were permitted. The energy used to charge the energy storage system will come from energy projects already evaluated under CEQA and/or other applicable environmental review processes. Please also refer to the response to Individual Responses L21-27 and L21-28. Laydown of construction materials is addressed in response to Individual Response L21-29.

L21-84 This is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. Please refer to Topical Response No. 6.

L21-85 The 100 percent Clean Energy study modeled both the 72 MW increase in Southern Transmission System (STS) transmission and 25MW associated with Eland and concluded that dispatchable combustion engines are still required to maintain system reliability.

The additional 72 MW has made the STS line a potential N-1-1 resource by 2027. Eland transmission will provide Glendale energy from the Eland project but not the capacity to supply reserves. The line is dedicated solely for Eland generation, which is a must-take resource. For detailed discussion, please refer to Topical Response Nos. 1 and 5.

L21-86 Please refer to Individual Comment L21-85 and Topical Response Nos. 1 and 8.

L21-87 Please refer to Topical Response No. 8.

L21-88 Please refer to Topical Response Nos. 2 and. 8.

L21-89 Please refer to Topical Response Nos. 6 and 8.

L21-90 Please refer to Topical Response No. 2.

L21-91 The commenter opines that GWP should have evaluated other alternatives, including an alternative based on Portfolio F from the 2109 IRP, but taking into account the additional 72 MW of transmission on the Southern Transmission System in 2027. Although the Southern Transmission System (STS) line (referred to in the comment as the SWAC line) increases by 72 MW in 2027, this increase will create a new and larger Second Largest Contingency, or N-1-1. In the event of the loss of the STS line, it would be a significant challenge to sufficiently maintain the 100 MW battery in the 2019 IRP Portfolio F during long duration contingencies. In addition, the Eland project is a must-take resources whose transmission is reserved for its generation and does not meet contingency reserve criteria. Please refer to Topical Response Nos. 1, 6 and 8.

L21-92 This is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. Please refer to Topical Response Nos. 2 and 5.

L21-93 This is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. Please refer to Topical Response No. 6.

L21-94 This is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L21-A This attachment to the email received from Elise Kalfayan on behalf of Glendale Environmental Coalition, received November 15, 2021, is a City of Glendale Report to the City Council regarding Amendment of Contracts with Stantec Consulting Services, Inc. and Black & Veatch Corporation for Additional Professional Services Pertaining to the Limited Notice to Proceed Phase of the Proposed Grayson Repowering Project Alternatives. The Action Item was approved for the December 15, 2020, calendar. The attachment is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. See Individual Response L21-9

L21-B This attachment to the email received from Elise Kalfayan on behalf of Glendale Environmental Coalition, received November 15, 2021, indicates search results from ceqanet.org of CEQA related projects between January 1, 2019, and November 12, 2021, in which the City of Burbank is the Lead/Public Agency. The attachment is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. See Individual Response L21-24

L21-C This attachment to the email received from Elise Kalfayan on behalf of Glendale Environmental Coalition, received November 15, 2021, indicates search results from ceqanet.org of CEQA related projects between January 1, 2019, and November 12, 2021, in which the City of Glendale is the Lead/Public Agency. The attachment is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. See Individual Response L21-24

L21-D This attachment to the email received from Elise Kalfayan on behalf of Glendale Environmental Coalition, received November 15, 2021, is a May 2021, BloombergNEF publication titled "The Spectacular Energy Storage Growth - Keeping the Power On: Sparking Energy Storage Solutions in Developing Countries" by Yayoi Sekine. The attachment is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. See Individual Response L21-88

L22 - Responses to Comments from Lee and Francesca Smith, received November 15, 2021

L22-1 This comment is a cover email to Lee and Francesca Smith, November 15, 2021 comment letter.

L22-2 See Topical Response Nos. 3 and 6. On December 15, 2020, the City Council expressly directed staff to not include a Project alternative that would preserve the boiler building.

L22-3 This comment contains a summary of alleged PR-DEIR inadequacies. See Topical Response No. 3.

L22-4 Comment contains a summary of reasons why commenter believes a supplemental or updated Cultural Resources Technical Report must be prepared. See also Topical Response No. 3.

L22-5 See Individual Response to L22-4.

L22-6 The commenter alleges the City undertook an "elaborate circumvention of the eligibility determination by California High-Speed Rail (HSR) for the Grayson Project Plan." Attachment 1 to Individual Response L22 is correspondence between HSR and Julianne Polanco at SHPO, and also correspondence from the

City of Glendale to HSR. Far from an elaborate circumvention as alleged by the commenter, the correspondence reflects the City's participation in the public comment process on HSR's DEIR as authorized by CEQA, a process in which TGHS could have also participated in but chose not to. As TGHS and the commenter were aware, the City's 2018 FEIR for the Grayson Repowering Project concluded that the site did not contain any eligible historic resources. The City had already published the 2018 FEIR when HSR released its DEIR for public comment in 2020. HSRs decision to revise its determination on National Register of Historic Places eligibility and to request SHPO's concurrence with its updated determination is part of the public participation process that can result in updated assessments based on new information, which HSR admits was "previously unknown to the Authority including documentation of substantial physical alterations to the power plant that diminished its integrity and ability to convey its historic significance". The comments concerning eligibility are moot as the City has elected to treat the See also Topical Response No. 3.

L22-7 The commenter asserts that the Grayson Power Plant was determined to be eligible for the National register of Historic Places in 2019. This assertion is based on High Speed Rail's survey for its DEIR and ignores High Speed Rail's correspondence attached to the commenter's comment letter, which reflects High Speed Rail's change in its determination based on new information. See RTC L22-6 above and Attachment D. Commenter also alleges that TGHS is a "by-right consulting party." TGHS is not a "by-right consulting party". See Topical Response No. 3, and Individual Response L22-6 above regarding required consultation, and whether the City was obligated to provide High Speed Rail with TGHS's opinions (e.g., its comments on the 2018 FEIR).

L22-8 The commenter alleges that no consultation efforts were made with TGHS. The allegation is false and is contradicted by the commenter's own correspondence. TGHS commented on the Grayson Power Plant DEIR; its comments and other's comments on cultural resources issues were included in and responded to in the 2018 FEIR. TGHS also participated in six months of discussions with the on the PR-DEIR. On December 15, 2021, Ms. van Muyden, one of the City's attorneys, referenced the November 3, 2020, letter from HSR to Julianne Polanco at SHPO, wherein HSR was recommending that SHPO concur with HSR's updated determination that the Grayson Power Plant was not eligible for the National Register of Historic Places, however she referenced the letter in reverse (Polanco to HSR). See also Individual Responses L22-6 and L22-7 above and Topical Response No. 3.

L22-9 The commenter alleges that the "Glendale Switch Rack was central to the property's operation as a power plant and should be considered historically significant as well. See Topical Response No. 3.

L22-10 The commenter asserts that the Grayson site was not evaluated for its engineering significance, but the DPR included as Attachment 1 to the commenter's letter includes a description of the place Grayson Power Plant's occupies within the history of power generation in California and in Glendale. The engineering significance is recognized; however, that is not the issue. The issue is whether or not significant building modifications that occurred over time as documented in the 25-page intensive level DPR diminished the Grayson Power Plant's ability convey historical significance. The expert conclusion following intensive level investigation was that it did not retain sufficient integrity to convey NRHP, CRHR or local register listing.

L22-11 The comment expresses a paraphrase or opinion (not a recitation of law) concerning the CEQA public participation process.

L22-12 See Topical Response No. 3.

L22-13 See Topical Response No. 6.

L22-14 See Topical Response No. 6.

L22-15 See Topical Response No. 6.

L22-16 See Topical Response No. 6. Comment is an opinion on reuse of power plant buildings and is does not provide a specific comment on the Project or the PR-DEIR.

L22-17 See Topical Response No. 6.

L22-18 The comment accuses the City of using the PR-DEIR as a post hoc rationalization for a predetermination that the Grayson Power Plant be demolished. The Commenter asserts, without evidence, that the Power Plant is more likely a locally and California Register Historic District. See also Topical Response No. 3.

L22-19 See Topical Response No. 3.

L22-20 See Topical Response No. 3 regarding the role of the Historic Preservation Commission.

L22-21 See Topical Response No. 3 regarding the role of the Historic Preservation Commission.

L22-22 See Topical Response No. 3 regarding the role of the Historic Preservation Commission.

L22-23 See Topical Response No. 3 regarding the role of the Historic Preservation Commission.

L22-24 See Topical Response No. 3 regarding cumulative impacts and related projects. The commenter questions the selection of related projects for the cumulative impact analysis and suggests additional projects should have been considered in the PR-DEIR. The purpose of the PR-DEIR was to evaluate additional feasible alternatives that could meet the Project objectives and reduce environmental impacts of the proposed Project rather than re-evaluate the proposed Project and the related projects that were considered in the cumulative impact analysis. Cumulative impacts to all other environmental resource categories were previously addressed in the Initial Study, Draft EIR, and/or 2018 FEIR.

Generally, a cumulative impact is an impact created by the combination of the project reviewed in the EIR together with other projects causing *related impacts*. CEQA Guideline 15065(a)(3), 15130(b)(1)(A), and 15355(b)(Emphasis added). An EIR need not discuss cumulative impacts that do not result in part from the Project CEQA Guideline 15130(a)(1); *Santa Monica Baykeeper v City of Malibu (2011) 193 Cal App 4th 1538, 1539. Also, in Sierra Club v West Side Irrig. Dist. (2005) 128 Cal App 4th 690, 700,* the court explained that if a project does not make some contribution to a cumulative environmental effect, the cumulative environmental effect cannot be characterized as a cumulative impact of that project. Accordingly, the projects chosen for determining a cumulative impact are those that create a “related” impact, in this case an impact on historic resources; otherwise, the impact is not characterized as cumulative.

L22-25 The commenter references the demolition of a 1908 craftsman home that was torn down by a private property in violation of Glendale Municipal Code as an example of the City’s allegedly overly restrictive review of cumulative impacts, which example the commenter believes should be included in the list of related projects. First, the illegal demolition was not a project – it was a crime, and that property owner was prosecuted. The commenter does not demonstrate how the prior unauthorized demolition of an historic building by a private property owner is related to the impacts on historic resources from this Project which would be undertaken based on a full environmental review in compliance with CEQA. See also Topical Response No. 3 (Historic Resources). See Individual Response L22-24 and 25 regarding cumulative impact analysis.

L22-26 The commenter inquires as to the potential historical resources impacts of the Western Reservoir & Bel Air Electric Substation Improvements and suggests those impacts would be known if the City conducted a city-wide survey as proposed by TGHS. The Western Reservoir & Bel Air Electric Substation Improvements project is a separate project from the Grayson Repowering Project and includes slope repair, erosion control measures, site drainage improvements, access road repairs, retaining wall repairs, fence replacement, and landscape and irrigation improvements. Activities potentially affecting the Pump House would involve reconfiguring the stairway to avoid a blower, flattening of the driveway, and modifying the driveway approach to allow better vehicle access. The Western Reservoir & Bel Aire Electric Substation Improvements are located more than 1.5 miles north of the Grayson Power Plant. The commenter does not provide substantive evidence that the proposed Project would result in cumulatively significant impacts when considered with the Western Reservoir & Bel Aire Electric Substation Improvements which are primarily limited to drainage and erosion control facilities that would not result in demolition of buildings. The comment is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. See also Topical Response No. 3 regarding mitigation measures.

L22-27 This comment is a continuation of the commenter's opinion concerning the cumulative impact analysis in the PR-DEIR.

L22-28 This comment is a continuation of the commenter's opinion concerning the cumulative impact analysis in the PR-DEIR, which is based on the commenter's presumption that the related project list is inadequate for purposes of analyzing cumulative impacts.

L22-29 See Topical Response No. 3 regarding embodied energy.

L22-30 See Topical Response No. 3 regarding embodied energy.

L22-31 See Topical Response No. 3 regarding embodied energy and the Sustainability Commission.

L22-32 This comment is a closing to the comment letter and reflects the commenters' opinion concerning the Project. The commenter's statement is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L22-33 Individual Responses L22-33 through -36 are attachments to L22, which are referenced in the comment letter, and which attachments are responded to within the Individual Responses to L22 and in Topical Response No. 3.

Individual Response L22-33 describes Attachment 1 to comment L22.

L22-34 Individual Response L22-34 describes Attachment 2 to comment L22.

L22-35 Individual Response L22-35 describes Attachment 3 to comment L22.

L22-36 Individual Response L22-36 describes Attachment 4 to comment L22.

L22-A This attachment to the email from Lee and Francesca Smith, received on November 15, 2021, contains letters regarding *High-Speed Rail Program, Burbank to Los Angeles Project Section Draft EIR*, and the unrestricted, updated DPR Primary Record for the Grayson Power Plant. The attachment is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L22-B This attachment to the email from Lee and Francesca Smith, received on November 15, 2021, is a letter originally submitted in November 2017, regarding *Comments on Proposed Grayson Repowering Project Draft Environmental Impact Statement*. Comments within this letter were responded to in Section 9.0, Response to Comments, of the 2018 FEIR. Please refer to Individual Response L781 for individual responses to comments made within the attachment. The comments within the attachment are included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L22-C This attachment to the email from Lee and Francesca Smith, received on November 15, 2021, contains letters regarding *High-Speed Rail Program, Burbank to Los Angeles Project Section Draft EIR*, Additional Information and Request for Review and Concurrence on Revised National Register of Historic Places Determination of Eligibility for Grayson Steam-Electric Generating Station (Grayson Power Plant). The attachment is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L22-D This attachment to the email from Lee and Francesca Smith, received on November 15, 2021, contains letters regarding Mitigation Measures recommended for the Project by the Glendale Historical Society. The attachment is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L23 - Responses to Comments from Lupe Ruelas on behalf of EarthJustice, received November 15, 2021

L23-1 This comment is a general statement expressing the commenter's comments are found in the pages below and requesting confirmation of receipt. The comments were received.

L23-2 This comment is a general statement expressing the commenter's previous comments submitted for the 2018 FEIR remain relevant. Please see the 2018 FEIR Individual Responses L959 and L1128 and 2018 FEIR Topical Responses No. 16: Groups of Similar Comments, which respond to Commenter's prior comments on the 2018 Draft and Final EIR.

L23-3 This comment is a general statement about the history of the Project.

L23-4 The commenter refers to a 93 MW Project Alternative's ability to meet all Project objectives with 65 percent less fossil-fueled generation compared to the proposed Project as demonstration that clean energy technologies and strategies to meet Glendale's energy needs are available. It is assumed that the commenter is referring to Alternative 7, which is the only Alternative evaluated that includes 93 MW of natural-gas fueled electricity generation. As noted on page 5.76 of the PR-DEIR, both Alternatives 7 and 8 would meet all Project objectives, but not until 2027. Please also refer to Topical Response Nos. 1, 5, and 6.

L23-5 This comment claims that GWP has used the incorrect reserve obligation to inflate Glendale's energy needs because GWP plans to sell excess fossil-fuel energy to neighboring regions. There is no basis in the letter to support this claim. Reserve requirements and the circumstances under which GWP would need to sell energy, and the parameters the City Council has set for use of natural gas generation at Grayson, are addressed in the Topical Response No. 1. Please also refer to Individual Response L23-17 and Topical Response Nos. 1, 5, 6, and 7.

L23-6 The comment claims that GWP should have included Aliso Canyon's potential closure in its project description, including the reduced availability of natural gas, gas costs, and impacts from acquiring natural gas from other sources. The potential closure of a different facility by a different agency is not proposed as part of the Grayson project and GWP cannot control the manner in which the Aliso Canyon facility may or may not be closed. Further, this comment presumes Glendale obtains natural gas from Aliso Canyon only. The comment is not supported by any evidence and constitutes speculation, which is not substantial evidence. GWP does not purchase natural gas directly from the Aliso Canyon facility and has various existing gas supply arrangements in place.

GWP's gas purchases utilize the SoCalGas transport services for delivery to Glendale. Gas supply agreements are in place, as well as transport service agreements with GTN Transcanada, Foothills, and PG&E pipelines, allowing GWP to import gas from Canada, or purchase gas from various hubs as necessary. Generally, GWP only purchases the estimated amount of gas needed based on the anticipated dispatch plan, and then uses what was purchased for a given day, so as to avoid exposure to Operational Flow Order (OFO) imbalance penalties. SoCalGas calls an OFO event during high or low pipeline inventory, and customers are required to balance gas deliveries with usage within a specified tolerance that has been tightened since the Aliso Canyon leak. The

Aliso Canyon Withdrawal Protocol[140] was also established in 2017 (revised in 2019) to define the conditions for withdrawal, limiting the use of the storage facility. In the 2021 Summer Technical Assessment[141], SoCalGas concluded that there is sufficient supply and capacity to meet the forecasted summer demand even without Aliso Canyon.

L23-7 This comment is a statement followed by a conclusion about the adequacy of the PR-DEIR without providing any supporting evidence. GWP solicited proposals for green energy and carefully considered and modeled potential additional sources of clean energy and is incorporating 50 MW of clean distributed energy resources into its utility supply plan. Please also refer to Topical Response Nos. 5, 6, and 7.

L23-8 This comment is a section heading in the commenter's letter that repeats the contentions previously stated in L23-5 and L23-6. Please refer to Responses L23-5 and L23-6.

L23-9 This comment states the general requirement under CEQA for an accurate project description. The PR-DEIR includes an accurate description of the project. The PR-DEIR was prepared and processed in accordance with all CEQA guidelines and California regulations. Please also refer to Topical Response No. 7 and Individual Responses L23-4 through L23-8.

L23-10 This comment claims the project description is incorrect because it overstates the reserve obligation, hides from decisionmakers GWP's alleged plans to sell excess energy, and does not include or evaluate impacts from the closure of Aliso Canyon. Please refer to Individual Responses L23-5 and L23-6 and Topical Response No. 1.

L23-11 This comment claims that GWP misstates its reserve obligations. GWP does not assert that the Balancing Authority Area Services Agreement (BAASA) is the source of GWP's N-1-1 reserve obligation; nor that the NERC's "Resource and Demand Balancing" or "BAL" Reliability Standards, which apply to Balancing Authorities, directly apply to GWP. However, GWP does have to comply with certain Reliability Standards that apply to in its roles as a Distribution Provider –

[140] Aliso Canyon Withdrawal Protocol (https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/withdrawalprotocol-revised-april12020clean.pdf)

[141] California Energy Commission SoCalGas 2021 Summer Technical Assessment as docketed https://efiling.energy.ca.gov/GetDocument.aspx?tn=237363&DocumentContentId=70549

Under-Frequency Load Shed (DP-UFLS) entity and as the Planning Authority for its system.

GWP has longstanding contractual obligations with LADWP, which broadly require GWP to meet its system's reserve obligations and operate and maintain its system in conformance with Good Utility Practice, and the applicable reliability standards**.** These contractual obligations have been in place for over 50 years and, in compliance with them, Glendale alone has met its system's load and reserve obligations, including covering its N-1 and N-1-1.

GWP currently relies on its BAASA with LADWP to procure 80 MW of contingency reserves to cover GWP's "N-1" contingency for 60 minutes. If GWP has a contingency that exceeds 80 MW or if the contingency last longer than the 60-minute period, GWP must obtain additional reserves to cover the contingency. GWP is also required to return in-kind any energy it procures from LADWP to cover this N-1 contingency, after the 60-minute period has run. The BAASA does not allow GWP to purchase reserves from LADWP to cover an "N-1-1" system contingency.

LADWP does not include GWP's load or reserve obligations in LADWP's planning and LADWP does not allow GWP to purchase additional reserves to cover GWP's N-1-1 contingency. LADWP also does not incorporate GWP's N-1-1 reserve requirements in LADWP's reserve calculation. Please also refer to Topical Response No. 1 and Individual Response L23-12.

L23-12 This comment claims that LADWP carries full reserves for its own N-1-1 contingencies and that those reserves cover GWP. LADWP does not carry reserves to cover GWP's N-1-1 contingencies as it has confirmed in correspondence to GWP that is referenced and quoted in Topical Response No. 1.

The N-1 and N-1-1 reserve obligations in the NERC Reliability Standards are not limited to Balancing Authorities under the "BAL" Reliability Standard. Such obligations are also reflected in the reliability standards applicable to Transmission Operators, Planning Coordinators, Planning Authorities, Transmission Planners and Distribution Providers who are interconnected to the Bulk Electric System.

In addition, LADWP does not include GWP in its planning and LADWP does not allow GWP to purchase planning reserves from it.[142] Please also refer to Individual Responses L23-5 and L23-11 and Topical Response No. 1.

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[142] See http://www.oasis.oati.com/woa/docs/LDWP/LDWPdocs/Pending_Attachment_K.pdf, which states: *"LADWP has provided and continues to provide wheeling services to the Cities of Burbank and*

L23-13 This comment claims that GWP's only reserve obligation is from the BAASA and it is 80 MWs.

The BAASA is not the agreement that establishes GWP's N-1 and N-1-1 reserve obligations. GWP's reserve obligations are established through multiple longstanding contracts with LADWP that make GWP responsible for meeting its system's reserve requirements.

The BAASA only allows GWP to purchase 80 MW of reserves (for 60 minutes) from LADWP to help cover GWP's N-1 contingency. If GWP's N-1 contingency exceeds 80 MW or 60 minutes, GWP has to procure obtain additional reserves to cover the contingency. That is why Schedule 5, Section 4.c. of the BAASA states "If GWP schedules more than 86 MW (at Nevada Oregon Border ("NOB")) on the PDCI sinking in the BAA, *GWP shall self-supply or purchase additional Spinning Reserves from a third-party to support the schedules greater than 86 MW*." That is also why Schedule 6, Section 4.c of the BAASA states "If GWP schedules more than 86 MW (at Nevada Oregon Border (NOB)) on the PDCI sinking in the BAA, *GWP shall self-supply or purchase additional Supplemental Reserves from a third-party to support the greater than 86 MW.* The additional 6 MW above the 80 MW is included to cover for transmission losses. However, it does not necessarily mean GWP will be able to use 86 MW of transmission. Therefore, it is inaccurate to say that GWP's reserve obligation under the BAASA is only 80 MW and that GWP is not subject to any reserve obligation outside of the 80 MW. Please also refer to Individual Responses L23-8, L23-11, and L23-12 and Topical Response No. 1.

L23-14 This comment again asserts that GWP inflates its reserve obligation and questions GWP's statement in the Integrated Resource Plan that it must maintain sufficient reserves to cover an N-1-1 event because termination of the BAASA would cause GWP to automatically become its own balancing authority.

The BAASA contains a "Termination for Convenience by the Party(ies)" clause, which provides that "[e]ither Party may seek to terminate this Agreement at any time with at least eighteen (18) months prior written notice to the nonterminating Party." This means either party can terminate the agreement whenever they like, without needing to have grounds for the termination. Therefore, GWP cannot rely on the BAASA to meet its reserve needs for the next several decades.

If the BAASA were to be terminated, GWP would have little choice but to become its own Balancing Authority. The fact that the Southern California Utility Power Pool (SCUPP) Agreement terminated in 2011 and it took until 2015 for the

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Glendale (which are in the LADWP control area), however, these cities perform their own transmission and resource planning.")

BAASA to be finalized has no bearing on this issue. After the SCUPP was terminated. GWP and LADWP agreed to continue to operate as if the SCUPP were still in place while they negotiated the BAASA. This oral agreement between the parties was contingent on GWP and LADWP continuing to actively negotiate the BAASA. If the BAASA negotiations would have ceased, so would the oral extension of the SCUPP. Therefore, the four-year extension of the SCUPP is inapplicable to a termination of the BAASA and in no way demonstrates that LADWP would continue to provide GWP balancing services if the BAASA is canceled. Put another way, it would be imprudent for GWP to assume that LADWP would agree to a similar extension if the BAASA is terminated and no replacement balancing agreement was being negotiated, which would be the case if LADWP is the entity prompting the termination.

The potential termination of the BAASA is not "a future political decision." The "Termination for Convenience" language allows either utility's General Manager to cancel the agreement at any time, without cause. Therefore, a termination of the BAASA can occur simply by LADWP's General Manager deciding that it is no longer profitable for LADWP to participate in the agreement. GWP cannot predict whether LADWP is planning to terminate the BAASA, and cannot opine on LADWP's intent regarding the BAASA, as the comment suggests. This is precisely why the BAASA cannot relied upon as a long-term solution to GWP's reserve needs. Please refer to Individual Responses L23-8, L23-1, L23-12 and L23-13 and Topical Response No. 1.

L23-15 This comment suggests that Burbank Water and Power's statements about its own reserve obligations are applicable to GWP and demonstrate that GWP is overstating its reserve obligations. GWP does not offer any opinion about Burbank Water and Power's (BWP) reserve obligations. GWP notes, however, that BWP has a different generation and transmission portfolio than GWP, which includes transmission rights over paths to which GWP does not have access, and rights that exceed those of GWP on paths that both cities use. In addition, BWP has the Magnolia Power Station at its disposal. This is a 323 MW natural gas-fired combined-cycle electrical power generating facility located in the City of Burbank. Therefore, BWP's configuration and resource mix (both transmission and generation resources), put it in different position than GWP.

Also, it is important to note that the quote from BWP's 2019 Integrated Resource Plan, referenced in the comment, fails to reflect the entire paragraph, which also reads:

> "*In this connection, it is important to note that LADWP does not guarantee that the full 80 MW of these reserves will be available for purchase every year,*

subject to LADWP's load growth and resource planning. BWP staff works closely with LADWP staff to manage this risk."

Therefore, even though BWP's circumstances are distinguishable from GWP, BWP's IRP acknowledges the limited nature of the BAASA and its associated risks. Please refer to Individual Responses L23-1, L23-6, L23-12, L23-13, and L23-14 and Topical Response No. 1.

L23-16 This comment claims that GWP intends to sell fossil-fueled energy to third parties during peak demand. Please refer to the Individual Response L23-6. Please also refer to Topical Response No. 1.

L23-17 This comment cites graphs in the 2019 IRP as purported evidence that GWP intends to sell energy to third parties. As noted in GWP's July 23, 2019 City Council staff report presenting the 2019 IRP, an IRP is a planning document that does not authorize specified actions. Rather, an IRP is designed to evaluate and provide guidance regarding the utility's electric supply over the course of the planning period.

The "Economic Opportunity" discussion referenced in the 2019 IRP, and the simulations shown in the referenced graphs, were presented as an option to the ratepayers of Glendale, not only to lessen the financial impact of the proposed repowering project, but to also have a potentially positive impact on the environment by offsetting even higher polluting resources. For example, Figure 16 simulates a dispatch of resources to meet load in the spring and summer of 2035. The text explanation notes: "The sales reflected in this graph reflects the option of GWP to run excess capacity resources to produce power more efficiently, cost-effectively, and in a more environmentally-friendly manner than other resources could while bringing revenue in for Glendale. In short, the relative efficiency of the proposed Ice units could allow Glendale to prevent the need for highly-polluting resources to be turned on elsewhere by generating power locally (at lower emission rates) and selling it to neighboring regions in need of power. Alternatively, GWP has the option of leaving these resources idle to reduce emissions locally, at the cost of increased emissions elsewhere and higher costs to GWP ratepayers."[143]

The 2019 IRP's modeling of potential cost-savings options is consistent with IRP requirements for Publicly-Owned Utilities (POUs), as stated in the California Energy Commission's Guidelines for Publicly-Owned Utilities' Integrated Resource Plans: "PUC [(*i.e.,* Public Utilities Code)] 9621 requires POUs to adopt an IRP to ensure the POU achieves the goals of fulfilling its obligations to serve its customers at just and

143 2019 IRP at page 47.

reasonable rates and minimize impacts on ratepayer bills."[144] Moreover, the IRP figures cited by the Commenter, and the unit dispatch modeled therein, do not reflect the limitations on new Grayson natural gas units imposed by the City Council in its July 23, 2019 Motion. Please refer to Topical Response No. 1.

L23-18 This comment continues to cite data in the 2019 IRP to argue that GWP intends to sell excess energy to third parties. Please refer to Individual Response L23-17. Please also refer to Topical Response Nos. 1 and 7.

L23-19 The comment provides information regarding the Aliso Canyon methane gas link and claims that GWP must analyze the significant environmental impacts from the Grayson Project that will result from the closure of Aliso Canyon. This comment presumes, without evidence, that the Project will create a significant environmental impact due to the closure of Aliso Canyon. Please refer to the Individual Response L23-5. Please also refer to Topical Response Nos. 1 and 7.

L23-20 This comment claims that the PR-DEIR fails to consider and improperly rejects several alternatives that would avoid or substantially lessen the Project's environmental impacts. This comment claims the PR-DEIR's consideration and rejection of alternatives was improper but does not provide any evidence to support this contention. Please also refer to Topical Response Nos. 1, 6 and 7 and Individual Response L23-21.

L23-21 This comment claims that the PR-DEIR improperly dismissed an alternative to rely on LADWP to supply 100 MWs for an additional six years as an interim solution until GWP acquires an additional 72 MWs from the Southern Transmission System in 2027. This comment contends that GWP has a commitment from LADWP to assume a "full obligation" to provide Glendale with the full contingency reserve under the BAASA. This is not a correct statement. GWP is not currently islanded and shares interconnection with LADWP. GWP has transmission capacity contracts with LADWP, which are fully utilized during peak load conditions and with increasing renewable and clean power. In addition, LADWP's agreement to provide GWP with power during Grayson Repower, referenced by the Commenter, expired when the City Council did not act on the 2018 FEIR. GWP discussions with LADWP regarding GWP's procurement of long-term power or reserves have been unfruitful. It is important to note that due to the transmission constraints on the VIC-LA path that it is difficult to import power into the GWP

[144] See California Energy Commission Publicly Owned Utility Integrated Resource Plan Submission Guidelines (Second Edition), available at: TN224476_20180813T120545_Publicly_Owned_Utility_Integrated_Resource_Plan_Submission_and.pdf

system outside of Glendale's existing TSAs with LADWP. Please also refer to Topical Response No. 1.

L23-22 This comment claims that the PR-DEIR fails to thoroughly evaluate alternatives to manage project load growth, specifically an alternative to encourage electrical vehicle charging during off-peak hours. The comment claims further that Burbank Water and Power's statements regarding its ability to manage anticipated increases in demand due to electrical vehicle charging will not result in future load growth. GWP cannot opine on BWP's load forecasts, but it agrees with the comment that "GWP and BWP manage different energy portfolios." This comment is an opinion about how GWP should manage its utility compared to a utility in a neighboring jurisdiction.

Regarding the comment on load management alternatives, in its Clean Energy RFP, the City issued an open-ended solicitation for proposals for any form of clean energy alternatives to help reduce the size of the proposed Grayson Repowering Project. The proposals for demand side management received by GWP did not offer sufficient capacity to cover GWP's power demand. After evaluating and modeling the Clean Energy Proposals, GWP selected Lime Energy/ Willdan to provide a commercial direct install energy efficiency program, and selected Franklin Energy to deliver a commercial and residential demand management program. The PR-DEIR is based upon the successful installation of 50 MW of energy efficiency, demand response, and distributed clean energy resources. These programs are in addition to GWP's many other successful and ongoing energy efficiency and demand side management programs, including behavioral demand response and electric vehicle programs. GWP is currently developing an electric rate plan which, at the option of City Council may include changes to time-of-use rates and continues to evaluate new energy efficiency and energy savings opportunities. Please also refer to Topical Responses Nos. 1, 6 and 7 and Individual Response L23-15.

L23-23 This comment claims that the PR-DEIR incorrectly rejected alternatives that would require additional transmission. This comment claims that Glendale can join the CAISO at any time and bases its contention on the 2015 IRP and also bases its contention on a citation to a Sierra Club comment letter on the 2018 FEIR. The information on which this comment is based is either incorrect or outdated. GWP would have to become part of the CAISO Balancing Authority Area (BAA) to participate in the CAISO markets. GWP could in theory make bi-lateral purchases from generators located in the CAISO BAA if it were able to get that electricity through and out of the CAISO, through the LADWP BAA and into GWP's system. This requires GWP to have an interconnection with the CAISO BAA and sufficient transmission rights over LADWP's BAA to deliver this electricity. The lack of available transmission through LADWP's BAA is why GWP has been unable to procure additional energy from remote generators. For GWP to interconnection directly to the CAISO, it would require it to build new transmission facilities.

Construction of new transmission facilities is extremely difficult. In addition, there are a number of risks and concerns with building new transmission and CAISO interconnections, which were presented in the 2015 Integrated Resource Plan and still exist, even more so, today. There are uncertainties around transmission development cost, reliability of connection to CAISO, and an increase in GWP's single largest contingency (SLC). (See 2018 FEIR, Topical Response No. 2). The City of Glendale is landlocked and the available of right-of-way for transmission development is next to none.

Also, with new CAISO interconnections, there is no guarantee that the energy, needed to serve Glendale's load, would be available when needed most, during high temperature/load days, typically encountered during the summer months, when energy demands are the highest. The CAISO's recent actions (August 2020 export curtailments) and forecasted capacity shortfall, makes Importing energy from the CAISO a non-firm option.

Further, the $66 million figure referenced in the comment, from 2014, does not reflect current costs, especially, in light of inflation. In addition, it should not be compared to the repower costs without adding the additional costs of the energy and transmission that would have to be purchased within the CAISO to deliver power to the GWP system.

Most importantly, if a 150 MW interconnection with the CAISO were built it would become GWP's most severe single contingency, also referred to as its SLC (*i.e.,* its new N-1). This means that GWP would have to maintain 150 MW of reserves to cover this new N-1 contingency, which is over 100 MW greater than would be required under the Grayson repower alternatives. Therefore, if the costs of energy and transmission are included with the costs of the additional reserves GWP would have to procure to meet this new N-1 contingency, it is likely that costs of an interconnection with the CAISO would exceed the Grayson repower costs. And Glendale would still need to figure out how to meet these new, increased reserve requirements with its limited transmission and no local generation.

For the reasons stated above and in the 2018 FEIR and PR-DEIR, GWP determined that interconnecting with the CAISO is an infeasible alternative to the Project. Please also refer to Topical Response No. 6 and 2018 FEIR Topical Response No. 2, and 2018 FEIR Individual Response L298-80.

L23-24 This comment claims that GWP is proposing an imprudent economic decision to invest in new fossil-fueled generation when additional transmission beyond 2030 will be required to meet its obligations under Senate Bill 100. Please refer to response to comment L23-23. Please refer to Topical Responses Nos. 1 and 6.

L23-25 This comment claims that the PR-DEIR does not provide clear information as required by CEQA because it relies on fundamental errors and flawed analysis to justify a project that exceeds Glendale's energy needs. Please refer to Individual Responses L23-1 though L23-24 and Topical Response Nos. 1 and 7.

L23-26 This comment claims that errors in the PR-DEIR needed to be corrected. Please refer to Individual Responses L23-1 through L23-24 and Topical Response Nos. 1 and 7.

L23-27 Exhibit 1 to comment letter L23 is commenter's prior comments to the Grayson Project Draft EIR. Please see 2018 FEIR Individual Response L959, which responded to these comments.

L23-28 Exhibit 2 to comment letter L23 is commenter's prior comments to the Grayson Project Final EIR. Please also refer to 2018 FEIR, Response to L959.

L23-29 Exhibit 3 to comment letter L23 is an Order on Compliance filing issued by FERC on October 15, 2015. Please refer to Individual Response L23-12.

L23-30 Exhibit 4 to comment letter L23 is the WECC Contingency Reserve Standard. Please refer to Individual Response L23-12.

L23-31 Exhibit 5 to comment letter L23 is the Glossary of Terms Used in NERC Reliability Standards, updated on June 28, 2021. Please refer to Individual Response L23-12.

L23-32 Exhibit 6 to comment letter L23 is a webpage from the CEC regarding Senate Bill 100. Please refer to Individual Response L23-24.

L23-33 Exhibit 7 to comment letter L23 is a research paper assessing methane emissions from the United States oil and gas supply chain. Please refer to Individual Response L23-19.

L23-34 Exhibit 8 to comment letter L23 is an editorial in the Los Angeles Times regarding the Aliso Canyon methane blowout. Please refer to Individual Response L23-19.

L23-35 Exhibit 9 to comment letter L23 is an article in the New York Times regarding the Biden Administration's moves to limit methane. Please refer to Individual Response L23-19.

L23-36 Exhibit 10 to comment letter L23 is an article in the Los Angeles Times regarding a planned expansion of the Aliso Canyon facility. Please refer to Individual Response L23-19.

L24 - Responses to Comments from Webster, McKinsey and Lea, received November 10, 2021

L24-1 This is a general statement introducing the commenter and stating that they are submitting 13 arguments against certification of the EIR. In response, each of those 13 arguments is repeated below, followed by a response.

L24-2 This is a general statement introducing the commenter.

L24-3 This is a general statement about the commenter's opinion of (or preference about) the Project and the 2019 Integrated Resource Plan.

L24-4 This is a Table of Contents for the comment.

L24-5 The commenter stated "*A cursory look at GWP's plan (figure 1 from the 2019 IRP, shown on the facing page, clearly shows that GWP has no intention of complying with this State law. Recent actions by GWP (such as contractually obligating the City to purchase fossil fuel generated energy from the repowered Intermountain gas project through the year 2077) lend further evidence to this conclusion.*"

The 2019 IRP submitted to the California Energy Commission had a planning horizon through 2030. Nonetheless the plan sets Glendale up to comply with SB 100. The Intermountain Power Project (IPP) has a plan to transition to 100 percent green hydrogen fuel starting from 30 percent hydrogen in 2025 while moving to 100 percent by 2035. Green hydrogen is created through the process of electrolysis powered by carbon-free energy. Participation in the IPP Repower Project also allows for additional transmission capacity for renewable power to be delivered to the City of Glendale. Magnolia Power Plant and Grayson Unit 9 are expected to be retired before 2040 and Glendale will explore how to replace their capacity with clean resources in the next IRP. The 93 MW of reciprocating engines are primarily intended for contingency and high load events, and GWP is exploring the options to power the reciprocating engines with clean renewable fuels. Alternates 7 and 8 have pathways for green hydrogen. Please also refer to Individual Response L5.

The commenter further stated, "*A further statement (page 23 of the 2019 IRP) that: "Carbon-free retail sales by 2045 ... translates to approximately 90 percent Green-House-Gas free total energy when accounting for system losses." is incomprehensible, incorrect and completely absurd. It misstates both the letter and the intent of SB 100 and purports to say that somehow energy delivered to retail customers and energy consumed by system losses (about 7 percent in*

Glendale, and about 3 percent on our incoming transmission lines) are different, and that the energy consumed by system losses can be fossil-fuel derived."

The text of SB 100 is clear that retail sales are to be carbon free. SB 100 does not state the electricity sector should have zero emissions. In resource planning, we refer to "retail sales" as the amount of energy delivered to the customer retail meter while "net energy for load" is the amount of energy output by remote grid resources, the difference being the energy lost in transmission and distribution. The difference in losses is on average a 10 percent difference. SB100 was specifically worded this way to allow for a small amount of natural gas emissions for critical reliability units such as the proposed 93 MW at Grayson. This clause manages costs for all ratepayers. Decarbonizing the last 10 percent of emissions is widely believed to be orders of magnitude more expensive than the first 80 to 90 percent. Please refer to Topical Response No. 5. See also, California Water and Power Magazine, Fall 2021 edition, Cover Story – Pathways to Zero-Carbon Energy, available at https://ruralite-cmua-ca.newsmemory.com/?mc_cid=9ddbb8dca8&mc_eid=6a8cca7ce7

L24-6 The commenter stated *"Over the past 10 years GWP has been generating (with fossil fuels) or importing 500 GW hrs more of energy annually than is needed by Glendale and selling this excess energy on the wholesale market at a significant financial loss to the City. There are valid reasons for such action in a fossil-fuel oriented energy environment. In a zero-carbon environment, required by 2045, this will no longer be permitted. In 2017, for example, we generated or imported 1,710 GW hrs of energy to service a Glendale load of only 1,062 GW hrs. Only 31 percent of the total was zero-carbon. GWP claims a much higher percentage of renewables or zero-carbon by completely ignoring the 522 GW hrs of our total energy supply which was sold to other utilities at a large financial loss to the City."*

SB100 clean energy requirement applies to retails sales. It does not apply to non-retail sales, transmission and distribution losses, and storage roundtrip-efficiency losses. In 2017, GWP Retail Sales were supplied with 37 percent Renewable and approximately 57 percent zero-carbon, not 31 percent as stated. See below:

Version: July 2018

2017 POWER CONTENT LABEL		
City of Glendale		
ENERGY RESOURCES	Power Mix	2017 CA Power Mix**
Eligible Renewable	37%	29%
Biomass & biowaste	15%	2%
Geothermal	2%	4%
Eligible hydroelectric	3%	3%
Solar	0%	10%
Wind	17%	10%
Coal	6%	4%
Large Hydroelectric	13%	15%
Natural Gas	27%	34%
Nuclear	7%	9%
Other	5%	<1%
Unspecified sources of power*	5%	9%
TOTAL	100%	100%
* "Unspecified sources of power" means electricity from transactions that are not traceable to specific generation sources. ** Percentages are estimated annually by the California Energy Commission based on the electricity sold to California consumers during the identified year.		
For specific information about this electricity product, contact:	City of Glendale (818) 548-3300	
For general information about the Power Content Label, please visit:	http://www.energy.ca.gov/pcl/	
For additional questions, please contact the California Energy Commission at:	844-454-2906	

GWP forecasts load and balances supply on an hourly basis. Short positions are usually filled with bilateral short-term or spot purchases and in block of hours (peak/off-peak). Historically, this is the most cost-effective approach to minimize exposure to price volatility. Since hourly load shape does not exactly match the supply profile and forecasted load may drop based on changes in temperature, GWP may have excess energy to sell (after ramping down variable resources) to maintain system frequency and reliability. Off-system sales might also occur when there is a transmission outage/derate that prevents delivery of contracted generation to Glendale's load. GWP may also need to unload power from other non-RPS resources and replace with renewables to meet RPS compliance requirements. Please also refer to Topical Response No. 1 Section 13 "Third Party Sales of Energy" for further discussion.

L24-7 The commenter stated *"Figure 3 from the IRP shows GWP's projected GHG emissions from its fossil fuel energy production, both local and imported. Please* *observe the 2030 projection, which shows generation of GHG at 250,000 metric tons. Using the EPA equivalency standard of 1022 pounds (0.46 metric tons) CO2 per Mega Watt hr delivered energy, this equates to 543 GW hrs of fossil fuel energy generation, somewhat more than the average of the previous 10-year period or 523 GW hrs per year. Is This Progress?"*

The 2030 projection of the IRP is within the GHG planning targets established by the California Energy Commission, and this has been confirmed by the California Energy Commission through its own review.[145]

The commenter further stated *"A further misrepresentation in the figure is GWP's treatment of EV's and tailpipe emissions. Please observe the green bar in the 2030 section of figure 3. This segment represents 200,000 metric tons of GHG emissions which GWP mysteriously claims credit for avoiding. It is as if these EV's are driving around the City sucking up 200,000 metric tons of GHG per year and getting rid of them. The reality is quite the contrary. Not only do the EV's not remove GHG's, but tailpipe emissions are not a factor in the EIR evaluation of a new gas plant in Glendale. Furthermore, every MW hr of the energy these EV's use must be generated locally or imported, and our use of locally generated or imported fossil fuel based energy is increasing not decreasing."*

Figure 3 demonstrates the linkage between transportation sector and the electric sector. The figure and narrative clearly state that in the future electric vehicles will take trips that were previously taken by gasoline vehicles. These vehicles run on clean electricity provided by GWP. This represents a GHG reduction in the transportation sector that would not be possible but for the clean electricity provided by GWP. Even in the case of an EV owner having solar panels, most at home charging occurs at night when GWP is providing power. Tailpipe emissions are relevant as the vast majority of criteria air pollutants as well as GHGs in the LA basin come from vehicles. As the 93 MW of reciprocating engines are an integral part of a reliable Glendale power system, they help enable a region-wide conversion of vehicles as well as indoor air and water heating to electricity, and thus it has a direct impact on improving air quality in the region.

L24-8 The commenter stated *"In 2019, for GWP's proposed Portfolio E, Glendale is responsible for 540,000 metric tons of GHG emissions or the equivalent of 1,174 GW hrs of electric energy generation. By 2030 this figure is reduced to 191,000*

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[145] See page 14 of California Energy Commission Staff Report, Review of Glendale Water and Power's 2019 Integrated Resource Plan, dated November 2019, and available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=231964&DocumentContentId=63826. See also, the California Energy Commission Resolution No. 20-0220-9, entitled "Resolution Finding Glendale Water and Power's Integrated Resource Plan Consistent With Public Utilities Code Section 9621," available at California Energy Commission : Docket Log

tons of GHG, showing definite progress. But from 2030 to 2038 GHG emissions rise from that 191,000 tons to 270,000 metric tons, well in excess of the CARB's upper limit of 200,000 metric tons."

For the 2019 IRP, CARB established a GHG emission target range of 119,000 to 210,000 metric tons of carbon dioxide equivalent (MMT CO2e). As stated in the 2019 IRP, "while these limits are non-binding, they are meant to be used as planning criteria and GWP has chosen to use them as targets in this IRP" (2019 IRP at page 23). The California cap and trade system enables purchasing of emissions allowances for compliance[146]. The table below[147] shows GWP's resources associated with GHG, as modeled in the 2019 IRP:

Table 4 shows GHG emissions for Glendale's portfolio of resources in 2019, 2025, and 2030.

Table 4: Greenhouse Gas Emissions from Glendale's Resources Portfolio

Source	Fuel Type	GHG Intensity (MT CO_2e /MWh)	2019 Emissions (MT CO_2e)	20205 Emissions (MT CO_2e)	2030 Emissions (MT CO_2e)
Grayson Units 3-8	Natural Gas	0.702	12,230	-	-
Grayon Unit 9	Natural Gas	0.684	13,836	5,188	4,724
Wartsila ICEs	Natural Gas	0.532	-	62,647	56,803.7
MSCG/Skylar (not RPS-eligible)	Unspecified	0.428	57,620	28,810	28,810
Magnolia	Natural Gas	0.535	70,143	76,281	62,164
IPP - Coal	Coal	1.303	269,914	120,284	-
IPP - Repower	Natural Gas	0.492	-	51,580	78,702
Spot market purchases	system	0.428	157,809	64,193	65,447
Spot market sales	system	0.428	-49,198	-97,194	-103,257
Total Portfolio emissions	NA	NA	532,354	311,789	193,394

Source: California Energy Commission, based on Glendale's 2019 IRP Filing.

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146 2019 IRP at page 12.

147 See page 14 of California Energy Commission Staff Report, Review of Glendale Water and Power's 2019 Integrated Resource Plan, dated November 2019, and available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=231964&DocumentContentId=63826. See also, the California Energy Commission Resolution No. 20-0220-9, entitled "Resolution Finding Glendale Water and Power's Integrated Resource Plan Consistent With Public Utilities Code Section 9621," available at California Energy Commission : Docket Log

Based upon green developments since 2019, GWP's portfolio is expected to be even cleaner in future years than was projected in the 2019 IRP. Factors that will drive a decrease in GWP emissions include the plan to use hydrogen fuel at the Intermountain Power Project – 30 percent green hydrogen by 2025, with a plan to transition to 100 percent hydrogen by 2035, thus eliminating all resources associated with this resource. In 2024, the Eland I Solar and Storage Project will reduce future short term energy purchases. Beginning in 2027, the additional 72 MW of capacity on the Southern Transmission System transmission line will enable Glendale to import more long-term renewable energy sources, thereby further reducing GHG associated with short-term purchases. Magnolia and Unit 9's natural-gas fueled technology will also be replaced with cleaner alternatives in the future.

GWP and Ascent Analytics presented the 2030 100 percent Clean Energy study to City Council in March 2021that shows the potential for an 89 percent around the clock clean energy portfolio. The next IRP will explore options to further increase clean energy content while maintaining compliance to regulatory requirements. See also, Individual Response L24-5.

The commenter further stated *"GWP rationalizes this approach by stating that only energy delivered to meet our retail load need be "counted" in the zero-carbon requirement. But where will there be a wholesale market for this fossil fuel energy when the entire California grid becomes zero carbon in 2045? Will we build new transmission lines to states where fossil fuel energy is still permitted?"*

2045 is too far away to speculate on wholesale market rules. SB 100 states retail sales must be carbon-free, which can allow for limited amounts of carbon emitting resources at the generation level.

L24-9 The commenter stated that the IRP and PR-DEIR fail to analyze and optimally size the BESS in any of the alternate systems considered. The commenter expressed concern that a 300 MW-hour battery in the proposed Alternatives would be significantly undersized and will not provide the required reliability or ancillary services required for a modern, repowered Grayson.

Batteries are critical assets to enable Glendale's clean energy future and the 75 MW/300 MWh storage is optimal for the current repower project. Additional storage capacity and duration is envisaged to be added through time. Current, models indicate that a much larger battery would be difficult to keep sufficiently charged when needed given transmission and local generation constraints. GWP will continue to evaluate battery storage options in the next IRP. Also, please refer to Topical Response No. 8.

L24-10 The commenter stated that GWP's 300 MWH battery sizing is not correct.

Current, models indicate that a much larger battery would be difficult to keep sufficiently charged when needed given transmission and local generation constraints. GWP will continue to model additional storage in the next IRP. The ICE engines proposed in Alternative 7 are primarily operated for reliability events and to serve in extended N-1 or N-1-1 contingencies, and high load scenarios, and not for charging the battery. See Individual Response L24-9 and Topical Response No. 1.

L24-11 The commenter stated *"Our studies indicate the same! If we cannot get to a zero-carbon electric utility without new transmission, then we must look to new transmission, and we must begin immediately if we are to achieve this capability, even by 2045!"*

In 2020/2021, GWP was able to secure an additional 72 MW on the STS line. The additional transmission capacity will enable Glendale to import more renewables into Glendale starting in 2027. Additionally, as part of the Eland 1 Solar and Storage project, LADWP delivers that energy to Glendale. The Eland transmission rights that Glendale will gain in 2024 can only be used for the transmission of Glendale's 25 MW share of the Eland project.

GWP is continuously looking for opportunities to increase its transmission capacity. (Refer to Topical Response No. 1 to "Why Hasn't GWP Added More Transmission Import Capacity Instead of Proposing to Repower Grayson").

The commenter identifies "Four Approaches" to new transmission. All these interconnections would require GWP to join the California ISO and the transmission line could become our single largest contingency. See Individual Response L23-23 and Topical Response No. 1.

L24-12 The commenter stated that options for New Transmission were not considered. In fact, no options for new Transmission were considered.

Please refer to Individual Response L24-11 and Topical Response No. 1.

L24-13 The commenter stated *"GWP does not have the transmission capability to import even the renewable and zero carbon energy resources they have included in the proposed portfolio E."*

Based on the optimization model used in the [2019 IRP 100 percent Clean by 2030 Study] GWP over-procures solar and wind capacity in reference to transmission capability. Wind and solar generation profiles tend to complement each other, i.e., have minimal overlap. Importing both solar and wind energy on the same transmission system is an efficient way of utilizing the City's limited transmission system. In addition, solar and wind resource types have low capacity factors.

Generally, grid scale solar resource capacity factors range between 20 percent to 30 percent and 35 percent to 40 percent for wind. Also, solar and wind energy is generally not coincident (meaning, their peak generation does not happen at the same time), GWP's over-procurement allows it to maximize the utilization of GWP's contracted and limited transmission capacity. This strategy minimizes the City's costs. (See Topical Response No. 2).

In the event the generation of solar and wind exceeds the available transmission, excess output can be stored in offsite storage, sold in the bilateral market, and/or used for generating green hydrogen.

L24-14 The commenter stated, *"Unfortunately, in Argument 5, we show that GWP plans to make use of fossil fuel generation at over 500 GW hours per year (approximately one third of our energy needs) up through their planning horizon of 2038."*

This statement is incorrect. The 100 percent Clean by 2030 Study shows the 93 MW plant can operate as low as 1 percent capacity factor in average conditions. This is equivalent to ~8 GWh/year. Anticipated growth in renewables will reduce usage of the reciprocating engines except during periods where the grid is stressed due to exceptionally high load or resource outages. The air permit will impose limits on the reciprocating engines to restrict the number of times the engines can startup and the operating hours on both a monthly and annual basis and the amount of fuel they can burn. See Topical Response No. 4.

The 100 percent Clean by 2030 Study shows 375 GWh from thermal plants during the year 2030 due to must run commitments from Magnolia and IPP. By the year 2030, IPP will run on a blend of at least 30 percent green hydrogen which will reduce carbon emissions from IPP. GWP is exploring options for the future of Magnolia.

L24-15 The commenter stated *"The gray bar appearing in 2036 is said to be a modeling of a transmission failure, but that failure criterion (N – 1 – 1) is already built into the basic system parameters to be modeled. Are they not double-booking transmission failures to put their strawman system in a bad light and justify further their fossil-fuel-heavy preferred portfolio E?"*

Transmission failures are not "being double-booked." The model assumes normal system conditions. A simulated N-1-1 condition (grey shaded area) shows what would happen in the absence on the 93 MW of ICE units proposed in Alternative 7; extended rolling blackouts. With respect to the range of alternatives generally, please see Topical Response No. 6, as well as Topical Response No. 4 in the 2018 FEIR. See also Topical Response No. 1.

L24-16 The commenter stated *"GWP's plan gets us to 72-80 percent zero carbon by 2045 and is not even close to meeting State law."*

Under the 100 percent Clean Energy by 2030 study, GWP can reach up to 89 percent clean around-the-clock by 2030 using only commercially available technologies with increased STS transmission capacity and Eland energy. The last 11 percent would require additional transmission and advancements in long duration storage and alternate renewable fuel for combustion engines such green hydrogen. LADWP, in their LA100 Study, authored by National Renewable Energy Laboratory in partnership with LADWP, also came to a similar conclusion. (Refer to Topical Response No. 5 for more details)

Glendale's plan also includes local residential/commercial storage components, as well as storage options for grid-scale solar projects. The 300 MWH of local grid scale storage is the optimal size given the limitation in transmission capacity. GWP will evaluate augmenting local battery storage to address anticipated increase in peak demand in the next IRP. Please also refer to Individual Response L24-9.

Alternatives 7 and 8 includes storage and combustion engines that are hydrogen-ready or can be retro-fitted to use hydrogen in the near future, once green hydrogen becomes commercially available. (Refer to Topical Response No. 1 for more details)

L24-17 The commenter stated that "A majority of the City Council Promised the Voters of Glendale a Zero Carbon 2030 Plan**."** The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. Please see Topical Response No. 5.

L24-18 This comment is primarily a quote from James Hansen to the effect that climate change is an emergency. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L24-19 The comment is providing contact information of the commenter. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L25 - Responses to Comments from Rachel Ridgway, received November 15, 2021

L25-1 This comment is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L25-2 This comment requests consideration of Denver's plan to convert a coal plant to an energy storage facility. Energy storage is included as a part of the Grayson project alternatives. Lithium-ion battery energy storage technology was chosen for the alternatives over thermal energy storage because thermal energy storage would typically require an associated steam turbine power generation cycle to convert the thermal energy into electricity. Such a system does not offer the quick response (<10 minutes from not operating to full load) that either the battery energy storage system or the proposed thermal generations options offer. Molten salt thermal energy storage would also require electric heat to maintain the salt temperature adding to GWP's electric load. While solar thermal could be used, available space is a constraint. Additionally, retrofitting new equipment into the Boiler Building would necessitate a seismic upgrade of the building as well as the already-planned removal of all of the hazardous materials. Please see Topical Response No. 6.

L25-3 This comment asserts that the City could use the money being used to purchase offsets for greenhouse gas emissions from this project to instead expand its distributed network of green energy. The proposed Project is required to acquire offset credits for the increase emissions of greenhouse gas. The GHG emissions from Alternatives 7 and 8 are below the significance thresholds of 10,000 metric tons per year; therefore, pursuant to CEQA, the GHG emissions from both Alternatives 7 and 8 are not significant and do not require any offsets or similar mitigation actions (Please see Topical Response No. 4). Additionally, please refer to Topical Response No. 1 of why Grayson is needed to assure the ability to meet peak load and cover contingencies.

L25-4 This comment is a closing statement and the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L25-5 This attachment to the email from Rachel Ridgeway, received on November 15, 2021, contains a September 23, 2021, article from The Denver Gazette entitled "Xcel Energy looking at preserving Hayden plant as molten salt energy storage facility." The attachment is included in the Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project. Please see Individual Response L25-2 above.

L26 - Responses to Comments from Jennifer Pinkerton, received September 13, 2021

L26-1 This is a general statement thanking the GWP General Manager.

L26-2 Please refer to Topical Response No. 3.

L26-3 The commenter asks about the required procedure for providing notice of the PR-DEIR issuance. The required procedure is the same as for an initial draft EIR, a notice of availability is posted and circulated. In addition, notice must be given to parties that commented on the original Draft EIR. The City complied with these requirements by issuing a new notice of availability on August 9, 2021 and on October 1, 2021, and by providing notice to all parties who commented on the Draft EIR. The City also extended the comment period for the PR-DEIR by an additional 60 days.

L26-4 This comment is a general statement regarding additional individuals copied on the email.

L27 - Responses to Comments from Larry Moorehouse, received September 21, 2021

L27-1 This is a general statement notifying the email will be sent to all council members.

L27-2 Please see Individual Response to L27-3.

L27-3 The Final EIR for the Scholl Canyon Biogas project analyzed the environmental impact of locating the internal combustion generators proposed for the Biogas Project at the Grayson Power Plant and sending the landfill gas (LFG) to the Grayson Power Plant to be utilized in those new engines. The Final EIR for the Biogas Project concluded that this alternative (Alternative 4) was not the environmentally superior alternative. For more information, please see Section 5 of the Final EIR for the Scholl Canyon Biogas Project.

Burning LFG in the existing Grayson boilers is no longer permitted by the SCAQMD due to the health risks of this practice. Burning LFG does not allow the boilers to "burn cleaner and provide more energy output and meet the SCAQMD environmental rules."

LFG used to be burned in the Grayson boilers in combination with natural gas. Through the analysis for the proposed Project, it was determined that burning the LFG in the existing boilers was contributing to an unacceptable level of emissions based on SCAQMD's Health Risk Assessment and the boiler technology in place. The health risks were reported to City Council and the public and GWP committed to the SCAQMD, through an enforceable Risk Reduction Plan, to immediately and permanently discontinue the combustion of LFG in the boilers. No other device at Grayson is permitted to combust LFG or a blend of LFG and natural gas. As a result of health risks, since mid-2018, LFG is no longer combusted at Grayson, and the LFG is being flared at the Scholl Canyon Landfill in compliance with the Los Angeles County Sanitation District air permit.

Even assuming there were no Risk Reduction Plan in place, reintroducing LFG into the Grayson boilers would require the LFG to first be cleaned up as is being done as part of the proposed Biogas project. The SCAQMD would also have to re-permit the use of LFG at Grayson. GWP would then need to place the existing pipeline back in service after performing a pipeline inspection.

The existing boilers at Grayson cannot be fired on LFG alone. Experience has shown that a mixture of at least 25 percent natural gas/75 percent LFG (co-firing) is required to maintain LFG flame stability in the boilers. Given the need to burn a mix of LFG and natural gas, this would require the use of natural gas at all times, result in even more gas being burned, and more CO_2 emissions, than would result from combusting the LFG in the engines at Scholl Canyon.

As LFG is produced continuously and there is no means to store it, using the boilers to combust LFG would require at least one boiler to be online continuously.

None of the existing emissions control system technologies in place are capable of achieving the emissions control levels required by SCAQMD Rule 1135. To reduce the original levels of emissions from Boilers 3, 4 and 5, they have been retrofitted with Low NOx burners and flue gas recirculation. Additionally, Unit 5 has been retrofitted with a rotating over-fire air and non-catalytic SCR, in order to meet their current air permit limits of approximately 40 to 80 ppm NOx. To further reduce the boiler emissions down to the 5 ppm Rule 1135 requirement for boilers, GWP would need to add selective catalytic reduction systems.

Regarding the recommendation to "*see what it would take for* ALL [sic] of the *old steam units to be brought up to reliable standards for everyday use and the total cost*"*:* There are several issues with continuing to try to operate the existing boilers:

One of the goals that everyone agrees upon is the need to reduce emissions. Because of their age, the Grayson boilers and steam turbines, unlike modern reciprocating engines or gas turbines, have much longer startup times – multiple hours, as compared to minutes for reciprocating engines or gas turbines -- due to the need to slowly warm the boilers and steam turbines from a cold to a hot condition. This results in a boiler plant having much greater startup emissions than a fast-starting gas turbine or reciprocating engine plant like the technology proposed in the Grayson Repowering EIR Alternatives 7 and 8. (In both Alternatives, the reciprocating engines or gas turbines can start and reach full load within ten minutes; the steam turbine and once through boiler associated with Unit 8BC being new and of a modern design, is expected to be on-line within two hours which has no effect on emissions).

Because the existing boiler plant cannot startup quickly, it cannot respond to daily peak loads or intermittency issues associated with renewable energy imports. The boilers must be kept hot (which can only be done by burning natural gas in the boiler), and kept on idle, without generating any power, so they would be ready to respond more rapidly, such as approximately 4 hours instead of the 24-48 hours if they were cold. Keeping the boilers hot creates additional emissions. By contrast, the reciprocating engines or gas turbines proposed in the Grayson PR-DEIR Alternatives 7 or 8 can be turned off and then re-started when needed.

Units 1 through 5 steam boilers and turbines were built between 1941 and 1964 (between 57 to 80 years old) and cannot compete with current technology. (See 2018 FEIR Table 2-2). They are less efficient than either Alternative 7 or 8. Existing Units 3, 4, and 5 at full load have thermal efficiencies of approximately 26 percent, 30 percent, and 28 percent, respectively. Whereas Alternative 7 (Wartsila) and Alternative 8 (Unit 8A and 8BC), at full load have thermal efficiencies of approximately 41 percent, 25 percent, and 37 percent, respectively. Thus, Alternatives 7 and 8 can produce the electricity more efficiently than the boilers.

In summary, burning the LFG in the Grayson Boilers is prohibited by the City's Risk Reduction Plan, and would result in increased emissions and decreased efficiency. Making the investment to extend the operational life of the boilers commits the City to burning even more natural gas than would be generated if Alternatives 7 or 8were implemented because of the boilers' operational limitations. Alternatives 7 and 8 utilize more current technology, that can start faster, produce electricity more efficiently, do it more cleanly, and produce less CO_2.

L27-4 This comment is a general statement about the commenter's opinion of (or preference about) the Project, and the cost of the project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L27-5 This comment is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L27-6 This comment is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L28 - Responses to Comments from Larry Moorehouse, received October 15, 2021

L28-1 This comment is an email from Mr. Brotman, forwarding a comment from Mr. Moorehouse.

L28-2 This comment is the email that Mr. Moorehouse submitted to Mr. Brotman, and it is identical to Comment Letter 27. See Individual Response L27-1 through L27-6.

L29 - Responses to Comments from Daniel Brotman, received September 21, 2021

During the PR-DEIR public comment period, City Councilmember Dan Brotman requested that GWP respond to a set of questions regarding the Grayson Repowering. The responses previously provided to Councilmember Brotman are attached to the Bracketed Comment Letter L29 and set forth below for ease of reference, with updates or references to applicable Topical Responses added, to amplify and clarify the responses. The City responded to Councilmember Brotman on December 15, 2021; the original response is included as **Attachment H**.

L29-1 The commenter inquired why GWP is still recommending the same/similar mix of thermal, BESS and DERs as it did in 2019 [IRP] even though there have been some important developments that were not part of the original modeling.

The previous response provided to Councilmember Brotman is attached to Bracketed Comment L29. An expanded version of the response previously provided to Councilmember Brotman is provided in Topical Report No. 1.

L29-2 The commenter inquired about the potential for commercial solar/storage through a Commercial VPP or FiT program and noted that Ascend plugged

20MW into the 2030 Plan, but wondered if Glendale did something along the lines of LADWP's FiT whether Glendale would be looking at closer to 25MW. The commenter further inquired why isn't this factored into the model for determining the thermal-BESS-DER mix.

Increasing 20MW to 25MW will decrease the number of MWHs generated from the thermal units but wouldn't reduce the required capacity. Contingency requirement is based on the PDCI and STS lines.

L29-3 The commenter stated that the 2019 IRP assumed 10MW of solar/storage on City sites and asked about the current expectation based on projects GWP is working on today and any other available sites.

GWP is working on getting at least 10 MW of solar on City sites as planned. Glendale engaged with Black and Veatch (B&V) to conduct a study to identify potential sites. The study deliverables include technical specifications, solar capacities, and cost estimates for the sites that are deemed viable for solar. This "master list" of specifications will then be used to bid each site for the construction of solar. GWP anticipates having the master list available by Q1 2022. B&V started with an initial list of 101 sites which has been reduced to 77 potential sites. These sites are still being vetted.

L29-4 The commenter noted the 2019 IRP assumed 28MW of residential/commercial Energy Efficiency (EE) and Demand Response (DR) and asked about the current expectation based on the programs with Willdan (Lime Energy) and Franklin? He inquired how much more could Glendale do in EE and DR if we went at this harder (e.g., DR programs for other appliances, including EV charging, EE and DR for our largest customers, etc.).

GWP requested that each of the Clean Energy vendors provide "stretch" numbers for the maximum amount of clean energy capacity they could offer. The maximum energy efficiency capacity that Willdan (Lime Energy) is able to guarantee is 8.32MW by the 7th year of the program implementation. The maximum amount of demand response capacity that Franklin Energy is able to guarantee is 10MW of Demand Response by the 4th year of the program. If the 10 MW are achieved there is an option for GWP to purchase an additional 1 MW of demand response capacity from Franklin during the four-year contract term. Largest customers are eligible for both of these programs (as well as other GWP programs) and are already taken into account. GWP will continue to develop and implement more Energy Efficiency and Demand Response programs and will continue to explore new and innovative ways to reduce demand and increase energy efficiency. We will always aim higher. However, 28 MW of Energy Efficiency/Demand Response is an extremely aggressive plan that puts GWP at the forefront among other utilities. For planning and reliability purposes, it would not be prudent to count on more than 28 MW of projected Energy Efficiency/ Demand Response growth.

L29-5 The commenter asked if the City is doing anything for people who already have solar that want batteries and are willing to allow GWP to control them.

The City has executed a contract with Shpigler Consulting to assist GWP in three phases (assessment, requirements and procurement) to move towards the implementation of not only residential energy storage program but commercial solar + energy storage program as well. The scope of work includes preparation of RFP, vendor selection and coming up with incentive programs for customers. The project has commenced and is now underway.

L29-6 The commenter requested estimated costs for the two alternatives asap, disaggregated as much as possible to break out equipment costs, site prep and engineering costs, etc.

See Attachment H to Comment Letter L29. An expanded version of this response is provided in Topical Response No. 2.

L29-7 The commenter inquired about the assumptions made for cost of carbon, gas prices, and equipment depreciation.

On the cost of carbon, GWP assumed a carbon cost of $96/ton of CO2. This includes the EPA's social cost of carbon at $58/ton. For natural gas prices, GWP used a forward-looking price of approximately $3.68/MMBTU for the COSA modeling in November 2021. It's expected that both Alternatives 7 and 8 will be depreciated over 25 years.

L29-8 The commenter inquired about GWP's thoughts on laying out operating protocols for the City's thermal assets that would them a last resort resource, only used if the City cannot otherwise meet load with imports, stored energy or DERs.

GWP's dispatch strategy already utilizes the following dispatch order which dispatches thermal generation only when needed. Energy efficiency is presumed to always be engaged and to have already somewhat reduced the load.

GWP would rely first upon transmission imports and local renewable (rooftop solar) generation.

In the event that transmission imports and local renewable generation were not sufficient, then demand response would then be considered with recognition that demand response can only be called upon a limited number of times per year.

Additionally, frequent calls for demand response could lead participants to opt out as they are allowed to do.

Energy from the BESS could be called upon subject to maintaining sufficient spinning reserve to meet reliability requirements and consideration of the forecasted power/energy demand for the remainder of the day. The alternative of fully committing the BESS to serve load would necessitate starting a thermal unit to provide spinning reserve.

If the above was not sufficient, then GWP would need to call upon local thermal resources (currently thermal resources are sometimes run in anticipation of their need due to lengthy startup times. With either alternative and their ten minute start capability, thermal resources will only be started when required).

L29-9 The commenter inquired about the electric cost of service analysis and rate design and opportunities for Councilmember input.

This comment does not pertain to the proposed Project or Project Alternatives. The response is set forth in Attachment G to Comment Letter L29.

L29-10 The commenter requested clarification why the permit applications to the SCAQMD do not satisfy the July 1, 2022 Rule 1135 requirements?

The air permit application for Alternative 7 was only to add the new Wartsila units and removal of the existing Units 1-8.

The air permit application for Alternative 8 was to: convert Unit 8A to simple cycle and while keeping Unit 8BC a combined cycle unit and replace the heat recovery steam generator with a once through boiler (to allow 10 minute starts on the gas turbine as well as simple cycle operation if the steam plant is not needed or unavailable); and remove Units 1 through 5.

If neither Alternative is approved and the City desires to keep any/all of the Units, a new permit application would be needed to identify: 1) which Units are being retained, and 2) what modifications would be made to bring the Units into compliance with Rule 1135 by end of 2023. Additionally, based upon the current regulation, the application to address reducing Unit 9's permitted emissions to the Rule 1135 levels still needs to be prepared and submitted by June 30, 2022. However, the SCAQMD recently informed Glendale that the SCAQMD staff will be proposing an amendment to the regulation allowing Glendale until January 1, 2023 to submit its application. The proposed change in the application deadline will be considered by the SCAQMD Board in early January 2022. It should be noted that if that change is adopted, the change would only shift the deadline for Glendale to file its permit application with the SCAQMD. The December 31, 2023 deadline to bring the units into compliance would not change.

To update this prior response to Councilmember Brotman, GWP notes that on January 7, 2022, the SCAQMD adopted a modification to Rule 1135 that will extend to December 31, 2022 GWP's deadline to submit its application to bring the Grayson Power Plant units into compliance. The extension provides Glendale with six more months to submit its application, but does not change the December 31, 2023 deadline to achieve compliance with Rule 1135's requirements. (See also Topical Response No. 1).

Bringing Units 8ABC into compliance with Rule 1135 is expected to require:

- Replacing the SCR and SCR/CO catalyst in both heat recovery steam generators;
- Changing out the Continuous Emissions Monitoring Systems analyzers to analyzers that can measure lower levels of emissions;
- Adding electric boilers for steam turbines 1 and 2. The electric boilers are needed to provide steam to maintain the steam turbine steam seals and condenser vacuum for startup purposes. The electric boilers would also keep the steam turbines warm so Unit 8A and/or 8BC could startup within 2 hours. The electric auxiliary boiler is required since the existing boilers, which currently provide the necessary steam for startup of the combined cycle units, would not meet Rule 1135 requirements starting January 1, 2024.
- Adding a condenser steam bypass system to support startup of the units during the time that the heat recovery steam generator steam outlet conditions are not up to pressure and temperature for the steam turbines.

In conjunction with these modifications, it would also be desirable to replace the control system and portions of the electrical system due to their age.

The above recommendations for Units 8A and 8BC modifications are subject to further study, discussions with vendors on their willingness to offer performance guarantees, and analysis of SCAQMD rules.

L29-11 The commenter requested information regarding what is needed to satisfy the Rule 1135 deadline, what the City has already done, and what still needs to be done.

As discussed in response to L29-10, the City needs to determine what the plan is for Units 1-5 and 8A and 8BC. If the City Council does not proceed with the proposed Project or a project alternative, GWP presumes Units 1-5 would be retired and Units 8A and 8BC retained. No engineering work has been performed to date to study this option. Some engineering work would be needed to scope the required upgrades, work with vendors, and support development of the application to SCAQMD for Units 8A, 8BC, and 9.

Alternative 8 contemplates converting Unit 8A to simple cycle and keeping Unit 8BC as a combined cycle unit but replacing the existing heat recovery steam generator with a once-through boiler. If those changes are not made and the existing heat recovery steam generator is retained, the stack exit location, height, and mass flow would be different from Alternative 8, and thus new air modeling and health risk assessment may be needed.

Note that if the decision is to still convert Unit 8A to simple cycle and replace the Unit 8BC heat recovery steam generator with a once-through boiler, that may also necessitate replacing the steam turbine due to the differences in outlet steam pressure and temperature conditions.

L29-12 The commenter asked how much time is needed to prepare and submit the parts of the application that aren't already complete following City Council direction on the project.

If City Council elects to proceed with the project or either Alternative 7 or Alternative 8, GWP will only need to submit an application to address reducing Unit 9's permitted emissions to the Rule 1135 levels. It is expected that it will take GWP 1-2 months to prepare the application and SCAQMD 6-9 months to process the application.

If the City Council does not approve the project or Alternative 7 or Alternative 8, GWP would need to submit an application not only for Unit 9, but also to modify Units 8A and 8BC to comply with Rule 1135.

At this time, we expect it would take six months to: 1) work with potential vendors and confirm the feasibility of upgrading the existing Units 8A and 8BC heat recovery steam generator emissions control systems, and their willingness to guarantee the required emissions performance, 2) develop project work scope and cost estimates, 3) perform required air modeling and prepare the application, 4) obtain City approvals, and 5) submit the application to SCAQMD.

For Unit 9 the work to prepare the application can proceed more quickly as all that should be required are tuning changes within the emissions control system to increase ammonia injection rates as well as possible changes to the water injection flows.

L29-13 The commenter inquired whether the application be modified after July 1 (e.g., if there are changes to the number of gas-burning units) without being out of compliance with the deadline?

Yes, any of the applications could be modified after the application deadline but doing so will delay permit issuance and subsequent activities. While demolition could begin without an air permit, construction (beginning with excavation for foundations) or modification to existing equipment cannot begin without an issued air permit.

If Alternative 7 is selected by the City, and the City subsequently choses to build fewer units, that could be done without a permit change as long as the starts and operating hours for the remaining units are not changed (e.g., the starts and operating hours associated with the units not being built cannot be transferred to the units being built without a modification to the air permit). The total number of starts and operating hours planned for all five units could not be preserved with fewer units without a modification to the air permit.

If Alternative 8 is selected by the City, and the City subsequently chooses not to permit Unit 8A or Unit 8BC, the process would be similar to that outlined immediately above for Alternative 7.

If the Proposed Project or any alternative were not selected, the existing air permits would still remain in effect but only until December 31, 2023.

L30 - Responses to Comments from Larry Moorehouse, received October 15, 2021

L30-1 This comment is a general statement that the City needs to make the right decisions about GWP, in light of recent news reports. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter’s statement is included in the 2022 Final EIR for the decision-maker’s consideration as part of the City’s deliberations on the Project.

L31 - Responses to Comments from Larry Moorehouse, received October 26, 2021

L31-1 This comment raises a number of questions in response to the GWP General Manager’s presentation at the October 26, 2021, City Council Meeting, including concerns about energy supply, cost, rates, outages, and supply during the repower, and need for backup generation in light of transmission limitations.

During the repower, GWP will rely upon its neighboring utilities (including LADWP) to provide additional power to Glendale for peak load days and contingency events. This backup power will be in lieu of the 75 MW that LADWP was going to supply for the proposed Project which lapsed in 2018 when the City held off on a decision on the 2018 FEIR. Because some of GWP's contingencies affect GWP's neighbors as well such as loss of the Pacific DC Intertie or derates on the STS line, coverage for some contingencies may be limited during the repower.

L31-2 This comment suggests keeping some old units and adding some new units. Alterative 8 was added as an alternative that partially re-uses the existing Grayson facilities – the Units 8A and 8BC gas turbines – while replacing other equipment. This would accomplish the following:

1) Removing the Units 1 through 5 boilers which are infeasible to upgrade for continued operation. As discussed in Topical Response No. 1, Units 1 through 5 cannot be feasibly modified to meet future emissions requirements and support future operational requirements because none of the existing emissions control system technologies in place have the capability of achieving the emissions control levels required by SCAQMD Rule 1135. To reduce the original levels of emissions from Boilers 3, 4 and 5, they have been retrofitted with low NOx burners and flue gas recirculation. Additionally, Unit 5 has been retrofitted with a rotating over-fire air and non-catalytic SCR, in order to meet their current air permit limits of approximately 40 to 80 ppm NOx. To further reduce the boiler emissions down to the 5 ppm Rule 1135 requirement for boilers, GWP would need to add selective catalytic reduction systems. Further, even if those modifications were successful, the boilers would still be slow start units requiring the burning of gas to keep them warm and ready for startup (adding to emissions) and even then, could not react quickly enough to system demands.
2) Addressing obsolescence of the old Units 8A and 8BC equipment.
3) Replacing old equipment with new equipment that will allow the units to start within 10 minutes so they can respond quickly and count towards non-spinning reserves.
4) Adding a 75 MW/300 MWH battery energy storage system to provide spinning reserve and help meet peak loads.

L31-3 This comment is a general statement that the City has run out of time. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L32 - Responses to Comments from Larry Moorehouse, received October 26, 2021

L32-1 This comment was received shortly after L31 from the same commenter and is a statement that "this is where we are at." Please refer to response to Individual Response L31.

L33 - Responses to Comments from Larry Moorehouse, received November 2, 2021

L33-1 The comment states that not having the Grayson Power Plant is one of the big problems, and notes that Glendale is restricted in obtaining power, and losing Grayson or the transmission would result in going "into the BLACK." The commenter opines that the City will not be able to supply load by rooftop solar. GWP agrees the commenter that the repowering of the Grayson Power Plant is an essential element of ensuring a reliable and resilient supply of energy for the City of Glendale's residents. This topic is addressed further in Topical Response No. 1.

GWP also agrees that any energy storage system will need to be recharged. The 2019 IRP and a separate independent evaluation contained within the Alternatives section of the PR-DEIR (Section 5.2.2) and Topical Response No. 8 all addressed that point. The Battery Energy Storage System (BESS) was sized considering the available energy that could be imported to charge the (the difference between transmission import capacity and demand).

In response to the comments criticizing the team, the City has assembled, a very competent group of professionals to work on the Grayson Repower. Some of the key members of the project team include the following:

<u>Rostamik "Rome" Chetin, Glendale Water & Power, Plant Engineer</u>

Mr. Rostamik "Rome" Chetin holds a BS in Mechanical Engineering and a minor in Physics from the California State Polytechnic University, Pomona. He is also a licensed California Mechanical Professional Engineer. Mr. Chetin is the Plant Engineer for GWP's Grayson power plant. He has been involved with Grayson for over twelve years, and in his role is responsible for the engineering support of the plant's boilers, steam turbines, gas turbines, and other equipment. Mr. Chetin is primarily involved in resolving engineering issues, supporting operations, environmental compliance, and modifications to the plant.

<u>Dr. Gary Dorris, Ascend Analytics – Integrated Resource Plan and Clean Energy Study</u>

Dr. Gary Dorris has been a pioneer of innovative solutions for portfolio management and resource planning for over two decades. He has delivered expert testimony on portfolio management, risk management, energy trading, asset valuation, and resource planning, including acting as a lead expert witness for NorthWestern Energy and Hawaii Electric in reshaping of their energy supply portfolios to be renewable. He has been an advisor to the Board of Directors for Turlock Irrigation District and other utilities. He was also lead expert for Merrill Lynch in the prominent Enron proceedings and served as lead witness for portfolio management practices of Nevada Power.

Dr. Dorris has organically grown Ascend Analytics over the last two decades to be a leading provider of quantitative software solutions for energy portfolio management and data infrastructure. His analytic vision to bridge the physical models for production costing with the financial models of risk management has led to development of over a dozen software applications used by over 100 energy companies. He has been engagement director for major solutions of over two dozen for portfolio and risk management infrastructure solutions. In 2001, Dr. Dorris won distinguished recognition from the IPE for contributions to the field of energy risk management.

Prior to founding Ascend, he served as CEO of e-Acumen, a 60-person energy analytics software firm. He began his career developing structured power transactions at Citizens Power & Light. Dr. Dorris holds a Ph.D. in applied economics and finance from Cornell University and a BS in mechanical engineering and BA in economics with Magna Cum Laude distinction also from Cornell University.

<u>Thomas Ettinger, Stantec Consulting Services Inc., Owner's Engineer</u>

Mr. Tom Ettinger is a Mechanical Engineer and Project Manager at Stantec Mr. Ettinger is a resident of Glendale, holds a BS degree in Mechanical Engineering from University of Vermont, is California registered Professional Mechanical Engineer and has a California A Construction License. In addition to Glendale Water & Power, Mr. Ettinger has worked with several other southern California municipal utilities including Anaheim Public Utilities, Burbank Water & Power, Pasadena Water & Power, and Riverside Public Utilities.

Mr. Ettinger has 52 years of heavy industrial and power engineering plus construction experience. Mr. Ettinger has been working for Stantec and legacy companies for most of his career and is the manager of Stantec's power team in Pasadena, CA. Most of his experience has been in engineering, procurement, and construction (EPC) projects both as the engineer of record or the construction manager on power projects. Tom most recent experience been as an owner's engineer including engineering and construction management for new and operating geothermal and gas power generation projects. Mr. Ettinger has also been involved with energy transition projects such as battery energy storage and electric vehicle charging projects.

<u>Michael Fisher, Black & Veatch, Owner's Engineer</u>

Mr. Michael Fisher is a Project Manager within the Black & Veatch global energy business. He holds a BS degree in Mechanical Engineering from the University of Tulsa and is a registered Professional Engineer. In addition to Glendale Water & Power, Mr. Fisher has worked with other California municipal and public utilities including Anaheim Public Utilities, California Department of Water Resources, Los Angeles Department of Water and Power, Northern California Power Agency, Sacramento Municipal Utility District, Silicon Valley Power, Turlock Irrigation District, and Vernon Public Utilities.

Mr. Fisher began his career with Central and Southwest (now American Electric Power) as a plant engineer in their gas and coal-fired power plants. After leaving American Electric Power, Mr. Fisher embarked on a career as an Independent Engineer providing power plant, renewable energy, mining, and oil and gas services to the financial community. With over 30 years of technical and commercial experience, Mr. Fisher has significant experience with a variety of power plant technologies and industrial facilities, including both supercritical and drum-style steam units firing coal and natural gas, simple-cycle combustion turbines, combined-cycle combustion turbines, reciprocating internal combustion engines (RICE), hydroelectric, wind turbines, solar photovoltaic, solar thermal, and other Long Duration Energy Storage technologies.

<u>Christine Godinez, City of Glendale, Project Counsel</u>

Ms. Christine Godinez represents the City of Glendale as a Principal Assistant Attorney for the Glendale City Attorney's Office and is lead counsel for the Grayson Repowering Project. She has served as legal counsel for the City of Glendale for 20 years, representing Glendale Water & Power for the last 16 years. Ms. Godinez is a Phi Beta Kappa graduate of U.C. Berkeley and earned her juris doctorate at UCLA. In her role as counsel for GWP she has represented the City on a wide range of transactions, including renewable energy projects, electric transmission agreements, commodity purchase agreements, utility rate cases, bond financings, complex construction projects, real property transactions, and regulatory and environmental matters.

Edward Krisnadi, Montrose Environmental, Principal – Air Permitting and Compliance

Mr. Edward Krisnadi is a Principal at Montrose Environmental. Mr. Krisnadi holds a BS in Chemical Engineering degree from University of California, Riverside and is a South Coast AQMD Certified Permitting Professional.

Mr. Krisnadi has been an air quality consultant for eighteen years. As a principal at Montrose, Edward responsibility includes providing guidance on air quality rules and regulations, developing emission inventory, and preparing air quality related reports, such as permit applications and compliance documents.

In addition to Glendale Water & Power, Mr. Krisnadi has provided air quality compliance services for other Southern California municipal utilities, such as Riverside Public Utilities, City of Palm Springs, and Orange County Central Utility Facility. Mr. Krisnadi is also a California Air Resource Board (CARB) certified third party verifier for greenhouse gas programs.

Karl Lany, Montrose Environmental, Principal – Air Permitting and Compliance

Mr. Karl Lany is a Senior Principal at Montrose Environmental, a firm specializing in air emissions permitting, testing, and compliance. Mr. Lany oversees permitting and compliance management operations for Montrose clients in California. Mr. Lany holds a BS in Civil Engineering Technology from Colorado State University Pueblo and a MS in Environmental Studies from California State University Fullerton. He is also a South Coast AQMD Certified Permitting Professional.

Mr. Lany has 30+ years of experience in air quality management. His clients include leaders in a variety of industries, as well as utilities and government agencies. Prior to joining Montrose, Mr. Lany was on staff at South Coast Air Quality Management District (SCAQMD). While there, coordinated the development of rules governing operating requirements and market participation requirements for the Regional Clean Air Incentive Market program.

Mr. Lany is a member of the SCAQMD Best Available Control Technology Scientific Review Committee and has served on the SCAQMD New Source Review Working Group as well as many SCAQMD and California Air Resources Board rule working groups on behalf of his clients. His fields of expertise are in Air Quality Policy, Compliance Management, Environmental Planning and Permitting and Environmental Impact Mitigation Strategies. He has provided testimony in SCAQMD, CEC, and other proceedings.

Brandon Mauch, Ascend Analytics – Integrated Resource Plan and Clean Energy Study

Dr. Brandon Mauch, Manager of Resource Planning Analytics, leads a team of analysts in Ascend's consulting group providing modeling support for resources planning and regulatory activities. He manages projects for multiple clients including NorthWestern Energy, Los Angeles Department of Water and Power, and Indianapolis Power and Light. He is an expert in analytical methods for power system economics and reliability analysis.

Prior to joining Ascend, Dr. Mauch was a Senior Program Manager for CLEAResult Consulting where he managed utility energy efficiency and demand response programs for Midwestern utilities. Working with a diverse team of energy specialists, he oversaw all aspects of utility energy efficiency programs. Dr. Mauch has worked in utility regulation as a Utility Regulation Engineer for the Iowa Utilities Board where he worked on regional energy policy issues, resource planning and rate cases for Iowa's investor-owned utilities. He has expertise in resource planning, energy markets, regulation, and utility demand side management.

Dr. Mauch holds a Ph.D. in Engineering and Public Policy from Carnegie Mellon University where his research focused on wind power forecasting and risk assessment of wind forecasts. He also holds a master's degree in Mechanical Engineering from the University of Wisconsin and a bachelor's degree in Mechanical Engineering from the University of Kansas.

David Millar, Ascend Analytics – Integrated Resource Plan and Clean Energy Study

Mr. David Millar, Director of Resources Planning Consulting, leads Ascend's resource planning, valuation, and forecasting consulting practice, providing utility and community choice aggregation clients with expertise in risk-based, long-term resource planning, valuation, and fundamental power price forecasting. He has led groundbreaking integrated resource planning and all-source RFO processes and is a thought-leader in planning for high renewables/low carbon power systems. He leads a practice area of twelve staff and over $3 million in annual consulting revenue. Prior to joining Ascend, Mr. Millar worked in Pacific Gas and Electric Energy Procurement and Regulatory Affairs departments. Mr. Millar has also worked in energy policy research in the Electricity Markets and Policy group at Lawrence Berkeley National Lab and Climate Action Plan consulting with KEMA (now DNV GL). He holds a master's degree in Energy Economics and Policy from Duke University and bachelor's degrees in Earth Sciences and Political Science from the University of California, Santa Cruz.

StephAnnie Roberts, Stantec Consulting Services Inc., Senior CEQA Manager for Assessment, Permitting, and Compliance

Ms. StephAnnie Roberts has 27 years of professional experience in environmental consulting. She has been involved in all aspects of regional and site-specific environmental, geohydrologic, and geotechnical investigations; she has also participated on CERCLA/SARA, and RCRA regulated projects. Within the last 17 years, Ms. Roberts' environmental consulting focus comprises projects involving land uses subject to discretionary agency approvals and public environmental review. She provides environmental services and leads and supports diverse teams that include project managers, biologists, environmental scientists, and planners, throughout the planning and implementation phases on projects. She works on issues analyses, project permitting, preparation of required environmental documents and supporting technical studies, and mitigation compliance. StephAnnie has experience with commercial, industrial, oil and gas, recreation, renewable energy, residential, transportation, and water.

Michelle C. St. Clair MA, RPA, Stantec Consulting Services Inc., Practice Leader, Geographic Technical Leader - Cultural and Social Sciences North Americas

Ms. Michelle C. St. Clair is a Stantec's North American Geographic Technical Leader for Cultural and Social Science. She is an archaeologist by training with over 21 years of experience. She has experience in cultural and environmental resources management. Ms. St. Clair has specialized training in historical archaeology, and she meets the Secretary of the Interior's standards and guidelines for a professional archaeologist. She is a Registered Professional Archaeologist (RPA) since 2005. She has served as project manager and senior archaeologist on numerous water-related projects. She manages in-house technical staff, supervises technical document preparation, and provides quality control and peer review for cultural resources studies. Her expertise includes archaeological identification, evaluation, and data recovery projects in compliance with local, state, and federal laws and regulations. She has extensive experience developing implementation programs in compliance with state and federal regulations, including the requirements of complex and controversial Section 106 of the National Historic Preservation Act (NHPA) and National Environmental Policy Act (NEPA) compliance projects. Ms. St. Clair works regularly with local and state agencies to facilitate California Environmental Quality Act (CEQA) compliance. Ms. St. Clair has experience managing laboratories and curatorial processes, as well as extensive experience conducting outreach, coordinating meetings, and public interpretation for cultural resources. She is comfortable working with Native Americans and other descendant communities, and as experience in faunal analysis, osteology, ceramic, glass, and other historic-era materials analysis.

<u>Mr. Jon R. Stickman, Federal Energy Regulatory Commission Council to City of Glendale</u>

Mr. Stickman is a partner with the law firm Duncan & Allen, Mr. Stickman has broad experience in a variety of energy regulatory, strategic planning and transactional matters, with an emphasis on rate issues, restructured electric markets and compliance with the various aspects of the Energy Policy Act of 2005 (EPAct 2005) and the North American Electric Reliability Corporation's (NERC) reliability standards. Using his knowledge of the FERC's restructuring mandates, the 2005 Energy Policy Act, the California energy crisis, and the restructured electric markets in the west and northeast, Jon provides strategic planning to facilitate his clients' successful participation in the electric markets, transmission access and energy pricing.

Mr. Stickman has represented publicly-owned utility systems (municipal electric utilities, rural electric cooperatives and irrigation districts) in California, Colorado, New Mexico, Arizona, Utah, New England, and the Midwest in matters before the Federal Energy Regulatory Commission (FERC), state public utility commissions, NERC and Regional Reliability Organizations (e.g., Western Electricity Coordinating Council (WECC), Southwest Power Pool (SPP), etc.).

Mr. Stickman has a B.A. from the University of Southern California and obtained his Juris Doctorate from the University of Tulane. He is admitted to practice law in California and in the District of Columbia.

<u>Dave Tateosian, P.E., Clean Power Consulting Partners, Project Manager</u>

Mr. Dave Tateosian is a Consulting Engineer and Principal at Clean Power Consulting Partners. Mr. Tateosian is a native Californian, holds a BS degree in Mechanical and Nuclear Engineering and a MS in Nuclear Engineering from UC Berkeley, and is California registered Mechanical Professional Engineer. In addition to Glendale Water & Power, Mr. Tateosian has worked with several other southern California municipal utilities including Anaheim Public Utilities, Imperial Irrigation District, Pasadena Water & Power, and Riverside Public Utilities.

Mr. Tateosian started at PG&E where he served in a series of technical and managerial positions, followed by a consulting career focused on Owner's Engineering, project and construction management, root cause analysis, and engineering services for new and operating power generation projects. Mr. Tateosian's experience spans design, development, permitting, construction, commissioning, and operating plant support, and he is well versed in many energy technologies including gas and steam turbines, reciprocating engines, cogeneration, nuclear, solar photovoltaic and thermal, geothermal, and energy storage. Mr. Tateosian has provided testimony in both California Energy Commission and Nuclear Regulatory Commission proceedings.

Emily Rinaldi-Williams, Stantec Consulting Services Inc., Architectural Historian

As the Architectural Historian at Stantec, Ms. Emily Rinaldi-Williams' experience encompasses identifying, evaluating, and documenting a wide variety of historic resources/property types, and preparing evaluations for local, state, and national designation. She received a Master of Science degree in Historic Preservation from Columbia University and has over seven years of experience in cultural resource management. Ms. Rinaldi-Williams has worked on numerous project types within the New York and Southern California regions and has prepared historic structure reports, historic resource survey reports, Historic Preservation Tax Credit Certifications and Mills Act applications, historic context statements, condition assessments, local landmark applications, National Register nominations, HABS/HAER Documentation, and interpretive signage. She is also experienced in preparing CEQA and Section 106 environmental compliance documentation. Emily qualifies as an Architectural Historian and Historian under the Secretary of the Interior's Professional Qualification Standards (as defined in 36 Code of Federal Regulations [CFR] Part 61).

Chie Valdez, Glendale Water & Power, Power Resources Manager

Ms. Chie Valdez is then Integrated Resources Planning Administrator at Glendale Water and Power. In the last 21 years, Ms. Valdez has worked exclusively in the electric power industry, including providing consulting services to California ISO, Western Area Power Agency, various power merchants, and other Load Serving Entities such as Silicon Valley Power, Anaheim Public Utilities, Pasadena Water & Power, Azusa Light and Water, and Riverside Public Utilities. She holds a BS degree in Mathematics and Computer Science.

Ms. Valdez' operational expertise spans long and short term resource planning, load-resource balancing, energy portfolio modeling and optimization, load forecasting, power contract negotiation and administration, wholesale energy/gas trading and settlements, market intelligence, system integration, and regulatory compliance (including California's Renewable Portfolio Standards and Greenhouse Gas / Cap-and-Trade programs).

Gillian Van Muyden, City of Glendale, CEQA Counsel

Ms. van Muyden has served the City of Glendale since 1997 in various capacities in the City Attorney's Office including as the City Prosecutor and General Counsel to the Former Glendale Redevelopment Agency. She received her bachelor's degree from U.C. Berkeley, Masters of Public Administration (with distinction) from

CSUN, and her juris doctor from Pepperdine. Prior to attending law school, she was a land use planner for the cities of Torrance and Thousand Oaks. She currently serves as a Chief Assistant City Attorney and manages the Departmental Services Division for the Glendale City Attorney's Office. She principally advises the City's Community Development Department which includes current planning, housing, building and safety and economic development divisions. She advises the City's Planning Commission, Sustainability Commission, Successor Agency as well as the Housing Authority and City Council on real property, land use, California Environmental Quality Act, redevelopment dissolution, First Amendment, and general municipal law matters. Ms. van Muyden gained national recognition for her role in successfully defending a CEQA challenge to the Americana at Brand mixed-use project. She was also part of the City's legal team that successfully defended a CEQA challenge to the City's Downtown Specific Plan, and most recently she also successfully defended a CEQA challenge to the City's 2018 approval of the South Glendale Community Plan.

She is currently the president of the City Attorney's Association of Los Angeles County and is an advisor to and past chair of the Executive Committee of the Real Property Law Section of the California Lawyer's Association (formerly California Bar) where she currently serves as the co-chair of CLA's Transactional/Land Use Practice Area Committee and advisor to the committee. She is the former Managing Editor of the California Real Property Journal, a quarterly publication of the Real Property Law Section of CLA and is a frequent articles editor. Ms. van Muyden recently served two years on the League of California City's Environmental Policy Committee. Additionally, Ms. van Muyden has served on the CEB Advisory Committee, and as a panelist and planning committee member for the Real Estate and Law (REAL) Symposium at Stanford University. Over her 28-year legal career Ms. van Muyden has been a frequent speaker and panelist on planning, land use/CEQA, redevelopment, and ethics issues for the State Bar of California, League of California Cities, Glendale Bar Association, Commercial Real Estate Women, among others. The Daily Journal listed her as a "Top 25 Municipal Lawyer" in California for her work on redevelopment dissolution. In 2018 she was honored by the California Lawyers Association Real Property Law Section with an Outstanding Service Award. She is adjunct professor of law at Pepperdine University School of Law where she taught land use law.

<u>Michael Weber, Stantec Consulting Services Inc., Assessment, Permitting, and Compliance Practice Leader for Stantec's Pacific Region</u>

Mr. Michael Weber is a Senior Principal Scientist and Assessment, Permitting, and Compliance Discipline Leader for Stantec's Environmental Services Practice. Mr.

Weber earned a BS degree in Environmental Studies from UC Santa Barbara that included study of atmospheric chemistry, energy and the environment, and environmental impact analysis. Now with 22 years of professional consulting experience, he has prepared hundreds of CEQA documents or supporting technical studies for a diverse range of project types including electricity generation (natural/landfill gas, PV solar, wind, and geothermal), transmission, and storage. In addition to a strong understanding of CEQA compliance, Mr. Weber possesses technical competencies in many of the environmental issues most relevant to the proposed Project such as air quality, greenhouse gas emissions, hazardous materials, and noise.

<u>David Welch, Black & Veatch, Owner's Engineer</u>

Mr. David T. Welch is an Engineering Manager within Black & Veatch's global energy business. He holds a BS in Electrical Engineering from Missouri University of Science and Technology and is a registered Professional Engineer. His responsibilities include Owner's Engineering, design team supervision, detailed control system design, specification development, project cost estimates, and project and contract administration. Mr. Welch also serves as the electrical and controls section head for power generation in Black & Veatch's Denver office.

With over twenty years of experience with Black & Veatch, Mr. Welch has worked on numerous renewable energy, conventional generation, energy storage, and grid automation projects in the project development design, construction, and start-up phases.

<u>Dr. Paul Wierzba, Stantec, Senior Noise Engineer</u>

Dr. Paul Wierzba holds B.Sc. and Ph.D. degrees in Mechanical Engineering and is a licensed professional engineer registered in British Columbia, Alberta, and Saskatchewan. Dr. Wierzba has over 28 years of engineering experience in the areas of environmental acoustics, vibration, industrial noise control, stress analysis, and thermo-fluids. During that time, Dr. Wierzba has been involved in consulting projects, research and development, applications engineering, and technology and product development undertakings, frequently guiding and managing teams of diverse individuals. Dr. Wierzba has spent the last 25 years dealing primarily with environmental noise and vibration pertaining to gas compression and power generation, performing numerous diagnostic and assessment measurements, carrying out noise impact studies, designing noise and vibration control measures, and frequently overseeing noise mitigation installation. Dr. Wierzba has also worked in the area of architectural acoustics. He has also taught senior-level courses in Mechanical Engineering at the University of Calgary.

Mark Young, Glendale Water & Power, General Manager

Mr. Mark Young started his career with Glendale Water & Power in 1989, after starting his electrical power generation career with the United States Naval Nuclear Power program in 1981. Along with a Bachelor of Science degree from the University of Phoenix in Business Management, Mr. Young has over 40 years of experience in power generation, operations, contract implementation and administration, marketing, and power resource planning.

Mr. Young is intimately familiar with GWP and Grayson having started as a power plant operator and having held titles such as Power Plant Control Operator, Senior Electric System Dispatcher, Energy Trader, Energy Trading Manager, Integrated Resource Planning Administrator, Deputy General Manager – Power Management, and more recently, Assistant General Manager - Power Management. Mr. Young has been hands on with the Grayson Repowering Project, working closely with his team to explore any and all options to provide Glendale with clean reliable energy.

L34 Responses to Comments from Hank Schlinger, received November 2, 2021

L34-1 This is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L36 Responses to Comments from Larry Moorehouse, received October 31, 2021

L35-1 This is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

L35-2 The commenter is proposing an alternative repowering scheme retaining Units 3, 4, and 5, adding LM600 [sic] and LM2500 gas turbines, and bringing landfill gas back to Grayson.

Continued operation of the boilers is problematic as described in Topical Response No. 1.

An LM6000 in combination with a pair of LM2500s would have a combined output 100-120 MW assuming they were operating in simple cycle (like Unit 9) depending on the specific unit configuration. As energy storage was not mentioned, it appears that the commenter is proposing a thermal generation only alternative. The capacity of 120 MW is even smaller than the combined thermal plus energy storage offered by Alternatives 7 and 8. As shown in Topical Response No. 1, this would be inadequate capacity to meet Glendale's peak energy and reserve needs.

This variant would also offer 10-minute start capability as does the proposed Project and Alternatives 7 and 8. Alternative 7 would offer a more flexible resource because it would have a large number of smaller capacity units. As with the proposed Project and Alternatives 7 and 8, emissions would meet SCAQMD requirements. The LM2500/LM6000 operating in simple cycle would have an efficiency comparable to the Wartsila units, better than Unit 8A, and worse than Unit 8BC when operating in combined cycle. Given the lack of energy storage and the smaller power output of the commenter's proposal, it would likely be a lower cost option.

Burning landfill gas in the boilers ceased in 2018 following an updated health risk assessment of that practice as described in the Individual Response L27-3.

L35-3 Please refer to Individual Response to L35-2.

L36 Responses to Comments from Adrienne Griffin, received August 15, 2021

L36-1 This is a general statement about the commenter's opinion of (or preference about) the Project. The comment does not identify a specific environmental analysis or CEQA issue relative to the 2022 Final EIR and compliance with CEQA. The commenter's statement is included in the 2022 Final EIR for the decision-maker's consideration as part of the City's deliberations on the Project.

8.0 MITIGATION MONITORING AND REPORTING PLAN

The following mitigation measures shall apply to the Grayson Repowering Project to reduce identified impacts to less than significant levels.

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
AES-1	AES-1: Screen Laydown Areas: Staging and laydown areas within view of residences, motorists, and recreational facilities shall be located away from public views or effectively screened using opaque fencing to limit views of materials, equipment, vehicles, and other items used during construction. All laydown areas shall be effectively reclaimed immediately following completion of their use.	Duration of construction	Engineering, Procurement, and Construction Contractor (EPC)	City of Glendale	Review of EPC's written documentation demonstrating compliance and/or site inspection(s)	
CR-1	Prior to demolition of the Boiler Building, the City shall prepare Historic American Engineering Record (HAER) documentation for the Boiler Building. That documentation shall include preparation of a written narrative, photography, and drawings that meet the latest requirements in	Prior to demolition	Qualified Consultant	City of Glendale	Written documentation demonstrating compliance	

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
	HAER History, Photography, and Drawing Guidelines. Archival and electronic full copies of that completed documentation shall be submitted to the HAER program in accordance with the most recent edition of “Preparing HABS/HAER/HALS Documentation For Transmittal.” The City shall maintain the HAER documentation at the Glendale Central Public Library and information about accessing that information shall be available on the City’s website. HAER documentation, as described, shall be complete and accepted by the HAER program before any demolition or dismantling of the Boiler Building. The City shall also display up to four (4) archival quality photographs of the historic Boiler Building in a publicly accessible location within the City’s Perkins Building,					

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
CR-2	City shall provide permanent plaque to be located at the Flower Street entrance to the Grayson Power Plant that identifies the location of the former historic Boiler Building and provides a narrative statement about the Boiler Building that provides historic context	Prior to demolition	Qualified Consultant	City of Glendale	Documentation demonstrating compliance	
CR-3	City shall salvage and preserve a piece of equipment from the Boiler Building and display the piece of equipment along with an historic context statement in a publicly accessible location in the City.	Prior to demolition	Qualified Consultant	City of Glendale	Documentation demonstrating compliance	
HAZ-1	HAZ-1: Prior to demolition of facilities associated with the Grayson Repowering Project, hazardous materials stored onsite and not required for continued operation of the facility shall be inventoried, packaged, removed, and disposed in accordance with a Hazardous Materials	Prior to demolition	Demolition Contractor	City of Glendale	Review of Demolition Contractor's Hazardous Materials Management Plan and site inspection prior to initiating demolition	

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
	Management Plan prepared by the demolition contractor and submitted to the City for review and approval prior to initiating demolition activities.					
HAZ-2	HAZ-2: Buildings or equipment to be demolished containing lead based paint or asbestos shall be either decontaminated or encapsulated prior to removal from the Project site and disposed in accordance with an Asbestos and Lead Paint Management Plan prepared by the demolition contractor and submitted to the City for review and approval prior to initiating demolition activities.	Prior to demolition	Demolition Contractor	City of Glendale	Review of Demolition Contractor's Asbestos and Lead Paint Management Plan	
HAZ-3	HAZ-3: Contaminated soil encountered during demolition activities shall be handled, removed, and disposed in accordance with regulatory requirements and the Project's Soil Management Plan.	During demolition	Demolition Contractor	City of Glendale	Review of Project's Soil Management Plan and site inspection(s)	
HAZ-4	HAZ-4: Hazardous materials used during construction shall	Duration of construction	Engineering, Procurement, and Construction	City of Glendale	Periodic site inspection	

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
	be limited to the quantities required for construction and shall be stored and handled in accordance with regulatory requirements.		Contractor (EPC)			
HAZ-5	HAZ-5: Utility trucks and refueling trucks operating onsite shall have a spill kit onboard at all times. Small spills of petroleum products or other hazardous materials during construction operations shall be reported to the Construction Supervisor and a Spill Response form completed with a description of the type and quantity of the spill accompanied by photographs and a description of the disposition of the spill material. Hazardous spill material shall be disposed according to regulatory requirements. In the event of a large spill of hazardous materials equal to or above reportable quantities federal, state, and local reporting requirements shall be followed.	Duration of construction	Engineering, Procurement, and Construction Contractor (EPC) and Demolition Contractor	City of Glendale	Periodic site inspection	

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
HAZ-6	HAZ-6: The surface area of the proposed and existing ammonia tank containment systems shall be effectively reduced by 90 percent or greater through the installation and maintenance of three-inch diameter high density polyethylene balls or similar method.	Duration of construction	Engineering, Procurement, and Construction Contractor (EPC)	City of Glendale	Review of EPC's written documentation demonstrating compliance for the duration of construction. Site inspection for confirmation	
NOI-1	NOI-1: Noise Source and Required Noise Control Measures: Cooling Towers: The noise emissions from each cooling tower shall be limited to 57 dBA at 400 feet (107 dBA sound power level). Mats may be required to limit the water splash noise.	During operation	Engineering, Procurement, and Construction Contractor (EPC)	City of Glendale	Review of EPC's written documentation demonstrating compliance of noise controls	
NOI-2	NOI-2: Noise Source and Required Noise Control Measures: Cooling Tower Fan Motors and Gearboxes: The sound power levels for cooling tower motors shall be limited to 98 dBA (85 dBA at 3') the motors shall be placed on the west side of the towers.	During operation	Engineering, Procurement, and Construction Contractor (EPC)	City of Glendale	Review of EPC's written documentation demonstrating compliance of noise controls and placement	
NOI-3	NOI-3: Noise Source and Required Noise Control Measures: Fuel Gas	During operation	Engineering, Procurement, and Construction	City of Glendale	Review of EPC's written documentation demonstrating	

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
	Compressors: The noise emissions from each of the two fuel gas compressor areas shall be limited to 44 dBA at 400 feet. Compressor enclosures or properly designed noise barriers can be utilized. Under the current assessment scenario open air compressor equipment packages with total sound power level of 108 dBA were treated with 21-foot sound barrier to yield appropriate results.		Contractor (EPC)		compliance of noise controls	
NOI-4	NOI-4: Noise Source and Required Noise Control Measures: Water Treatment Area: The noise emissions from the water treatment area shall be limited to 48 dBA at 400 feet. It is expected that this level can be achieved through a combination of equipment selection, small enclosures and barriers.	During operation	Engineering, Procurement, and Construction Contractor (EPC)	City of Glendale	Review of EPC's written documentation demonstrating compliance of noise controls	
NOI-5	NOI-5: Noise Source and Required Noise Control Measures: Boiler Feed Water Pumps for Combined Cycle Units: The sound power levels for	During operation	Engineering, Procurement, and Construction Contractor (EPC)	City of Glendale	Review of EPC's written documentation demonstrating compliance of noise controls	

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
	boiler feed water pumps shall be limited to 105 dBA when placed outside near the respective HRSGs.					
NOI-6	NOI-6: Noise Source and Required Noise Control Measures: Circulating Water Pumps for Cooling Towers: The sound power levels for circulating water pumps shall be limited to 101 dBA when placed outside near the respective cooling towers.	During operation	Engineering, Procurement, and Construction Contractor (EPC)	City of Glendale	Review of EPC's written documentation demonstrating compliance of noise controls	
NOI-7	NOI-7: Noise Source and Required Noise Control Measures: Generator Step-up Transformers: Standard NEMA 95 MVA rated transformers or lower shall be utilized.	During operation	Engineering, Procurement, and Construction Contractor (EPC)	City of Glendale	Review of EPC's written documentation demonstrating compliance of noise controls	
NOI-8	NOI-8: Noise Source and Required Noise Control Measures: Steam Turbine Building: The sound power level of the noise breaking out from the steam turbine building shall be limited to 95 dBA and 115 dBC (45 dBA and 65 dBC at 400 feet). Specialized enclosures for the gearboxes shall be required and steam turbine	During operation	Engineering, Procurement, and Construction Contractor (EPC)	City of Glendale	Review of EPC's written documentation compliance of noise controls	

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
	building walls and roofs shall have an STC 40 composite transmission loss rating.					
NOI-9	NOI-9: Noise Source and Required Noise Control Measures: Steam Pipe Rack: The sound power level for the steam pipe rack shall be limited to 82 dBA per meter of piping.	During operation	Engineering, Procurement, and Construction Contractor (EPC)	City of Glendale	Review of EPC's written documentation compliance of noise controls	
NOI-10	NOI-10: Noise Source and Required Noise Control Measures: Steam Sky vents and safety valves: Steam sky and safety valves shall be equipped with silencers to limit their noise emissions to 115 dBA sound power (approximately, 90 dBA at 5').	During operation	Engineering, Procurement, and Construction Contractor (EPC)	City of Glendale	Review of EPC's written documentation compliance of noise controls	
PAL-1	Worker training. A paleontologist who meets professional paleontological standards as defined by Murphey et al. (2019) shall design a Worker's Environmental Awareness Program reviewed and approved by a qualified consultant retained by the City that will provide training that communicates requirements and	Prior to Demolition	Qualified Consultant	City of Glendale	Review of qualified consultant Written documentation demonstrating compliance	

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
	procedures for the inadvertent discovery of paleontological resources during construction, to be delivered by the paleontologist or their designee to the construction crew prior to the onset of ground disturbance. The training will be provided by a qualified paleontologist.					
PAL-2	Paleontological Monitoring. A paleontologist meeting professional standards as defined by Murphey et al. (2019) shall be retained to oversee all aspects of paleontological mitigation, including the development and implementation of a Paleontological Monitoring and Mitigation Plan (PMMP) tailored to the Project that provides for paleontological monitoring of earthwork and ground disturbing activities into undisturbed geologic units with high paleontological potential (undisturbed sediments over 10 feet in depth), to	During Construction	Qualified Consultant	City of Glendale	Review of qualified consultant written documentation demonstrating compliance	

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
	be conducted by a paleontological monitor meeting professional standards (Murphey et al. 2019).					
PAL-3	Inadvertent Discoveries. In the event that paleontological resources are encountered during construction activities, all work must stop in the immediate vicinity of the finds while the paleontological monitor documents the find and the designated project paleontologist assesses the find. Should the qualified paleontologist assess the find as significant, it should be collected and curated in an accredited repository along with all necessary associated data.	During Construction	Qualified Consultant	City of Glendale	Review of qualified consultant written documentation demonstrating compliance	
TRA-1	TRA-1: To accommodate turning movements by large trucks (CA-Legal 65 feet) and public safety on Fairmont Avenue, the demolition and construction contractor shall be required to prepare a traffic control plan for	Prior to initiating demolition and construction	Engineering, Procurement, and Construction Contractor (EPC) and Demolition Contractor	City of Glendale	Review of EPC and Demolition Contractor's traffic control plan prior to initiating demolition and construction	

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
	City review and approval prior to initiating demolition and construction activities that includes the use of large trucks entering and departing the Grayson Power Plant from Fairmont Avenue.					
TRA-2	TRA-2: To reduce construction traffic at the San Fernando Road and Doran Street intersection during the p.m. peak hours, a construction traffic control plan shall be developed by the contractor, reviewed and approved by the City, and implemented for the duration of the construction phase. The plan shall include measures to limit vehicle trips to a total of 24 trips or less during the hours of 4 to 6 p.m. for the San Fernando Road and Doran Street intersection. Measures may include scheduling of construction activities or trip routing to minimized travel during peak p.m. traffic times, ride sharing, closing the parking lot, and/or other effective and	Duration of the construction	Engineering, Procurement, and Construction Contractor (EPC)	City of Glendale	Review of EPC's construction traffic control plan and periodic site inspection	

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
	verifiable measure.					
TRA-3	TRA-3: The applicant shall ensure that traffic control is implemented for the duration of demolition and construction phases. Traffic control shall include construction warning signs on Fairmont Avenue (Trucks Entering Exiting), and monitoring (flag person) on public roadways as needed during large transports.	Duration of demolition and construction	Engineering, Procurement, and Construction Contractor (EPC) and Demolition Contractor	City of Glendale	Review of EPC's written documentation compliance of traffic control plan and periodic site inspection	
TRA-4	TRA-4: A construction traffic control plan shall include provisions for days when high truck traffic is generated (soil delivery days, peak concrete delivery days). The plan will include considerations for truck staging to ensure that truck parking/staging can be accommodated off the City streets.	Duration of construction	Engineering, Procurement, and Construction Contractor (EPC)	City of Glendale	Review of EPC's traffic control plan	
TRA-5	TRA-5: Traffic control monitors shall direct traffic whenever heavy construction equipment is entering and exiting the plant as warranted to ensure public safety. The traffic monitor shall be	Duration of demolition and construction	Engineering, Procurement, and Construction Contractor (EPC) and Demolition Contractor	City of Glendale	Review of EPC's written documentation compliance of traffic control plan and written confirmation of coordination with Glendale	

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
	posted throughout the demolition and construction periods, as necessary. The applicant shall coordinate with the Glendale Fire Department in order to ensure that traffic control routes and procedures would allow for adequate emergency access.				Fire Department	
TRA-6	TRA-6: All construction-related vehicles, equipment staging and storage areas shall be located in approved pre-determined areas that are outside of adjacent road right of ways. The applicant shall provide all construction personnel with a written notice of this requirement and a description of approved parking, staging and storage areas. The notice shall also include the name and phone number of the applicant's designee responsible for enforcement of this restriction.	Prior to construction	Engineering, Procurement, and Construction Contractor (EPC) and Demolition Contractor	City of Glendale	Review of EPC's written notice of parking requirement	
TRA-7	TRA-7: Construction traffic shall comply with the California Vehicle Code sections related to vehicle weight and width. Any extra-	Duration of construction	Engineering, Procurement, and Construction Contractor (EPC) and Demolition Contractor	City of Glendale	Review of EPC and Demolition Contractor's written documentation compliance of traffic	

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
	legal loads needed for specialized deliveries shall be subject to special permit requirements from the City of Glendale. Should roadway damage occur along the haul route that is directly attributable to the demolition and construction of the Project, repairs will be assessed by the City and completed accordingly.				control regulations	
TRA-8	TRA-8: Fugitive dust control shall be implemented according to SCAQMD Rule 402, 403 and 1186, and California Vehicle Code Section 23114, and Building & Safety requirements. Dust control mitigation measures include: • Soil stabilizers and dust suppressants to control fugitive dust levels from exposed soils. • On-site water trucks to provide control of fugitive dust while soil is moved or disturbed. • Off-site vacuum and broom sweepers to remove any fugitive materials	Duration of construction	Engineering, Procurement, and Construction Contractor (EPC) and Demolition Contractor	City of Glendale	Review of EPC and Demolition Contractor's written documentation compliance of SCAQMD Rules 402, 403 and 1186 and California Vehicle Code Section 23114, and Building & Safety requirements for fugitive dust. Periodic site inspection	

Mitigation Measure	Monitoring Action	Required Time of Compliance	Implementation Responsibility	Verification Responsibility	Verification Method	Compliance Date
	from the public roadways. • Track-out control to prevent dirt and mud from being spread to public roadways: ○ Sweeping or spray cleaning trucks prior to leaving project site. ○ Adequate truck load covering. ○ Limit on-site vehicle speeds to 15 mph.					
TRA-9	TRA-9: The temporary parking lot on Doran Street is served by two driveways. To provide for sufficient spacing from the railroad tracks and sufficient queuing capacity, the driveway adjacent to the railroad tracks will be limited to entry only and the driveway located 400 feet west of the railroad tracks will be limited to exit only.	Duration of construction	Engineering, Procurement, and Construction Contractor (EPC) and Demolition Contractor	City of Glendale	Review of EPC and Demolition Contractor's written documentation compliance of traffic control plan	

ATTACHMENT A PUBLIC MEETING AND INDIVIDUAL RESPONSES

MC

In The Matter Of:

TRANSCRIPT OF PROCEEDINGS

SPECIAL JOINT MEETING

GLENDALE WATER & POWER

November 22, 2021

Ron Fernicola & Associates

"Transcripts You Can Trust"

1244 West Edgewood Circle

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TRANSCRIPT OF PROCEEDINGS

SPECIAL JOINT MEETING:

Glendale Water & Power

and Sustainability Commission

September 9, 2021

Council Chambers

613 E. Broadway, 2nd Floor

Glendale, CA 91206

Transcribed by: Dana Harris
Certified Shorthand Reporter
CSR No. 5700

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A P P E A R A N C E S

SUSTAINABILITY COMMISSION:
ALEK BARTROSOUF, CHAIRPERSON
RONDI WERNER, VICE CHAIRPERSON
HAIG KARTOUNIAN
JENNIFER PINKERTON
ALEEN LAURA KHANJIAN

GLENDALE WATER & POWER:
TED FLANIGAN, PRESIDENT
MARK YOUNG, GENERAL MANAGER
ROLAND KEDIKIAN
NINA JAZMADARIAN
JOEL PETERSON

PRESENTERS:
DAVE TATEOSIAN, CLEAN ENERGY CONSULTING PARTNERS
MICHAEL WEBER, STANTEC
KARL LANEY, MONTROSE ENVIRONMENTAL GROUP

CATALINA LEE, ADMINISTRATIVE ASSISTANT

P R O C E E D I N G S

PRESIDENT FLANIGAN: Greetings. Good evening, and welcome to a Special Joint Meeting of the Glendale Water & Power Commission and the Sustainability Commission.

I'm joined here in the chambers with Chairman Alek Bartrosouf. Good evening, Alek. And we have some of your Commissioners on the line as well, and my fellow Commissioners.

Today is September 9th, 2021.

To help slow the transmission of COVID-19 and protect the health and safety of the community, City Council as well as Board and Commission meetings will continue to be closed to the public for in-person attendance. The public is encouraged to watch and participate from the safety of their homes to practice social distancing.

Meetings are broadcast live on Glendale TV, viewable on Spectrum Cable channel 6, at AT&T U-verse channel 99.

Meetings are also streamed live in high definition, HD, on the city's web page, glendaleca.gov/live; on YouTube.com/myglendale; and on Apple TV, Roku, and on Amazon Fire devices using a free app called Screenweave and choosing "Glendale TV" from the menu.

For public comments and questions during the meeting, please call 818-937-8100. Public comments on a specific agenda item will be taken when that agenda item is discussed.

Next item, please.

MS. LEE: 1. Role call.

Before I proceed with the roll call and for the record, Commissioner Lall will not be participating in tonight's discussion due to conflict of interest.

Glendale Power & Water Commission roll call.

Commissioner Jazmadarian?

COMMISSIONER JAZMADARIAN: Here.

MS. LEE: Commissioner Kedikian?

COMMISSIONER KEDIKIAN: Here.

MS. LEE: Commissioner Peterson?

COMMISSIONER PETERSON: Here.

MS. LEE: President Flanigan?

PRESIDENT FLANIGAN: Here.

MS. LEE: Roll call for the Sustainability Commission.

Commissioner Kartounian?

COMMISSIONER KARTOUNIAN: Present.

MS. LEE: Commissioner Khanjian?

COMMISSIONER KHANJIAN: Present.

MS. LEE: Commissioner Pinkerton?

COMMISSIONER PINKERTON: Pinkerton here.

MS. LEE: Thank you.

Vice Chair Werner?

VICE CHAIRPERSON WERNER: Here.

MS. LEE: Chairperson Bartrosouf?

CHAIRPERSON BARTROSOUF: Here.

MS. LEE: Ex Officio Gang?

EX OFFICIO: Here.

MS. LEE: Ex Officio Prado?

EX OFFICIO: Here.

PRESIDENT FLANIGAN: Next item, please.

MS. LEE: 2. Reports, Information.

2a, Community Meeting Regarding the Partially Recirculated Draft Environmental Impact Report for the Grayson Repowering Project.

PRESIDENT FLANIGAN: Anybody have a staff presentation?

MR. YOUNG: Yes.

President Flanigan, Chairperson Bartrosouf, members of the Commission. I'd like to introduce three individuals that will be presenting to us today.

First person is Dave Tateosian. Been involved with this project for many years, and he's acting project manager. He's a principal of the Clean Energy Consulting Partners.

Dave is a native of California, holds a bachelor of science degree in mechanical and nuclear engineering and an MS in nuclear engineering from UC Berkeley. He's a California registered professional engineer.

Dave has provided testimony in both California Energy Commission and the Nuclear Regulatory Commission proceedings.

During his career, Dave has been involved with projects involving gas and steam turbines, reciprocating engines, co-generation, nuclear, solar PV and thermal, geothermal, and energy storage.

Next individual I'd like to introduce is Michael Weber. He's a senior principal scientist with Stantec. He has a BS in environmental studies from UC Santa Barbara and possesses more than 20 years of California Environmental Quality Act experience.

Michael's experience includes but is not limited to the environmental impact analysis for energy generation, transmission, and storage projects.

Michael is the city's consultant, technical lead assisting with the preparation of the environmental impact report, and has been involved with the project since 2015.

Lastly, but not least, Karl Laney is a regional manager for the permitting and compliance services division of the Montrose Environmental Group. He has overseen environmental analysis and permitting in support of Glendale's integrated resource plans and proposed project alternative aid described in the environmental impact report, with a focus on air quality, greenhouse gas, health risk, and AQMD permitting and compliance.

Mr. Laney provides similar permitting and compliance services for other local municipal utilities including the cities of Riverside, Anaheim, and Colton, all of which are regulated by the South Coast AQMD.

Mr. Laney is also a member of the South Coast Best Available Control Technology, BACT, scientific review committee and several regulatory development working groups that are sponsored by the Air District.

And I'll leave it to Dave to start the presentation.

MR. TATEOSIAN: Good evening, President --

UNIDENTIFIED SPEAKER: We cannot hear Dave.

MR. TATEOSIAN: Got it. Okay. Sorry about that.

I'll start again.

Good evening, President Flanigan, Chairperson Bartrosouf, fellow members of the Glendale Water & Power and Sustainability Commissions, and members of the public.

So tonight we're going to talk about Grayson Repower. And, you know, probably the foremost question in people's minds are why are we repowering Grayson with a thermal generation component when we're all worried about climate change?

And the simple answer to that is because there's inadequate alternate resources to ensure reliability. Building new transmission lines into Glendale is infeasible.

If you look at the current transmission capacity that comes into Glendale, that's about 200 megawatts. The historical peak in Glendale's 346 megawatts.

GWP's resources that are nonthermal resources that are expected to come online over the next coming years is 50 megawatts of local demand-response energy efficiency in the virtual power plant that came out of the clean energy RFP, plus 72 megawatts of additional capacity on existing transmission that GWP will have access to by being a participant in the Intermountain Power Project repower.

If you add all that up, that's still short of the 346 megawatts. So something more is needed.

And, in addition, there needs to be a margin to cover contingencies and to meet peak load.

And that's what gets us to needing additional generation at Grayson.

And when I say "additional," I mean in addition to clean energy because what's being proposed is to replace what's there.

If you look at the industry-accepted reliability standards for what Glendale will have with the transmission access, you would need 172 megawatts of resources available to cover contingencies, the N-1, the N-1-1 or sometimes called the N-2.

Next slide, please.

So in -- as a result -- when we went to City Council back in 2018, the EIR was not certified, and GWP was asked to look for cleaner alternatives. And that led to the clean energy RFP.

And out of that process came two new alternatives, what we're -- today we're calling Alternatives 7 and 8.

The original EIR addressed five alternatives plus the originally proposed project, the Siemens Repower.

And so this partially recirculated draft environmental report does two things, really. Okay.

It updates the original EIR for the original proposed project, the Siemens Repower, to address two new topics that CEQA law now requires that weren't required at the time: Energy and wildfire.

And then, in addition, it evaluates two new alternatives in addition to the existing -- or the original five. And that's what we're calling Alternative 7, Alternative 8.

Alternative 7 involves Tesla batteries and Wartsila engines to provide the thermal component.

Alternative 8 is the same Tesla batteries and a refurbishment of the existing units 8A, B and C.

Next slide, please.

This is kind of the schedule we have been through.

The Notice of Preparation for the original proposed project goes back to 2016.

There was a public review period during the latter part of 2017.

And it was presented to the City Council for adoption in April of 2018.

Out of that, the clean energy RFP was issued in May and the results presented to the City Council in

July of 2019.

We've now done the work to develop the new alternatives; done the environmental analysis, the conceptual engineering; and so the partially recirculated draft EIR -- I think, for simplicity, we're just going to refer to it as "EIR" going forward tonight -- but that is now out for public comment.

The public comment period was lengthened to 60 days, and public comments are due by October 8th.

So the original proposed project that was the subject of the original EIR back in 2018, that retained Unit 9. Unit 9 is a simple-cycle gas turbine that was built in 2003. It demolished all the other units, Units 1 through 8. And then in their place, it built two new combined-cycle units and two new simple-cycle units.

So the original -- the benefits that were set forth for the original project was to maintain reliable service; keep rates affordable; comply with the renewable portfolio standard while they used thermal generation. Part of the requirement was that it be flexible generation to be able to accommodate the intermittency of solar and wind resources that were being imported. And then meet the electrical demands of the city if the city was separated from the grid. That happened back during the Sylmar earthquake, and Grayson was able to carry the load. That was one of the requirements.

And so a lot of hours, operating hours, was included in that air permitting for that proposed project. So the unit -- the units could carry the city if needed.

Then lastly, replacing the older units with cleaner technology, and then providing a local source of generation. That kind of ties into the point that I made before.

And lastly, limiting use of potable water for power generation.

This is an overview of the existing Grayson Power Plant.

You see the red dashed line that surrounds the structures colored in yellow. And that red dashed line is the limits of the project.

In the lower right-hand corner, what is not in yellow, that's Unit 9. That is currently in operation, and it will stay in operation.

What is colored in yellow is what would be demolished, either for the original proposed project or either of the two alternatives that we're talking about.

What's inside the white dashed line is what we're going to show next, which is the general arrangement for the originally proposed Siemens repower.

What's outside the white line there to the right side, what you're seeing is H and I, that area was going to be demolished, and then there was various -- an admin building, warehouse, workshop, other ancillary structures that were going to be going in there. Gas compressors.

So next slide, please.

This is an overview of what was originally proposed back in 2018.

So on the left, you have the two simple-cycle gas turbines. On the right, you have the two other gas turbines with their heat recovery steam generators and the two steam turbines sitting in a building in between.

Next slide, please.

Since April of 2018, there have been a number of things that have occurred that have influenced the project development. This is, if you will, a table of contents of what we're going to go through next, just to cover these points. So I won't go through them in detail. The subsequent slides will do that.

So I'm going to turn it over to Karl a second.

Okay.

MR. LANEY: Good evening, Chair, President, and members of the Commissions.

At the time the analyses for the original proposed project were being completed, South Coast also embarked on rural development that would affect power generating facilities in the South Coast Basin, including the generating units at the Grayson Power Plant.

The objective of the rule is to make existing legacy power generating systems as clean or as low emitting as new systems that would come into the basin.

So basically we talk about best available control technology that is -- and that's usually applied to new emission sources. This rule basically applies the equivalent of that to existing sources.

Only Unit 9 can meet those emission rates right now, and this is primarily a NOx rule and an ammonia slip rule.

It is feasible to modify units 8A, B and C with enhanced emission control systems; maybe some tuning, I understand; and also with emission monitoring systems that are designed to accurately read the lower emission rates that the rule would require.

It's not practical or feasible to do the same to boilers 1 through 5, for various reasons. It's different technology. It's harder to get to where they need to be. But also, the boilers don't provide the same kind of utility, operating utility, that gas turbines provide.

To comply with Rule 1135, the city has three choices, the first of which is to modify units to meet the standards and to do so by January of 2024. Again, Unit 9 is covered; Units 8A, B and C would require modification if you were to take that route.

Alternatively, you could replace the units with new generation to meet those standards, again by 2024; or, finally, to retire the existing units and forfeit the power generating capability.

The city does have an obligation to notify and submit applications to the Air District by June of 2022 and, again, come into compliance by January of 2024.

MR. TATEOSIAN: Okay. Another significant thing that took place was the clean energy RFP.

That RFP went out to the marketplace; and it really had very few limits on what could be proposed, but there were a few, and they were critical.

One was that it had to be local generation, that it couldn't rely on transmission because Glendale's pipeline to bring electricity in was already booked.

Had to be at least one megawatt. And it had to be commercially demonstrated technology.

So, you know, there were no one-offs or science projects.

There were 34 proposals that were received; and out of that, Glendale selected the following. Some of the proposals, people were asked to increase the size of them so that Glendale could get more.

Franklin Energy, the demand response, that is in place; and, in fact, tomorrow will be the first occurrence of calling on Franklin to exercise demand response to reduce Glendale's load.

Lime Energy, that contract is in place; and that's energy efficiency.

Sunrun, I think as you know, is still in contract negotiations.

And then there's the Tesla batteries and the Wartsila thermal generation.

The 2019 integrated resources plan, that was presented to City Council in July of '19. That was built on what came out of the clean energy RFP. So it included what came out of the local generation clean energy, as well as the batteries and the thermal generation.

The IRP looks at two things. It looks at not only what do you plan to do generation-wise, but it looks also at what do you expect to happen with load.

And there's two aspects to load. One, what is the peak demand that you have to serve? And then, secondly, what is the overall amount of energy that you have to serve?

So energy demand is expected to grow. How -- it's expected to grow slowly, but that's based on the assumption that all the energy efficiency, demand response, and local comes into play.

And peak load is expected to grow also. And where this growth is coming from is electrification of both transportation and infrastructure.

There's the Intermountain Power Project in Utah. GWP is a participant, one of the owners of IPP.

Today, IPP is a coal-fired power plant; and the plan is to repower it as a gas turbine combined-cycle power plant.

Part of the IPP project brings with it transmission capacity on the Southern Transmission System.

Some of the participants chose not to participate in the repower. And so that made available some transmission capacity that GWP was to -- able to obtain.

And so there's 72 megawatts of additional transmission capacity that will become available in 2027 to GWP that wasn't even on the table back in the original proposed project.

When IPP is repowered, the plan is to run those gas turbines initially on a mix of 70 percent gas, 30 percent hydrogen, and then transition over time to 100 percent hydrogen.

And then what would happen is local solar and wind resources would be used to take local water, turn it into hydrogen, and then use that hydrogen as a fuel source for the gas turbines.

SB 100 got enacted. And SB 100 basically required that utilities procure 60 percent of their electricity from renewable resources by 2030. And then, by 2045, that would increase to 100 percent.

And then the City Council requested that GWP perform a 100 percent clean by 2030 study. Now, was it possible to get to 100 percent clean renewable resources as a source of supply by 2030?

That was presented earlier this year. And basically the study concluded that it was possible to get to 89 percent by 2030. And along with that, there was going to be a required rate increase to cover the resources.

And then how would we get to the other 11 percent?

So the other 11 percent was either going to require new transmission to bring in more renewables, and then the additional renewables with storage so that -- we need the storage to address nighttime load that would come over that new transmission; or it's local renewables with storage, or it's using renewable natural gas at Grayson.

And then, while not a generation issue per se, there was the September 2019 rolling blackout. And that was precipitated by an equipment failure within the GWP transmission distribution system.

But what came out of that, then, was right now, with the Kellogg switching station at the utility operations center, which is where the Grayson Power Plant is also located, the UOC is basically -- I'm sorry. Kellogg switching station is basically a nexus for the entire GWP system.

So out of that event, the decision was made to add the Glendale switching station to the project and -- so that would provide additional resiliency. While it wouldn't be a complete 100 percent redundancy to Kellogg, it would provide a lot more resiliency to the GWP system and make it more fault tolerant. And so that got added to Alternative 7 and 8.

And at this point, I'm going to turn it over to Michael Weber.

MR. WEBER: Thank you, Dave; and good evening, President and Commissioners.

There has also been a change in air quality and greenhouse gas emissions occurring at the Grayson Power Plant since the original EIR.

In 2018, when that original EIR was considered, landfill gas was being combusted in the Grayson boilers at the Grayson Power Plant; and that's what our air quality and greenhouse gas conditions evaluated and assumed in that original 2018 EIR.

Since that time, in April 2018, the city has discontinued combusting landfill gas at the boilers. It is now being flared at the Scholl Canyon Landfill itself.

So, as part of the updated EIR, we did look at those differences in those air quality and greenhouse gas conditions, looking at both scenarios and evaluated both scenarios, and did conclude that both the air quality and greenhouse gas emissions impacts of the proposed project under either scenario would be less than significant.

The new alternatives that Dave spoke to have now also been evaluated in the Alternatives section of the updated EIR. That is Alternative 7 and Alternative 8.

Alternative 7 includes five Wartsila reciprocating internal combustion engine units with a generation capacity of approximately 93 megawatts. Also includes a battery energy storage system producing 75 megawatts with a storage capacity of 300 megawatt hours as well as a new Glendale switching station to help with reliability as well.

Alternative 8 has a lot of similarities as Alternative 7. It would include the same battery energy storage system as well as the Glendale switching station. Just replaces the five Wartsila reciprocating internal combustion engines with retaining and refurbishing the existing units 8A and 8BC generation units.

In 2018, Confluence Park had not yet been developed. This is a new park that is located just southwest of the Grayson Power Plant, sandwiched right in between the power plant, the Los Angeles River, and Highway 134. So in the updated EIR, we did consider that park as a new sensitive noise receptor, as well as a key observation point for potential aesthetics impacts. So we did analyze that receptor in the updated EIR for all issue areas and resource categories as well.

In 2018, when the city presented the final EIR to City Council to consider certification and City

Council requested staff look at cleaner energy alternatives, City Council also requested city staff to consult with the Glendale Historical Society related to demolition of the boiler building itself.

Pursuant with those consultations, the city has elected to treat the boiler building as a discretionary historical resource under the California Environmental Quality Act.

The city has updated and recirculated the cultural resources section of the EIR and has also incorporated new cultural resource-related mitigation measures to the EIR as well.

And here's a summary of those mitigation measures that are added into the 2021 EIR update. That includes doing a Historic American Engineering Record survey of the boiler building; installation of an informational plaque on Flower Street; preserving a piece of the salvaged equipment from the boiler building for informational display. And the city will also display photographs of the historic boiler building in a publicly accessible location on the city campus.

That fourth bullet is not in the draft EIR right now. The City is committing to add that into the final EIR as well.

However, despite those mitigation measures, demolition of the boiler building would constitute a significant and unavoidable impact under CEQA.

Want to also note that the boiler building would be required to be removed for the proposed project and any and all alternatives involving new generators or battery storage at Grayson Power Plant.

The updated EIR also includes a noise update as well. That included more quantitative construction noise analysis and modeling for the proposed project. Previously, in 2018, it only looked at nighttime concrete pouring, as well as potential vibrations from pile driving. The update now looks at the worst case or noisiest demolition or construction activities as well and quantifies those and determined that those construction impacts would also be less than significant.

Also evaluated noise impacts on Confluence Park that we just previously discussed and updated the noise technical report and analyzed potential operation phase noise impacts of Alternative 7 and 8 quantitatively as well.

The updated EIR includes a determination that there would either be no or less than significant impacts to air quality, agricultural -- agriculture and forestry resources, excuse me; biological resources, geology and soils, greenhouse gas emissions, energy, land use and planning, mineral resources, population and housing, public services, recreation, tribal cultural resources, utilities and service systems, environmental justice, socioeconomics, and wildfire.

You will note there is a bullet on there for cultural resources. Please forgive us. That is an error and a typo. And we'll talk about cultural resources in the next slide as well.

All right. EIR determined that there would be less than significant impacts with mitigation to aesthetics, hazards and hazardous materials, noise, paleontological resources, and transportation and traffic.

There would be significant and an unavoidable impact to cultural resources related to demolition of the boiler building that the city is treating as a discretionary historic resource.

Just summary of the mitigation measures that have been integrated or incorporated into the EIR. I'm not going to read through all of these. I just want to note that the ones in black text are from the original EIR. The mitigation measures shown in blue text are ones that were added to the updated EIR. And that does include these cultural resource-related mitigation measures we just spoke to on a previous slide.

And hazards and hazardous materials-related mitigation measures.

And noise-related mitigation measures. Largely related to a specific requirement to meet specific noise limits for different components of the equipment that are either guaranteed by the vendors or equipment manufacturers or have been determined based on noise-modeling expertise to be reasonable standards to be able to meet, even if they are conservative.

Paleontological resources, some new mitigation measures to do worker training prior to start of construction as well as having a paleontological monitor and a plan in place to handle and manage any inadvertent paleontological discoveries as well as a range of transportation-related measures during the construction phase.

Again, all of these mitigation measures are in the EIR and can be referred to there as well.

Okay. The alternatives that were evaluated in the EIR. Eight of them total. Really seven, and we'll explain this.

The first five were evaluated in the 2018 EIR, and 7 and 8 were added to the 2021 updated EIR.

So those alternatives include, number 1, the no project alternative. Essentially taking no action and doing nothing.

The second one is an energy storage project alternative, essentially including no generation or no new transmission, just storing energy.

Number 3 was an alternative energy project. That would involve generating of renewable energy, likely outside of the city, of utility scale, PV solar, wind energy projects, and constructing a new transmission line to bring those resources into the city.

Number 4 was a 150-megawatt thermal generation project.

Alternative 5 was a 200 megawatt thermal generation project.

Alternative 6 was a Tesla battery storage and Wartsila reciprocating internal combustion engines alternative.

As engineering started to look at that in terms of site layout for the environmental team to evaluate potential impacts, it was determined that the siting of that alternative was not going to be feasible from an engineering standpoint, and it was therefore excluded from further analysis.

Alternative 7 is the same equipment. It's just in a slightly different configuration than was envisioned for number 6. And those include the alternatives that we just talked about in previous slides, number 7 being the 75 megawatts of energy storage or battery storage as well as the 93 megawatts from the five engines; or Alternative 8, that is refurbishing 8A, 8BC, then also includes the energy storage and new switching station.

There were a range of alternatives that were considered but just not evaluated in the EIR.

There is section 5, I believe, of the EIR that explains all of these in substantial detail as well as the reasonings as to why they were not carried forward into a more detailed evaluation in the EIR.

Those included that Alternative 6: Range of different power plant site alternatives; project technology alternatives, including combustion generation technologies; conventional boiler and steam turbines; large simple-cycle combustion turbine generators; large combined-cycle combustion turbine generators; alternative fuel technologies; and even power plant cooling alternatives as well.

The comparison of the proposed project against Alternative 7 and 8 for some key components that really help to summarize some key differences.

The total storage and generation of the proposed project is 262 megawatts. That comes entirely from thermal generation with no energy storage.

Alternative 7 has a total of 168 megawatts: 75 from the energy storage and 93 from thermal generation.

Alternative 8, 176 megawatts total: 75 from the energy storage and 101 megawatts from the thermal generation.

There's a substantial difference in the natural gas combustion between the proposed project in both Alternative 7 and 8, measured in millions of BTU per year. You can see, for the proposed project, it is almost 10 million, million, with the metrics there.

Alternative 7 is just over a million. And Alternative 8 is a little bit more than 1.2. But you can tell, just looking at that, you know, you're looking at 80, 90 percent reduction in natural gas combustion.

That's a function of the reduction in thermal generation capacity, but also a reduction in the number of proposed operating hours that Dave explained in the previous slide for the proposed project. So that's why you see a substantial reduction in the natural gas combustion -- combustion. Excuse me.

As a result of the decrease in natural gas combustion, you also have a substantial decrease in the carbon dioxide equivalent emissions for the proposed project and the alternatives where the proposed project expressed in metric tons per year would be almost 500,000, whereas Alternative 7 is slightly above 50,000, and Alternative 8 is slightly above 60,000 or less than 70,000. So big reductions.

Also wanted to express the differences in terms of health risks. And these health risks are expressed, pursuant with CEQA, in the number of predicted or modeled cancer cases in a population of one million. So the threshold of significance would be 10. If you had a population of 10 in one million expected to get cancer, that would be considered a potentially significant impact under CEQA.

For the proposed project, it was 0.91. For Alternative 7, the health risk is even reduced substantially more, to 0.5; and Alternative 8, 0.014. So you are seeing some marked reductions in the health risks as well.

Okay. Sorry, skipped one slide there.

This is just a comparison of the project and all seven or eight of the alternatives that were evaluated in the EIR. Again, those first five, 1 through 5, were evaluated in the 2018 EIR; 7 and 18 [sic] were added in an updated EIR.

The blue text in here just shows the changes that were made or the update to the table from the 2018. So 2018 is black text. Anything that is shown in blue was added.

So I'm just going to focus on -- a minute or two on 7 and 8. Again, all of the detail in this table is included in section 5 of the EIR.

So Alternative 7 compared to the proposed project, and these potential impacts were qualified for comparison purposes as being potentially less, similar, or greater environmental impacts than the proposed project.

So we have the potential for less environmental impacts to aesthetics, air quality, energy, greenhouse gas emissions, and noise, and no greater environmental impacts than the proposed project. All of the other environmental resource categories would have similar impacts to the proposed project.

For Alternative 8, there would be less potential environmental impacts to aesthetics, air quality, energy, and greenhouse gas emissions. There would be greater potential environmental impacts to noise, and all of the remaining environmental categories would have similar environmental impacts to noise. I'm sorry. To the proposed project.

I did want to mention, in noise, that the modeling for that was very conservative. The level of engineering design was not as advanced as the proposed project or the other alternative with specific equipment being selected, so we didn't have access to equipment and vendor guarantees and how to build in what we believe were some reasonable but conservative assumptions for noise levels on that. So that's why you see that as being higher; but we believe that, in reality, that it would likely be very similar to the proposed project.

Just some photo simulations of the proposed project as well as Alternative 7 and Alternative 8 we will get in the next slide.

This is from what is referred to as key observation point 1 considered in the EIR. This is from the corner of Fairmont Avenue and Flower Street. The image on the left shows a simulation of what the proposed project would look like.

The photograph on the 8 -- I'm sorry, on the right-hand side shows a photo simulation of what Alternative 7 would look like.

Simulation of the proposed project and Alternative 8. Again, this is from the same key observation point at the corner of Fairmont Avenue and

Flower Street. The proposed project is shown on the left, and Alternative 8 is shown on the right.

Okay. The CEQA path forward and how anybody that is interested can provide a comment on the 2021 partially recirculated draft EIR.

This is where we are right now, anticipating to respond to comments and notice of final EIR in November of this year, as well as presenting that final EIR to the Glendale Water & Power and Sustainability Commissions; again anticipating that to occur in November as well. Followed by presenting the final EIR to Glendale City Council to consider for certification, also anticipated to be in November of 2021 as well.

I won't read through the slide on how to comment. It is on here. Erik Krause with the city Community Development Department and the Planning Division is the contact. His address is on here. His telephone number is on here. His e-mail address is on here. And comments must be received no later than 5:00 p.m. on October 8th, 2021, and the city will review and respond to all comments received. That includes questions and comments received tonight as well.

And thank you very much. I'm going to turn it back over to Dave.

MR. TATEOSIAN: So we've come full circle, back to the original question. And that is why repower Grayson given the challenges we face with climate change?

And as I said in the beginning, it comes back to one -- a question of needing to meet load and reliability.

GWP takes climate change and renewable energy seriously. And you just have to look at the last 20 years of what GWP has been doing.

They started a solar solutions program back in 2002 that resulted in 20 megawatts of rooftop solar being built within the city. That was all prior to the clean energy RFP.

There was net metering programs. Feed-in tariffs. There was demand reduction through the Ice Bear program as well as energy efficiency program.

So GWP -- and, you know, there's street lighting. There's -- so you can go -- there's a lot of programs that GWP's been doing over the last 20 years to try and reduce load as well as generate things renewably within the city.

And then we did the clean energy RFP. And as I said earlier, that was open to everything. And out of that is expected to result about 50 megawatts.

You total it all up, and it just doesn't come up enough to serve peak load and ensure reliability.

So as much as GWP's got a responsibility to manage the utility responsibly with the environment in mind, it also has a responsibility to serve the residents and assure them a reliable source of electricity.

And all those programs and what they're able to import and the limitation on new transmission, basically not being able to build it, limits what you're able to import using only renewable energy resources.

And so the backup, all that's left, really, is locally generated power; and that's going to come from thermal.

And so, hence, we're here.

You take -- you do the math and you add, like I said, the 200 megawatts of imports and the 72 megawatts that comes online in '27 and the 50 megawatts that comes out of clean energy, you come up short on the 346.

And you've got to be able to cover contingencies. Because as happened this summer, you had wildfires to the north. Those wildfires may have been hundreds of miles away from Glendale, but it resulted in curtailing the transmission lines that -- the power that GWP obtains from the north to come south to Glendale. That capacity, that got curtailed.

And so there needs to be a way to back that up. And when your major sources are all imported over transmission lines, that limits your ability and really forces a local solution.

So what we're proposing with Alternative 7 and 8 gives you 75 megawatts of batteries, and that can be used for spinning reserve; that can be used to support load. But those batteries, just like what you buy in the store, have a finite life. And then you need to recharge them. And the ability to recharge the batteries is contingent on how much spare capacity there is at night in the transmission lines.

And so the combination of the batteries and the thermal generation provides you the level of reliability, the backup resources that we think are needed to ensure a reliable supply of electricity.

So with that, that concludes our presentation; and I think, at this point, it's open to questions and comments.

Thank you very much for your time, and we appreciate it.

PRESIDENT FLANIGAN: Well, thank you for your -- thank you all for your presentation and all the work that you've done thus far.

MC-1

And just a procedural question, I guess for our

MC-1

attorneys: Are we seeking any sort of a resolution from each Commission this evening or a recommendation to anybody? Or we are just commenting and hearing public comment as well?

CHIEF ASSISTANT ATTORNEY GILLIAN VAN MUYDEN: Yes, Commission President, Commission Chair.

We are just receiving comments. As indicated, those comments will be captured, and each of the subject matter experts here is carefully taking comments as it pertains to their matter of -- their area of expertise. And all of those comments and responses to those comments will be incorporated into the final EIR, which is expected to be released in November.

PRESIDENT FLANIGAN: All right.

ATTORNEY GILLIAN VAN MUYDEN: And then the staffs will be bringing back that final EIR in November to the Commissions. At that time, the staff will be seeking recommendation from the joint commissions.

PRESIDENT FLANIGAN: But the EIR will be certified based on the proposed project as well as the alternatives?

ATTORNEY GILLIAN VAN MUYDEN: It --

MC-2

PRESIDENT FLANIGAN: It will not specify -- through this process, we will not specify which alternative?

ATTORNEY GILLIAN VAN MUYDEN: You may, yes. That would be --

PRESIDENT FLANIGAN: We may.

ATTORNEY GILLIAN VAN NUYDEN: -- part of your recommendation. Yes.

ATTORNEY CHRISTINE GODINEZ: President Flanigan: But, to clarify, not this evening. When it comes back to you in November, we'll ask for your recommendation regarding the final EIR, including this partially recirculated portion and responses to comments. But for today, we're just gathering comments --

PRESIDENT FLANIGAN: Very good.

ATTORNEY CHRISTINE GODINEZ: -- from yourselves and the public.

PRESIDENT FLANIGAN: Very good.

So I think we'll start with Commissioner comments from the GWP Commission. Is that okay if we do that?

ATTORNEY CHRISINE GODINEZ: Good. Yes.

PRESIDENT FLANIGAN: Chairman Bartrosouf?

And then we'll switch over to the Sustainability Commission.

So with that, let's start with Commissioner Jazmadarian. Questions? Comments?

COMMISSIONER JAZMADARIAN: There we go.

MC-3

So for -- I do have a question, and it's about the contingency area.

So with Alternatives 7 and 8, we're fine after 2027 with the contingency. What happens in the few years after either Alternative 7 or 8 is built and before 2027? Is -- what would we use as the contingency? We borrow from LADWP or Burbank, something along those lines?

MR. TATEOSIAN: We're not okay after -- after 2027, that -- and that 72 megawatts becomes available -- sorry.

After 2027, that 72 megawatts becomes available, that does not satisfy all the contingency needs. The amount of contingency needs are -- is 172 megawatts.

The single largest contingency is 100 megawatts of transmission off the DC Intertie. The second largest contingency is the 72 megawatts that you gain in 2027.

So we would need to cover, if you -- you want to assume the peak load doesn't grow from 346 megawatts and the IRP says otherwise; but if you take that 346 and you add 172 to it, you're at 520 megawatts. And that's about how much resources -- and it goes up from there -- that GWP needs to have available.

COMMISSIONER JAZMADARIAN: Okay. Thank you.

MR. TATEOSIAN: Okay.

PRESIDENT FLANIGAN: Other questions, Commissioner Jazmadarian?

COMMISSIONER JAZMADARIAN: That's fine.

PRESIDENT FLANIGAN: Commissioner Kedikian?

COMMISSIONER JAZMADARIAN: No. That's it.

PRESIDENT FLANIGAN: Thank you.

Commissioner Kedikian?

COMMISSIONER KEDIKIAN: Thank you. Thank you, President.

I had a question with regards to our participation in the IPP and where we gained about 72 megawatts of transmission.

MC-4

You indicated some people chose not to participate in that project.

Now, the question may not be related to this particular thing, but I want to know why did other people choose not to participate in the IPP project? Was it because it was gas or hydrogen? What was the reason, if you know?

MR. YOUNG: Mr. President, Mr. Chairperson, Members of the Commission.

While I think I know, I haven't vetted the answer to everyone that decided to get out. But the most -- the people that got out were part of the CAISO.

And the CAISO mechanism is very different than the LA Balancing Authority.

The LA Balancing Authority takes generation at the source, uses its transmission, and brings it to the load.

In the CAISO, it's not necessarily that way. Once it gets into Los -- once it gets into California, it's deemed delivered, and the CAISO manages transmission.

So that was the primary reason why the CAISO participants got out. That gave us a good opportunity to be able to increase our share of IPP. And because we increased our share of IPP, the transmission is linked to percent ownership share or quasi-ownership share of IPP. So we were able to maximize that benefit.

MC-5

COMMISSIONER KEDIKIAN: And the IPP, when we're talking, that's the northern line that comes down to Glendale; is that correct? Or am I wrong?

MR. YOUNG: No, that's incorrect. That's part of the AC line. When we said we have 100 megawatts on the AC, the AC isn't one line. There's a couple of different lines. There's actually five lines that come into the Calif -- the LA Basin. But, for simplicity reasons, we consider that one line. And it's part of that one line. It comes from Adelanto to -- to or from

Utah.

So there's a high voltage DC line that goes from Delta, Utah, to Adelanto. Goes through a converter station. And then it goes through what they call the Vic-LA line, which is five transmission lines that Los Angeles owns that brings it into the basin.

MC-6

COMMISSIONER KEDIKIAN: What kind of event would cause us to lose that 72 megawatt transmission that we gained by participating in this IPP?

MR. YOUNG: Wildfire is a perfect example of why you would lose that transmission. It's one line -- it's a DC line. So think of it as two lines. One's a plus line. One's a minus line. If there is an accident on that line, if something happens to the infrastructure that supports that line, it would go out.

If there was an electric disturbance on either of the converter stations, you'd lose half of that line. It's possible that that happens.

It is integral in the voltage stability of the WECC on that line. So it's a critical line. But you still have to manage for half of that line going out.

MC-7

COMMISSIONER KEDIKIAN: With regards to Alternative 7 and 8, and in particular with regards to the Wartsila engine -- Wartsila engines or the refurbishing of 8A, BC, any idea on the difference in

MC-7

cost? Is one double the other? Or any idea about the cost of either putting the new engines or refurbishing the ones that we have as Alternative 8?

MR. TATEOSIAN: Cost estimates for the two options are underway. We haven't completed that work. We're in the process of starting to negotiate contracts with Tesla and Wartsila. We have their proposals.

The work to do the demolition site improvement and the other work, that is in process of being estimated.

When we go to City Council in November and we come to you before then, the plan is to have costs of the alternatives complete so you understand both the financial aspects as well as the environmental aspects of both alternatives.

COMMISSIONER KEDIKIAN: Thank you, Dave.

MC-8

The reason I asked that question is both Alternative 7 and 8, from a generation point, they're very close to each other; however, I understand Alternative 7 gives you the refinement to be able to turn on less and be more flexible.

But I think a cost would be very beneficial to understanding the decisions because -- between those two. So I would encourage in getting a cost as much as possible on that as well.

MR. TATEOSIAN: Yeah, we -- we will.
I'll add, you know, it's -- you know, Alternative 7 is likely to be the lesser-cost option. But, you know, Alternative 8 -- I'm sorry. Alternative 8 is likely to be the lesser-cost option.
Alternative 7 brings -- like you said, you know, with the Wartsila we can dispatch it in smaller chunks. So there's -- there are trade-offs with both.
COMMISSIONER KEDIKIAN: Right.
That's all the questions I have for now. Thank you.
PRESIDENT FLANIGAN: Thank you, Commissioner Kedikian.
Commissioner Peterson.
COMMISSIONER PETERSON: Thank you, President Flanigan.
MC-9
On the pro forma views, the photos with the potential view of the proposed project and Alternative 7, 8, the visual impact that they might have, would it normally have visible discharge from the stacks? Because in all the photos, it only showed the various stacks but didn't show what it might look like when in operation.
MR. YOUNG: I think it was ironic that there was clouds in the picture.

No, there's no visible discharge out of the stacks.

COMMISSIONER PETERSON: Thank you.

And then my second question is -- show the extreme lack of understanding that I have, probably, of underlying physics and thermodynamics, but the IPP project we're looking at is -- that is projecting to go ahead and use solar and wind to then -- I take it, to do reverse osmosis to separate out hydrogen from water and then use the hydrogen in fuel cells or -- or burn it, I take it, to then generate electricity.

MC-10

How do you get past the -- sort of the second law of thermodynamics where you're -- wouldn't it be -- if you're able to generate enough power to generate enough hydrogen to then generate power, wouldn't it be more efficient to just go directly with the renewables and not lose the inefficiencies and the entropy?

MR. YOUNG: Oh, that's a great question.

What we plan on doing is we plan on using excessive green energy, so energy that we don't need to meet load to because we're going to be -- we'll have excess -- we'll have excess solar and wind in that area. We'll use that to create electrolysis to create hydrogen.

There's salt caverns in that area, which is very unique to that area; and we'll be pushing the hydrogen into the salt caverns. And then what we'll do is we'll use that hydrogen for nighttime generation.

So it's really about shifting the generation curve from the middle of the day, which is where solar is its strongest, to be able to use it at night, to be able to do the things that we need and to be able to get to 100 percent clean. Without the ability to store -- whether it's hydrogen or batteries or water, without the ability to store, we would be deficient generation at night.

So --

COMMISSIONER PETERSON: So --

MR. YOUNG: -- you are right that it is going to be very expensive to create hydrogen. They say that it takes three megawatts to create one megawatt of hydrogen. But if we have excess generation by -- that's created by solar or wind that would normally go to waste, we can utilize that to create the hydrogen. So there should be some synergies there where the value of that megawatt at night far exceeds the three megawatts during the day.

MC-11

COMMISSIONER PETERSON: So what I'm hearing is that what makes this all feasible, again, is the excess renewable generation during daytime coupled with the

MC-11

ability to store the hydrogen so that you start out at the small amount of hydrogen production over time, and then you have a storage capacity that then allows you to be able to generate at night at the levels that you need to power the demand requirements at night.

Is that a fair summary?

MR. YOUNG: That was better -- better that you said it than I did.

COMMISSIONER PETERSON: Well, thank you for answering those questions. That's all I have for now.

PRESIDENT FLANIGAN: Thank you, Commissioner Peterson.

I'm glad we've covered the second law of thermodynamics in this meeting. It's comforting to know that we're handling that.

And I'll just start off my comments.

But first off, thank you for all the work that's gone into this. And those of you that have been working on this for years, I commend all of your efforts.

And I'll just start off with a little bit of a disturbing comment that I heard from someone in the community who said, "My God, we could be building the last gas plant in California."

And I thought, no, that couldn't possibly be.

There must be other utilities that are building a similar capacity. I understand system dynamics, what we need to keep a system resilient.

But that's a little bit disturbing, that potentially we are, if we move forward with repowering with any thermal capacity that uses fossil fuels, that we could be leaving a little bit of a legacy for us here.

And I'm glad -- somebody brought up Copenhagen, Denmark earlier; and, you know, I've traveled to cities around the world that really have maximized their energy efficiency and their thermal efficiency. And it's very obvious when you go there. It's omnipresent.

And it makes me think that we -- I doubt that we have really fully tapped the local resources that I think, perhaps, in hindsight, we might wish that we had; that we would want to leave a legacy of a community that took really bold action on climate. And I think we're taking strong action on climate with the -- even with these alternatives. But I'm not sure we're taking bold action on climate.

I'm discouraged that the Sunrun contract hasn't been finalized. You know, that's capacity that we needed last year. That's -- those are kilowatt hours -- green kilowatt hours that we could be putting into our system. I think we could double the size of that.

We haven't gotten our commercial solar program going. The IRP called for 10 megawatts. There's probably significant multiples of that in our community.

With Commissioner Peterson, who's at Glendale Community College District, we've talked about hillside solar. We talked in our last meeting last week about solar on the landfill. We haven't really introduced a community solar program yet.

There's interesting demand response programs. I know we're doing -- I know we're starting out some, and I applaud that. I'm thrilled that we have our first demand response event tomorrow.

Interesting programs like OhmConnect -- I don't know if you've all heard of that -- which is tapping into individuals' households to provide capacity; not just from air conditioning, from turning off other loads in the house as well.

Admittedly, I'm an energy efficiency guy; and so I'm not sure -- at all sure that we have fully tapped the community spirit that would be required to have a campaign where we become a truly green community like a Copenhagen, Denmark, or a Freiberg, Germany, or a Carbondale, Colorado, or Boulder, Colorado, some of these communities -- Portland, Oregon -- that have really stepped up and moved efficiency and distributed energy resources to a much higher level.

And so I guess that's a bit of a preamble.

A comment that I have is it's fantastic that we've gone from 240 megawatts to 238 megawatts along this path, now to 93 megawatts.

MC-12

And do we need the 93 megawatts? Do we need the five units? Have we fully vetted that in the past year, to look at the current conditions? There's another 25 megawatts of transmission capacity coming in from DWP. Do we really need that 93, or could we make do with three units or four units?

I appreciate that Commissioner Kedikian brought up the cost.

MC-13

I think it'd be very interesting to know, you know, sort of this winding road. What was the projected cost of the original repowering project? It doesn't have to be exact. We can -- we as Commissioners would appreciate, probably, the -- to the closest 10 million or something would be adequate. But then what is the cost of Alternative 7, and what is the cost of Alternative 8?

I have a question about the useful life or the projected life.

MC-14

If we -- what is the life of Unit 9? How many

MC-14

more years do we have? How many more years do we have
with Alternative 8? If we refurbish units -- what is
it, 8A and 8BC, how many years will those -- will those
plants be operable?

And maybe we -- can I just ask that question
right now?

MR. YOUNG: Yes, sir.

It's really not years. It's run hours. So if
we're not going to run it and we're only using it for
extreme heat conditions or for reliability, we might not
need to run it very much. I'm hoping that we don't.

I think the chart that you saw shows a
90 percent reduction in MMBTU use.

So we don't anticipate running it. So it would
live a long time if that were the case.

MC-15

PRESIDENT FLANIGAN: Like, for example, the
Wartsila engines I imagine have a useful life of 30 or
40 years. Would the refurbished units also have 30 or
40? I know it's -- I appreciate what you said about
runtime. I mean, I'm just wondering, is it comparable?

MR. YOUNG: I believe so.

PRESIDENT FLANIGAN: Okay.

MR. YOUNG: I believe they are.

PRESIDENT FLANIGAN: Okay.

MC-16

And then in terms of runtime, I appreciated

MC-16

those -- the chart that showed the approximately 10 million BTUs for the proposed project and then Alternative 7 and Alternative 8 being a tenth of that.

And that's based on -- what runtime is that based on? I mean, is that a certain number of hours? Must be a certain number of hours per year.

MR. TATEOSIAN: Yeah, that's correct.

For the Wartsila engines, I believe it's like 1,500 hours per year per engine.

So it -- for both cases, Alternative 7 and 8 comes out to about 15 percent capacity factor.

So even if you ran all five engines to their maximum hours, that doesn't total up to a year's worth of running. You know. If that makes sense.

PRESIDENT FLANIGAN: It does make sense.

MC-17

And what if we -- would we permit for that amount of runtime or --

MR. TATEOSIAN: Yeah, that's --

PRESIDENT FLANIGAN: -- would we permit for more than that?

MR. TATEOSIAN: No, that's what -- the permits have already been submitted to South Coast. That's what the -- we had to put permits in, and those were -- the hours and the starts that we permitted are described in the draft EIR.

PRESIDENT FLANIGAN: Right. Right.

MC-18 So people that live in that community around the plant don't need to worry that they permitted for a relatively small number of hours, shorter runtime, and then that that gets changed over a few years and the neighboring utilities are all begging to use the plant's capacity and --

MR. TATEOSIAN: You know, those are the hours and starts that we put in, and Glendale will get an air permit that says for each unit, here's the hours and the allowed starts.

PRESIDENT FLANIGAN: Thank you. Thank you.

MR. TATEOSIAN: The one -- I'd just like to add to your comment about the life.

You know, when -- you know, most people talk about a 30-year life. That's -- just to piggyback on what Mark was saying, you know, that's 30 years of being used. Okay.

When you consider the fact that we're permitting at a 15 percent capacity factor, you know, one year of use is really more like seven -- turns into seven years.

And so you look at the eight units, for example, or even look at the older units, you know. Rotating machinery has a long life because it's just --

particularly like the gas turbines. They just sit there and -- they just sit there and turn.

PRESIDENT FLANIGAN: It's sort of not a good thing in this case, though, because we're trying to phase out --

MR. TATEOSIAN: No, I --

PRESIDENT FLANIGAN: -- our gas.

MR. TATEOSIAN: -- I understand. But I'm trying -- just to your point --

MC-19

PRESIDENT FLANIGAN: So I'm hoping -- I was hoping you guys were going to tell me that the refurbished units have about a 10-year useful life and then they'll be toast and that'll cost a whole lot less to do and then we'll be out of gas all together as opposed to building the RICE units or Wartsila units and have 30 years of amortization in front of us.

MR. TATEOSIAN: Unit 8 refurbished would probably have a life longer than 10 years.

PRESIDENT FLANIGAN: Yeah. Right.

MR. TATEOSIAN: Yeah.

MC-20

PRESIDENT FLANIGAN: Dave, were you the one who talked about the hydrogen purchase, or was that one of your colleagues?

Did I hear right that we're going to start off with a 25 percent blend of hydrogen in these units? Or

MC-20

did I -- was I dreaming?

MR. YOUNG: It was 30 percent by volume -- it's 30 percent by volume of Intermountain Power Project.

MR. TATEOSIAN: Yeah. It's IPP.

PRESIDENT FLANIGAN: Okay.

MR. TATEOSIAN: Right now there is no hydrogen supply to Glendale.

PRESIDENT FLANIGAN: Okay. So let's talk about that.

MC-21

These engines -- I believe we asked this before, and these engines can be converted or can take renewable natural gas and/or hydrogen? Is that correct or incorrect?

MR. TATEOSIAN: That's correct.

So the Wartsila engines currently, they're able to run engines on a blend of hydrogen and natural gas. And their goal, like with the gas turbine manufacturers, is to get to 100 percent hydrogen. My understanding is they're not quite there yet.

MC-22

PRESIDENT FLANIGAN: Right.

And I take it renewable natural gas they could take right away, if we could purchase RNG. Or if the price --

MR. TATEOSIAN: That's --

PRESIDENT FLANIGAN: -- of RNG becomes

MC-22

competitive, they could burn that.

MR. TATEOSIAN: Yeah. You know, the RN -- that's -- yes. Presumption is the RNG you get meets SoCal's -- you know, California Rule 30 standards, yes.

MC-23

PRESIDENT FLANIGAN: Right. Right.

But there is a -- there is potentially a use -- I mean, this goes back to my opening comment about building the last gas plant in California.

There is potentially a means to convert those units to renewable natural gas and ultimately to hydrogen so that we are not having the fossil fuel dependency that is, I think, alarming to people in the community.

MR. TATEOSIAN: Yeah, I think, for both Alternative 7 and 8, RNG is looked at as that's what -- once it becomes widely available, that's what you would use.

Alternative 8 probably can't run on hydrogen.

Alternative 7, you know, can work on a blend today.

I'll say there's two parts to that equation. One is having the equipment that can burn the hydrogen, and the other part of it is having the hydrogen supply. And that's the other part of the equation.

PRESIDENT FLANIGAN: Yeah.

MC-24

You know, it's fascinating, as I look around the world, all of the infrastructure that's being built for hydrogen right now. It's -- I think it's coming out a lot faster than any of us would have thought.

We were talking about resiliency in the city and Grayson providing resiliency in the city. Would Alternatives 7 or 8 carry the city with a -- with the --

MR. TATEOSIAN: No. What --

PRESIDENT FLANIGAN: -- capacity of Grayson?

MR. TATEOSIAN: What I was talking about there --

PRESIDENT FLANIGAN: Would we lose transmission? No?

MR. TATEOSIAN: No. The original -- no.

What I was talking about there with the resiliency had to do with the Glendale switching station, okay.

The Glendale switching station is being added to provide a backup to Kellogg; a secondary nexus, if you will, for the distribution lines going out to the various substations in the city.

And the generation, whether it's Alternative 7 or 8, both -- either alternative, the generators would be able to connect to Kellogg or a Glendale switching station.

So -- but no. If the city was separated from the grid, then Alternative 7 and 8 don't have enough capacity to carry the city.

MC-25

PRESIDENT FLANIGAN: Whereas the proposed project could?

MR. TATEOSIAN: Yeah, it was basically one of the requirements of the proposed project, that the 262 megawatts plus the 50 megawatts, 48 megawatts from Unit 9, you couldn't have carried the full city on a peak load day; but on a lot of days, you could have carried the city.

Obviously, having less megawatts available with 7 and 8, that -- it's a fewer number of days. And, you know, you're getting down -- you know, at 93 megawatts, you're pretty much at minimum load for the city.

Am I correct, Mark?

MR. YOUNG: That's correct.

MR. TATEOSIAN: Yeah.

MR. YOUNG: That's close.

MR. TATEOSIAN: So you're -- even on a cold day, if Glendale was separated from the grid, I don't think you could -- well, really Mark's call, but you'd be challenged, I would think, to operate with just 7 or 8.

You could do it while you still have the batteries; but after four hours and the batteries are gone, you're -- you're turning people off.

PRESIDENT FLANIGAN: Gotcha. Gotcha.

That -- thank you very much.

MR. TATEOSIAN: Okay.

PRESIDENT FLANIGAN: That concludes my questions.

Chairman Bartrosouf, I pass the baton to you.

CHAIRPERSON BARTROSOUF: Thank you.

Let's go ahead and take any questions or comments from the Sustainability Commission.

Anybody want to go first?

I see, Jennifer, your hand is up.

COMMISSIONER PINKERTON: Yes. Thank you.

Thank you to staff and the consultants. I think I neglected to thank you at our last meeting.

Just a preface with a couple comments, and then I do have some specific questions.

MC-26

I'd like to echo what the previous speaker said. Although costs typically are not part of the DEIR, it would be very helpful to have costs presented because those costs do impact decisions made by Council.

MC-27

We heard climate change and resiliency. But I'm concerned that we're still too wedded to gas through these proposals.

And also, long-distance transmission makes us highly vulnerable. It does not make us more resilient. So that is another factor very much concerning me. If we want to be more resilient, we need much more of our power strictly from local sources, in case of fires, in case of, you know, all sorts of acts. I just -- reliance on long-distance transmission is a very old kind of utility model, and I think we need to switch away from that.

MC-28

Plus, please correct me if I'm wrong, but I believe the average loss of electricity over transmission lines is about 2 percent. So I think -- I wonder if your EIR has downgraded for that loss from long-distance transmission of power. That's one comment.

I -- these comments -- these questions are probably best directed to Mr. Young.

On slide -- believe it was 33, about IPP. Glendale's 2019 power content label shows 3 percent coal. I -- my question is I assume that's all from -- sourced from IPP. Is that correct?

MC-29

MR. YOUNG: That is correct.

COMMISSIONER PINKERTON: The 3 percent coal? Okay.

My -- couple comments on the IPP.

MC-30

MC-30

So they're converting that plant. They're not even going to start the construction phase at the IPP until 2025, if I'm correct. And that plant will not be a hydrogen plant until 2045. That's many, many years away.

That just seems highly too speculative to me.

Are we going to be increasing our purchase of natural gas from the IPP as it goes through this transition? Because it will not go from coal to hydrogen. First it becomes a gas plant, is my understanding.

So are we going to -- do we plan to increase our purchase of gas from IPP at all in those intervening years?

MR. YOUNG: So, Commissioner Pinkerton, I think you have a misunderstanding.

IPP will be repowered by 2025, not starting in 2025.

In 2025, 30 percent of the output of IPP by volume will be sourced by hydrogen. So we'll be moving away from coal to hydrogen and natural gas at that particular time.

Will we be buying natural gas to transition from hydrogen -- transition from natural gas to hydrogen at IPP? That's correct. But remember, we won't be buying coal anymore.

COMMISSIONER PINKERTON: Right. But will we be buying more natural gas?

And I just read an article where they quoted the GM, and it cited 2045. So if you could provide me a link showing a different end date --

MR. YOUNG: So --

COMMISSIONER PINKERTON: -- for when that plant will be fully -- you know, will be a hydrogen plant, that would be really helpful.

MC-31

But, again, I just feel like we're too wedded to gas. I would like to see more local resources. I would like to see the $40 million for the Scholl Canyon plant used for PV or other local renewables.

All right. Thank you.

CHAIRPERSON BARTROSOUF: Did you want to --

MR. YOUNG: I think the misunderstanding is by 2045, IPP will be 100 percent hydrogen. By 2025, it'll be 30 percent, and it'll ramp up to 100 percent by 2045.

CHAIRPERSON BARTROSOUF: Okay. Thank you for clarifying.

Rondi, I see your hand up.

VICE CHAIRPERSON WERNER: Yes. Hello. I'm Rondi Werner, Vice Chairman of the Sustainability Commission.

MC-32

I have two questions.

Last August, the Sustainability Commission heard a presentation from a group that is lobbying pretty hard to ban natural gas for new construction and major remodels for both commercial and residential development.

Was the possibility of having a substantial influx of all-electric buildings taken into account when you were calculating how many megawatts of energy would be needed to power the city in the future?

MR. YOUNG: That's a very good question.

With the electrification of vehicles and building electrification, we anticipate our peak can go north of 450 megawatts. I've heard nationally that a good rule of thumb is to double your load for electrification of vehicles and then double your load again for building electrification. But that doesn't really apply in Southern California. It's really Northeast where it's very cold.

So we anticipate going just shy of 500, 450 to 500. And I believe that's in the integrated resource plan.

VICE CHAIRPERSON WERNER: Okay. Great.

MC-33

And my second question was whether the committee considered the visual impact of the project.

MC-33

Like, did they consider mitigating it with visually screening it by using large trees? I've worked on projects where that's been very effective. But I'm not sure what the heights are of the stacks and that kind of thing. But I just wondered if that was explored.

MR. YOUNG: I don't know the answer to that question.

But I do know that if you were on San Fernando looking at Griffith Park today, which you can't, you would be able to see Griffith Park if this repower to go into affect. By taking the old building down, you would actually be able to see Griffith Park.

And I believe, in the EIR, you can see a picture of what it would look like from San Fernando.

So the impact is a lot less.

VICE CHAIRPERSON WERNER: Great. Thank you.

No further questions.

CHAIRPERSON BARTROSOUF: Thanks, Rondi.

Anybody else on the Sustainability Commission have questions?

COMMISSIONER KHANJIAN: Yes, I do. I apologize. I couldn't find the button to raise my hand digitally.

MC-34

What are the construction timelines? How do they differ between Alternative 7 and 8?

MR. TATEOSIAN: They're not too different.

With the assumption that when we go to City Council in November, one of the alternatives is selected, then we would start demolition.

There's a couple months of work to separate Unit 9 from the rest of the units so that Unit 9 can operate in a standalone basis while the rest of the plant is being demolished and the replacement units constructed.

Demolition would start in March of next year, and that would extend for about a year.

And then the construction period is about a year and a half after that.

And so probably the first units -- the goal is to have the first units available to help serve load for summer of '24 and, you know, finish by the fall of '24.

COMMISSIONER KHANJIAN: Thank you. That answers my additional questions as well. I appreciate that.

MC-35

CHAIRPERSON BARTROSOUF: Sorry. Just a quick clarification.

That's for both alternatives? That time line that you articulated, summer 2024 is for 7 and 8?

MR. TATEOSIAN: That's correct.

CHAIRPERSON BARTROSOUF: Okay. Thank you.

MR. TATEOSIAN: You know, within a few months. There's -- and -- within a few months. Still details to be worked out.

CHAIRPERSON BARTROSOUF: Thank you.

Okay. Thank you for that question.

Haig?

COMMISSIONER KARTOUNIAN: Yeah. Couple quick questions if you don't mind.

MC-36

In preparation for SD 100 and the requirement to deliver 100 percent electric retail sales to customers: How much of the thermal generation will we still need beyond 2045, given that, you know, we're going to have capacity with IPP and possibly even Unit 9? I don't know if they'll survive till 2045. I'm concerned that we may have orphaned resources at some point.

MR. YOUNG: I think the expectation is that load is going to expand, as we start to shift our reliance of fossil fuels from transportation and heating, that that reliance will go to the utility. So we anticipate the utility load to go up.

We're also looking for renewable gas, whether it be RNG or hydrogen, to be able to make that unit a viable solution post 2045.

So I don't believe it'll be a stranded asset.

MC-37

COMMISSIONER KARTOUNIAN: But in terms of capacity, megawatts, how much do you think will we need

MC-37

beyond 2045 of thermal generation?

MR. YOUNG: I don't know. 2045 is very far away. They might put a mini nuke in Burbank. Who knows. Maybe. I don't know.

Sorry. I was trying to make a little joke. Maybe that didn't fly very well.

But --

MC-38

COMMISSIONER KARTOUNIAN: All right.

The next question I have, on slide 33, comparing both alternatives, the cancer health risk is less under Alternative 8, .014, even though the CO2 emissions are more compared to Alternative 7. Can you explain that.

And Alternative 7 is a hybrid engine, five or so internal combustion engines that can be ramped up incrementally.

The CO2 levels that you indicated, do they take into consideration that it's not going to be all or none?

MR. TATEOSIAN: Yes.

So first on the cancer risk.

That's a -- that's due to the difference in dispersion coming out of the stacks.

The gas turbines, 8A and 8BC, Alternative 8, those have a lot of volume coming out of the stack, and it's higher velocity so you get better dispersion, and so the cancer risk is lower locally.

With Alternative 7, the Wartsilas, those are not mass flow machines processing a lot of mass like a gas turbine does. And so the stack velocity is lower, so you don't get as good dispersion; and so that's why you see the higher cancer risk numbers on Alternative 7.

I would like to reiterate, though, what Michael talked about, and Karl, in that when you look at those numbers and you think about what the CEQA threshold is for significance, you know, those numbers are very small. The risk is very small.

To your point on the CO2, what you're seeing there, the CO2 numbers are lower on the Wartsila engines because they are more efficient.

When -- you know, for Alternative 8, 8A would be a simple-cycle unit. 8BC would be a combined-cycle unit.

So 8A and 8BC -- when they run 8BC for the first couple hours are less efficient than a Wartsila engine. Once 8BC gets into its combined-cycle mode and is producing an extra 20 megawatts just by recovering the waste heat, then 8BC is more efficient than a Wartsila unit.

So we modeled how the units would be

dispatched, starts per day, operating hours; and the CO2 emissions that you see are a result of that modeling.

Does --

COMMISSIONER KARTOUNIAN: Okay.

MR. TATEOSIAN: -- that answer your question?

COMMISSIONER KARTOUNIAN: That does.

MR. TATEOSIAN: Okay. Thank you.

CHAIRPERSON BARTROSOUF: Any other questions, Haig?

COMMISSIONER KARTOUNIAN: None.

CHAIRPERSON BARTROSOUF: Okay. Thank you.

I did have some questions and comments.

One thing that I couldn't quite wrap my head around was this additional 73 megawatts of transmission that's coming into the city by 2027 and how that changes our calculation for this EIR that did not take into account that additional capacity.

MC-39

So am I getting it right that we expect 73 megawatts in 2027 that we were not expecting before, and yet the proposal to put in these five RICE engines is not changing?

Okay. Can I get confirmation on that and how it is or why it is that we are not changing the proposal based on that additional capacity that's coming in?

MR. TATEOSIAN: I think maybe there's a slight misunderstanding.

So the original EIR was based on what was then the Siemens repower, the two combined-cycle, two simple-cycle units, totaling 262 megawatts.

That 72 megawatts wasn't available back then; wasn't part of the calculus; wasn't part of the math. All right?

In reducing the size of the project from the 262 thermal down to the roughly 100 megawatts of thermal and the 75 megawatts of batteries, part of what let us got -- get there was the fact that now there's 72 megawatts of additional transmission that becomes available in 2027.

So it was accounted for.

CHAIRPERSON BARTROSOUF: Okay. Thank you for clarifying that.

MC-40

And then I know we're also getting 25 from another source by 2024; is that also factored into this calculation?

MR. TATEOSIAN: That is a developmental thing. We did not account for that.

There's a table in the draft EIR in the Alternatives section that shows you everything we accounted for in the megawatts.

MR. YOUNG: So Chairperson --

MR. TATEOSIAN: Oh, and -- well, let me -- sorry.

It's not -- the way that's accounted for is in the 200 -- because that 25 megawatts is not local; it's imported over the transmission. So it's not explicitly accounted for. It's part of -- that 200 megawatts you get today is a mixture of renewable and fossil resources.

So what that 25 megawatts does, it doesn't affect the map. It just displaces 25 megawatts of thermal that's being imported with 25 megawatts of renewable. That's why you won't see it in that table.

CHAIRPERSON BARTROSOUF: Okay.

MR. YOUNG: And to add to that, the Eland project is a noncoincident resource. And what that means is that you could be getting the most energy you can out of that resource during two -- 12:00 to 2:00 o'clock in the afternoon.

Our peak is in the evening. And when it's in the evening, you won't be able to get that resource at all. Because it's solar.

CHAIRPERSON BARTROSOUF: I see.

MC-41

So if we're expecting that additional capacity, why is it that we're not changing the calculus with the battery storage, for example?

MC-41

So I know I've asked -- I asked last week about Scholl, about our limitations with battery, and that was that we don't have enough transmission or we don't have enough local source of energy to charge the batteries.

It seems like this additional capacity would inherently change that calculation. Would it not?

MR. TATEOSIAN: During the day, it's providing renewables over the transmission line.

Those projects, I think when you look at the slide, you'll see there's a storage component to it too; right? So part of those renewables get stored, okay.

So that battery capacity -- because we can't put more than about 75 megawatts in the -- in locally of energy storage, because then there just isn't the transmission capacity available at night to both serve load and charge more than that.

So those distant projects whose renewable energy is being imported during the day, their excess renewables during the day are used to charge batteries; then those -- the energy of those batteries is imported at night. And that's how you would serve load at night, is off of imported battery energy, imported energy from IPP running off of hydrogen at night, and your local batteries.

CHAIRPERSON BARTROSOUF: Okay.

MR. TATEOSIAN: Does -- today, pretty much, you see all renewable projects going in, you know, solar PV projects. These are now required to have a component of energy storage. And it's to address this whole issue of how do we -- how do you get enough renewable energy at night?

CHAIRPERSON BARTROSOUF: Okay. Thank you for that.

MC-42

I had a question about our use of hydrogen.

So you had mentioned that Alternative 8 -- I can't remember if you said probably or probably not, could use hydrogen. It seems like this is a fundamental question that needs to be answered.

So do we know for a fact that the RICE units can take clean hydrogen? And same question for the refurbished units. It seems like our decisionmakers need to know that.

MR. TATEOSIAN: So the Wartsila engines today, what Wartsila tells us is that they can run on a mix of hydrogen and -- hydrogen and natural gas. Their goal is to get to 100 percent natural gas.

They're not very different than, you know, the gas turbines; some gas turbines are almost there already. But everyone's got the goal to get to 100 percent natural gas.

In the case of Alternative 8 --

PRESIDENT FLANIGAN: I think you mean 100 percent hydrogen, don't you?

MR. TATEOSIAN: Yes. I'm sorry. I misspoke. Thank you.

Yeah. So the goal is to get to -- they're already at 100 percent gas. The goal is to get to 100 percent hydrogen. My apologies.

MC-43

CHAIRPERSON BARTROSOUF: But are we -- we're purchasing these units with the understanding that they can be run on 100 percent clean hydrogen and --

MR. TATEOSIAN: They're not there. They have not demonstrated that yet. They're working on that.

MC-44

CHAIRPERSON BARTROSOUF: So we're making an assumption that in the future, these will run on clean hydrogen, but we're not certain of that?

MR. TATEOSIAN: That's -- that is a goal. It's not a certainty.

CHAIRPERSON BARTROSOUF: Okay.

MR. YOUNG: And jump the next question --

MR. TATEOSIAN: And you asked me about --

CHAIRPERSON BARTROSOUF: What's --

MR. YOUNG: Gas turbines can't do that either. So gas turbines can't run on 100 percent, but they're getting there.

So I don't believe any thermal generation can actually run on 100 percent hydrogen at this particular time. But they are moving in that direction to get there.

So if we were to buy the Mitsubishi engines at IPP, the assumption is that they are going to get the -- we have guarantees from Mitsubishi that they will get there.

So we would still be talking to Wartsila with regard to the transition of their fuel to hydrogen.

And it is hydrogen; right? How you make the hydrogen makes it green.

CHAIRPERSON BARTROSOUF: Right.

MR. TATEOSIAN: Yeah, versus blue hydrogen or...

And then your question about Alternative 8 and the unit 8A, BC, and can they run on hydrogen.

And the answer to that is probably no. And the reason is those are older-technology engines. And doubtful anyone's going to spend the R and D money to make that generation turbine run on hydrogen. You know, hydrogen's a gas, but it's a very different gas than natural gas. The flame spread velocity is really different, and that affects the combustion dynamics. And you can't just take a gas turbine and turn off the natural gas and turn on the hydrogen and all is well in the world.

So that's why there is technology development to get to 100 percent hydrogen.

CHAIRPERSON BARTROSOUF: Okay. Thank you.

I did want to -- I'm glad Haig asked about the emission -- the carbon dioxide emissions between 7 and 8. I was also curious about that.

I did want to go back to slide 10, if it's not too difficult to put the slide back up just so the public knows what we're looking at, about Rule 1135.

MC-45

So I know there's an exemption for -- there's, like, something called the low-use exemption.

Can we talk about what that means for us here in terms of Grayson and what's being proposed for Grayson.

MR. LANEY: The low-use exemption is pretty stringent in Rule 1135. It allows, on a rolling three-year average, 10 percent utilization.

So while it does exist, it's very low. Whether or not that's a practical presumed operating load for any utility, I can't speak to.

But do keep in mind, if you're talking 10 percent utilization, in that scenario, you're talking about older-generation emission levels, not the 2 ppm and 2.5 ppm NOx levels that the compliant units would be.

MC-46

CHAIRPERSON BARTROSOUF: So are you saying that we could use the older units so long as we don't exceed 10 percent, using -- under the low-use exemption?

MR. LANEY: That is correct. And that becomes a matter of what is an appropriate level of -- what continues to allow a turbine to be useful to a city at 10 percent.

MC-47

CHAIRPERSON BARTROSOUF: Got it.

I guess I'm curious, then, what is the actual difference between what that 10 percent capacity is with the 15 percent that we expect to use with the new units? Is that an actual -- a large difference --

MR. LANEY: 15 --

CHAIRPERSON BARTROSOUF: -- in use?

MR. LANEY: -- percent utilization on the new units would be lower emissions as far as criteria pollutants or NOx emissions. That should come out to be lower than 10 percent utilization without modification.

CHAIRPERSON BARTROSOUF: Okay.

MR. TATEOSIAN: There's also an operational perspective to that. Because with the 10 percent utilization, the boiler units, for example, they have a long start-up time. Okay. Not on the order of minutes, like with the recips or Alternative 8, but it's hours --

MR. YOUNG: Days.

MR. TATEOSIAN: -- and days.

And so that 10 percent, you can't compare that directly to the 15 percent. Because you get all the 15 percent, but you're going to lose a significant amount of the 10 percent on every start-up. And so you really get very little out of it. And that's a significant issue.

And we looked at the low-use exemption. And we basically concluded that was not -- that was not workable from an operating -- practical operating perspective. It wasn't workable.

CHAIRPERSON BARTROSOUF: Okay. Thank you.

MR. LANEY: Just to clarify.

The district did not presume at any point, to my knowledge, that anyone would retain a boiler and expect to operate it at that utilization.

In my comments to you, I was already drawing the conclusion that the boilers would not be retained, and I was comparing Unit 8 today with Unit 8 in the future controlled.

CHAIRPERSON BARTROSOUF: Got it. Thank you.

MC-48

I do want to dive in a little bit deeper into the 15 percent. And it sounds like you've already

MC-48

submitted permits to use that amount.

Can we get a little bit more information about how we got to that 15 percent, and for what time horizon is that permit for; and does it factor in these new -- the transmission lines that are coming in, the virtual power plant, all of the different programs that are being deployed by the city?

MR. TATEOSIAN: Yes. You can go -- I don't have the numbers memorized. And if we need to, we can pull up the draft EIR and look at it.

But in the Alternatives section -- I believe it's in the Alternatives section of the draft EIR, yeah, it's all spelled out. And we did a "build it up from the bottom"; and we looked at, kind of, past experience with hot days; and I think we assumed like three hot days in a row and the start in the morning and a start in the afternoon and expected run times, and we built it up from zero in terms of how many starts and operating hours we're going to need on each of the units. And that's how we got to 15 percent.

And then after we did that, GWP looked at it from an -- you know, how did that look from their expected dispatch, and it worked, and that's what we put in the air permits.

MC-49

CHAIRPERSON BARTROSOUF: Okay. So there's a

MC-49

scenario in which we've submitted for 15 percent, but maybe likely or possibly that we wouldn't be using all 15 percent?

MR. TATEOSIAN: That's correct. Because we also -- on top of that, we put in some amount for contingencies. So we looked at what do we need to do, run for our -- cover a series of hot days, and then we put some more on top for contingencies. That's how we got to 15 percent. And it's spelled out in a fair amount of detail in the draft EIR.

MR. YOUNG: Or less.

MC-50

CHAIRPERSON BARTROSOUF: Or less?

MR. YOUNG: On a cool summer, you'd use less.

So I think, in permitting, you have to look at worst-case scenario.

So we're looking at a scenario that's still doable. Because we don't want to handcuff ourselves. Because with AQMD, if you exceed that standard, you immediately are forced to shut that unit down. So if we ever got to our limit, we would have to shut it down regardless of the effect of the community or not. So we want to make sure that we have enough operating margin to be able to do what we need to do. But we already know to keep the units off as long as possible and use them when load is in excess of our import capability.

CHAIRPERSON BARTROSOUF: Okay. Thank you.

And so -- this may be my last question for now. I do want to make sure we get to public comment. And I might have follow-ups after that.

But is -- are we factoring in the necessity for having -- let's say we move forward with 7 versus 8 and we want to proceed with five new units.

MC-51

Is there a phase-in portion to this where we could possibly install one or two units and use those at a higher frequency so that we're not investing in five units that we're only using 15 percent of the time? And what are the -- are there associated cost savings to that?

I'm thinking about the long term. We've talked about we want to eventually transition out of using natural gas at all, of course.

So it's -- we're at this point where, you know, we're constantly going to be asking do we really need this?

So do we really need five units of new units that are burning natural gas? And can we do with less?

MR. TATEOSIAN: So there's two aspects to that. One is energy, and one is power. All right.

So the number of units is driven by the amount of power that we need. So each unit you take off reduces the available power to help address a peak load situation. All right.

And then the hours are not transferable between units. So as you lop off a unit, you lose 1,500 hours of generation off of that unit, off of the whole plant.

So, you know, number of units that -- the reason they're not -- the reason we don't have one unit permitted for 8,000 hours, for example -- because one unit operating for 8,000 hours is more than the five units operating for 1,500 hours.

And the reason we didn't do that is because one unit is woefully short of helping us meet peak load and cover contingencies.

So that's why there's the number of units there are. It's driven by the power need. And then the hours came out of the energy need.

CHAIRPERSON BARTROSOUF: Thank you for clarifying that.

And then I did want to just get clarification. I guess I misunderstood something.

MC-52

I thought that the 72 megawatt transmission line was factored in post IRP, 2019 IRP. Is that not the case? We always factored in that 72 megawatts as part this analysis?

MR. YOUNG: I don't believe that was factored in in the IRP, but it was factored in in the modeling that we ran for this --

MR. TATEOSIAN: Yeah.

MR. YOUNG: -- for this project.

MR. TATEOSIAN: I know the 72's in the EIR. I wasn't involved directly in the IRP so --

CHAIRPERSON BARTROSOUF: Okay. And the --

MR. TATEOSIAN: But the --

MC-53

CHAIRPERSON BARTROSOUF: And the 25 Eland project as well?

MR. YOUNG: In the IRP?

CHAIRPERSON BARTROSOUF: In either.

MR. YOUNG: Not in the IRP. We just signed the contract for both of those projects last couple of months.

CHAIRPERSON BARTROSOUF: Okay.

MR. YOUNG: And the IRP was a couple of years.

MC-54

CHAIRPERSON BARTROSOUF: Okay. So it's -- and it's not in this EIR?

MR. TATEOSIAN: It is implicitly. Because right now -- the 200 megawatts of imports today is a mixture of renewables, like what you get -- you've got -- there's a geothermal project in Nevada: Hoover. So it's a mix of renewables and fossil. Okay.

That 25 megawatts is a -- is renewable energy that's going to get imported, and that's going to displace existing fossil that's being imported.

So when you go to the draft EIR and you look at that megawatt table I was talking about in the Alternatives section, and you'll see transmission imports, it's buried in there.

The assumption is is that over time, those transmission imports are going to move from a mixture of fossil and renewable to all renewable.

MC-55

CHAIRPERSON BARTROSOUF: Okay. So we're getting the same amount of energy, but we're getting it from different sources --

MR. TATEOSIAN: Right.

CHAIRPERSON BARTROSOUF: -- or different types of energy?

MR. TATEOSIAN: Yes.

CHAIRPERSON BARTROSOUF: Got it.

Okay. The only other thing I wanted to say, I mean, it's kind of going along the lines of what Ted had said earlier, is, you know, the whole thing is ironic because all within the span of seven days, we're -- the City of Glendale is now talking about investing heavily in two new natural gas power plants. And between those -- between those seven days, we have our neighbor, the city of LA, committing to 100 percent renewable by

2035.

And I was skimming through the LA 100 study that was made available to the public in March of this year. And it goes pretty deep into all of the alternative scenarios: Local source, transmissions. The executive summary alone is 70 pages, and I can't absorb all this information.

But it talks about local sources, the various types of local sources; battery storage; all the various alternatives and their associated costs.

And I feel like we're in this moment here in the city of Glendale where we are talking about natural gas plants and how they factor into our future needs.

MC-56

And it just seems like it's "cart before the horse" kind of thing. Like, why aren't we going through an exercise of understanding how we can get to 100 percent renewable and working our way backwards from that?

And maybe that's happening, but that's not clear to, perhaps, me and the public. There seems to be some confusion around that, in the context of these two new natural gas power plants.

So I had another question, but it's been lost. So maybe we can move to public comment and I reserve the right to come back, if that's okay with you, Ted.

PRESIDENT FLANIGAN: That is perfectly fine.

MR. YOUNG: President Flanigan, if I may just make one comment.

The Scholl Canyon project is not a natural gas project. It's a renewable project.

CHAIRPERSON BARTROSOUF: Mixed --

MR. YOUNG: Not -- not --

CHAIRPERSON BARTROSOUF: But -- but --

MR. YOUNG: Not natural gas.

CHAIRPERSON BARTROSOUF: Sure. But there's a mixture of natural gas as part of it, isn't there? We are -- we're going to continue to rely on natural gas as a mixture as part of that power plant? Increasingly --

PRESIDENT FLANIGAN: If -- if --

CHAIRPERSON BARTROSOUF: Increasingly over time.

PRESIDENT FLANIGAN: If the concentration falls below, what was it, 34 percent or 32 percent, we have to inject natural gas, I believe.

MR. YOUNG: The goal is never to make that a natural gas plant. But this is the Grayson Repower Project discussion.

CHAIRPERSON BARTROSOUF: I understand.

MR. YOUNG: But --

CHAIRPERSON BARTROSOUF: Thank you.

PRESIDENT FLANIGAN: Let's move to public comment.

And, Catalina, do we have any?

MS. LEE: We do. We have eight.

PRESIDENT FLANIGAN: We have eight?

MS. LEE: Yes.

PRESIDENT FLANIGAN: So shall we follow our long-standing tradition of last week and limit comments to three minutes? Is that acceptable to you, Chairman Bartrosouf?

CHAIRPERSON BARTROSOUF: Yes.

PRESIDENT FLANIGAN: That okay?

Comments, make them short and sweet and punchy and convincing and within three minutes.

Thank you.

MS. LEE: Yes.

Our first caller is Stephanie McGreevy.

Stephanie, you're on the air.

MS. McGREEVY: Hi. My name is Stephanie McGreevy, and I'm a citizen of Glendale and work in the clean energy industry.

MC-57

I have comments regarding the technologies being proposed for the Grayson Repowering Project. Because there's cleaner, more efficient, more affordable commercialized and proven technologies for power

MC-57

generation, fuel types, and for battery storage.

I believe GWP is required to disclose cleaner, more affordable options to the City of Glendale 60 days prior to purchasing any equipment.

Starting with the Wartsila internal combustion power generators: These are absolutely dirty technologies. Better technologies actually do exist.

Utilities, universities, and businesses, like Edison, Cal Tech, and Walmart have turned to cleaner, more affordable, reliable, responsive technologies like fuel cells that can operate with 100 percent renewable natural gas, or RNG; 100 percent hydrogen; or a mix of both. These fuel cells were developed and manufactured in California, and more cost effective.

Fuel cells are quieter and emit zero NOx, SOx, and particulates, because they use an electrochemical process to generate electricity without any combustion. No moving parts.

Fuel cells can produce electrons for about 10 cents per kilowatt hour.

Should the City elect not to procure RNG, then carbon capture can be added to the technology.

MC-58

Next is fuel.

We have renewable natural gas, or RNG, that meets Rule 2130 for pipeline-quality natural gas from

MC-58

digested dairy manure and land gas fill, carries low carbon intensity or enough CI value, and can be procured to replace pipeline natural gas. The lower the CI rating, the less carbon that's released. Anything below zero means carbon already exists in the atmosphere and is being reused.

Digested dairy manure rates at a negative 250 CI rating. The reason is that digesters divert manure from open lagoons that would have normally vented methane to the atmosphere.

Methane is much more effective to holding heat than CO2 is. Preventing one molecule of methane from reaching the atmosphere is equivalent to 32 molecules of CO2, which accounts for the negative CI value for dairy RNG.

MC-59

Next up, for the lithium ion battery systems like Tesla, we have multiple cases of overheating, exploding, and catching fire. The latest fire in Australia a few months back burned for four days and took 150 firefighters to contain the fire. The fire was never put out. They had to let it burn itself out. In the meantime, all the surrounding neighborhoods received toxic air alerts.

Vanadium flow batteries are a simple mixture of vanadium ions, which are abundant and easily collected in a self-contained nonflammable solution.

The redox flow battery is not limited in runtime and can run for 24 hours seven days a week with unlimited cycles. It does not degrade. And it has a frequency response of a couple hundred of milliseconds.

MC-59

Lithium ion degrades over time, has strict guidelines for usage, with limited cycles and downtime between cycles, preventing the user from full benefit of power storage and limiting the ability to future-proof.

The redox flow battery is 100 percent recyclable and nontoxic.

Glendale can take advantage of energy savings performance contracts which are zero out of pocket, no capital expenditure. It's operational off-the-book expense.

MC-60

All these solutions are commercially available, reliable, and carry a smaller footprint. They provide redundancy, are scalable to meet increasing demand, and are more economical. These solutions should be a part of Glendale's bold actions.

Please feel free to contact me for additional information.

PRESIDENT FLANIGAN: Thank you very much for your comment.

Next caller, please.

MS. LEE: Our next caller is David Dennick.
David, you're on the air.
MR. DENNICK: Hello. Thank you for taking my call. I have a brief comment to make.
The overall objections listed in the DEIR on page 110 through 111 are focused on reliability, control, and flexibility. All objectives are probably top of mind to GWP staff and engineers.

MC-61

But what about the goal that has become increasingly urgent to transition to 100 percent clean energy?
The IPCC report says the time for action is now.
Glendale should prioritize the maximum possible clean energy generation; and it's not clear from this report that every option has been explored to (unintelligible) clean energy, especially distributed clean energy innovative programs that combine lots of solar with storage.
We shouldn't rush to approve a plan that meets engineers' objectives but not the community's aspirations: Aspirations for clean air, clean energy, and a future livable climate.
Please go back to the drawing board, and do not approve this DEIR.

Thank you very much.

PRESIDENT FLANIGAN: Thank you.

Next caller, please.

MS. LEE: Our next caller is Roberta Medford.

Roberta, you're on the air.

MS. MEDFORD: Hi. Thank you for taking my call. I'm calling from Montrose.

MC-62

My comment is that from the UN to the President of the United States down to little me, it is so clearly code red right now for our climate, in that if we don't take action now, climate change will be irreversible. Yet here we are hearing something very similar from QWP that we heard over three years ago.

I am very disappointed that, in apparent defiance of City Council direction, the GWP is once again trotting out major new fossil fuel spending while having done actually very little in the way of action in the way of clean energy.

This lack of urgency about the climate crisis on the part of our publicly owned utility is completely unacceptable to me.

Thank you.

PRESIDENT FLANIGAN: Thank you for your comment.

Next comment, please.

MS. LEE: The next caller is Kate Unger.
Kate, you're on the air.
MS. UNGER: Hello. Thank you, Commissioners and staff. It's Kate Unger. I'm calling from the Pelanconi Estate area close to the Grayson Power Plant.
I've been following this project since 2018, and I will say I appreciate the presentation. I have some comments on the project and on the EIR. I echo questions from the Commissioners and comments from the other people.
I did want to start by mentioning that in July 23rd, 2019, when the IRP was approved, the presentation didn't mention that it was approved with conditions. The City Council wanted staff to move forward with the plan with five units as a starting point, not an end point; and they specifically asked for options to reduce or eliminate the need for those units.
They asked GWP to develop a plan for goals or methods to achieve 100 percent clean energy by 2030; as Chairperson Bartrosouf mentioned, like the LA 100 plan. That's what we asked for. That's what Council asked for. We didn't get that.
I will not go on with detail, but you know that GEC has been asking for additional clean energy locally, and it just hasn't happened. It's incredibly

MC-63

MC-63

frustrating.

So here we are with this project adding new natural gas -- okay. Guys, this is insanity. It's insanity. If we want to preserve anything close to life and Earth that we all know and care about, we have to stop doing this.

Every week there's more news about how drastic the climate crisis has become. The latest -- a new report just from yesterday in the journal Nature that says we have to stop global coal and oil use immediately. If we don't do this, then we're going to have -- only a 50 percent probability of limiting global warming to 1.5 degrees even if we do that.

So we need to keep fossil fuels in the ground. And how can we be thinking about putting in new gas-burning equipment? It is crazy. We have the obligation to not commit new fossil fuel-burning capacity. We are talking about the stability of the global ecosystem.

MC-64

Okay. The environmental analysis in the PR-DEIR, using a three-year-old EIR that analyzed the project we all know is no longer in consideration. It cut corners and meant that the analysis of the present alternative is truncated. And it's confusing. We have to triangulate back to an old document. You all watched

MC-64

a presentation that listed the impact of old project and compared the alternative to that instead of to each other.

The document doesn't allow for a real understanding of these alternatives head to head, and that's what we need.

And we do also need the cost information. I appreciate you asking for it. We need to insist on having that.

Thank you all very much.

PRESIDENT FLANIGAN: Thank you.

MS. LEE: Our next caller is Burt Culver.

Burt, you're on the air.

MC-65

MR. CULBERT: Hello, Commissioners and staff; and thanks for taking my call. I'm calling about the EIR, obviously.

Wartsila makes the 50S, which we're buying, or you propose to buy; and they also make the 50DS, which takes gas and biodiesel. So why wasn't that explored as an alternative? Biodiesel would be at least carbon zero or net carbon zero. But wasn't even studied.

MC-66

Why was (unintelligible) a study of additional transmission lines? You basically just throw it out without even going into it. I don't know why. I

MC-66

don't -- let's see.

MC-67

Obviously, LA is planning on going 100 percent clean energy. What -- how are they going to do it? Maybe they're going to do new transmission lines as well that we could piggyback on.

MC-68

I agree with one caller about lithium versus vanadium. Vanadium is also smaller and has a lower risk of fire so you could probably fit more megawatts in the space that you're dedicating to lithium in the current plan.

Let's see.

MC-69

How about turning the transmission lines coming into Glendale with the HD DC? I think you could get more power through that.

MC-70

The last plant built -- so if we're going to build the last gas plant for Glendale, that means we're going to have the last plant standing. So green -- emerald green Glendale is going to be the last city in California with their own power plan. Pasadena's going to lose theirs. Next -- the city next door, starts with a B, they're going to lose theirs as well, and we'll still be generating with gas. Ridiculous.

I'm a citizen of Glendale. I'm part owner of GWP, and I say no new gas. Period.

MC-71

Hydrogen, which you're proposing to go to, has

MC-71

less power per -- or less therms. And so have you considered how your engines would be derated and thus your max peak power out of the plant would be reduced when you go to hydrogen? I don't think you have.

MC-72

And why was Kellogg switching station added to this project? Like -- it seems like a different project that should be -- get its own EIR.

MC-73

And, once again, why did you split up Scholl Canyon and -- and this plan?

That's all. Thank you.

PRESIDENT FLANIGAN: Thank you. Thank you for your comment.

Next caller.

MS. LEE: Our next caller is Cat Tilardi (phonetic).

Cat, you're on the air.

MC-74

MS. TILARDI: Hi. Just -- my name is Cat, and I am a woman in my 30s, considering starting a family in Glendale.

I am concerned about the pollution and the climate. I'm honestly, like, in tears a lot of days because I'm scared to bring children onto the planet right now.

I do not want to continue investing in dirty energy. I want to invest in clean energy.

MC-74

Now, I'm looking at the air quality index for Glendale today. I'm looking at a couple sites.

On AccuWeather, it's listed as 64. And that is defined as "Poor. The air has reached a high level of pollution and is unhealthy for sensitive groups."

And this is on a good day. You know, this isn't during, like, fire season or, you know, a fire that has happened, right, like last year.

So I'm concerned about the air quality in general in Glendale, and I don't want to contribute and invest in anything that's going to make that worse.

I totally understand the need for a just transition out of fossil fuels, but there really isn't the time to be dainty about this. Scientists have proven time and again that fossil fuels are emitting carbon that is causing our climate to change and our temperatures to rise. And not just by a degree or two.

I mean, if we look at the Portland and British Columbia heat waves this year, those were seven or eight degrees higher than they'd ever been.

So, you know, like 486 people died in British Columbia. The bridges started to melt in Portland. And -- you know, and our climate is traditionally hotter than theirs. So what's next for us?

It feels really urgent to me; and I understand

MC-74

that maybe people investing in gas are scared to lose money or, you know, that change feels hard; but I just question you to think about if you have kids or if you want them to be able to have grandkids. It feels very urgent to me.

Thank you.

PRESIDENT FLANIGAN: Thank you for your comment.

MS. LEE: Our next caller is Monica Campagna.

Monica, you're on the air.

MC-75

MS. CAMPAGNA: Good evening, Commissioners and staff. My name is Monica Campagna. Thank you for your presentations tonight.

I'm a Riverside Rancho Glendale resident, and I want to begin by reminding people listening how incredibly hard we residents have had to fight since 2017 to get it down from the original 262 megawatts of gas proposed to where we are now.

I want to remind everyone listening that there was a time we sat in meeting after meeting after meeting hearing about how we couldn't do this and we couldn't do that; but with public pressure came political pressure, and that translated to an investigation of new local clean energy options and one round of clean energy proposals.

MC-75

It was at the 2019 integrated resource plan presentation that GWP identified its preferred project. Out of that came three energy projects from the 2018 clean energy RFP, a new 75 megawatt battery storage component, and 93 megawatts of gas.

This project was based on 200 megawatts of available transmission.

Council certified that IRP but placed conditions on GWP's proposal, as a previous caller noted, asking to -- staff to push for more renewable power transmission and other ways to reduce that gas number.

That has not happened. Two years have gone by, and we're still at the same number.

But things have changed.

Since that IRP was written, we have secured 72 megawatts of new transmission on our southwest AC line starting 2027, as we've talked about tonight.

That's more transmission we could be using to fill batteries for different parts of the evening; early, early morning hours, perhaps. Ascend Analytics has assured -- assumed a hypothetical 20 megawatt commercial solar project in their 100 percent clean energy feasibility study.

The city funded an owner's engineer to study

MC-75

solar and storage on city owner's property -- city-owned properties; and the Eland project does bring with it its own 25 megawatts of transmission, from what I'm understanding. That's its own transmission. That's more transmission. It's my understanding that project comes with that.

So I bemoan the fact that we're sitting here two years later with new opportunities on the table looking at the same -- two proposals for the same -- well, different proposals, but the same amount of gas.

I want to remind our Commissioners that all this time since that first round of RFP, GEC has urged Council to request our utilities to forward another round, in particular for the commercial sector.

In various formats, public and private, we've offered to resolve the legwork that took months of our time, mapping huge parking lots and rooftops that could be utilized for solar.

We suggested an alliance with QSP, probably the biggest landowner in Glendale, to work on a battery storage project that could benefit them both.

We suggested a reach ordinance to require solar in multi-storage buildings.

We collected over 350 contacts for the virtual power plant which has not yet launched.

MC-75

We urge the utility and Council to keep looking for more projects so we would not be in a position where we were pressed up against the wall with no new solutions.

So again I'm bemoaning the fact that here we are, apparently against the wall with no solution.

So please, Commissioners, when you're asked to do so, I ask you to recommend to City Council that they reject this project proposal, both of them, and hold to their request for a better alternative. Support Council's 2019 request for less gas. Support Council's desire to power ourselves with 100 percent clean energy sooner than 2045, which they have signaled they desire in multiple ways.

PRESIDENT FLANIGAN: Okay. Thank you very much for your comments.

MS. LEE: Our next caller is Elise Kalfayan.

Elise, you're on the air.

MC-76

MS. KALFAYAN: Hello. Thank you.

Good evening, Commissioners.

This month, anticipating this fall's many global climate meetings, more than 200 medical and public health journals jointly published a call for emergency action to limit global temperature increases, restore biodiversity, and protect health.

MC-76

The editorial warned of increasing health problems due to rising global temperatures and warned: Ahead of these pivotal meetings, we the editors of health journals call for urgent action to keep average global temperature increases below 1.5 degrees centigrade, halt the destruction of nature, and protect health. The environmental crisis demands an emergency response.

They go on to say that huge investment will be needed beyond what is being considered or delivered anywhere in the world.

I would put this new Grayson Repower plan in the bucket of what the authors disparage as, quote, what is being considered or delivered, unquote.

It's not enough at all. I echo Commissioner Flanigan's statement that this isn't a bold plan.

MC-77

I have the same concern as Commissioner Bartrosouf as to why we are building all of this expensive gas infrastructure when our surrounding communities are committing to 100 percent clean energy.

MC-78

The authors mentioned that reduced air pollution is a big problem and say that better air quality alone would realize health benefits that easily offset the global cost of emission reduction.

And air quality is a huge issue here, and

MC-78

Grayson is surrounded by residences and sensitive receptors.

MC-79

You know, Glendale Water & Power, as others have commented, has had two years since it submitted and City Council conditionally approved its integrated resource plan in 2019. There are no more clean energy projects in this plan.

Glendale Water & Power is not operating as if we are in a climate and environmental emergency, and this incremental plan that involves building new gas burning, air polluting infrastructure proves it.

MC-80

This plan should be rejected and a new one proposed that includes dramatically more local solar with storage, which is what Glendale's Environmental Coalition has been asking for for the past several years.

This could have been accomplished if it had been given top priority.

Thank you.

Please reject this plan.

PRESIDENT FLANIGAN: Thank you for your comment.

Do we have other callers?

MS. LEE: We do. We have three more.

Our next caller is David Eisenberg.

MC-81

David, you're on the air.

MR. EISENBERG: Good evening, Commissioners.

And -- I'd like to thank you for all your patience. And I read through this document, and there's a lot of pages; and for those of you that put this work together, I'm very impressed.

I'd like to ask a question. Hopefully, at the end of this presentation, someone will answer the question.

In the document -- you know, we kept talking about 15 percent usage of the facilities. And in the document, I never found 15 percent.

I did find a number repeated of 1,120 hours per year with 280 start-ups. And if you calculate that, that's 15 percent; but it doesn't actually say 15 percent.

And that's repeated all through the DEIR, in the analysis of the pollution and in the analysis of everything.

But I'm trying to read the permits, and I even read them tonight during the meeting, and I tried to find out where in the permit -- what page of the DEIR does it say that the permits are limited to 15 percent?

And the reason I'm concerned about this, because I seem to remember at another meeting that GWP

MC-81

spokespeople talked about the permit would be higher; and I believe I heard the number 68 percent of the time.

And if the calculations are done on 15 percent and the actual permit is five times as much, then that's five times the pollution. And then that makes the DEIR inaccurate.

So what I would like to request from this is I would like somebody from GWP to say which page of the DEIR, the PR-DEIR, exactly says on the permit -- not on the calculations, but on the permit, where the GWP is limited to that 1,120 hours with the 280 start-ups.

Otherwise, there's no guarantee that, you know, in a year, the -- that, you know, year after the construction, they say, "Well, we have an emergency. We're going to have to run it 30 or 40 percent of the time," if it's not limited by permit.

So again, I'd like to repeat that I'd like somebody from GWP to give me a page number I can look on the permit where it limits the hours of operation to 1,120 plus 280 hours.

All right. Thank you very much.

PRESIDENT FLANIGAN: Thank you for your comment.

MS. LEE: Our next caller is Francesca Smith.

Francesca, you're on the air.

MC-82

MS. SMITH: Thank you very much.

Good evening. My name's Francesca Smith. I serve on -- I'm privileged to serve on the design review board for the City of Glendale, and I'm a qualified architectural historian.

I've been watching tonight. I've been reading alongside all of you. Thank you so much for your hard work.

I am very disappointed in this PR-DEIR and its technical appendages, especially in the fact that there's not a revised cultural resources technical appendix.

The lead agency, after more than six months of discussion with the Glendale Historical Society, has at long last conceded that Glendale -- Grayson Power Plant boiler building is a historical resource for the purposes of CEQA, but failed to provide a thorough evaluation of the property considering the significance of it and its direct connection to the Glendale switch rack and other parts of the property. The switch rack was constructed roughly concurrently with the boiler building.

And in the text of the PR-DEIR, every mention of the historical property's resource is diluted by repetition of the modifier "presumptive." Presumptive.

MC-82

It's called a presumptive historical resource everywhere it's referred to, which is intended to lead nonprofessionals into believing that the property's significance is somehow in doubt.

MC-83

The most important cultural resources-related inadequacy is that the document fails to analyze or even address alternatives to the proposed project that would retain the historical resource that was identified at the subject property location.

The document needs to describe a reasonable range of alternatives to the proposed project that could feasibly attain most -- the most basic project objectives and would avoid or substantially lessen the project's significant effects.

Because it's a historical resource, it absolutely needs to look at specific alternatives, including a smaller project, a project that is in conformance with the standards for rehabilitation, a different location; and it warrants a lot more than the few paragraphs that were afforded it.

MC-84

In the few paragraphs, meetings are described with representatives of the city without any records of when those meetings took place, who attended, what was discussed and what wasn't discussed, or how the city held out a carrot and then snatched it back. That's the nicest way I can put it.

MC-84 There are lots of power plant buildings that are reused as offices, as museums. They're even used as schools.

In looking at the alternatives analysis that we were provided, there is absolutely nothing I could find that showed what the volumes are of what is being studied, as in maps or even diagrams showing why this building, which is in the middle of everything, can't be reused as a building that would serve this property.

It's legally inadequate in its description of existing conditions in that it identifies no character-defining features as well as the alternative.

MC-85

The lead --

PRESIDENT FLANIGAN: Thank --

MS. SMITH: -- agency is attempting to use the PR- --

PRESIDENT FLANIGAN: Thank for your --

MS. SMITH: -- -DEIR as a post hoc --

PRESIDENT FLANIGAN: Can -- can you wrap up --

MS. SMITH: -- rationalization -- hello?

PRESIDENT FLANIGAN: Sorry. Can you wrap up. You're a little over time. Thank you.

MS. SMITH: Sure. I'm sorry.

It's a post hoc rationalization for its

MC-85

predetermination that it can be demolished. It should instead have considered feasible alternatives that could include new construction with adaptive reuse, which is done all over the world.

MC-86

My closing sentiments are that this PR-DEIR didn't inform the public the way we need to be to make this decision, and the cumulative impact section is overly narrow and only addresses the three other historic buildings owned by the City of Glendale.

TGHS requested a mitigation measure that would have surveyed historic properties -- well, identified historic properties owned by the city; and if that had already been in place, none of this -- well, a lot of this would not have taken place.

PRESIDENT FLANIGAN: Okay. Thank you.

MS. SMITH: I am --

PRESIDENT FLANIGAN: Thank --

MS. SMITH: -- absolutely in favor --

PRESIDENT FLANIGAN: Thank you.

MS. SMITH: -- of green energy.

And thank you for your time.

PRESIDENT FLANIGAN: Okay. Thank you for your comment.

MS. LEE: Our last caller is Diana Matsushima.

Diana, you're on the air.

MC-87

MS. MATSUSHIMA: Thank you.

Hi. I'm Diana Matsushima, and I agree with several of the recent speakers in being concerned about this recirculated draft environmental impact report.

Yes. Inconsistent with the Race to Zero Commission that Glendale made of a 50 percent reduction in greenhouse gas emissions by 2030, and also was inconsistent with the climate -- mayor's commission to uphold the Paris Climate Agreement goals.

The intergovernmental panel on climate change, as we all know, just issued a dire report, warning that we have to take action now. And we should especially disparage any plan that involves building new fossil fuel-burning capacity.

There's no new clean energy in this plan, and there isn't looking at more solar and more storage for that.

So I think the report should be rejected, and GWP should investigate all options for expanding local solar generation and storage.

And that's -- that's all I have to say.

PRESIDENT FLANIGAN: Thank you. Thank you for your comment.

Catalina, does that conclude the public comment?

MS. LEE: Yes, it does.

PRESIDENT FLANIGAN: Why don't we -- because I know that Chairman Bartrosouf had -- would probably like to have a few more questions, why don't we circle back, if it's okay with everybody in the room. I know it's a long meeting, but we're doing well getting through it.

But let's circle back through the Glendale Water & Power Commissioners and see if there's additional comments and questions, and then we'll follow with the Sustainability Commission; and after that, we'll adjourn.

Commissioner Jazmadarian, do you have any other additional comments or questions at this time?

COMMISSIONER JAZMADARIAN: No. No other comments or questions. Thank you.

PRESIDENT FLANIGAN: Thank you.

Commissioner Kedikian?

COMMISSIONER KEDIKIAN: Just a brief question.

One of the speakers mentioned about the type of battery. And with regards to the Tesla battery, I know currently Tesla uses lithium batteries, but I think

MC-88 they're starting to also use lithium ion phosphate, which seems a little bit more reliable and has a better shelf life. And I was wondering, with regards to GWP, whether any particular decision has been made with

MC-88

regards to the type of the battery or the component or the chemical of the battery.

PRESIDENT FLANIGAN: Thank you.

We're going to have a response to that.

Please, Dave, go ahead.

MR. TATEOSIAN: Yeah, we would probably end up with the phosphate chemistry batteries.

COMMISSIONER KEDIKIAN: Okay. Thank you.

No other questions.

PRESIDENT FLANIGAN: Okay. Thank you, Commissioner Kedikian.

Commissioner Peterson, any follow-up questions or comments?

COMMISSIONER PETERSON: President Flanigan, thank you.

Only comment is that I wanted to express my gratitude for the work and the thoroughness that staff has been doing.

You know, as the -- being on the Glendale Water & Power Commission, we interact with them on a monthly basis, and topics like this are a little more familiar to us, and possibly we are more aware of the thoroughness of all options that the staff are constantly looking into and considering. And I just want to acknowledge that thoroughness and that effort on their part.

PRESIDENT FLANIGAN: Thank you very much.

And I'll just -- I'd just like to thank all those that made comments. I took notes on all of the comments, and it's -- it certainly echoes my concerns about the climate crisis and this need for really bold action right now. And to -- utilities have to -- in my view, have to take a leadership role in this transition.

With that said, I pass it to you, Commissioner -- or Chairman Bartrosouf.

CHAIRPERSON BARTROSOUF: Thank you.

Any Sustainability Commissioners have additional questions or comments?

Rondi, I see your --

VICE CHAIRPERSON WERNER: Yes --

CHAIRPERSON BARTROSOUF: -- hand's up.

VICE CHAIRPERSON WERNER: -- I do.

CHAIRPERSON BARTROSOUF: Yes, please, Rondi.

VICE CHAIRPERSON WERNER: Yes. Can you hear me?

CHAIRPERSON BARTROSOUF: Yes.

VICE CHAIRPERSON WERNER: Okay. Thanks.

I'm out camping, so excuse the messy background here.

MC-89 But anyway, I wanted to just mention that, you

MC-89

know, obviously we can all agree that the peak demand needs to be flattened in order to reduce the need for the high-capacity project, which is, of course, based on the highest anticipated usage so we're not leaving anyone in the dark, literally.

So I was all excited about the GWP peak savings program. Seemed like a great step in that direction. So I decided to lead by example and sign up for it.

First of all, I found it very difficult to find on the website. I assumed it would be on the front page. You know, save the planet, save money, you know, all that; but it was -- but I had to spend about 20 minutes looking for it. And then when I did, I was disappointed to find that my smart thermostat is not on the list of supported thermostats.

So I was wondering what the plan is.

Right now, apparently, it's Nest, Ecobee, Sensi, and then Energate and Carrier are, quote/unquote, coming soon; not sure when that is.

So what's the plan to get all of these meters -- thermostats supported? Mine is a Honeywell system, which is supported by LA GWP. So I don't think it's them.

But I'm just wondering, like, what obstacles there are to having all of them on there because this

MC-89

just seems like a perfect way to be able to, you know, flatten that curb and -- or curve and not have to build such a massive project.

MR. YOUNG: Yes, Commissioner Werner.

I'm sorry, I don't have that detail on when we'll be able to get all the thermostats in the program. But that's -- that's a high priority, for Franklin to be able to incorporate that into their software. Their first thought was to pick the ones that the majority of the people had. And unfortunately there's some people that don't have the majority. But I will get back to you and let you know.

And, I'm sorry, I didn't get your thermostat. What -- which thermostat did you have?

VICE CHAIRPERSON WERNER: Mine is Honeywell.

MR. YOUNG: Honeywell.

MC-90

VICE CHAIRPERSON WERNER: Yeah, so that was the other piece of it is, like, how would a ratepayer find out when they're going to be supported, when they go on the website and they see that, oh, theirs isn't on there? It might be out of sight, out of mind, and you need to check again. I feel like we're missing an opportunity here.

MR. YOUNG: Understand.

What I'll do is I'll take a look at the website to make sure that it's as easy to find as possible, and I'll get back with you as to when -- the expectation to be able to incorporate the Honeywell thermostat into the program.

VICE CHAIRPERSON WERNER: Thank you.

CHAIRPERSON BARTROSOUF: Thank you, Rondi.

Jennifer, you have your hand up?

COMMISSIONER PINKERTON: Yes. Thank you, Alek.

Oh, for Vice Chair Werner, just ironic that I signed up for that program, and someone knocked on my door a couple weeks ago and said, "We're here to do it," and switched out my thermostat. So it was a good thing.

I'm not sure if this would be directed to Mr. Young or to one of the Stantec presenters.

MC-91

One of our callers, I believe Mr. Eisenberg, asked for a page number in reference to -- I think it was the 15 percent, or it was run hours or something.

Can anybody provide that page number? He said he had looked for that number and that data in the original document and in the recirculated and could not find it.

So if anybody could find that page number and maybe e-mail our chair, Alek, and let him know so we can get that information out there.

That was it. Thank you.

MR. YOUNG: I'll take that as an action item.

CHAIRPERSON BARTROSOUF: Thank you, Jennifer.

Aleen, hi. Do you have questions? And -- just in case you're not able to virtually raise your hand?

COMMISSIONER KHANJIAN: None for me. Thank you.

MC-92

CHAIRPERSON BARTROSOUF: Okay. Thanks.

I have some -- I think what are quick follow-ups.

One thing I did want to get confirmation, Mark, is the 25 megawatts from Eland.

So that is confirmed that that is power that was expected as part of this analysis? It is not new power that is not part of the analysis?

MR. YOUNG: That's correct.

How we started this process was we indicated that 100 percent of our transmission capability would be imported power that's renewable. And then we were looking for excess power.

MC-93

CHAIRPERSON BARTROSOUF: Okay. And then we had talked about the units eventually moving towards hydrogen or a mix of hydrogen. Do we know what the associated costs of those upgrades are going to be and what physical changes need to happen to the units for that transition to occur? And is that cost associated

MC-93

into this -- or factored into this analysis?

MR. YOUNG: No, sir. It -- I believe that there's a certain percent hydrogen capable when we go ahead and buy it, because we're going to buy -- whenever we go ahead and engage with the company, we will get the most advanced technology that they have, which will give us that capability. And as they develop further capabilities, they might have to change the nozzles or they might have to change the firing mechanism in order for them to incorporate the change in the flame pattern of the hydrogen.

MC-94

CHAIRPERSON BARTROSOUF: Okay. I know, just generally speaking -- and perhaps something to consider for the next time this comes around -- is there have been a lot of questions associated around cost; and I know perhaps it's not part of the typical EIR process to talk about cost, but there's a lot of interest in what these things cost in comparison to alternatives. And quite frankly I'm not comfortable recommending anything without understanding the associated costs.

So hopefully we can come back next time and understand what these costs are to make some informed recommendation to Council.

MR. YOUNG: Yes, sir. Our goal is to try to find the best numbers that we can provide Council and

MC-95

the Commissions when it's time to make that decision.

CHAIRPERSON BARTROSOUF: Great. Thank you.

And then the other -- the question that I had before that had slipped my mind earlier was -- if we would be so kind to move to slide 11 or showcase that to the public, the clean energy RFP slide.

You know, we started this process with a need to build a plant that would generate 262, and now we've cut that down drastically to 93 using these methods that are part of this clean energy RFP.

I know that over time since it was initially introduced, the virtual power plant, for example, was, I think, half or something close to half of what is -- what we are now expecting to be 25 megawatts.

My question is is how are we maximizing the megawatts from each and every one of these elements in this clean energy RFP to reduce that 93 down even further? And the things that come to mind immediately are commercial -- the virtual power plant component for the commercial side of things.

And then I'm curious about, like, the demand response, for example. You know, we're going to do a test run tomorrow, it seems.

Are we reaching the number of people that we expect to or hope to? And how are those calculations

MC-95

made? Can we reach more people to make that 10 go to 15? Like, how is that analysis done to determine what the actual caps are for each of these elements?

MR. YOUNG: So for the demand response event that's supposed to happen tomorrow, they'll be able to provide a report to me to find out how many people are involved and what the actual reduction in peak is.

So we're still in the infant stage so people are still having to get the thermostats in play. The ones that already have the thermostats are probably the ones that are in play right now; but if you wanted a thermostat -- if my mother wanted a thermostat, she would have to arrange with Franklin to come to the house and to install it. So those things do take a little bit of time.

I'm not sure how many -- I still think we're not in megawatts. I think we're in the infant stage where we might be at a megawatt.

But back to the other question that you had asked: We had asked all three of these companies as -- in the first meeting with them, can you give us more? What is the most that you can give us?

And with that, we put a caveat that whatever that number was, we were going to hold you accountable for that number. Because we were going to take thermal generation out of play, we were going to count on that.

So these are the numbers that they gave us. These were not the numbers that GWP asked them for.

And a 50 megawatt virtual power plant on a 350 megawatt-generating -- load-serving entity is huge. It's a big, big virtual power plant. Sunrun acknowledges it's going to be one of the biggest that they have.

At the time of our negotiations with Tesla, it was going to be one of the biggest batteries in the country on a per-person basis, on a per-resident basis -- it still is -- if not the world.

So we are doing as much as we possibly can in looking at alternative sites and alternative options for us.

To say that we've not worked hard to try to get to where we are, I think it doesn't serve us well. We worked very hard to get down to the 93.

The 262-megawatt-of-thermal option, that was going to be able to supply us 99 percent of the time even if we were islanded; even if we were a microgrid, which is what Glendale is.

MC-96

CHAIRPERSON BARTROSOUF: Okay. And can you speak briefly on the commercial piece of it. I mean, to me, it seems like there's so much potential there with

MC-96

industrial property, commercial property. They're obviously so much larger than residential.

So how does that play into all of this?

MR. YOUNG: So if there was anything that we were somewhat slower on, would be the initiation of commercial. But we are getting out of a pandemic. We are coming back to work. We're dealing with all these other things that we weren't dealing with a year and a half ago.

All of these projects that you see right now were all coming to a head at the same time. That was not by design. They were supposed to be staggered, and they were supposed to actually be implemented in '18 and '19 and '20, not all coming in at the same time. So having to juggle all these things is rather difficult.

We are looking at -- the Sunrun is using multifamily residence, which is somewhat of a commercial penetration.

So once we start to get that into play, they'll be more comfortable; and we'll open it up, and we'll see if they want to expand or if there are other entities involved that would want to participate.

CHAIRPERSON BARTROSOUF: Got it.

I'll just end with saying, you know, I understand the enormity of work that entailed getting to where we are today; and, as you can tell from the type of calls that we've gotten and the type of comments that we've gotten from the public and from the Commissioners, there's a burning desire to get to zero. And we know that you know that. You are the technical experts. I by no means am a technical expert in the energy sector.

And so, you know, we appreciate all the work that you're doing; but we're always going to be giving you a hard time to get to that zero eventually.

So I hope you understand that -- the position that we're in as a -- at least as the Sustainability Commission to keep advocating and ensuring that we're striving to get to that as quickly as possible.

So I appreciate all the work that you've done and hope that you understand the fight that we're fighting to get Glendale to get to zero.

So --

MR. YOUNG: Yes, sir, I --

CHAIRPERSON BARTROSOUF: Thank you.

MR. YOUNG: -- do. I appreciate the check and balance. It's healthy.

CHAIRPERSON BARTROSOUF: Yeah.

And I -- we know that there are real-world constraints too. You know, there's a reality check and understanding that we can't get to zero tomorrow, that there has to be a transition; and I think most people understand that.

So I guess I'll make that clear to folks, that -- that I -- that's how I feel, at least.

Thank you.

PRESIDENT FLANIGAN: Well -- well put. Thank you very much, Chairman Bartrosouf.

And thank you to staff and to the consultants today and to our attorneys present; Catalina, for organizing the meeting. Thanks to our callers for calling in.

Could we have the next item, please.

MS. LEE: The next item is 3. Adjournment.

PRESIDENT FLANIGAN: Do we have a motion to adjourn, Alek?

CHAIRPERSON BARTROSOUF: Yes.

PRESIDENT FLANIGAN: I'll second that.

Good evening, everybody.

CHAIRPERSON BARTROSOUF: Thank you.

(End.)

C E R T I F I C A T E

I, Dana Parrott Harris, do hereby certify that the foregoing proceedings were transcribed into typewriting from video recording to the best of my ability, by myself, a Certified Shorthand Reporter and a disinterested person in said cause; that I was not present to clarify certain words, and some unintelligible or inaudible phrases may appear in the transcript.

I do further certify that I am not of counsel for any of the parties to said proceedings, nor in any way interested in the before-mentioned cause named in the said caption.

IN WITNESS WHEREOF, I have hereunto set my hand.

Dana Parrott Harris, CSR No. 5700

Date: November 22, 2021.

Q

R

L1

From: patlarrym@aol.com
To: Krause, Erik
Date: Monday, September 13, 2021 3:00:07 PM

CAUTION: This email was delivered from the Internet. Do not click links, open attachments, or reply if you are unsure as to the sender.

Dear Mr. Krause

L1-1 This is Larry Moorehouse and I am notifying you that I have sent to you for the Grayson EIR two separate letters with some of my questions, including some ideas for a memorial should the removal of Grayson happens. Thankyou for your help.

L2

From: Jennifer Pinkerton <jenniferpinkerton@fastmail.fm>
Sent: Tuesday, September 28, 2021 5:27 PM
To: Young, Mark <MYoung@Glendaleca.gov>
Subject: Permit and operatng hours

CAUTION: This email was delivered from the Internet. Do not click links, open attachments, or reply if you are unsure as to the sender.

Hello Mr. Young:

L2-1

Just following up on my question of 9/10 (below); any luck in obtaining this information?

Best

1. A resident presented the following Grayson question to me, and I realized I'm unclear on the same issue.

Specifically, the DEIR indicates that there will be 1120 operating hours and start ups. (Criteria, page 4.3, page 392; Appendix Table B4, page 483, and Appendix Table B5, page 484).

And 1,260 is a number which includes startup times that appears in Table 5-2 page 510

The resident said: "What I don't see in the PERMITS is any mention of operation limits."

Can you please provide a copy of the permit that shows the limitation on the number of hours of operation and start-ups.

--

Jennifer Pinkerton
jenniferpinkerton@fastmail.fm

L3

From:	Calin Ursea
To:	Krause, Erik
Subject:	Grayson Repowering Project
Date:	Friday, October 01, 2021 11:02:20 AM

L3-1 Hi Erik,
I strongly encourage that we upgrade the plant to ensure reliable power for our city.

Calin Ursea
Verdugo Woodlands, Glendale

L4

From:	Emily Griffin
To:	Krause, Erik
Subject:	grayson power plant
Date:	Sunday, October 03, 2021 8:46:47 AM

CAUTION: This email was delivered from the Internet. Do not click links, open attachments, or reply if you are unsure as to the sender.

L4-1 i am a glendale homeowner and i am deeply concerned about the environmental impact this project could have. based on my understanding of the information provided by the updated EIR provided i would advocate for the tesla/warsila project alternative.

EZG

L5

From: Barseghian, Vahan
To: Krause, Erik
Subject: Grayson Repowering Project PR-DEIR
Date: Monday, October 04, 2021 1:05:32 PM

Dear Mr. Krause,

L5-1 I reside at 404 Ross Street, Glendale, CA 91207. Regarding the Grayson Repowering project, is it possible to install such new gas turbines that will burn not only Natural Gas but also a combination of Natural Gas and Hydrogen? It seems that in the future hydrogen is going to play a role in energy storage technology.

Sincerely,

Vahan Barseghian

(818) 649-0543 cell

L6

From: Lin, Alan S@DOT
To: Krause, Erik; OPR State Clearinghouse
Subject: SCH # 20216121048-Grayson Repowering Project
Date: Wednesday, October 06, 2021 12:31:25 PM
Attachments: LA-2017-01133-DEIR_Granson_Repowering_Project.pdf
LA-2016-03680 Grayson Repowering Project-PR-DEIR.pdf

L6-1 Attached please find Caltrans comment letter.

Alan Lin, P.E.
Transportation Engineer, Civil
IGR, Division of Planning
State of California
Department of Transportation
Mail Station 16
100 South Main Street
Los Angeles, CA 90012
213-269-1124 Mobile

DEPARTMENT OF TRANSPORTATION
DISTRICT 7
100 S. MAIN STREET, MS 16
LOS ANGELES, CA 90012
PHONE (213) 269-1124
FAX (213) 897-1337
TTY 711
www.dot.ca.gov

*Making Conservation
a California Way of Life*

October 6, 2021

Mr. Erik Krause
City of Glendale
633 East Broadway, Room 103
Glendale, CA 91206

RE: Grayson Repowering Project
SCH # 20216121048
Vic. LA-134/PM R6.075, LA-5/PM 25.76
GTS # LA-2016-03680-PR-DEIR

Dear Mr. Krause:

L6-2 Thank you for including the California Department of Transportation (Caltrans) in the environmental review process for a Partially Recirculated Draft Environmental Impact Report (PR-DEIR). The City is proposing to replace the existing generation equipment and related facilities with a combination of new combined cycle and simple cycle gas turbine generation units. The generating capacity would increase from 267 megawatts (MW) net to 310MWnet (an increase of 43 MW net). The PR-DEIR examined impacts of two additional clean energy Project alternatives, updates the Cultural Resources and Paleontological Resources Section, and provides analysis required in recently added Wildfire and Energy environmental impact categories.

L6-3 For all future projects, VMT is the standard transportation analysis metric in CEQA for land use projects after July 1, 2020, which is the statewide implementation date. As a reminder, please reference to Caltrans comment letter dated October 23, 2017, see attached letter.

L6-4 If you have any questions, please feel free to contact Mr. Alan Lin the project coordinator at (213) 269-1124 and refer to GTS # LA-2016-03680-PR-DEIR.

Sincerely,

Miya Edmonson

MIYA EDMONSON
IGR/CEQA Branch Chief

email: State Clearinghouse

STATE OF CALIFORNIA—CALIFORNIA STATE TRANSPORTATION AGENCY EDMUND G. BROWN Jr. Governor

DEPARTMENT OF TRANSPORTATION
DISTRICT 7
100 S. MAIN STREET, MS 16
LOS ANGELES, CA 90012
PHONE (213) 897-8391
FAX (213) 897-1337
TTY 711
www.dot.ca.gov

Serious Drought.
Making Conservation
a California Way of Life.

October 23, 2017

Mr. Erik Krause
City of Glendale
633 East Broadway, Room 103
Glendale, CA 91206

RE: Grayson Repowering Project
Vic. LA-134/PM R6.075, LA-5/PM 25.76
SCH # 2016121048
GTS # LA-2016-01133AL-DEIR

Dear Mr. Krause:

Thank you for including the California Department of Transportation (Caltrans) in the environmental review process for the above referenced project. The City of Glendale, Department of Water and Power (City) is proposing to repower the Grayson Power Plant. The majority of the equipment and facilities at the Grayson Power Plant are proposed to be replaced with more reliable, efficient, flexible, and cleaner units.

L6A-1 The mission of Caltrans is to provide a safe, sustainable, integrated and efficient transportation system to enhance California's economy and livability. Senate Bill 743 (2013) mandated that CEQA review of transportation impacts of proposed development be modified by using Vehicle Miles Traveled (VMT) as the primary metric in identifying transportation impacts for all future development projects. For future project, you may reference to The Governor's Office of Planning and Research (OPR) for more information.

https://www.opr.ca.gov/s_sb743.php

Caltrans is aware of challenges that the region faces in identifying viable solutions to alleviating congestion on State and Local facilities. With limited room to expand vehicular capacity, future development should incorporate multi-modal and complete streets transportation elements that will actively promote alternatives to car use and better manage existing parking assets. Prioritizing and allocating space to efficient modes of travel such as bicycling and public transit can allow streets to transport more people in a fixed amount of right-of-way.

Caltrans supports the implementation of complete streets and pedestrian safety measures such as road diets and other traffic calming measures. Please note the Federal Highway Administration (FHWA) recognizes the road diet treatment as a proven safety countermeasure, and the cost of a road diet can be significantly reduced if implemented in tandem with routine street resurfacing.

We encourage the Lead Agency to integrate transportation and land use in a way that reduces Vehicle Miles Traveled (VMT) and Greenhouse Gas (GHG) emissions by facilitating the provision of more proximate goods and services to shorten trip lengths, and achieve a high level of non-motorized travel and transit use. We also encourage the Lead Agency to evaluate the potential of Transportation Demand Management (TDM) strategies and Intelligent Transportation System (ITS) applications in order to better manage the transportation network, as well as transit service and bicycle or pedestrian connectivity improvements.

L6A-1

After reviewing the Draft Environmental Impact Report for this project, Caltrans has the following comments:

Transportation of heavy construction equipment and/or materials, which requires the use of oversized-transport vehicles on State highways, will require a transportation permit from Caltrans. The construction time schedule of working hours should be considered off peak hours for the large size truck trips to minimize traffic congestion and to provide maximum safety to the pedestrians and vehicular traffic on the streets and freeways.

Storm water run-off is a sensitive issue for Los Angeles. Please be mindful that projects should be designed to discharge clean run-off water. Additionally, discharge of storm water run-off is not permitted onto State highway facilities without a storm water management plan.

If you have any questions, please feel free to contact project coordinator Mr. Alan Lin at (213) 897-8391 and refer to GTS # LA-2017-01133-AL.

Sincerely,

MIYA EDMONSON
IGR/CEQA Acting Branch Chief

cc: Scott Morgan, State Clearinghouse

L7

From: Lloyd The Rock"n Unicorn
To: Krause, Erik
Subject: Grayson Repowering Project PR-DEIR
Date: Wednesday, October 06, 2021 10:34:27 AM

CAUTION: This email was delivered from the Internet. Do not click links, open attachments, or reply if you are unsure as to the sender.

Good morning,
My name is Colin Fleming. I've been a resident of Glendale since 2012. I'm reaching out to voice my opposition to the repowering of the Grayson gas fire power plant.

L7-1

As a resident of Glendale, I want to encourage GWP to exclusively pursue renewable energy systems as a means of increasing reliable power output to the residents and businesses of Glendale.

Though, I'm sure this isn't the case for all our fellow residents, I'm not bothered by rare, momentary power outages. I would rather experience those from time to time, while the city pursues more clean, renewable energy methods.

I realize this is MUCH easier said than done, but if we are to improve the service that GWP provides, let's see that it's done without fossil fuels.

Thank you,

Colin Fleming
419 Griswold St, Apt 5, Glendale, CA 91205
(562) 309-5165

L8

From: Hank Schlinger
To: Krause, Erik
Subject: Grayson Repowering Project
Date: Wednesday, October 06, 2021 10:21:40 AM
Attachments: PastedGraphic-6.png

L8-1 I am oppposed to the plan to repower the Grayson Power Plant. As we are already in the throes of a human-caused climate crisis, which will only get worse, any power generation that isn't completely clean and sustainable will continue to add to the problem. Glendale needs to rethink power generation in this context.

Thank you.

Henry D. Schlinger, Jr., Ph.D.
1755 W. Mountain St.
Glendale, CA 91201

See my new book at www.buildgoodbehavior.com

Amazon.com

Vroman's Bookstore

L9

From: Alina Mullins
To: Krause, Erik
Cc: Lijin Sun; Celia Diamond
Subject: Technical Data Request: Grayson Repowering Project PR-DEIR
Date: Thursday, October 07, 2021 4:16:26 PM

CAUTION: This email was delivered from the Internet. Do not click links, open attachments, or reply if you are unsure as to the sender.

Dear Mr. Krause,

L9-1 South Coast AQMD staff received the Partially Recirculated Draft Environmental Impact Report (PR Draft EIR) for the Proposed Grayson Repowering Project (South Coast AQMD Control Number: LAC210819-11). Staff is currently in the process of reviewing the PR Draft EIR. The public commenting period is from 8/19/2021 – 11/15/2021.

Upon review of the files provided as part of the public review period, I was able to access the PR Draft EIR on the City's website.

L9-2 Please provide an electronic copy of any live modeling and emission calculation files (complete files, not summaries) that were used to quantify the air quality impacts from construction and/or operation in the PR Draft EIR as applicable, including the following:

- CalEEMod Input Files (.csv files) and Output Files (PDF ok);
- Live EMFAC output files;
- Any emission calculation file(s) (live version of excel file(s); no PDF) used to calculate the Project's emission sources (i.e. fueling operations);
- AERMOD Input and Output files, including AERMOD View file(s) (.isc);
- HARP Input and Output files and/or cancer risk calculation files (live version of excel file(s); no PDF) used to calculate cancer risk, and chronic and acute hazards from the Project;
- Any other files related to post-processing done outside of AERMOD to calculate pollutant-specific concentrations (if applicable).

L9-3 You may send the above-mentioned files via a Dropbox link in which they may be accessed and downloaded by South Coast AQMD staff **by 10/14/21**. For downloading purposes, please add Ms. Celia Diamond, at cdiamond@aqmd.gov, as our contact to access the Dropbox link. Without all files and supporting documentation, South Coast AQMD staff will be unable to complete a review of the air quality analyses in a timely manner. Any delays in providing all supporting documentation will require additional time for review beyond the end of the comment period.

If you have any questions regarding this request, please contact me.

Thank you,

Alina Mullins
Air Quality Specialist, CEQA IGR
Planning, Rule Development & Area Sources

South Coast Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765
P. (909) 396-2402
E. amullins@aqmd.gov
**Please note that South Coast AQMD is closed on Mondays. Additionally, in response to COVID-19, our building is currently closed to the public and I am working remotely. I will be responding to emails and voice messages during my scheduled work hours, Tuesday through Friday 7:00 am to 5:30 pm.*

L10

From: Randy Wise
To: Krause, Erik
Subject: A Terrible Idea
Date: Wednesday, October 13, 2021 9:02:01 AM

Hello Erik,

L10-1

I just read the PR-DEIR for the Grayson Repowering. It is a terrible idea. Why would you want to create a polluting facility near major residential neighborhoods and on a major fault line? It is a recipe for disaster. Here is what I really don't understand: there is a functional pipeline to carry methane from the dump to our existing power generation facility. Why not create the Repowering facility there? The facility already exists and any pollution would be localized.

I strongly oppose the creation of a repowering facility at the Scholl Canyon Landfill.

And finally, the Landfill should be closed in 2028 as agreed.

Thank you for your attention.

Randall & Nancy Wise
2105 Hollister Ter.
Glendale, CA 91206

L11

From: Andre Sarkissian
To: Krause, Erik
Cc: Devine, Paula; Agajanian, Vrej; Najarian, Ara; Kassakhian, Ardashes; Brotman, Daniel
Subject: Grayson Re-powering Project PR-DEIR
Date: Wednesday, November 03, 2021 1:29:59 PM

Dear esteemed council members,

L11-1

My name is Andre Sarkissian and I am a first-year student at Glendale Community College. I am writing to you today in regards to the upcoming decision about the expansion of the Grayson Power Plant. As a member of the Students for Sustainability Club, I feel it is my responsibility to share the concern I feel about this expansion.

L11-2

As a college student living with the reality of climate change, I want to urge the use of clean energy sources instead of fossil fuel based sources. Renewable power and transmission will permit the reduction of natural gas generation. Limiting or eradicating the use of fossil fuels will promote clean air and a healthy environment for all. Utilizing sources harmful to the environment will only worsen the effects of climate change. California is mandating 100% clean energy by 2045; environmentally friendly energy investments must be made in order to reach and comply with this goal. This decision is of the utmost importance to me because I am extremely concerned about the potential worsening of the pollution and air quality issue in our area.

L11-3

Taking the future into consideration, a fossil-free Glendale is essential to ensuring the safety of both the environment and the public. I am not only writing to you as a concerned citizen, but also as a concerned student obtaining his higher education at a college five minutes away from the Grayson power plant. I would like to be able to attend my college campus knowing that my safety is being taken into consideration. Furthermore, I urge you to hold off on any new gas power at the Grayson power plant until all clean-energy solutions have been examined.

Sincerely,
Andre Sarkissian

L12

From: Emily Mirzakhan
To: Krause, Erik
Cc: Devine, Paula; Agajanian, Vrej; Najarian, Ara; Kassakhian, Ardashes; Brotman, Daniel
Subject: Grayson Re-powering Project PR-DEIR
Date: Wednesday, November 03, 2021 2:00:55 PM

Dear Esteemed Council Members,

L12-1

My name is Emily Mirzakhan and I am a first year student at Glendale Community College. I am writing to you today in regards to the upcoming decision about the expansion of the Grayson Power Plant. As a member of the Students for Sustainability Club, I feel it is my responsibility to share the concern I feel about this expansion.

As a college student living with the reality of climate change, I want to urge the use of clean energy sources instead of fossil fuel based sources. Renewable power and transmission will permit the reduction of natural gas generation. Limiting or eradicating the use of fossil fuels will promote clean air and a healthy environment for all. Utilizing sources harmful to the environment will only worsen the effects of climate change. California is mandating 100% clean energy by 2045; environmentally friendly energy investments must be made in order to reach and comply with this goal. This decision is of the utmost importance to me because it is important to me to make sure that Glendale ,which I consider my home, is working to become as sustainable as possible. I walk out of my home everyday to breathe the air around me and hope that that air is clean. The health of my family and neighbors is extremely important to me and I hope that you, as the decision makers of today, will take responsibility for this issue and make the decision of choosing clean energy resources.

Taking the future into consideration, a fossil-free Glendale is essential to ensuring the safety of both the environment and the public. I am not only writing to you as a concerned citizen, but also as a concerned student obtaining her higher education at a college five minutes away from the Grayson power plant. I would like to be able to attend my college campus knowing that my safety is being taken into consideration. Furthermore, I urge you to hold off on any new gas power at the Grayson power plant until all clean-energy solutions have been examined.

Sincerely,

Emily Mirzakhan

L13

From: M M
To: Krause, Erik
Cc: Devine, Paula; Agajanian, Vrej; Najarian, Ara; Kassakhian, Ardashes; Brotman, Daniel
Subject: Grayson Re-powering Project PR-DEIR
Date: Wednesday, November 03, 2021 1:30:22 PM

Dear Esteemed Council members,

L13-1

My name is Melany Mirzakhan and I am a First year student at Glendale Community College. I am writing to you today in regards to the upcoming decision about the expansion of the Grayson Power Plant. As a member of the Students for Sustainability Club, I feel it is my responsibility to share the concern I feel about this expansion.

As a college student living with the reality of climate change, I want to urge the use of clean energy sources instead of fossil fuel based sources. Renewable power and transmission will permit the reduction of natural gas generation. Limiting or eradicating the use of fossil fuels will promote clean air and a healthy environment for all. Utilizing sources harmful to the environment will only worsen the effects of climate change. California is mandating 100% clean energy by 2045; environmentally friendly energy investments must be made in order to reach and comply with this goal. This decision is of the utmost importance to me because I am a citizen of Glendale and living so close to the power plant I worry about the air quality I am intaking. This will be very detrimental to the health of the citizens of Glendale. While attending GCC and living in such a modernized city, I feel that it should not be a students worry, the air quality they are breathing.

Taking the future into consideration, a fossil-free Glendale is essential to ensuring the safety of both the environment and the public. I am not only writing to you as a concerned citizen, but also as a concerned student obtaining her higher education at a college five minutes away from the Grayson power plant. I would like to be able to attend my college campus knowing that my safety is being taken into consideration. Furthermore, I urge you to hold off on any new gas power at the Grayson power plant until all clean-energy solutions have been examined.

Sincerely,

Melany Mirzakhan

L14

From: Candace Hodder
To: Krause, Erik
Subject: Grayson Repowering Project PR-DEIR
Date: Monday, November 08, 2021 10:25:06 PM

Hello,

L14-1 After reviewing the Grayson Repowering Project PR-DEIR I do not understand why alternative energy is positioned as a standalone project option that is incapable of meeting Glendale's energy needs rather than an essential element of every other plan considered.

L14-2 I also do not understand why the analysis does not account for the children living and going to school in the so-called "industrial area" that the report claims Grayson is located in. I believe the report should have to define what is meant by "industrial area" as I am aware of early education programs, schools, and residences within less than a 1-mile radius of Grayson. With so many children nearby, I believe the report has not adequately evaluated the health impacts of pollutants from the repowering project on children specifically.

L14-3 I do not believe this PR-DEIR has adequately accounted for children growing up in the surrounding area in its assessment of health risks, nor that alternative energy sources have adequately been incorporated into all proposed models. I will carry my comments forward to city council as needed.

Candace Hodder
Current Resident of Glendale, CA

L15

Note:
cc to CCP p4

November 10, 2021

Paula Devine, Mayor &
City Council Members: Vreg Arajanian, Ara Najarian, Ardy Kasssakhian and Dan Brotman
City of Glendale
613 Broadway Blvd
Glendale, CA 91206

Subject: Public Comments for the February 6, 20018 Public Hearing on the Proposed Grayson Energy Plant Expansion

Dear Mayor Devine:

L15-1 I oppose the proposed Grayson Energy Plant Repower expansion. The current, Partially Recirculated Environmental Impact Report (PR-EIR) abjectly fails to address numerous structural problems in which the initial EIR clearly failed to met fundamental CEQA standards for environmental analysis.

L15-2 Underlining the focus of this critique is that this proposed action is potentially the single largest expenditure of public funds in the modern history of the City of Glendale.

L15-3 Thus what the GWP is presenting to both the City Council and the rate payers/ Glendale residents is a all to typical foil in the planning profession. They are relabeling a legally incompetent EIR and arbitrarily limiting a range of conventional environmental impact analysis directly related to the scope, scale and specifically the cost of this proposed action.

L15-4 A key problem with the public information is the fact that there is No Cost Estimate or general Cost Range provided to the public. This essential and critical aspect of the proposed project must be presented in a Socio-Economic Impacts section, a fundamental component of CEQA.

L15-5 In addition, in relation to the substantial cost, I assume approximately $500 million of more (since no document presented to the public in relation to this most recent generalist concept offers a price range, I will admit, this is speculative cost estimate), there is no Economic Impact Analysis between the benefits of a strategy based on renewable energy sources versus non-renewable energy sources over time. This is specifically why California adopted CEQA, to offer public officials with legitimate information, comparative impact analysis and technical data to assess the merits of any proposed project.

L15-6 This is especially pronounced for a proposed action of this scale, actual size, cost and long term environmental impacts.

L15-7 In addition, there remains the same problem with the original EIR, there is no Public Health Impact analysis which would address a range of conventional issues between a substantially renewable resources future for the City versus this dated, potentially incompetent and environmentally damaging reliance on gas power energy generation.

L15-8 Without either of these two key, fundamental issues this latest, inept PR-EIR again fails to meet conventional CEQA standards in environmental analysis.

L15-9 This project, which has not fundamentally changed in scale and scope since 2018, it is a bad idea and/or strategy to address the future energy demand for the City.

Since the failure to incorporate a Public Health Impact section has been addressed in prior public comments, I want to focus on the Economic Impact Analysis related to projected costs of the proposed action.

What is acknowledged in the document is that state law will demand a minimum of 60% renewable energy by 2040. The PR-EIR claims the City can achieve 89% by that date.

L15-10 The legal failure and inadequacy of this latest document is that it fails to address the following:

Long term costs to rate payers when GWP/ Glendale will be forced to either completely cease operation and/or substantially reduce operations after 2040.

What additional costs GWP rate payers will incur having to assist in paying for the bonds directly related to this proposed action and significant costs for additional energy in the future.

If the total amount, $500 million was invested now, 2022-2025 in renewable energy, what would be the long term cost savings to rate payers over time.

GWP is required under CEQA to provide rate payers, Glendale residents and their Council representatives a Economic Impact Analysis of the total cost for energy over the projected life span of the proposed project.

Under CEQA this fundamentally includes it's projected 15 years of operation, costs to shut it down, costs for replacement energy, penalties for operating an illegal plant if GWP fails to plan for a renewable energy future and total cost to rate payers, in essence bond costs for 30 to 40 years and costs for energy when the plant is legally forced to close by state law.

The Economic Impact Section should also present a comparative analysis of how a $500 million investment in renewable energy starting in 2022-2025 compares with the proposed action which relies on an energy source that every single public official in the State of California knows will not be allowed in the mid term future.

L15-11

The manipulation of the PR-EIR, with the GWP's self imposed limitations on providing the City, the City Council and rate payers is an illegal abuse of the CEQA legislation.

The essence of this charade of the environmental review process, is that in three years since the original concept failed in City Council, 2018, instead of improving the scope of environmental analysis to address Public Health Impacts, Economic Impacts, offer a conventional, technical analysis of a total reliance on renewable energy sources versus non-renewable, which this Repower project proposal advocates, GWP has arbitrarily attempted to do less.

There is no rational excuse for this level of ineptitude and failure to properly inform the public on a full range of environmental impacts, alternatives, cost estimates, and long term negative costs to GWP rate payers.

The Mayor and City Council must reject this revisionist attempt to evade a full scale review of a wide range of conventional environmental issues, especially since GWP has had three years to improve what was widely acknowledged as an inept and on some levels, incompetent EIR presented in 2018.

L15-12

Glendale needs to establish a long term strategy based on renewable energy sources. The city will be required to meet state mandates to rely on 40% renewable sources in about 15 years, assuming that any project would not be completed until approximately 2025.

L15-13

The Project Description, which fails to incorporate a Cost Estimate nor a Public Health Impact section remains wholly inadequate and does not meet CEQA standards.

L15-14

In addition, the original DEIR section related to land use and planning issues is, at best, incompetent. relied on a 1993 City of Glendale General Plan. The land use element, per City, was last updated in '1986'. The Housing Element was last updated in 2014 (2014-2021), and will be outdated in 'seven weeks'. This General Plan is significantly out of date. The city is required to update it's General Plan every 20 years.

Thus, the PR-EIR's analysis is based on a substantial level of information from the 1980s, and most likely some information developed in the late 1970s. Utilization of this document has no credibility. The proposed action has definitive, long term negative environmental land use impacts on the entire City and neighboring cities. The PR-EIR fails to address this structural CEQA problem.

L15-15

Due to the long term, significant negative environmental impacts to the Public's Health, it is essential that the PR-EIR create a Public Health Impact section. This should have been established under the CEQA Socio-Economic Impacts requirement.

L15-16

Conclusion:

Prior to any serious consideration of the proposed project it is essential that the Mayor, City Council and Glendale residents are fully informed about the true cost of energy generation for the entire 40 plus years of projected functional use. The total cost of the bonds, total estimated construction costs, long term administration and staffing costs, and essentially, post 2040, all additional costs to secure energy once this proposed action is either required by state law to substantially reduce energy production and/or cease operations completely.

L15-16 Without this total cost analysis, which I had anticipated in an Economic Impact Section, that does not exist in the PR-EIR, it is irrational for the Mayor and City Council to assess this proposed action.

In addition, I hope that this is established knowledge and acknowledged by GWP, renewable energy generation is the future of this state and this City.

Thus, the real question before the City Council and Mayor's office, once given the total cost analysis, is it a substantial savings to rate payers and residents, and wiser to initiate investment in renewable source between 2022-2025, versus wasting public funds on non-renewable energy generation strategy that will be forced to substantially reduce operations within a decade and a half, by state and possibly federal law.

Until a full, Economic Impact Section addressing this fundamental public policy demand is produced by GWP, your office and the City Council cannot validly assess the merits of this proposed action.

Respectfully,

David R Diaz

Dr. David R. Diaz
M.C.R.P. City and Regional Planning, UC Berkeley, 1976
Ph. D. Urban Planning, UCLA, 1994
Director of Urban Studies, CSU Los Angeles (retired)
1211 Scenic Dr
Glendale, CA 91205; Adams Hill

cc: GWP Community Development Department, Planning Division

L16

From: John Schwab-Sims
To: Krause, Erik
Cc: Steve Hunt
Subject: TGHS Comments on Grayson Repowering Project PR-DEIR
Date: Wednesday, November 10, 2021 9:55:31 PM
Attachments: TGHS Grayson Comments PR-DEIR.pdf
TGHS Letter Grayson Power Plant EIR- 11 19 2017.pdf

CAUTION: This email was delivered from the Internet. Do not click links, open attachments, or reply if you are unsure as to the sender.

L16-1

Dear Mr. Krause,

Attached are comments from The Glendale Historical Society on the posted PR-DEIR for the Grayson Repowering Project.

TGHS would like this included in the official record.

Thanks for your consideration.

John Schwab-Sims
VP Preservation
The Glendale Historical Society

THE GLENDALE HISTORICAL SOCIETY

CONSERVING OUR HERITAGE

P.O. Box 4173 Glendale CA 91202
www.GlendaleHistorical.org

November 11, 2021

Mr. Erik Krause
Deputy Director of Community Development
City of Glendale
Sent via e-mail to ekrause@glendaleca.gov

RE: Comments on Partially Recirculated- Draft Environmental Impact Report Grayson Repowering Project

Dear Mr. Krause:

L16-2 The Glendale Historical Society is grateful to be able to provide the following comments on the Partially Recirculated Draft Environmental Impact Report for the Grayson Repowering Project in Glendale, CA (August 6, 2021, hereinafter PR-DEIR). Kindly ensure that this letter and its attachment are included in the Administrative Record for this project.

TGHS is a non-profit organization with over 1000 members dedicated to the preservation of Glendale's rich and diverse history and architectural heritage through advocacy and education. TGHS is one of two Preserve America Stewards in California. It was recognized by the Advisory Council on Historic Preservation for the volunteers who contribute in direct and tangible ways to preservation, protection and promotion of historic properties. Our advocacy efforts were recently acknowledged by the Los Angeles Conservancy with a Preservation Award.

L16-3 A number of important problems have been identified regarding historical resources in the PR-DEIR. The main problems are the alternatives analysis, the failure to prepare an updated cultural resources technical report, an incomplete discussion of consultation with TGHS, omission of any coordination with the City of Glendale's Historic Preservation Commission (HPC) and the flawed consideration of cumulative historical resources impacts.

L16-4 There is no description of an alternative in the alternatives analysis that would retain historical resources. If an EIR studies a feasible alternative to demolition, the lead agency may be required to change the project to reduce its impact on historical resources. Was any reuse of the Boiler building of the Glendale Switch Yard considered as part of the proposed project? We recommend compliance with the requirements in CEQA that would clearly describe and fully analyze alternatives that would retain historical resources. According to CEQA, an EIR must describe a reasonable range of alternatives to a proposed project that could feasibly attain most of the basic project objectives and would avoid or substantially lessen any of the proposed project's significant effects.

L16-5 The absence of an updated cultural resources technical report that would have identified all historical resources associated with the independent power source in Glendale as well as their character-defining features is a serious omission. That report would have fully evaluated the property and its components for local

L16-5 and California Register eligibility. Despite TGHS's attached letter of nearly four years ago (November 19, 2017), which provided substantial evidence that the project would cause significant impacts on cultural resources, the lead agency has insisted until this year that the Grayson Steam-Electric Power Plant was not historically significant. It was only after TGHS members contacted California Office of Historic Preservation staff and confirmed with them that the property in its entirety (not merely the Boiler Building) is eligible for listing in both the National and California Registers that the Lead Agency fully understood that implementation of the proposed project would cause a historical resources impact. Now that the lead agency recognizes this incontrovertible fact, it must be supported in the technical reports.

L16-6 In that referenced 2017 letter regarding this project TGHS stated that "CEQA strongly encourages early consultation with interested or affected parties, which includes local historic advocacy groups." Despite our best efforts, that did not happen until 2021. In the PR-DEIR, there is no clear discussion of the dates, content or the unfavorable outcome of discussions that transpired between February and June 2021 between the lead agency, its consultants and TGHS regarding this project and historical resources impacts. Those discussions notably included our recommendation of a meaningful, fully developed mitigation measure that entailed preparation of an intensive survey of City-owned properties for historic significance. That mitigation measure was discarded, without justification, despite its clear nexus to the proposed project and to the expected loss of a historical resource to the community.

L16-7 There is no reference in the PR-DEIR of any future plans for or demonstrated past actions of the lead agency presenting the proposed project to the City of Glendale Historic Preservation Commission for consideration. Such review of a project of this type, the proposed demolition of historical resources clearly falls under that commission's powers and duties. See *Glendale Municipal Code* Section 15.20.080, A, B, C and D and City of Glendale Historic Preservation Commission "Powers and Duties," A-O. An HPC meeting must take place before the project environmental clearance documents are adopted. Without the HPC's express participation in this process, the City will violate the requirements in its own established, adopted Historic Preservation Ordinance.

L16-8 The PR-DEIR used an overly narrow lens for cumulative impacts to municipal power property types in Glendale. Because those properties have, in fact, not been surveyed for historic significance, it makes the focused view analyzing cumulative impacts on currently proposed future and recent projects with the proposed project impossible. Without the implementation of the recommended mitigation measure, the City does not know what municipal power properties are historically significant in order to make such an analysis. It is comparable to comparing the proposed demolition of a yellow house only to demolition of other yellow houses. The Lead agency must consider a comprehensive list of recent and expected future projects that would affect historical resources; therefore, the combined impacts of those projects considered with the proposed project has not been properly analyzed.

L16-9 We are disappointed that the environmental clearance process for this project has taken years to come this far. TGHS is not opposed to new, cleaner and greener solutions to gas power in Glendale, but any such solutions must fully consider and mitigate impacts to historical resources.

Thank you for your consideration.

Sincerely,

John Schwab-Sims
VP Preservation
The Glendale Historical Society

Attachment: TGHS Comment Letter on Proposed Grayson Repowering Project Draft Environmental Impact Statement, November 19, 2017

L16A

THE GLENDALE HISTORICAL SOCIETY
CONSERVING OUR HERITAGE

P.O. Box 4173 Glendale CA 91202
www.GlendaleHistorical.org

L16A-1

November 19, 2017

Mr. Erik Krause
Interim Deputy Director of Community Development
City of Glendale Community Development Department
633 E Broadway, Room 103
Glendale CA 91206

RE: Comments on Proposed Grayson Repowering Project Draft Environmental Impact Statement

Dear Mr. Krause:

On behalf of the Board of Directors of The Glendale Historical Society (TGHS), I would like to thank you for the opportunity to comment on the draft Environmental Impact Report (DEIR) for the Proposed Grayson Repowering Project. Established in 1979, TGHS is a non-profit organization with more than 700 members dedicated to the preservation of Glendale's history and architectural heritage through advocacy and education.

We disagree with the findings that the Grayson Steam Electric Power Plant is not a historical resource as defined in CEQA. We believe that the consultant's assessment of historic significance is fundamentally flawed. TGHS believes that the Grayson Steam Electric Power Plant may be eligible for listing in the National Register and that it is eligible for listing in the California and Glendale Registers for its associative as well as for its design and engineering significance. We also believe the DEIR is flawed in other important ways described in detail below.

<u>Tribal Cultural Resources</u>
We note that the "Tribal Cultural Resources" chapter of the DEIR is incorrectly titled. This inaccuracy demonstrates a lack of basic understanding of the intent of the section and the task by preparers. The purpose of what is normally called a Cultural Resources chapter in an EIR is to identify and evaluate the potential for a project to affect paleontological, archaeological and historical resources. Resources of concern include fossils, prehistoric and historic artifacts, burials, sites of religious or cultural significance to Native American groups, and historical resources.

Its essential questions should be:

Is there a historical resource that may be affected by the proposed project; and

Will the project result in a substantial adverse change to the extent that the resource's historical value is materially impaired or lost?

L16A-1 Evaluations for historic significance are not normally "negative" as stated in the document; historical resources either exist or they do not. Negative findings are an archaic term that was used in solely archaeological investigations and do not apply to the built environment. That paragraph, along with the section title, the evaluation and analysis contained therein, alerts informed readers to the fact that the entire section may have been prepared primarily by archaeologists practicing outside of their fields of expertise.

The Tribal Cultural Resources title implies that only archaeological resources and tribal concerns were considered. Under CEQA, Initial Studies and EIRs address Cultural Resources, not merely "Tribal Cultural Resources."

Preparer Qualifications

The preparer qualifications presented in the Initial Study (1.4 Cultural Resources Project Staff Qualifications) do not demonstrate that any staff meet the Secretary of the Interior's Professional Qualifications Standards. A statement in the closing paragraph claims "The Stantec Cultural Resources *Program Manager* and *Senior Architectural Historians* directing the survey meet the Professional Qualification Standards of the Department of the Interior" but provides no particulars regarding degrees attained and more importantly does not identify any staff members' fields of expertise (emphasis added). Each provides numbers of years preparing reports, but none of the brief biographies provides evidence to corroborate meeting the Secretary of the Interior's Professional Qualifications Standards codified in CFR Part 61.

The guidance in Archeology And Historic Preservation: Secretary of the Interior's Standards and Guidelines [as Amended and Annotated] directs "The qualifications define minimum education and experience required to perform identification, evaluation, registration, and treatment activities. In some cases, additional areas or levels of expertise may be needed, depending on the complexity of the task and the nature of the historic properties involved." The website for the Historical Architect responsible for the report states that he specializes "in custom residential architecture, and also do[es] commercial projects" (http://www.johnterryarch.com/Introduction-1). Enumerated experience on that website includes two "renovations" but no rehabilitations or restorations are listed. No evidence of a year or more of graduate study or of professional experience including "detailed investigations of historic structures, preparation of historic structures research reports, and preparation of plans and specifications for preservation projects" as cited in the Professional Qualifications Standards is provided. We submit that this evaluation for historic significance is a complex case, and that the preparers provide no evidence of additional levels or areas of expertise and show no demonstrated experience with successful evaluations for the National, California, or Glendale Registers.

Archaeologists are not normally qualified to prepare built environment evaluations, and historians are not interchangeable with historic architects. In the FEIR revised cultural resources technical report all preparers' professional qualifications should be clearly stated, otherwise the reviewers suspect that it was prepared by staff who have generated reports for specific numbers of years rather than persons with demonstrated expertise necessary to perform the tasks required for this evaluation of historic significance and analysis of effects.

<u>Laws, Ordinances, Regulations and Standards</u>

The introductory "Laws, Ordinances, Regulations and Standards (LORS)" section is fatally flawed. The applying LORS enumerated are not demonstrated to have any specific application to the project. If federal regulations apply to the proposed project, then Section 106 of the National Historic Preservation Act (as amended) would pertain to the project. If the project has *any* federal nexus, the proper environmental document would likely be an Environmental Impact Statement/Environmental Impact Report (EIS/EIR) rather than merely an EIR.

L16A-1 It is not clear that Section 106 of the National Historic Preservation Act does or does not apply to the proposed project. We expect that a project of this type requires federal permits, licenses or other approvals. If so, Section 106 applies and the appropriate clearance document may be an Environmental Impact Study and well as an Environmental Impact Report.

The federal Environmental Protection Agency (EPA) promulgated the Steam Electric Power Generating Effluent Guidelines and Standards (40 CFR Part 423) in 1974, and amended the regulations in 1977, 1978, 1980, 1982 and 2015. *The regulations cover wastewater discharges from power plants operating as utilities.* The steam electric regulations are incorporated into National Pollutant Discharge Elimination System (NPDES) permits. If a NPDES permit or any other federal approval or license is required for the proposed project, *there is a federal nexus and Section 106 applies*.

Further, the EPA released a final rule to limit greenhouse gas emissions from new power plants on August 3, 2015. The final "Carbon Pollution Standard for New Power Plants" establishes New Source Performance Standards to limit emissions of carbon dioxide from fossil fuel-fired power plants. If the "Carbon Pollution Standard for New Power Plants" applies to the proposed project or any other federal approval or license is required for the proposed project, *there is a federal nexus and Section 106 applies*.

Please explain how the National Environmental Policy Act would or would not apply to the proposed project. Can the proposed project be considered a major federal action that would be determined to significantly affect the quality of the human environment?

The "Applicable Federal, State, Local LORS for Tribal [*sic*] Cultural Resources" table and section notably contains no discussion of whether or not the listed LORS apply and why, which is an obvious necessity in such documents. Merely listing the language in LORS does not inform the public or decision-makers in making their decisions regarding the proposed project.

In the "Applicable Federal, State, Local LORS for Tribal Cultural Resources" table, there are significant errors and omissions. The administering agency column is incorrect *in each entry*. For instance, Section 106 is not administered by the Code of Federal Regulations (CFR). CFR is not and has never been an administering agency; it is codification of the general and permanent rules and regulations (or administrative law) published in the Federal Register by the executive departments and agencies of the federal government. Applicable Federal Agency Programs administer Section 106 with the Advisory Council on Historic Preservation. If that table, which provides no information of value to the analysis, remains, it must be corrected in the Final EIR or a supplemental EIS/EIR. We strongly recommend that it be completed (most of it is blank) and corrected to list correct administering agencies.

Further, where each of the LORS is enumerated in the narrative sections below, applicable language was merely cut-and-pasted into the document. There is notably no description of how the listed LORS apply to the proposed project, and why, or what it means to the project or analysis, which is critical to understanding what the document is and why preparers came to whatever conclusions they did. Absent this information, the "Tribal Cultural Resources" section of the document is useless, devoid of worthwhile information for decision makers and the public. Reviewers are left wondering what laws, ordinances, and regulations apply to the proposed project, why and how that fits into the analysis at hand.

Archaeology

L16A-1 Neither the "Existing Conditions" section nor the other parts of the larger "Tribal Cultural Resources" chapter make reference to any archaeological surveys being performed, presenting the property only above-ground when whatever does or does not exist below grade is undeniably part of the subject property's cultural resources existing conditions. No reference was made to any archaeological surveys being performed for the proposed project, to the likelihood of encountering archaeological resources, or to what the expected impacts of effects would be on those resources.

Review of the Initial Study, where the technical reports are sequestered, provides an overview of archaeological surveys being performed in 2003 and 2016, providing no further details. What methods were used? How much of the subject property was surveyed? More importantly, who at the City of Glendale has the appropriate credentials (meeting the Secretary of the Interior's Professional Qualifications Standards in Archaeology) to critically review the reports that ostensibly resulted? Was a subcontractor engaged to review whatever reports resulted from those surveys? Please provide the name and professional qualifications of the archaeologist who reviewed the confidential section of the Initial Study for the City.

Methodology

The "Methodology" section of the EIR is inadequate as well. The two sentences describing Senate Bill 52 efforts is not equivalent to what should be a description of how project Cultural Resources procedures were carried out. Inserting words that do not apply into a section does not satisfy the requirements of CEQA. The methodology section is intended to explain how the evaluation and analysis were prepared that lead the preparers to arrive at the conclusions they did.

Evaluation for Historic Significance

We additionally submit that because the evaluation of the subject property's historic significance is not included in the document or the appended technical reports, decision makers cannot review the evaluation. Because of that omission, decision-makers and the public cannot make their own conclusions based on information presented as to whether or not the Grayson Steam-Electric Power Plant is historically significant. Thus decision-makers and the public are not able to judge whether substantial adverse change to a historical resources would be materially impaired or entirely lost. The California Code of Regulations (CCR) directs under Technical Detail:

> The information contained in an EIR shall include summarized technical data, maps, plot plans, diagrams, and similar relevant information sufficient to permit full assessment of significant environmental impacts by reviewing agencies and members of the public. *Placement of highly technical and specialized analysis and data in the body of an EIR should be avoided through <u>inclusion of supporting information and analyses as</u>*

> *appendices to the main body of the EIR.* Appendices to the EIR may be prepared in volumes separate from the basic EIR document, but shall be readily available for public examination and shall be submitted to all clearinghouses which assist in public review (emphasis added, CCR Section 15147).

The applicable cultural resources analysis is not contained in the technical report section, or in an appendix, but was secreted in the Notice of Preparation. Once TGHS was able to locate the "Architectural Resource Evaluation of The Grayson Power Plant For City of Glendale, California" it was reviewed for adequacy by a professional qualified under the Secretary of the Interior's Qualifications Standards in both history and architectural history and was found not to be correct in its conclusions.

L16A-1

Other EIR reviewers will not know where to find the evaluation for historic significance. Because that analysis is not "readily available for public examination" it does not "assist in public review" as required. We strongly stress that the conclusion that the Grayson Steam-Electric Power is not historically significant was made in error and that the revised, corrected evaluation should be a technical appendix to the FEIR and that the FEIR should address alternatives to the project that would retain the historical resource and/or mitigate its loss if it were proven not to be feasible, based on facts.

The evaluation failed to consider the power plant as a contributor to a larger, previously unevaluated historic district as well, which is a fundamental component in any such survey.

Like the archaeological investigation, no evidence is provided of any lead agency review of the conclusions in the report being performed by qualified staff or consultants for the City of Glendale. The conclusions in the EIR that are based on incorrect finding in the Initial Study must be peer-reviewed for accuracy by professionally qualified professionals with demonstrated expertise in the applicable fields.

Reconnaissance Survey

The evaluators note in the survey type on the DPR form that the evaluation is an "Architectural Inventory and Evaluation *Reconnaissance* Survey." We strongly assert that an intensive evaluation must be prepared by local qualified architectural historians who have clear understanding of the Grayson Steam-Electric Power Plant's place in local and regional history and who have demonstrated experience in applying the criteria for Glendale Register of Historic Resources to evaluations for significance. We assert that the property's National, California Register and local significance were not properly considered and that its conclusions are incorrect.

National Register guidance prepared by the Department of the Interior provides a definition in "Guidelines for Local Surveys A Basis For Preservation Planning: "*Reconnaissance* may be thought of as a 'once over lightly' inspection of an area, most useful for characterizing its resources in general and for developing a basis for deciding how to organize and orient more detailed survey efforts."

Likewise directions in "The Secretary of the Interior's Guidelines for Identification" state

> Reconnaissance survey might be most profitably employed when gathering data to refine a developed historic context—such as checking on the presence or absence of expected property types, to define specific property types or to estimate the distribution of historic properties in an area… *In most cases, areas surveyed in this way will require resurvey if*

> *more complete information is needed about specific properties*" (emphasis added, Archaeology and Historic Preservation: Secretary of The Interior's Standards and Guidelines, as Amended and Annotated, 48 Federal Register 44716, effective 1983).

We believe a reconnaissance survey, buried in the Initial Study was not the correct level of evaluation, which should rightly be an intensive survey in a technical appendix to the EIR that would allow reviewers the opportunity to consider the logic of a full evaluation for historic significance.

<u>Is the Grayson Steam-Electric Plant a Historical Resource?</u>

L16A-1 The "Tribal Cultural Resources" [*sic*] EIR section commences with a statement where the authors refute their own justification for finding the Grayson Steam-Electric Power not to be historically significant:

> While the [Grayson Steam-Electric Power] Plant does possess potential significance under the… [California Register] and Glendale Register of Historic Resources Criterions [*sic*] 1, 2, 3, and 4, a lack of integrity under all aspects of integrity recognized by the… [California Register], and implemented for the City of Glendale Register… *which is silent on aspects of integrity*, undermines the property's ability to convey importance/significance for either the state or local registers.

The Glendale Register has no requirement for integrity. Finding a property not eligible for the Glendale Register because of supposed alterations is not supported in the stated requirements for designation on the local register. Because the Glendale Register has no specific requirements for integrity a property's significance should not be dismissed because of alterations, particularly when the facility being evaluated remains absolutely recognizable to its original appearance.

When properties are significant for associations with the development of the community or with important persons they need not retain the same aspects or level of integrity as a property that is significant only for its design. That concept is a fundamental principle in evaluating properties for historic significance and was markedly not recognized by the document preparers. Furthermore, the addition of separate cooling towers, maintenance and storage buildings, oil tanks and trailers over time would be essential to its continued use as a power plant and would be well-known to qualified, experienced practitioners.

The inadequate evaluation in the Initial Study does not make clear where the described, overly emphasized alterations are, or how they would collectively reduce the property's integrity of design. Table 4 in the Initial Study curiously lists more than 57 building permits (only post 1964), but after review, it is discovered that few, if any are actual alterations to the Grayson Steam-Electric Power Plant that would affect its integrity. The document states "Some of the projects associated with these permits are visible in the aerials…" but no connection between listed building permits and actual alterations that would affect the ability of the property to convey its significance, which is central to the claim of the property not being eligible, has been made.

Supposed alterations such as "Constructed a new concrete block chemical pump house with concrete roof" (1964), "Constructed one metal shed" (1970) and "Constructed a foundation (only) for a temporary modular trailer" (2012) demonstrate the consultant's lack of understanding of the crux of an evaluation for historic significance. Does the property have historic significance and if it does, is it recognizable, depending on the type of significance?

None of those predominately separate actions described as alterations in the Initial Study table or annotated aerials affected the design, location, materials, workmanship, feeling or association of the power plant. Its setting may have changed since it was completed, but its setting in an industrial yard is not as essential to its significance as would the setting of other buildings such as a barn in an open field or adjacent to a barnyard. The subject property remains in a utility yard setting as it has been historically. The additional small buildings and other structures and objects that have been added to the subject property are located on the northwest and southwest,
L16A-1 non-character-defining, secondary and rear sides of the plant as demonstrated in Figure 1.

Figure 1 makes evident the fact that there are no alterations on the façade or northeast side, none are shown on the southeast end wall (a carport was added sometime after 1950 that does not affect its integrity), various small additions on the non-character-defining southwest side and only a ramp was added on the northwest side.[1] Further text will describe why other small changes do not affect its integrity. The building's principal cladding materials remain, its original ribbon, hopper-type and glass block multi-story windows remain, the original metal sign on stand-outs and the distinctive, staggered, horizontal corner fillets remain intact. An experienced architectural historian would have exercised appropriate professional judgment and omitted items that were not alterations that affected the actual resource under consideration. The Grayson Steam-Electric Power Plant structure retains more than adequate integrity to its original design by Daniel A. Elliott, AIA, and remains recognizable.

[1] An "addition to boiler room" at the southwest corner is noted in the Initial Study Figure 15 annotated aerial photographs incorrectly as being added around 1979 (Aerial 4). That small addition is clearly evident in Aerial 2, the 1964 aerial photograph.

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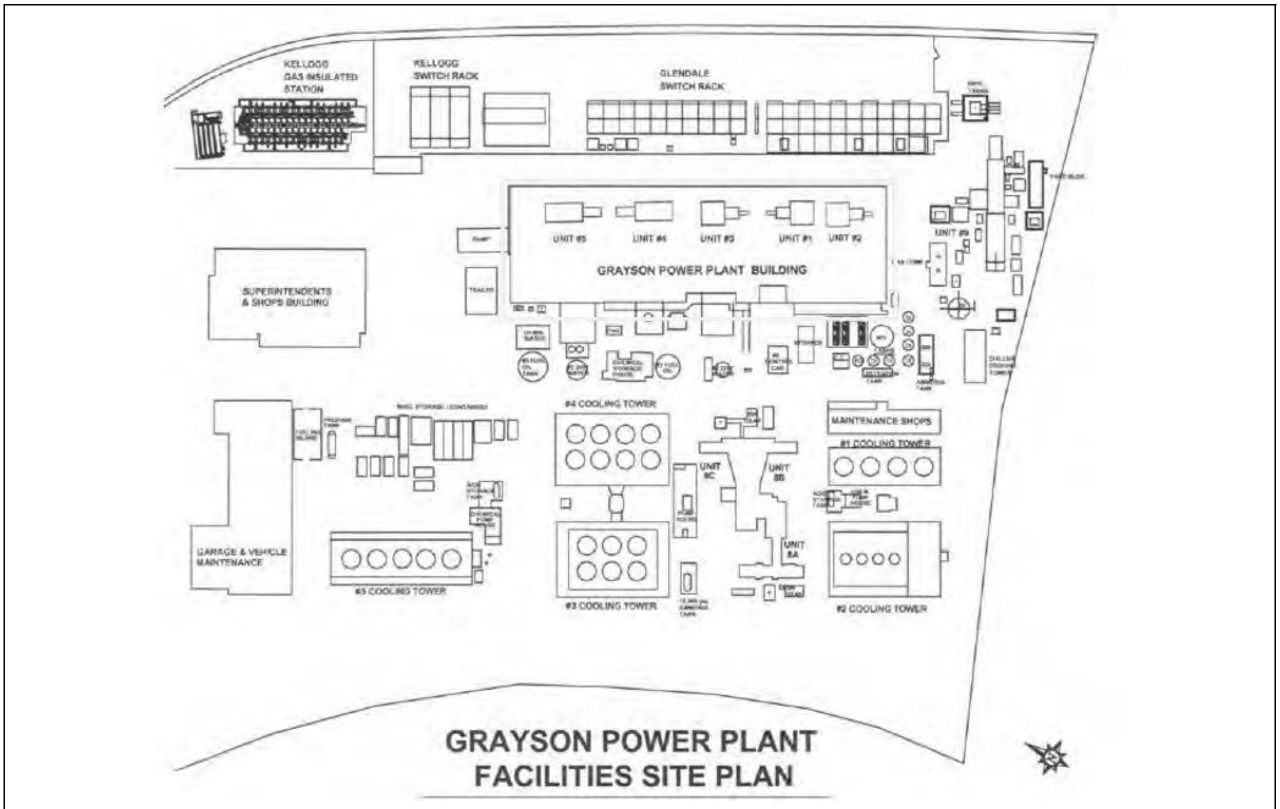

Figure 1: Excerpted and annotated from Architectural Resource Evaluation of The Grayson Power Plant For City of Glendale, California, showing only a ramp and trailer on the northwest (left-hand) side of the main building and various additional facilities at the back or southwest side of the Grayson Steam-Power Plant Building. Note that very few alterations in this figure are connected to the main, Grayson Steam-Power Plant Building, which is highlighted in yellow.

Grayson Steam-Electric Power Plant Significance

The Grayson Steam-Electric Power Plant is significant for its association with the development of the community, for its direct association with Lauren W. Grayson, likely for its Stripped Classicism design, as the work of a master architect, and as the first earthquake-proof power plant. Its integrity of design remains, clearly visible from all but one nearby street, the large, metal and stucco-clad building is visible, and the inventive, original design remains easily distinguishable.

Association with the Development of the Community

The power plant's connection to the development of Glendale is reasonably straightforward and is undeniable. Almost immediately after Glendale's incorporation, locals recognized the importance and costs savings of establishing independent utilities. Once street lighting became an issue, the new city government took action to establish a "light and power" entity, holding a bond election to acquire and construct an electric works system for the city by 1909 (Winston W. Crouch and Beatrice Dinerman, *Southern California Metropolis: A Study of Development of a Government for a Metropolitan Area*, 1964). An expanded distribution service and the establishment of the Glendale Light and Power Company were part of the consequences of that election. Without the existence of the subject property power plant, the community would not have had the necessary utility capacity to grow as it did after the second World War. In 1938, the *Los Angeles Times* substantiated the assertion that the power plant made development of the community possible, reporting "City officials have maintained steadily that there are no available sources of power and that erection of the generating plant is necessary" ("City Officials Deny Charges in Glendale Power Plant Plan" 26 May 1938:14). The resulting power plant was built at an estimated cost of $1.5 million.

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In the two decades spanning its construction, the population of modern Glendale increased by more than 50 percent between 1930 and 1950, from approximately 63,000 to 96,000 (U.S. Census). Neighboring Pasadena and other comparable communities' populations did not grow by nearly as great a percentage as Glendale's unfettered growth during that period. The stratospheric evolution of Glendale as a population and business center was spurred partly by annexation but as much by its increased ability to independently provide inexpensive power to newly expanding and establishing businesses and the thousands of new homes and apartments that were built during that time. That tendency continued "between 1980 and 2000, Glendale grew significantly more than neighboring areas" (City of Glendale, Government Departments, Economic Development, "Great Demographics," "Top 10 Reasons You Want Your Business in Glendale" at http://www.glendaleca.gov/government/departments/glendale-economic-development-corporation-/top-10-reasons-you-want-your-business-in-glendale/analytic-information). Sustaining that trend that was made partly possible by the existence of an independent power source, the population of Glendale soared by nearly 40 percent during that 20-year period, significantly more than any other single city in Los Angeles County and more than the county itself. Without an autonomous power source providing economical electricity, the unbridled population growth and expansion of Glendale after World War II would not have been possible. The power plant shaped that development rather than merely reflecting it. Because of that direct connection between Glendale's growth and the Grayson Steam-Electric Power Plant, it is eligible for listing in the California and Glendale Register under each Criterion 1 for its essential role making the postwar development of the community possible.

Distinctive Stripped Classicism Design, Work of a Master, and Engineering Significance

Stripped Classicism was a twentieth century architectural style that reduced all, or nearly all superfluous ornamentation. It was favored primarily by government agencies for public building designs and was widely used by the Works Progress Administration during the Depression. The style embraced simplified but recognizable classicism in its overall massing, scale and proportions while eliminating traditional decorative detailing.

The significance of the restrained design by architect Daniel Anthony Elliot, A.I.A. for the main building remains plainly visible and recognizable, but it is not adequately explored in the reconnaissance level evaluation. The original, remaining design placed a large amount of equipment inside a metal-clad, deftly stepped shell that articulated a large volume from what could have been an ungainly multi-street block shape into human-scaled units, reducing its apparent mass and creating an elegant solution to what could well be an entirely utilitarian facility. In addition the electrical turbines, which are entirely functional apparatuses used to drive generators to transform mechanical energy into electrical energy by electromagnetic induction, are cloaked in cleverly designed covers that supplement the large scale Stripped Classicism design elements of the facility into smaller units. At least three pencil-drawn renderings were made to demonstrate design alternatives that would camouflage the practical features.

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It would be helpful to reviewers to understand the architect's remarkable career. Elliott was a designer for Gilbert Stanley Underwood, a recognized master architect, between the years 1925 and 1932, was a contributor to the Colorado Aqueduct Project (1932-'41), and was responsible for the designs of various other water and power plants (see "Experience Record," Daniel A. Elliott, AIA, Architect at http://dbase1.lapl.org/webpics/calindex/documents/04/515676.pdf). Elliott designed the Burbank Water & Power Building (1949, 164 W. Magnolia Bl, Burbank) which is a noted example of Late Moderne design, as illustrated by the Los Angeles Conservancy on its website (Explore LA, Historic Places <https://www.laconservancy.org/locations/burbank-water-and-power>). His utility portfolio was described in the "Public Imagery and Its Uses" section of *Los Angeles In the Thirties: 1931-1941*, which is considered an expert source on local architecture during that period (Gebhard and Von Bretton 1989).

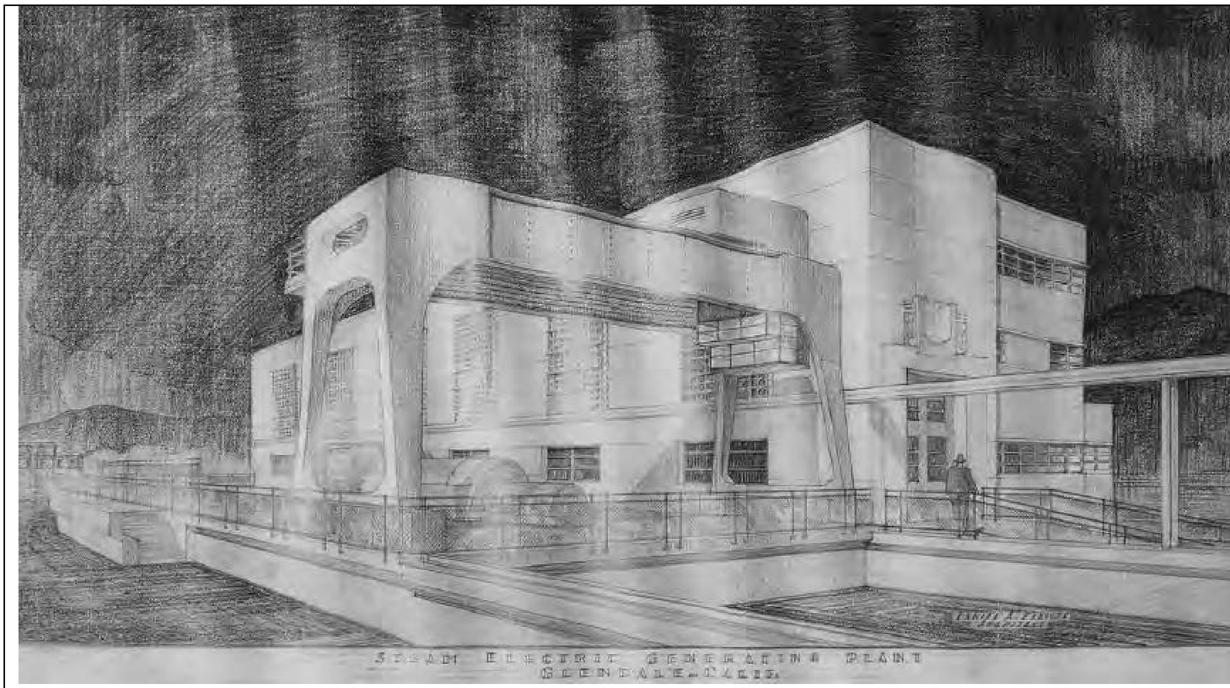

Figure 2: Pencil rendering of Glendale "Steam Electric Generating Plant" by Daniel A. Elliott, AIA excerpted from Initial Study, Architectural Resource Evaluation of The Grayson Power Plant For City of Glendale, California, Figure 9 (page 4.5). Compare with the recent photograph in Figure 3 that shows a series of multi-story, glass block windows in the boiler building portion of the Grayson Steam-Electric Power Plant building. If the crane in the foreground was at the south rather than the north end, the rendering and the power plant as it exists today would appear nearly the same, clearly expressing its distinctive Stripped Classicism design. The design treatment for the endwall in the above rendering was ultimately executed without the cartouche or the inset entrance. It is mistakenly called an "architectural drawing" rather than a rendering in the Initial Study.

The still-recognizable, Stripped Classicism design of the Grayson Steam-Electric Power Plant is understated, exquisitely proportioned, and was undeniably futuristic for its time. The three staggered, green horizontal strokes that wrap around the southeast corner skillfully punctuate the otherwise staid building composition and assert the Modernism of the design. At the north façade, left-justified bronze letters on stand-outs primly identify the facility: "City of Glendale Public Service Department Steam Electric Generating Plant." Most power plans in the 1930s and now have no architectural design, reducing their aesthetic effects on the community, which is part of the significance of the Grayson Steam-Electric Power Plant's design.

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Figure 3: Excerpted, cropped photograph from Initial Study, Architectural Resource Evaluation of The Grayson Power Plant For City of Glendale, California, Figure 18 (page 6.6). View is of the northwest, main façade, no date (estimated 2016). Note the staggered green horizontal bands at the left corner of the tower, the sign at the right side, sets of multi-story, glass block windows of the boiler portion of the building, original, riveted "Cyclops" crane at left foreground and Units 3, 2 and 1 (left-to-right) in the foreground. The turbine covers for Units 1-3 have radiused roof-wall connections on the main volumes at each endwall, modulating the appearances of otherwise entirely utilitarian structures. Double fillet bands wrap around their lower cornices and corners, emphasizing the carefully expressed scale and proportion.

At the cornice of the boiler building, a simple, dimensioned band interposes the roof-wall junctions. The band motif is repeated in pairs on the turbine covers for Units 1-3, the small, utilitarian structures in the foreground of the main elevation (Figure 3). In the design for the Grayson Steam-Electric Power Plant, different volumes are manipulated using varying scale and proportion strategies. The factory-painted, metal exterior of the main tower is clad in small rectangles that together form a grid. The lower, "Boiler Building" main portion of the plant is has a stucco-finished exterior divided by stacked horizontal scoring lines. The turbine covers for Units 1-5 are painted metal, single-story housings with curved ends and lower, filleted endwalls. The Initial Study cultural resources evaluation mistakenly identified the exterior metal panel material as asbestos, which is likely incorrect as well as needlessly alarming (Figure 20, 6.7). Nearly 15 years after its completion, the unique exterior shell on the turbine covers at Glendale Power Plant was described in *Power Plant Management,* "the housing is fabricated of steel and is lifted in a piece from over the turbine- generator"(Robert Henderson Emerick, 1955). We assert that the Stripped Classicism design of the power plant is an outstanding example of a rare

L16A-1 type of architecture, the architect-designed power plant. The Stripped Classicism design should be considered the work of a master architect, Daniel A. Elliot, AIA (1898-1978). California Register Criterion 3 includes properties that "…represent… the work of an important creative individual." The Grayson Steam-Electric Power Plant is eligible for listing in the California and Glendale Registers under both Criteria 3 for Stripped Classicism design and as the work of a master architect.The subject property is further significant for its engineering and construction methods. The Grayson Steam-Electric Power Plant was described in the *Los Angeles Times* as "the world's first completely earthquake-proof … plant… Among its unique features is the location of the huge turbo-generator on an uncovered deck… the only building is a shell built of light steel and stucco filter walls that will more or less cover the unsightly appearance of boilers."[2] R.R. Martel, a Caltech professor and widely recognized international authority on seismic engineering collaborated on the design. Martel (1890-1965) was among the first engineers in the nation to concentrate on earthquake-resistant buildings and is considered the first in California.[3] He was one of two founders of the Earthquake Engineering Research Institute, an independent, nonprofit organization which was established "to promote research on safe and economical earthquake resistant structures" worldwide and continues to thrive, providing that service on an international scale to this day.

Its earthquake-proof structure was prescient for the late 1930s. An engineering periodical by the Earthquake Engineering Research Institute focused on seismic safety. "Earthquake Spectra: The Professional Journal of the Earthquake Engineering Research Institute" ran numerous articles specifically describing earthquake-related damage to power plants in the greater Los Angeles area fifty years later, between 1987 and 1994. While Glendale's Power Plant is listed in data and tables with plants that sustained significant damage, no damage to Grayson Steam-Electric Power Plant from those events is enumerated. Similarly, "Seismic Experience Data--Nuclear And Other Plants: Proceedings Of A Session," prepared by the American Society of Civil Engineers, describes Glendale's Power Plant remaining "on-line" during the 1971 earthquake, despite its proximity to Sylmar, which was considered the epicenter (1985). We are not saying the subject property building can withstand all earthquakes; in the past it demonstrated superior seismic strength compared to its peers in the Los Angeles area. The Grayson Steam-Electric Power Plant was designed to be "earthquake-proof" before any other facilities of its type were, which is overridingly consequential in California engineering. The property possesses significance as the earliest known example of an earthquake-proof power plant in California or anywhere else.

Both the California and the local register recognize construction and engineering innovation. California Register Criterion 3 states "It embodies the distinctive characteristics of a type, period, region, or *method of construction*; represents the work of an important creative individual." The Grayson Steam-Electric Power Plant is eligible for listing in the California and Glendale Registers under each Criteria 3 for its method of early earthquake proof construction. None of those avenues of its significance was addressed in the reconnaissance level survey prepared for the Grayson Steam-Electric Power Plant.

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[2] "Power Plant Built In Open: Glendale Will Have First Completely Quake-Proof Setup." *Los Angeles Times*. June 30, 1940: A10.

[3] "R. R. Martel, Professor of Structural Engineering Staff" *Engineering and Science*, Volume 19, 1956: 22-24.

<u>Direct Association with Lauren W. Grayson</u>

The significance of Chief Engineer and General Manager Lauren W. Grayson (1907-1972) is also not adequately evaluated. When Grayson retired in 1970, he had served the city for nearly two decades and expanded water and power capacity by 400 percent and the budget by an even higher percentage during his tenure ("Public Services Head in Glendale to Retire" *Los Angeles Times.* 25 January, 1970: SG-B2). The visionary civil servant was responsible for bringing together other agencies for collaboration in the northwest. That joint power alliance was considered monumental in the field, and brought electrical capacity diversification, as well as lower costs, to Glendale-based users. He oversaw both water and power utilities, constantly interpreting and planning for future community needs.

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Lauren Grayson was responsible for the addition of cleaner technologies, including a steam-electric generating unit (1965) and the nation's first gas turbine peaking unit in his final year. Grayson served as president of American Water Works and California Municipal Utilities associations and was elected American Water Works Man of the Year (1959). He was considered a national leading authority on public utilities and delivered academic papers on a wide variety of utility-based subjects throughout his career. Grayson was published on subjects ranging from visionary long-range planning to the unique needs of car wash and drive-in usage in a number of national and regional industry periodicals, including *The American City*, *Engineering News & Record*, *Western City* and *Aqueduct News*. Under his leadership, Glendale was one of the first local communities to require subterranean power lines. The *Times* succinctly described his career at retirement as an "outstanding achievement in the field of water and power" (Don Snyder "Glendale Official: Public Service Chief to End Long Career" *Los Angeles Times.* 6 July 1970:B9). The Power Plant was named in his honor in 1972. Mr. Grayson lived in Glendale after 1951 was buried at Forest Lawn. The Grayson Steam-Electric Power Plant is eligible for listing in the California and Glendale Registers under each Criteria 2 for its direct association with Lauren W. Grayson during his period of significant, local utility-related achievements.

The period of significance of the Grayson Steam-Electric Power Plant commenced in 1941 when it was completed and ended in 1970, when Loren W. Grayson retired. Neither the California nor the Glendale Register has requirements that a property be completed more than 50 years ago. For the purposes of National Register eligibility, the period of significance would end in 1967, because it does not meet the requirements in Criterion Consideration G for properties that have achieved exceptional significance in the past 50 years.

Because the California Register Technical Assistance Bulletin 7 is currently under review for updates and revisions, there is no current state guidance for nominating California Register properties and National Register of Historic Places guidance is used in its place. In the National Park Service-prepared National Register Bulletin "How to Prepare the National Register Criteria for Evaluation," under "Determining the Relevant Aspects of Integrity" for properties associated with important events or persons it states:

> A property important for association with an event, historical pattern, or person(s) ideally might retain *some* features of all seven aspects of integrity: location, design, setting, materials, workmanship, feeling, and association. *Integrity of design and workmanship, however, might not be as important to the significance,* and would not be relevant if the property were a site. A basic integrity test for a property associated with an important

event or person is whether a historical contemporary would recognize the property as it exists today.

Grayson Steam-Electric Power Plant retains integrity to its location. The building remains on the original site where it was completed in 1941. The power plant building's original Stripped Classicism design is intact, the painted stucco walls and metal panels that camouflage day-to-day operations of the facility, including the three staggered, green bands that wrap around the southeast corner and original signage, are visible and recognizable to the general public from the public right of way. Its setting in an essentially flat yard among other large utility apparatuses has changed over time, reflecting upgrades, increases in capacity, and new technologies, but
L16A-1 continues to be the basic, recognizable surroundings of a power plant. Its distinctive painted metal and stucco exterior materials endure, as do other visible elements from its original design including multi-story glass block banks of windows, awning-type steel sash windows, decorative fillets, metal sign letters, decorative turbine covers and the essential building configuration. The condition of those materials reflect the passage of 77 years, as should be expected. The fit, finish and connections of those original materials remains impeccable, revealing its inventive, Depression-era workmanship. Because the other aspects of integrity remain intact, the feeling and associations of the Grayson Steam-Electric Power Plant, while somewhat reduced by the additions of new outbuildings and facilities, remains. The property maintains its original, intended use, and judging by publicly visible portions of the building, it retains essential qualities that evoke the aesthetic and historic senses it would have had in 1941 when it was completed.

National Register guidance clearly states "A property that has lost some historic materials or details can be eligible *if* it retains the majority of the features that illustrate its style in terms of the massing, spatial relationships, proportion, pattern of windows and doors, texture of materials, and ornamentation." The Grayson Steam-Electric Power Plant retains its original inventive massing, its essential spatial relationship with the larger yard, the carefully designed proportions, the original, visible, main fenestration, the textures of painted metal, stucco and other materials and its distinctive, austere ornamentation (Figures 2-5)

The improperly prepared evaluation for historic significance in the Initial Study expended an inordinate amount of research to justify the misguided point that the power plant has impaired integrity because of alterations. The architect-designed power plant is the resource in question- not the not the entire surrounding yard. The Initial Study ardently describes the addition of switching yards, additional units, cooling tanks and towers, sheds, a warehouse, storage buildings and a garage which are not connected to the Grayson Power Plant and are immaterial to the evaluation of the building. Those non-contributing features comprise the setting of the subject property and do not affect its integrity or significance. To the average reader, hurrying through the document to achieve a basic understanding, their assertion that the power plant is not historically significant would seem well justified. Professionally qualified reviewers who are experienced as performing such evaluations arrive at entirely different conclusions as described in this letter.

We assert that if Lauren W. Grayson, for whom the property was named, were able to see the subject property today, he would plainly recognize the Grayson Steam-Electric Power Plant. Whether or not a person associated with the property during its period of significance would find it recognizable is among the National Register thresholds for integrity. It remains clearly recognizable to its original appearance. The addition of buildings, cooling towers, fuel tanks and other equipment is typical of and are necessities to continuously operating a power plant,

particularly in a community where its existence made population growth possible. It can be assumed that no public power plant dating from 1941 that remains in operation would be devoid of any alterations made since its completion. Keeping up with requirements, particularly those for life safety, requires inevitable alterations to buildings and structures. Comparison between
L16A-1 the photographs in Figures 3 and 4 as well as others validates that the building is absolutely recognizable to its original design, and claims of its loss of integrity are exaggerated and not based in facts.

L16A-1

Figure 4: Grayson Steam-Power Plant Building, view northwest of south endwall, circa 1950s. Source: https://commons.wikimedia.org/wiki/File:Grayson_Power_Plant.jpg, not for publication.

Figure 5: Excerpt from Initial Study, Architectural Resource Evaluation Of The Grayson Power Plant For City of Glendale, California, undated photograph estimated 2016, (Figure 26 Grayson Boiler Building page 6.10, same view as Figure 4 above). Note all visible awning-type, steel sash windows, exterior materials, the building configuration and Stripped Classicist design remain recognizable. Carport at lower center is an addition (year unknown). Note the stucco scoring bands at the right-hand boiler building tower and the dimensioned continuous sill and header on the left-hand bank of ribbon windows that enunciate the endwalls, providing visual interest and relief. Other than the carport, no alterations are visible.

L16A-1 A brief review of National Register-listed power plants in the United States revealed that all remaining in use contain non-contributing buildings and structures and that nearly all of the main buildings had been altered.[4] In Pasadena, the Glenarm Power Plant was determined eligible for the National Register for its associative and design significance, despite hundreds of alterations made to the building and larger power plant complex over time and numerous changes to the building since it was completed in 1928. The very visible, east facing, rear side of the Glenarm Power Plant is entirely concealed by alterations made in the past 20 years. Comparison against like types is one of many tests for significance and the Grayson Steam-Power Plant stacks up favorably against its significant peers in terms of it importance to the development of the community, its design significance, and its retention of integrity. We believe that the Grayson Steam-Electric Power Plant is eligible for listing in the National Register as well as the California and local registers, but the property is not publicly accessible to make site visits and perform a complete, intensive evaluation of its significance.

Previously Recorded Resources

In the Initial Study, the preparers included a list of "previously recorded" built environment resources, mistakenly applying what is normally archaeological methodology to the built environment. Not only does the section not inform the evaluation, it demonstrates their misunderstanding of the task. The absence or presence of built environment resources within a half a mile is not a predicator as it can be in archaeology, of whether or not built environment resources can be expected to be encountered. Moreover, the list provided does not enumerate whether or not the studied properties were found to be significant or not, rendering it even less useful.

The only "previously recorded resources" that should be considered in this evaluation would be on the subject property (including any previous evaluations), or would be other power plants against which this property should rightly have been compared. See National Register guidance on "Comparing Similar Properties" in "VIII. How to Evaluate The Integrity of A Property" (National Park Service, "How to Apply the National Register Criteria For Evaluation")

Conclusion

CEQA strongly encourages early consultation with interested or affected parties, which includes local historic advocacy groups. No consultation efforts were made with TGHS. We were asked for information early in the process but have not otherwise been consulted on the project.

Predicated on the facts and issues presented above, TGHS believes that the Grayson Steam-Electric Power Plant must be re-evaluated for historic significance in a supplementary document and that the Cultural Resources section of the environmental document must be revised to reflect a good faith and more reasoned analysis of the property's historic significance. We have presented "substantial evidence" for the lead agency to change its conclusion and find that the Grayson Steam-Eclectic Power Plant building is a historical resource for the purposes of CEQA.

[4] National Register-listed power plants include: Adams Power Plant Transformer House (Niagara Falls, NY); American Falls Power Plant Transformer House (American Falls, IA); Moran Municipal Generating Station (Burlington, VT); Murray City Diesel Power Plant (Murray City, UT); Pratt Street Power Plant (Baltimore, MD); Power Plant No. 1 (McPherson, KS); Seaholm Power Plant (Austin, TX) and Spaulding Power Plant and Dam (Greely City, NB). The Adams Power Plant Transformer House is no longer is use; its contributing buildings are notably no longer extant. Seaholm Power Plant contained a non-contributing structure when it was listed in the National Register. It has since been redeveloped and is no longer used as a power plant.

Thank you for your consideration.

Sincerely,

Greg Grammer

President
The Glendale Historical Society

cc: Jay Platt

L17

From: Alina Mullins
To: Krause, Erik
Cc: Lijin Sun
Subject: South Coast AQMD Staff"s Comments on PR-DEIR for the Proposed Grayson Repowering Project (SCH No.: 2016121048)
Date: Friday, November 12, 2021 7:26:07 AM
Attachments: LAC210819-11 PR-DEIR Grayson Repowering Project_20211112.pdf

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CAUTION: This email was delivered from the Internet. Do not click links, open attachments, or reply if you are unsure as to the sender.

Dear Mr. Krause,

L17-1 Attached are South Coast AQMD staff's comments on the Partially Recirculated Draft Environmental Impact Report (PR-DEIR) for the Proposed Grayson Repowering Project (SCH No.: 2016121048) (South Coast AQMD Control Number: LAC210819-11). Please contact me if you have any questions regarding these comments.

Thank you,

Alina Mullins
Air Quality Specialist, CEQA IGR
Planning, Rule Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765
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**Please note that South Coast AQMD is closed on Mondays. Additionally, in response to COVID-19, our building is currently closed to the public and I am working remotely. I will be responding to emails and voice messages during my scheduled work hours, Tuesday through Friday 7:00 am to 5:30 pm.*

South Coast
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SENT VIA E-MAIL: November 12, 2021
ekrause@glendaleca.gov
Erik Krause, Deputy Director
City of Glendale, Community Development Department
633 East Broadway, Suite 103
Glendale, California 91206

Partially Recirculated Draft Environmental Impact Report (PR-Draft EIR) for the Grayson Repowering Project (Proposed Project) (SCH No.: 2016121048)

L17-2

South Coast Air Quality Management District (South Coast AQMD) staff appreciates the opportunity to comment on the above-mentioned document. The City of Glendale (referred to alternatively as "the City") is the California Environmental Quality Act (CEQA) Lead Agency and in September 2017 put forward a Draft EIR for the original repowering project, which involved removal of 238 megawatts (MW) gross (219 MW net) of existing generation equipment and replacement with approximately 270 MW gross (262 MW net) equipment. The Draft EIR also identified and evaluated five alternatives (Alternatives 1 through 5) to the original repowering project. In April 2018, the Glendale City Council considered a Final EIR for the original repowering project and the five alternatives but did not certify it, instead directing Glendale Department of Water and Power to consider greener alternatives as part of the repowering project[1]. In August 2021, the City released a PR-Draft EIR for public review and comments.

L17-3

South Coast AQMD Staff's Summary of the Project Information in the PR-Draft EIR

Based on the PR-Draft EIR, Alternatives 7 and 8 are new alternatives. Alternative 7 consists of replacement of the existing generation units with exception of the gas turbine Unit 9, which was built in 2003, with five identical reciprocating internal combustion engine (RICE) units producing approximately 93 MW net at average annual site conditions, and a battery energy storage system (BESS) providing 75 MW/300 megawatt-hour (MWH) of power and energy[1]. Alternative 8 consists of refurbishment and retrofitting of existing generation units Unit 8A and Unit 8B/8C and a 75 MW/300 MWH BESS[2]. The generating capability of Alternative 8 is anticipated to total 101 MW[3]. Alternative 6, which was identical to Alternative 7 but had a different layout configuration, is rejected as infeasible due to physical limitations.

L17-4

South Coast AQMD is a Responsible Agency for the Proposed Project (CEQA Guidelines Section 15381) since implementation of the Proposed Project requires permits from South Coast AQMD. South Coast AQMD received five permit applications [Application Numbers (A/Ns): 621976, 621977, 621978, 621979, and 621980] for each of the RICE units under Alternative 7, and three permit applications (A/Ns: 631261, 631262, and 631263) for refurbishing and

[1] *Ibid*. Page xxi.
[2] *Ibid*.
[3] Chapter 5 Alternatives Page 5.53.

L17-4 retrofitting the existing natural gas turbines 8A and 8B/8C under Alternative 8 (South Coast AQMD Facility ID No.: 800327).

South Coast AQMD Staff's Comments on the PR-Draft EIR

L17-5 Based on a review of the PR-Draft EIR and technical appendices, South Coast AQMD staff found that the Lead Agency calculated Alternative 7's criteria pollutants emissions based on an annual schedule of 1,260 total operating hours[4]. The criteria pollutants emissions inventory for Alternative 8 was based on a monthly schedule of 250 operating hours and an annual schedule 1,200 operating hours[5]. The operating schedule is a critical underlying assumption that went into calculating the criteria pollutants emissions for Alternatives 7 and 8. However, no information was provided in the PR-Draft EIR on this underlying assumption, and no mitigation measure or project condition was included in the PR-Draft EIR that would limit the operating hours at the Proposed Project. Because there is a direct nexus between the operating schedule and the amount of criteria pollutants emissions, the Lead Agency should provide additional information in the Final EIR as substantial evidence to support that the operating hours used in the air quality analysis for Alternatives 7 and 8 were appropriate. If it is reasonably foreseeable that Alternatives 7 and 8 could potentially have greater operating hours than those used in the air quality analysis in the PR-Draft EIR, the Lead Agency should re-evaluate the air quality impacts based on the greater operating hours in the Final EIR. It is important to note that the assumptions in the air quality analysis in the Final EIR will be used as the basis for evaluating the permits under CEQA and imposing permit conditions and limits.

Conclusion

L17-6 Pursuant to California Public Resources Code Section 21092.5(a) and CEQA Guidelines Section 15088(b), South Coast AQMD staff requests that the Lead Agency provide South Coast AQMD staff with written responses to all comments contained herein prior to the certification of the Final EIR. In addition, issues raised in the comments should be addressed in detail giving reasons why specific comments and suggestions are not accepted. There should be good faith, reasoned analysis in response. Conclusory statements unsupported by factual information will not suffice (CEQA Guidelines Section 15088(c)). Conclusory statements do not facilitate the purpose and goal of CEQA on public disclosure and are not meaningful, informative, or useful to decision makers and to the public who are interested in the Proposed Project. South Coast AQMD staff is available to work with the Lead Agency to address any air quality questions that may arise from this comment letter. Please contact Alina Mullins, Air Quality Specialist, at amullins@aqmd.gov, should you have any questions or wish to discuss the comments.

Sincerely,

Lijin Sun

Lijin Sun
Program Supervisor, CEQA IGR
Planning, Rule Development & Area Sources

RC/LC/CA/LS:AM
LAC210819-11
Control Number

[4] *Ibid*. Appendix C.1 Table B-4. PDF page 483.
[5] *Ibid*. Appendix C.2 PDF pages 597 and 598.

L18

From: Zarah Patriana
To: Devine, Paula; Agajanian, Vrej; Brotman, Daniel; Kassakhian, Ardashes; Najarian, Ara
Cc: Krause, Erik
Subject: RE: Comments opposing the Grayson gas-powered plan
Date: Friday, November 12, 2021 12:41:00 PM
Attachments: Earthjustice_GraysonLetter.pdf
Earthjustice_GraysonComments.csv

CAUTION: This email was delivered from the Internet. Do not click links, open attachments, or reply if you are unsure as to the sender.

L18-1

Dear Mayor Paula Devine, Councilmember Agajanian, Councilmember Brotman, Councilmember Kassakhian, and Councilmember Najarian,

I am writing to you on behalf of Earthjustice to submit comments from our supporters opposing the Grayson gas-fired power plant. Attached is the PDF of the letter (text also below) along with a .csv file containing the names of Glendale residents signed on to the letter. Please let me know if you have any follow up question and thank you for letting us submit comments before your Council meeting.

L18-2

As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plant when we should be transitioning to clean energy alternatives instead.

L18-3

Thousands of people live and work directly within the Grayson project's impact zone – schools, daycares, homes for the elderly, and work offices. Glendale's air quality is already terrible – it's time to invest in an energy grid that can turn that around.

L18-4

Furthermore, Glendale does not urgently need the power from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand using clean energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need.

L18-5

We have the means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across California are ditching fossil fuel power, and we can too. It's time for Glendale to step into a clean air, clean energy future.

Sincerely,
The Undersigned

____

Zarah Patriana (she/her)
Sr. Digital Advocacy Manager

50 California St., Suite 500
San Francisco, CA 94111
T: 415.217.2129
F: 415.217.2040
earthjustice.org

facebook.com/earthjustice
twitter.com/earthjustice

EARTHJUSTICE

Because the earth needs a good lawyer

EARTHJUSTICE

ALASKA CALIFORNIA FLORIDA MID-PACIFIC NORTHEAST NORTHERN ROCKIES
NORTHWEST ROCKY MOUNTAIN WASHINGTON, D.C. INTERNATIONAL

November 12, 2021

Glendale City Council
613 E. Broadway,
Glendale, CA 91206

This letter accompanies the names of 22 individuals who have submitted public comments to the Glendale City Council opposing the Grayson gas-fired power plant.

Re: Stop Glendale from being the last city in CA powered by gas

Dear Mayor Paula Devine, Councilmember Agajanian, Councilmember Brotman, Councilmember Kassakhian, and Councilmember Najarian:

L18-6

As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plant when we should be transitioning to clean energy alternatives instead.

Thousands of people live and work directly within the Grayson project's impact zone – schools, daycares, homes for the elderly, and work offices. Glendale's air quality is already terrible – it's time to invest in an energy grid that can turn that around.

Furthermore, Glendale does not urgently need the power from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand using clean energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need.

We have the means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across California are ditching fossil fuel power, and we can too. It's time for Glendale to step into a clean air, clean energy future.

Sincerely,

The Undersigned

L18-7

Supporter Name	Supporter City	Supporter State/Province	Message Text
Hedge, Joanne	Glendale	CA	As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people--including myself, a senior, and Rancho neighbors, just upriver from Grayson, live and work d within the Grayson project's impact zone – schools, daycares, homes for the elderly, and work offices. Glendale's air quality is already terrible – it's time to invest in an energy g turn that around. Furthermore, Glendale does not urgently need the power from this project. Even without Grayson, the City has enough energy to cover our daily needs a vas the time. We can meet our increased summertime demand using clean energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and G residents paying for) way more electricity than we need. We have the means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that w families and our checkbooks for decades. Cities across California are ditching fossil fuel power, and we can too. It's time for Glendale to step into a clean air, clean energy future
Cooper, Carole	Glendale	CA	As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. This power facility is not necessary. Step up City Council a project. Please reject plans to rebuild the Grayson gas power plant when we should be transitioning to clean energy alternatives instead. Thousands of people live and work d the Grayson project's impact zone – schools, daycares, homes for the elderly, and work offices. Glendale's air quality is already terrible – it's time to invest in an energy grid tha that around. Furthermore, Glendale does not urgently need the power from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast ma time. We can meet our increased summertime demand using clean energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glen residents paying for) way more electricity than we need. We have the means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that w families and our checkbooks for decades. Cities across California are ditching fossil fuel power, and we can too. It's time for Glendale to step into a clean air, clean energy future
Meyer, Tricia	Glendale	CA	As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project's impact zone – schools, daycares, homes f elderly, and work offices. Glendale's air quality is already terrible – it's time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It's time for Glendale to step into a clean air, clean energy future.
Levine, David	Glendale	CA	As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project's impact zone – schools, daycares, homes f elderly, and work offices. Glendale's air quality is already terrible – it's time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It's time for Glendale to step into a clean air, clean energy future.
Khanlian, Marco M.	La Crescenta	CA	As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project's impact zone – schools, daycares, homes f elderly, and work offices. Glendale's air quality is already terrible – it's time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It's time for Glendale to step into a clean air, clean energy future.
Leath, Jan	Glendale	CA	As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project's impact zone – schools, daycares, homes f elderly, and work offices. Glendale's air quality is already terrible – it's time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It's time for Glendale to step into a clean air, clean energy future.

L18-7

Goldberg, Susan	Glendale	CA	As a Glendale resident, I’m writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project’s impact zone – schools, daycares, homes f elderly, and work offices. Glendale’s air quality is already terrible – it’s time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let’s not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It’s time for Glendale to step into a clean air, clean energy future.
Sulatycky, Annemarie	Glendale	CA	As a Glendale resident, I’m writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project’s impact zone – schools, daycares, homes f elderly, and work offices. Glendale’s air quality is already terrible – it’s time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let’s not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It’s time for Glendale to step into a clean air, clean energy future.
Zachary, Thomas	La Crescenta	CA	As a Glendale resident, I’m writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project’s impact zone – schools, daycares, homes f elderly, and work offices. Glendale’s air quality is already terrible – it’s time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let’s not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It’s time for Glendale to step into a clean air, clean energy future.
Vaughan, Carolyn	Glendale	CA	As a Glendale resident, I’m writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project’s impact zone – schools, daycares, homes f elderly, and work offices. Glendale’s air quality is already terrible – it’s time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let’s not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It’s time for Glendale to step into a clean air, clean energy future.
Licht, Fred	La Crescenta	CA	As a Glendale resident, I’m writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project’s impact zone – schools, daycares, homes f elderly, and work offices. Glendale’s air quality is already terrible – it’s time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let’s not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It’s time for Glendale to step into a clean air, clean energy future.
Gatsby, Michelle	Glendale	CA	As a Glendale resident, I’m writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project’s impact zone – schools, daycares, homes f elderly, and work offices. Glendale’s air quality is already terrible – it’s time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let’s not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It’s time for Glendale to step into a clean air, clean energy future.

L18-7

Schilling, Christy	Glendale	CA	As a Glendale resident, I’m writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project’s impact zone – schools, daycares, homes f elderly, and work offices. Glendale’s air quality is already terrible – it’s time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let’s not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It’s time for Glendale to step into a clean air, clean energy future.
Smith, Claire	Redondo Beach	CA	As a Glendale resident, I’m writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project’s impact zone – schools, daycares, homes f elderly, and work offices. Glendale’s air quality is already terrible – it’s time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let’s not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It’s time for Glendale to step into a clean air, clean energy future.
Schumacher, Tim	Glendale	CA	As a Glendale resident, I’m writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project’s impact zone – schools, daycares, homes f elderly, and work offices. Glendale’s air quality is already terrible – it’s time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let’s not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It’s time for Glendale to step into a clean air, clean energy future.
Maksoudian, Arax	Glendale	CA	As a Glendale resident, I’m writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project’s impact zone – schools, daycares, homes f elderly, and work offices. Glendale’s air quality is already terrible – it’s time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let’s not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It’s time for Glendale to step into a clean air, clean energy future.
Jonkey, Barbara	Glendale	CA	As a Glendale resident, I’m writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project’s impact zone – schools, daycares, homes f elderly, and work offices. Glendale’s air quality is already terrible – it’s time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let’s not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It’s time for Glendale to step into a clean air, clean energy future.
Hull, Bettie	Glendale	CA	As a Glendale resident, I’m writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project’s impact zone – schools, daycares, homes f elderly, and work offices. Glendale’s air quality is already terrible – it’s time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let’s not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It’s time for Glendale to step into a clean air, clean energy future.

L18-7

poland, Barbara	La Crescenta	CA	As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project's impact zone – schools, daycares, homes f elderly, and work offices. Glendale's air quality is already terrible – it's time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It's time for Glendale to step into a clean air, clean energy future.
Gatsby, Michelle	Glendale	CA	As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project's impact zone – schools, daycares, homes f elderly, and work offices. Glendale's air quality is already terrible – it's time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It's time for Glendale to step into a clean air, clean energy future.
Hall, Christopher	Glendale	CA	As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project's impact zone – schools, daycares, homes f elderly, and work offices. Glendale's air quality is already terrible – it's time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It's time for Glendale to step into a clean air, clean energy future.
Drucker, Janet	Glendale	CA	As a Glendale resident, I'm writing to express my strong opposition to a new gas-fired power plant in our community. Please reject plans to rebuild the Grayson gas power plan should be transitioning to clean energy alternatives instead. Thousands of people live and work directly within the Grayson project's impact zone – schools, daycares, homes f elderly, and work offices. Glendale's air quality is already terrible – it's time to invest in an energy grid that can turn that around. Furthermore, Glendale does not urgently nee from this project. Even without Grayson, the City has enough energy to cover our daily needs a vast majority of the time. We can meet our increased summertime demand usi energy -- just like other communities in California. The Grayson project leaves Glendale sitting on (and Glendale residents paying for) way more electricity than we need. We h means to power our city with renewable energy. Let's not tie ourselves to fossil fuel infrastructure that will harm our families and our checkbooks for decades. Cities across Cal ditching fossil fuel power, and we can too. It's time for Glendale to step into a clean air, clean energy future.

L19

From: Jackie Gish
To: Krause, Erik
Subject: Grayson Repowering Project PR-DEIR
Date: Saturday, November 13, 2021 10:25:51 PM
Attachments: Comments on Grayson Repowering PRDEIR.docx

CAUTION: This email was delivered from the Internet. Do not click links, open attachments, or reply if you are unsure as to the sender.

Dear Mr. Krause,

L19-1 Please find attached my comments on the Grayson Repowering PR-DEIR.

Thank you for collecting the comments.

Jackie Gish

Comments on Partially Recirculated DEIR for Grayson Repowering Project

L19-2 I have a number of questions/comments on the air quality baseline in the PRDEIR (see table on the next page for comparisons):

- Where do the numbers for the Total Updated 2018 Baseline Emissions in Table 5-2 come from (they are the same as ones on page 599 Alternative 8 Baseline Emission Inventory, but does not say where they come from either other than "based on" SCAQMD AER 2018)? Are they the criteria pollutants in tons/year for 2018 from the AQMD website for ID # 800327 https://xappprod.aqmd.gov/find without unit #9? If so, what are the unit #9 numbers and hours?

L19-3
- Table E-2 on page 572 for 2016/2017 is what the document wants to use as a baseline for another comparison. So, I have included that in the table below as well.
- I also included the yearly emissions for 2019, which likely includes unit #9. Can you tell me the emissions for unit # 9 in 2019?

L19-4 The table below compares the numbers in various places in the PRDEIR and AQMD website. All units are tons/year.

I have also subtracted the pollution due to LFG for the entries which stated the emissions due to the LFG because the LFG emissions are counted toward the Biogas Renewable (Scholl Canyon) Project and should not be included in the baseline emissions for the project alternatives (these are the rows in green). This is the same reasoning as is on page 623 of the PDF, Alternative 8 Emission Inventory, GHG Emissions – where the "GHG emissions due to landfill gas are excluded as baseline emissions in the Alternative 8 because these emissions are counted toward Biogas Renewable (Scholl Canyon) Project."

L19-5

	NOx	CO	PM	VOC	SOx
Table E-2, page 572 of PDF for 2016/2017	28.3	55.3	13.4	8.7	2.0
Table E-2, page 572 of PDF for 2016/2017 **without any of pollution due to LFG**	16.4	46.8	3.9	4.0	0.3
Alternative 8 Baseline emission inventory page 599 of the PDF for 2015/2016 (same as Table 5-2, page 155)	29.9	67	15	12	2.2
Alternative 8 Baseline emission inventory page 599 for 2015/2016 **without any of the pollution due to LFG**	17.8	57.7	4.9	6.8	0.3
Criteria Pollutants from AQMD website for 2018 (includes unit # 9?)	31.1	59.3	17.3	6.3	1.1
Alternative 8 Baseline emission inventory page 599 of the PDF for 2018 (same as Table 5-2)	28.5	56.9	8.6	6.1	1.0
Alternative 8 Baseline emission inventory page 599 for 2018 **without any of the pollution due to LFG**	23.9	56.1	5.3	4.4	0.4
Criteria Pollutants from AQMD website for 2019 (includes unit # 9?)	15.6	43.8	8.6	3.8	0.4
Emissions from Tesla/Wartsila Repowering project Alternative Emission Units, assumes 1200 hours of operation/year (table 5-2)	8.2	13.9	5.0	8.4	0.4
If Tesla/Wartsila Repowering project was run ½ time (4380 hrs)	29.9	50.8	18.3	30.7	1.5

L19-6

By comparing the emissions from Tesla/Wartsila Repowering Project Alternative Emission Units (row in yellow) to the three entries in the table above **which exclude emissions from LFG** (the entries in green), one sees that:

- The Tesla/Wartsila Alternative **has more VOC emissions** than all of the various comparisons (including the 2015/2016, 2016/2017 and the 2018 comparisons and even 2019 which may include unit #9)
- The Tesla/Wartsila Alternative **has comparable or more PM emissions** than the 2015/2016 and 2016/2017 comparisons and slightly less than the 2018 comparison

L19-6

- The Tesla/Wartsila Alternative **has more SOx emissions** than the 2015/2016 and 2016/2017 comparisons and the same as the 2018 comparison
- The Tesla/Wartsila Alternative has less NOx and CO emissions than all of the various comparisons
- I put the AQMD numbers for 2019 on the chart as well, but they likely include unit #9. What are the pollution numbers for unit #9 in 2019? How many hours were the various boilers and turbines operated in 2019? What was the MWh for 2019 for the equipment without unit #9?
- The main reason that the project numbers are less than prior year emissions is that there is an assumption that the units are only operated 1200 hours (about 14% of the time). I just scaled the number of hours to see how the emissions would be if the engines ran ½ time. They exceed the emissions for the non-LFG numbers for all years and all pollutants except for CO. And, the differences for VOC and PM 2.5 may exceed AQMD significance levels and for NOx it may also exceed significance levels depending upon the baseline is chosen. What is the threshold of significance for the pollutants?

L19-7

It is not obvious to me what would be a fair baseline for the Grayson Repowering project. Perhaps a fair baseline would be a year that generated similar MWh (93 MW x 1200 hours = 112,000 MWh is what Alternative 7 would be). Is 2019 in the ballpark fair? And, 2019 is more recent data and does not include any LFG at all. In any event, no LFG should be used in the baseline numbers.

L19-8

On page 392 of the PDF, it says (emphasis mine):

> *"The highest hourly heat input and emission rates during normal operation occur at peak load. The plant may be operated under a wide variety of conditions over its life. The worst-case hourly emissions assume all five engines will undergo startups during the same hour. Maximum daily emissions are calculated assuming that each engine will undergo three startups/shutdowns per day, with the units operating at full load for the remaining hours of the day. Maximum monthly emissions are calculated assuming 50 startups and 225 full-load operating hours per engine per month. Maximum annual emissions are calculated assuming each engine operates a total of 1120 hours per year with up to 280 startups/shutdowns per year and remaining operations at full load.* ***These assumptions are not intended to be imposed as permit limitations."***

L19-9

The question is will there be limitations on the actual operation of the units? The permit applications seem to indicate that the engines could be run 24/7/365. Will GWP guarantee that the equipment won't be operated more than 15% of total hours in a year (1200 total hours) and no more than 250 hours in a month? How would GWP plan on keeping track of this? How would the public access this information? If not, then the whole analysis in the PRDEIR is based on a faulty premise and should be done assuming full time operation (if that is indeed the maximum that the units can be operated).

L19-10

Some side questions/comments:

- I could not get the same numbers as are listed on page 573 (unlabeled table in Appendix E) except for ones for boiler 3. For NOx for boiler 4, for instance, the adjustment factor times the numbers on the left, yield the numbers on the right. But then I think one should have added the numbers on top right for 2016 (8.19 + 14.71) to the ones below for 2017(7.97 + 13.3) and then

L19-10 averaged them to get 22.1. I think the only reason the ones for boiler 3 worked is that there were no emissions for 2017 to add. Again, I think taking credit for emissions due to LFG both for this project and for the Scholl project is not correct.

L19-11
- Another question on page 623 for Alternative 8 Emission Inventory, GHG Emissions. For which year are the baseline emissions? This page is correct in not taking credit for emissions due to LFG for both this project and for Scholl project.

L19-12

Summary:

Since currently the LFG is flared at Scholl, the approach that the Grayson Repowering PRDEIR uses for the baseline is faulty. There are three potential ways that I can think of to address this:

- Either any LFG emissions must be subtracted from the baseline emissions (as I have done in the green rows of the table) or
- The baseline should be a year with no LFG processing at Grayson (2019) or
- The flare emissions from Scholl should be added to the projected emissions for Alternative 7 or 8 for Grayson and then the emissions from a baseline year that includes the landfill gas at Grayson should be subtracted.

L19-13 2019 seems like a year that should be used for the baseline since it did not use LFG and was around the time that the DEIR was prepared.

L19-14 In addition, the Grayson PRDEIR assumes that the Alternative 7 and 8 equipment is operated about 15% of the time, but nothing seems to guarantee that. If this is exceeded, then the emissions will rise and could reach levels of significance and the whole PRDEIR analysis is incorrect.

L20

From: Andrew Ellis
To: Krause, Erik
Subject: Grayson Repowering Project - Partially Recirculated Draft Environmental Impact Report
Date: Monday, November 15, 2021 9:17:54 AM

CAUTION: This email was delivered from the Internet. Do not click links, open attachments, or reply if you are unsure as to the sender.

November 15, 2021

Mr. Erik Krause, Deputy Director of Community Development
Community Development Department, Planning Division
633 East Broadway, Room 103
Glendale, California. 91206-4386

Via E-mail to: ekrause@glendaleca.gov,

RE: Grayson Repowering Project - Partially Recirculated Draft Environmental Impact Report

L20-1

Dear Mr. Krause,

Please allow me to submit my comments on the proposed Grayson Repowering Project - Partially Recirculated Draft Environmental Impact Report. I am a long-time resident of the Citrus Grove neighborhood in Glendale, California. I am a retired environmental scientist and industrial hygienist with occupational experience in characterizing EPA listed SUPERFUND toxic chemical waste sites with the US Environmental Protection Agency. I spent the later part of my career in risk management for commercial insurance firms working mostly with the automotive industry. My scientific credentials and education include an undergraduate degree in microbiology from The University of Texas at Austin and a Master of Science degree in biology from the California State University - Northridge.

My graduate research was focused on plant habitat restoration and conservation biology questions. My current research is devoted to the study of paleontology, mass extinctions and their relation to climate change. I am currently associated with the Bighorn Basin Paleontological Institute in Red Lodge, Montana. I have been a volunteer with The Climate Reality Project as a Leadership Corps Member for the last eight- and one-half years and I currently serve on the national leadership team of the Climate Business Working Group (CBWG).

I thank you for the opportunity to provide these comments on the Grayson Repowering Project - Partially Recirculated Draft Environmental Impact Report. I look forward to adding my comments to the record and I will be grateful to receive a response to my comments and observations. Please contact me if I may clarify any of the issues and recommendations I've raised.

Sincerely,

Andrew Ellis | MS

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Glendale, CA 91206
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Grayson Repowering Project - Partially Recirculated Draft Environmental Impact Report

Introduction:

I've been following the developments of the repowering discussions going on in my City of Glendale for more than six years and I've spoken previously to the City Council in opposition to the use of fossil fuels to generate electricity and specifically in opposition to using natural gas obtained from hydraulic fracturing methods to generate electricity. I have spoken in support of finding renewable energy options to generate electricity for our city.

L20-2 The community has been asked to evaluate and provide comments on a Partially Recirculated Draft Environmental Impact Report covering two new repowering options, making comparisons to an outdated Final EIR that was prepared over four years ago for a project that is no longer being considered.

Comment #1: GRAYSON-PR-DEIR-GEN-01

Why was GWP not required to prepare a completely new Draft Environmental Impact Report? It doesn't make much sense to try to append two completely different, updated repowering project options to a "FINAL EIR" for a project that is no longer being considered. I raise the question whether this is the best method to evaluate and mitigate environmental risks and threats. It is of the utmost importance that we allow the public to participate in these important decisions before we allow any potential environmental threat to into our community. I believe that GWP is required to prepare an entirely new Draft Environmental Impact Report that provides FULL DISCLOSURE to the community about environmental risks and possible mitigation strategies.

L20-3

What the community needs in any Draft Environmental Impact Report is written in the executive summary of the Grayson PR-DEIR.

The overall purposes of the California Environmental Quality Act (CEQA) are to:

1. Identify the significant effects to the environment of a project, identify alternatives, and indicate the manner in which those significant effects can be avoided or mitigated.
2. Provide full disclosure of the project's environmental effects to the public, the agency decision makers who will approve or deny the project, and the responsible and trustee agencies charged with managing resources that may be affected by the project.
3. Provide a forum for public participation in the decision-making process with respect to environmental effects.

Section 15123(b) of the CEQA Guidelines requires that an EIR contain issues to be resolved, including the choices among alternatives and whether or how to mitigate significant impacts. The major issues to be resolved regarding the Project include decisions by the lead agency as to whether:

- The EIR adequately describes the environmental impacts of the Project.
- The recommended mitigation measures should be adopted or modified.
- Additional mitigation measures need to be applied.

I do not believe this PR-DEIR provides the community with the proper identification of significant effects. Alternatives appear to be rarely discussed. Mitigation measures provide only the barest of descriptions and we do not find specific mitigation measures that provide us confidence that our environment will be protected. Without a significant increase in the level of detail, it is hard to see how this Grayson PR-DEIR allows a "forum for public participation in the decision-making process".

What the community (and the California Environmental Quality Act) require and what we are asking for is FULL

L20-3

DISCLOSURE of the environmental impacts of the project. If we are provided with detailed information on environmental effects - the community will be able to understand the risk analysis process and contribute to the evaluation of any possible mitigation strategies.

I would also like to make the point that time for the community to participate in these risk assessments and develop possible mitigation strategies is limited and is closing fast. Our participation is required BEFORE Glendale decision makers act. Once the comment period closes, our opportunity to be heard about potential threats coming into our environment is forever foreclosed. The community is asking for FULL DISCLOSURE prior to being closed out of this process. The California Environmental Quality Act requires that environmental impacts be fully disclosed BEFORE decisions are made and our community opportunities to be heard have passed.

L20-4

Comment #2: GRAYSON-PR-DEIR-GEN-02

As a general comment, I find that the PRDEIR is deficient because it DOES NOT include enough information to enable the community members to understand the environmental impacts and possible mitigation measures for each of the Alternative repowering options. Because this PR-DEIR is deficient and does not contain sufficient information for the public to provide an informed comment, decision makers in Glendale will be deprived of crucial community input on environmental impacts.

L20-5

Comment #3: GRAYSON-PR-DEIR-GEN-03

A SECOND AMENDED DRAFT ENVIRONMENTAL IMPACT REPORT that corrects these noted deficiencies by providing revised, complete and detailed descriptions of the risk analysis process and mitigation strategies will allow for informed public comment to provide Glendale City Decision Makers with valuable input from those who are going to be most impacted.

L20-6

Comment #4: GRAYSON-PR-DEIR-PAL-01

Paleontological Impacts:

My evaluation of the GRAYSON PR-DEIR sections dealing with paleontological resource impacts indicates that the document lacks sufficient information that the community needs to provide important input on how these valuable scientific resources will be preserved. This PR-DEIR fails to provide detailed descriptions of how a mitigation plan will be implemented. A full disclosure of the project's environmental effects on paleontological resources is most essential for the community to be able to evaluate environmental risk and comment on potential mitigation efforts. The lack of adequate, detailed information on environmental effects and possible mitigation efforts for fossil materials also will deprive Glendale City decision makers of vital input from the community members who are in the best position to offer their concerns. Without a proper forum for public participation in the decision-making process, the California Environmental Quality Act (CEQA) process is circumvented.

L20-7

Conclusions:

This Grayson PR-DEIR FAILS to adequately describe the environmental impacts of the Project. The mitigation measures SHOULD NOT be adopted or modified. Additional disclosures are required to allow for a proper evaluation of mitigation measures, as required by California Environmental Quality Act (CEQA).

The risk assessment correctly classifies the GRAYSON PROJECT site has having high paleontological potential, which means that research revealed a high likelihood of disturbance to fossil material during demolition and construction, yet PR-DEIR lacks sufficient detailed information on how these valuable scientific resources will be protected, documented, removed, and conserved. The community will need to know the exact measures and procedures that

L20-7 are going to be implemented that provide a guarantee that these valuable scientific resources will be treated properly and preserved as part of our scientific heritage for future generations. The PR-DEIR for Grayson Project and Alternative repowering options fails to provide this level of detail.

Observations:

L20-8

1. The PR-DEIR correctly classifies the Grayson site as having a HIGH PALEONTOLOGIAL POTENTIAL.
2. Phases of the project where soil and sediment disturbance are likely to result in a significant impact on fossils have been correctly identified in both the demolition and construction phases.
3. The PR-DEIR correctly analyzes the relationship with INCREASING PALEONTOLOGICAL POTENTIAL as they excavate deeper into undisturbed sediments.
4. Mitigation measures presented in the PRDEIR include the development PALEONTOLOGICAL WORKER TRAINING PROGRAM without providing detailed descriptions of procedures.
5. The PALEONTOLOGICAL MONITORING PROGRAM to mitigate the environmental impacts in the event of an "inadvertent discovery" of fossil material is inadequately described for the community to evaluate risks and provide input on mitigation strategies.

Comment #5: GRAYSON-PR-DEIR-WFI-01

Wildfire Impacts

L20-9 My evaluation of the GRAYSON PR-DEIR sections dealing with wildfire impacts indicates that the document lacks sufficient information that the community needs to provide important input. The PR-DEIR states that the Grayson project would be at risk of a SIGNIFICANT IMPACT related to wildfire if it is in or near state responsibility areas or lands classified as very high fire hazard severity zone and the proposed Project would Impair an Emergency Response Plan, expose project occupants to pollutant concentrations from wildfire or require installation of fire breaks.

The site is located near (within 0.1 mile) a very high fire hazard severity zone, yet the risk is determined to be less than significant, and the Report indicates less than significant environmental impacts.

This PR-DEIR fails to provide detailed descriptions of how a mitigation plan will be implemented. A full disclosure of the project's environmental effects related to wildfire is most essential for the community to be able to evaluate environmental risk and comment on potential mitigation efforts. The lack of adequate, detailed information on environmental effects of wildfire and possible mitigation efforts will also deprive Glendale City decision makers of vital input from the community members who are in the best position to offer their concerns. Without a proper forum for public participation in the decision-making process, the California Environmental Quality Act (CEQA) process is circumvented.

Conclusions:

L20-10 This Grayson PR-DEIR FAILS to adequately describe the environmental impacts of wildfire on the Project. Proper mitigation measures SHOULD be revised and adopted. Additional disclosures are required to allow for a proper evaluation of mitigation measures by members of the community, as required by California Environmental Quality Act (CEQA).

Comment #6: GRAYSON-PR-DEIR-HAZ-01

L20-11

Hazardous Materials Environmental Impact

The risk analysis related to the planned storage and use of hazardous materials DOES NOT MEET the stated goals and purpose of an EIR in general, which is to provide the community with detailed information about the environmental impacts of a proposed project.

L20-11 The Project and alternative repowering options describe plans to substantially increase the quantity of 19% AQUEOUS LIQUID AMMONIA stored on-site during operations from 12,000 gallons to 24,000 gallons. This quantity of stored liquid ammonia (over 200,000 lbs.) exceeds the Clean Air Act threshold quantity of 20,000 lbs. and triggers the preparation of an OFF-SITE CONSEQUENCE ANALYSIS that models the environmental impact of a worst-case scenario. The worst-case scenario for ammonia storage described in this PR-DEIR is an unplanned release of the entire contents of the storage tank into the secondary container filled with 3" diameter polyethylene spheres to reduce surface area exposed to the atmosphere. I submit that this scenario is far from the worst-case that can be contemplated in a very well-characterized seismic region. A more accurate evaluation of potential worst-case scenarios when storing large quantities of ammonia would consider the possibility of a complete breach or rupture of both the primary and secondary containment vessels and subsequent release of liquid NH3 onto the Grayson site and into the atmosphere.

My evaluation of the GRAYSON PR-DEIR sections concerning the environmental impact of hazardous materials stored and used on site at the Grayson Project indicates that the document lacks sufficient information that the community needs to provide important input. Specifically, this PR-DEIR fails to provide detailed descriptions of worst-case scenarios relating to the storage of large quantities of liquid ammonia.

A full disclosure of the project's environmental effects related to the storage, handling and use of all hazardous materials at the Grayson Project is most essential for the community to be able to evaluate environmental risk and comment on potential mitigation efforts. The lack of adequate, detailed information on environmental impacts and mitigation measures relating to the possible uncontrolled release of large quantities of liquid ammonia and other toxic or noxious chemicals prevents the community to providing their evaluation of planned mitigation efforts. Without input from the community, Glendale City decision makers will be deprived of vital input from the community members who are in the best position to offer their concerns. Without a proper forum for public participation in the decision-making process, the California Environmental Quality Act (CEQA) process is circumvented.

Conclusions:

L20-12 This Grayson PR-DEIR FAILS to adequately describe the environmental impacts relating to the storage and use of hazardous materials at the Grayson Project. Proper mitigation measures SHOULD be revised, recirculated, and adopted. Additional disclosures are required to allow for a proper evaluation of mitigation measures by members of the community, as required by California Environmental Quality Act (CEQA).

Comment #7: GRAYSON-PR-DEIR-NOI-01

Noise Impact

L20-13 Noise from a power plant is of particular concern to nearby residents, medical facilities, schools, daycares, or users of nearby parks or other recreational places. Noise of different frequencies can have different effects. Lower frequencies are often felt as vibration or have the effects of vibration on structures. Heavy vibration can be annoying to nearby residents or cause damage to structures.

Power plant operation noise sources can include steam generators, steam turbine generators, fuel handling equipment, air compressors, air separators, cooling towers, and rooftop ventilation fans. Fans in the plant without speed controls can produce "tonal" noise, sounds centered on a narrow frequency band. Tonal noise has been shown to affect people more than other noises, especially at lower overall noise levels, and may require special silencer mechanisms.

Natural gas-fired combined cycle plants generate noise from the turbines, the air intakes, and the cooling towers. Combustion turbine plants generate noise from turbine operation and air handling facilities. Natural gas-fired plants also use diesel fuel as a backup fuel, and the trucks that deliver it would add to the local noise levels.

L20-13 The PR-DEIR fails to adequately estimate and assess excessive noise levels related to demolition, construction, and operation of the GRAYSON PLANT in a noise-sensitive residential area. The PR-DIER also fails to properly evaluate the construction and operational NOISE IMPACTS from the Project. Additionally, the PR-DEIR proposes generic mitigation measures without providing the necessary details and specifics to establish their effectiveness and feasibility.

To discover the noise impact of a power plant, existing noise levels (ambient sound) are measured in different locations onsite and near the site either before a power plant is built or when it is not operating. This sets benchmarks for impact measurements. Measurements are then taken at the same locations with the power plant operating. The difference in sound levels is attributable to the plant.

A "significant effect" under CEQA is "a substantial, or potentially substantial, adverse change in any of the physical conditions within the area affected by the project," which include a project's effects on "ambient noise." (CEQA Guidelines, § 15382; Pub. Resources Code, § 21060.5, 21151(b).)

CEQA defines a threshold as an "identifiable quantitative, qualitative, or performance level of a particular environmental effect, non-compliance with which means the effect will normally be determined to be significant … and compliance with which means the effect normally will be determined to be less than significant." (CEQA Guidelines, § 15064.7(a))

Short-term ambient noise measurements (15 to 20 minutes long) were taken during a two-day time four years ago. This is insufficient to establish the full range of noise exposure. A proper noise survey should be carried over several days-weeks to document existing conditions both in terms of ambient noise and noise generated by various activities in this mixed residential-industrial zone. The measurements should capture changes in noise levels throughout the day and night both in terms of average noise and statistical levels.

My evaluation of the GRAYSON PR-DEIR sections concerning the environmental impact related to excessive noise indicates that the document lacks sufficient information that the community needs to provide important input. A full disclosure of the project's environmental effects related to the generation of excessive noise at the Grayson Project is most essential for the community to be able to evaluate environmental risk and comment on potential mitigation efforts.

The lack of adequate, detailed information on environmental impacts of excessive noise prevents the community to providing their evaluation of planned mitigation efforts. Without input from the community, Glendale City decision makers will be deprived of vital input from the community members who are in the best position to offer their concerns. Without a proper forum for public participation in the decision-making process, the California Environmental Quality Act (CEQA) process is circumvented.

Conclusions:

L20-14 This Grayson PR-DEIR FAILS to adequately describe the environmental effects relating to excessive noise generated during the demolition, construction, and operation phases at the Grayson Project. This PR-DEIR describes an assessment of ambient noise levels as they existed four years ago. Ambient measurements were taken and

L20-14 averaged over a short time duration during one two-day period.
I feel that more accurate and recent measurements SHOULD be made and recirculated to the community. I believe that additional disclosures are required to allow for a proper evaluation of mitigation measures for excessive noise by members of the community, as required by California Environmental Quality Act (CEQA).

L20-15 Comment #8: GRAYSON-PR-DEIR-GEO-01

Geological and Soils Impact

The Grayson PR-DEIR states that there is a LOW TO MODERATE potential for surface rupture from the Verdugo fault and other nearby active faults during the design life of the Project. Strong ground shaking can be expected at the Project site during MODERATE TO SEVERE earthquakes in the general region and the Project area is located within a LIQUIFACTION ZONE and site conditions may be susceptible to seismically induced liquefaction in the event of a major earthquake. Yet, the Report indicates "…with the implementation of applicable building codes and recommendations made within the Geotechnical Study (Stantec, 2015), geological impacts are expected to be less than significant".

My evaluation of the GRAYSON PR-DEIR sections concerning the environmental impact related to Geological risks indicates that the document lacks sufficient information that the community needs to provide important input. A full disclosure of the project's environmental effects related to seismology and ground-movement at the Grayson Project is most essential for the community to be able to evaluate environmental risk and comment on potential mitigation efforts.

The lack of adequate, detailed information on environmental impacts related to seismic activity prevents the community to providing their evaluation of planned mitigation efforts. Without input from the community, Glendale City decision makers will be deprived of vital input from the community members who are in the best position to offer their concerns. Without a proper forum for public participation in the decision-making process, the California Environmental Quality Act (CEQA) process is circumvented.

L20-16 Conclusions:

This Grayson PR-DEIR FAILS to adequately describe the environmental effects relating to seismic activity during the demolition, construction, and operation phases at the Grayson Project. This PR-DEIR describes an assessment of MODERATE TO SEVERE seismic risk. Additional disclosures are required to allow for a proper evaluation of seismic risk by members of the community, as required by California Environmental Quality Act (CEQA).

L21

From: Elise Kalfayan
To: Krause, Erik
Subject: Grayson Repowering Project PR-DEIR - Comments on Partially Recirculated Draft Environmental Impact Report for Grayson Repowering Project, SCH Number 20161210480
Date: Monday, November 15, 2021 11:46:16 AM
Attachments: Grayson Repowering PR-DEIR Comments 11-15-2021.pdf
Attachment 1 - Report to Glendale City Council.pdf
Attachment 2 - SCH Burbank Project List.pdf
Attachment 3 - SCH Glendale Project List.pdf
Attachment 4 - Bloomberg NEF thespectacular_energy_storage_growth.pdf

L21-1 Grayson Repowering Project PR-DEIR Comment Letter and referenced attachments

Glendale Environmental Coalition

November 15, 2021

Erik Krause
Deputy Director of Community Development
City of Glendale
Community Development Department
633 East Broadway, Room 103
Glendale, California 91026-4386

Via email to ekrause@glendaleca.gov

Re: Comments on Partially Recirculated Draft Environmental Impact Report for Grayson Repowering Project, SCH Number 20161210480

Dear Mr. Krause:

L21-2 The undersigned members of the Glendale Environmental Coalition (GEC) steering committee provide the following comments, concerns, and questions about the proposed Grayson Repowering Project Partially Recirculated Draft Environmental Impact Report (PR-DEIR), which analyzes impacts of two potential project options currently being developed by Glendale Water and Power (GWP).

L21-3 GEC is a grassroots group of residents of Glendale and surrounding areas, which was formed in 2017 to advocate for clean energy and against the original proposed Grayson Repowering Project. GEC continues to advocate for clean energy and sound environmental and climate policy in Glendale.

L21-4 We believe that although the current potential project configurations for the Grayson Repowering are an improvement over the original proposed project, Glendale can develop an energy portfolio that further reduces the city's need for gas-powered energy generation and transitions Glendale more quickly to clean energy.

L21-5 Since the City Council rejected the original project in 2018, the imperative to avoid new investments in climate-altering infrastructure has become increasingly apparent. The climate emergency has recently been called a "code red for humanity." We are headed on a path toward mass extinctions, accelerating and compounding natural disasters, drought, food scarcity, sea level rise, increases in heat that will make vast areas of currently populated land unlivable, geopolitical instability, and mass suffering.

L21-5 Every new investment in "natural gas" power equipment locks in climate-harming emissions for decades. Governments across the globe and at all levels are continuing these investments and failing to make the transformative changes needed to avoid further emissions of greenhouse gases and begin to stabilize the climate.

L21-6 Every ton of greenhouse gases that is emitted makes the situation worse, and every ton of emissions avoided helps avoid the worst possible outcome. Glendale can choose to be part of the solution by avoiding the emissions this project will cause. Approving the Grayson project would instead lock Glendale into many years of continued emissions. We ask the City to take the time to fully explore the potential for Glendale to embrace a clean energy future that does not include any new gas-burning infrastructure.

Clean energy will have substantial local benefits as well, most importantly in improving air quality. Glendale, and especially the area where the project site is located, is heavily burdened by pollution from multiple sources. Reducing pollution will help ease health impacts and improve quality of life.

The Original and Current Grayson Projects

L21-7 The original Grayson project, for which GWP released a Draft Environmental Impact Report (DEIR) in 2017, proposed to replace existing gas-burning units at the project site (with the exception of Unit 9) with four new units totaling 262 MW net capacity. The public, including GEC, strongly opposed the project. When the project and its Final EIR (FEIR) were presented to the City Council for approval, the City Council declined to certify the FEIR or to approve the project. Instead, the City Council directed staff to investigate clean energy options in place of the proposed project.

L21-8 In 2019, the City Council approved an Integrated Resource Plan (IRP) that included a cleaner portfolio to meet Glendale's energy needs. That portfolio included the following:[1]

- 28 MW of energy efficiency and demand response, including behind-the-meter batteries
- 23 MW of distributed solar and storage
- 75 MW/300 MWh of local, utility-scale batteries
- 93 MW of Internal Combustion Engines (ICE)

[1] 2019 Integrated Resource Plan, City of Glendale Water & Power, 7/23/2019, https://www.glendaleca.gov/home/showdocument?id=51814, p. 9.

L21-9

At that time, the City Council authorized GWP to proceed with a study and development phase for the utility-scale batteries and ICE units at Grayson.[2] In March 2020, the City Council authorized a contract for owner's engineering services for this project, which was referred to as "Alternative 6" for purposes of environmental review. On December 15, 2020, GWP presented new configurations of the project with ICE units, one of which is the current "Alternative 7." Staff also presented another potential project at the Grayson Power Plant, involving retaining and refurbishing the existing turbine generator Units 8A and 8BC, and also including a 75 MW battery energy storage system. This potential project was designated "Alternative 8." The City Council directed staff to move forward with evaluating and developing the two project options currently under consideration.

L21-10

Thus, the original project is no longer under consideration and has been definitively rejected by the City, as shown by the City Council's actions in declining to certify the original project's EIR, directing staff to pursue a cleaner energy portfolio rather than approving the original project, and authorizing contracts for work toward project options with less gas-burning capacity.

L21-11

In summary, there are currently two options that GWP has presented as the future direction for the Grayson Power Plant. Both include a 75 MW/300 MWh battery energy storage system manufactured by Tesla. One includes the 5 ICE units identified in the 2019 IRP, with 93 MW of thermal capacity, and the other includes the refurbished Units 8A and 8BC, with 101 MW of thermal capacity.[3] Both also include a switching station and other elements.

L21-12

The PR-DEIR is misleading and obscures information

CEQA requires an EIR to present a detailed statement setting forth all significant environmental effects of a proposed project, and information explaining the reasons why the agency has determined that various environmental effects are not significant.

L21-13

As noted above, the original project is no longer under consideration, having been rejected by the City Council in 2018 and 2019. That project is no longer relevant to the public's and decision makers' understanding of the current project options and their decision about whether one of the proposed project options, or an alternative to them, would be the best choice for Glendale's energy future.

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[2] The information in this paragraph is taken from the December 15, 2020 Report to the City Council on Agenda Item for Amendment of Contracts with Stantec Consulting Services, Inc. and Black & Veatch Corporation, attached to this letter (**Attachment 1**) and also available at https://glendaleca.primegov.com/Portal/viewer?id=1917&type=0.

[3] This letter refers to the current project options as "Alternative 7" or the Tesla/Wartsila Project Option, and "Alternative 8" or the Tesla/Unit 8 Refurbishment Project Option.

L21-14

The PR-DEIR continues to treat the now-rejected original project configuration as the "Project" and the two project options as mere alternatives, meaning that the environmental review is based on a fiction. By continuing to treat the original project as a still viable, current project option, the PR-DEIR misleadingly confuses the analysis. It makes comparisons showing the project options as improvements to the original, **rather than dealing with the actual projects and comparing them with thresholds of significance so that decision makers can understand clearly what impacts these project options entail.**

L21-15

As one example of how the PR-DEIR fails to adequately disclose and evaluate potential impacts of the project options, for "Alternative 7," the PR-DEIR contains no separate discussion of any of these environmental impact categories that were separately analyzed for the original project: geology and soils, hydrology and water quality, and transportation and traffic. The discussion of several impact categories is less than a page: energy, greenhouse gas emissions, and noise. Similarly, for "Alternative 8," the PR-DEIR has no separate discussion of these same impact categories, and only three impact categories are discussed for more than one page: aesthetics, air quality, and hazardous materials. Energy is discussed in one paragraph, and greenhouse gases and noise each are discussed in three or fewer paragraphs.

L21-16

The fallacy at the heart of the PR-DEIR, in measuring the current project options against a rejected prior project option, also means that **the impacts of the two potential projects are not directly compared**. This impedes the ability to draw comparisons between the potential project options—which is a great detriment to decision makers and members of the public hoping to understand and weigh the relative merits of these options to choose between them.

L21-17

For example, in the area of air quality, making the following comparisons between the project options requires finding information in separate locations in the document:

- Natural-gas fueled generation capacity and the amount of natural gas consumed: p. 5.46 and p. 5.65.
- Criteria air pollutant emissions impacts: pp. 5.46-5.47 and pp. 5.64-5.65.

The same is true of aesthetic impacts, analyzed separately at pages 5.40-5.45 and pages 5.59-5.65, and hazards and hazardous materials, discussed at pages 5.49-5.51 and 5.68-5.70 respectively for the two project options.

L21-18

Changed Circumstances, Baselines, and Cumulative Impacts

Once an EIR has been certified, a new document would be needed if there are substantial changes in the project, substantial changes in the circumstances under which the project would be undertaken, or new information which was not known and could not have been known at the time the original document was certified. It is reasonable to apply the same standard to a document such as this one, which is tied to an older EIR that was developed several years ago.

In particular, changing circumstances mean that **several baselines in the PR-DEIR are**
L21-19 **outdated**. The baseline conditions for environmental analysis for the original EIR were conditions as they existed at the time the Notice of Preparation (NOP) for an EIR was published. In this case, the NOP was issued in 2016, meaning that using that as the time for measuring baselines would result in comparing the project against conditions from five years ago, or even earlier depending on what databases were used to establish baseline conditions. The environmental setting for many impact areas has changed significantly since the original baselines were established.

Agencies have discretion to determine baselines to define the environmental setting, but failing to describe the environmental setting is a violation of CEQA. Given the passage of time and the changed circumstances under which the current project options are being undertaken, the PR-
L21-20 DEIR fails to explain whether and why the five-or-more-years-old baselines from the original environmental analysis are still appropriate, or whether new baselines should have been adopted for the current round of environmental review.

The PR-DEIR should have examined and considered updating baselines for several impact areas that it did not. These include, at a minimum, transportation and traffic impacts during construction, hazards and hazardous materials, hydrology and water quality, and noise impacts.

Another area of concern that the PR-DEIR does not address is **environmental justice**. In the December 2016 Initial Study for the original project, the City concluded that the project would have no impact on environmental justice because Glendale is not considered an environmental justice community (original project DEIR, Appendix A, section 2.19, p. 2.55). Information available since that time should have led the City to evaluate environmental justice impacts for
L21-21 the current project options:

The OEHHA's CalEnviroScreen 3.0 was released in January 2017 and updated in June 2018. As explained at the CalEnviroScreen website, "CalEnviroScreen identifies California communities by census tract that are disproportionately burdened by, and vulnerable to, multiple sources of pollution." It shows that census tracts in the vicinity of the project have pollution burdens in the 99th and 100th percentile. There is no indication that the City took this information from 2017 and 2018 into account. See https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30. The communities surrounding the project site are also designated as SB 535 Disadvantaged Communities, which include the top 25% scoring areas from CalEnviroScreen. See https://oehha.ca.gov/calenviroscreen/sb535. "SB 535 requires CalEPA to take a multi-pronged approach to identifying disadvantaged communities that includes socioeconomic, public health and environmental hazard criteria." California Environmental Protection Agency's Designation of Disadvantaged Communities Pursuant to Senate Bill 535, https://calepa.ca.gov/wp-content/uploads/sites/6/2017/04/SB-535-Designation-Final.pdf, at p. 5.

L21-22

The PR-DEIR takes an uneven approach to changes in circumstances since the original environmental analysis was completed in addressing cumulative impacts due to other projects when combined with the project.

Section 4.11.2 of the PR-DEIR (p. 4.4-4.6) addresses other projects considered in addressing cumulative impacts, identifying projects originally included that are no longer anticipated to occur, including the Scholl Canyon Landfill Expansion Project and the Green Waste Digester Project. However, the section fails to note any additional project that may now be anticipated, only conclusorily stating that there are no additional related projects since the FEIR was completed. **The PR-DEIR thus uses a current baseline to eliminate previously considered projects, but fails to use a current baseline to add newly anticipated projects.**

L21-23

Further, **the analysis appears to have been artificially constrained to other power generating projects**. An EIR must consider the cumulative impacts from multiple projects that may cause related impacts, but this is not limited to projects of a similar type.

L21-24

The PR-DEIR also appears not to have considered projects outside Glendale. As only one example, there is a project currently under consideration at the Los Angeles Zoo, approximately 0.35 mile from the Grayson project site.[4] The Final EIR for the zoo project identifies that the project will cause emissions of criteria pollutants (see, e.g., LA Zoo FEIR pp. 3.2-30 to 3.2-35, including Tables 3.2-13 through 3.2-17); greenhouse gas emissions (see, e.g., LA Zoo FEIR pp. 3.8-35 to 3.8-40); use and potential release of potentially hazardous materials (see, e.g., LA Zoo FEIR pp. 3.9-20 to 3.9-30); and noise and vibration impacts (see, e.g., LA Zoo FEIR pp. 3.12-21 to 3.12-44). These are all impact categories that are relevant to the Grayson project, so cumulative impacts analysis is needed.

In fact, the LA Zoo FEIR identifies the Grayson Repowering Project in its cumulative projects list (LA Zoo FEIR, p. 3.18-7). It identifies emissions of NOx as cumulatively considerable as a result of the construction of the zoo project and other projects, including Grayson (LA Zoo FEIR, p. 3.18-17), and discusses cumulative hazardous materials impacts from the zoo project and the Grayson project (LA Zoo FEIR, pp. 3.18-26 to 3.18-27). Note that the LA Zoo FEIR specifically identifies the Grayson project as having the potential to affect the zoo project site because of the risk of hazardous materials release (LA Zoo FEIR at p. 3.9-23).

This one example shows that the PR-DEIR failed to consider obvious related projects for consideration of cumulative impacts of the current project options. There are likely several other past, present, and probably future projects producing related or cumulative impacts. As an example, the State Clearinghouse lists numerous additional projects in Glendale and Burbank

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4 See Los Angeles Zoo Vision Plan Project Final Environmental Impact Report, available at https://s36593.pcdn.co/wp-content/uploads/2021/06/LA-Zoo-EIR-Final_webres.pdf, at p. 3.9-10.

L21-24 for which environmental documents have been or are being prepared in the period from January 1, 2019, to present (**Attachments 2 and 3**).

Project Description

The PR-DEIR claims, "There are no changes to the proposed Project" (p. vii). This is simply
L21-25 untrue. As discussed above, the original project no longer exists as a potential, real-world project option. It was rejected over 3 1/2 years ago, and Glendale will not consider that project. **This is a fundamental change to the project that Glendale plans to pursue.** The PR-DEIR does a disservice to all those who wish to use this document to inform themselves about the Grayson Repowering Project by maintaining this fiction.

With respect to the current project options, the PR-DEIR describes both at length, but **important information regarding the project options is absent**. For example, it is not clear where and how the energy needed to charge the Tesla energy storage will be generated. The document makes such statements as the following:

L21-26
- The BESS, ***if charged*** with renewable sources, would represent a reduced potential energy impact (p. 5.53 [emphasis added])
- a BESS that ***could be charged*** [emphasis added] with renewable sources (p. 5.59)

However, there is no assurance that the storage batteries will ***actually*** be charged with renewables. Regardless of the source, generation of the energy needed to charge the batteries is part and parcel of the overall project.

If imported energy is used, air emissions within the South Coast Air Basin may not be
L21-27 increased, but greenhouse gases would be generated if energy from renewable sources were not available. In fact, the PR-DEIR anticipates just such a possibility, in a footnote to Table 5-15, presenting anticipated air emissions: "Does not include non-local air emissions resulting from generation of electricity to be imported to charge the BESS when renewables are not available" (p. 5.77). The PR-DEIR does not analyze these emissions.

Unfortunately, we are left in the dark as to potential air emission from this source of energy. This appears to be a gap in the analysis that should be addressed in the final environmental
L21-28 impact document. If the BESS may be charged from non-renewable energy sources, this may result in an increase in impacts including, but not limited to, energy/natural gas consumption, air emissions, and greenhouse gases, which should be addressed in the environmental analysis.

The PR-DEIR notes that offsite storage (or "staging") may be needed during construction (p.
L21-29 5.38). The off-site location and any impacts to that location and its vicinity must be identified. Vehicle trips between the off-site location and the project site must be included in all impact analyses, including construction traffic and associated air emissions.

L21-30 Lithium-based storage batteries can be charged and re-charged a limited number of times, and then must be replaced. In its discussion of Alternative 2, the PR-DEIR noted the need for battery replacement and disposal every five to ten years (see pp. 5.15-5.16) but fails to address this for the Tesla/Wartsila and Tesla/Unit 8 Refurbishment Project Options. The EIR must address how many of the large batteries would be replaced, how often, and where they would be transported for ultimate disposal or partial reprocessing, as well as the associated environmental impacts.

Air Quality

Information Gaps and Analytical Inadequacies

L21-31 **Analysis within the PR-DEIR Itself**

The analysis in the PR-DEIR is extremely inadequate and fails to disclose important information about air quality impacts. Air quality impacts of the two current project options are discussed in PR-DEIR section 5, Alternatives, with the specific air quality discussion a small part of sections 5.2.6 and 5.2.7. Looking purely at the amount of information presented, the original project DEIR's discussion of that one project's air quality impacts is 47 pages, whereas the combined length of the air quality analysis for the two current potential project options is less than 4 pages. Whereas the original project's EIR considered several topics related to air quality impacts, the PR-DEIR's air quality analysis presents only two sets of information: comparison of criteria air pollutant emissions with the defunct project for each project option (Tables 5-2 and 5-8) and information about health risks to adjacent residential receptors (Tables 5-3 and 5-9).

Analysis in Air Quality Appendices

L21-32 The PR-DEIR contains Appendix C, titled Updated Air Quality Technical Report. This is actually two separate appendices. Appendix C.1, beginning on page 372 of the PR-DEIR pdf file,[5] is designated as "Alternative 7," and consists of Foulweather Consulting's Revised Application to the South Coast AQMD for a Permit to Construct for the Grayson Repowering Project, dated June 2021. Appendix C.2, beginning on pdf p. 594, is designated as "Alternative 8." The contents are several pages of data tables and maps. The source of the contents is not identified. The total length of Appendix C.2 is less than 15% the length of Appendix C.1. This means that **the information disclosure for "Alternative 8" air quality impacts is dramatically lower than for "Alternative 7"**.

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[5] This letter uses pdf page references for the PR-DEIR's appendices because of a lack of consecutive page numbers within the appendices.

L21-33 GWP submitted a permit application package to the SCAQMD for "Alternative 8" before it released the PR-DEIR. That permit application would have presented a much more complete disclosure and afforded the public and decision makers a way to understand and compare the two project options much more directly and fully than is possible with the PR-DEIR. **That permit application should be released with at least 15 days for the public and decision makers to review it before the EIR is planned to be presented to any governmental bodies, including the GWP Commission and Sustainability Commission.**

L21-34

Omitted Types of Analysis

The PR-DEIR air quality analysis is also much more limited in terms of the range of potential impacts it considers, compared to the EIR for the original project. Here is a list showing examples of analysis that is not included in the PR-DEIR:[6]

- No analysis of construction-related air quality impacts for either project options. Compare with original project FEIR pages 4.3.20-4.3.24.
- No analysis of air quality impacts from facility occupancy. Compare with FEIR page 4.3.25.
- No analysis of air quality impacts from off-road equipment and vehicle trips. Compare with FEIR page 4.3.25.
- No ambient air quality impact analysis comparable to FEIR pages 4.3.36-4.3.40.
- No discussion of impacts under the threshold related to conflicts with or obstruction of the implementation of the applicable air quality plan. Compare FEIR pages 4.3.40-4.3.42.

L21-35 **Analysis of impacts from construction, facility occupancy, and off-road equipment and vehicle trips should have been completed.** These two project options include different elements that were not present in the original project, including the Tesla BESS and the switching station, and these impacts may be significant. Without a clear analysis set forth in the environmental review document, decision makers and the public are not able to assess these impacts.

L21-36 As noted, the PR-DEIR itself does not contain **an ambient air quality impact analysis** comparable to that provided in the original project's FEIR, at pages 4.3.36-4.3.40. To compare this measure of air quality impacts for "Alternative 7," the public and decision makers must locate and refer to Appendix C.1, section 4.6 (pdf pp. 401-402).

L21-37 An understanding of impacts is further impeded because of **differences in how data are presented**. The FEIR presents some of the original project's results in parts per million, whereas Appendix C.1 provides all results in micrograms per cubic meter. Other differences in the data

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[6] It is possible some of this analysis can be found by searching through the voluminous Appendix C.1 for "Alternative 7." Appendix C.2 does not have any of these types of analysis.

L21-37 presentation also render comparison difficult if not impossible, such as multiple values for various pollutants that are identified differently between the two documents, and different presentations of the standards against which impacts are measured.

L21-38 For "Alternative 8," there is no ambient air quality impact analysis, so it is impossible to evaluate this measure of impacts for that project option, whether in comparison to the original project, to "Alternative 7," or to standards of significance.

L21-39

Difficulty in Comparing Impacts of the Project Options

Because the emissions and health risks of the two project options are presented in separate tables, comparing impacts of the two options being presented to decision makers requires referring to the separate tables. This is another example of how the PR-DEIR's treatment of these options as mere alternatives to the original project misleads and impedes understanding of the project options' environmental impacts.

L21-40

Air Quality Baseline

The PR-DEIR fails to adequately justify or support the baseline used for air quality analysis of the current project options.

Need for Updated Baseline

As discussed previously, the circumstances under which the project will be undertaken have changed substantially since environmental analysis was conducted for the original, now-defunct project. These changes include a key element of the environmental setting for air quality purposes: whereas GWP used to combust landfill gas at the Grayson power plant, after discovering that burning the LFG at Grayson caused emissions to exceed potential health risk notification and action plan thresholds, GWP stopped burning LFG at Grayson on April 1, 2018 (p. xiv). Under these circumstances, use of the original baseline is inappropriate. The City recognized as much in the PR-DEIR, stating that it updated the environmental impact analysis to consider not only the original baseline conditions while LFG was being combusted at Grayson, but also an updated baseline "that considers flaring of landfill gas at Scholl Canyon Landfill" (p. xiv).

As explained, the current Grayson Repowering Project is two project options that were identified and selected for analysis in July 2019 and December 2020, respectively.

In stating that the City updated the baseline to a time when LFG was flared at the landfill instead of at Grayson, the PR-DEIR appears to have done what sound decision making, CEQA, and logic require: update the baseline to account for the environmental conditions at the time

L21-40 that the City Council decided to pursue the new project options, i.e., in 2019 or 2020. But reviewing the PR-DEIR and its air quality appendix shows that the City failed to do this.

L21-41

Problems with the 2018 Updated Baseline

<u>Difficulty Finding Source of Baseline Values</u>

To begin, we had to identify the source of the baseline values used in the PR-DEIR. The PR-DEIR's Alternatives section does not present any discussion explaining the updated baseline for air quality analysis, but it presents Tables 5-2 and 5-8, which each refer to an "Updated 2018 Baseline" (pp. 5.46, 5.65). Those tables present the same updated baseline values, in tons/year: NO2: 28.5; CO: 56.9; PM10: 8.6; VOC: 6.1; SO2:1.0.

L21-42 These values are consistent with values presented in PR-DEIR Appendix C.1's Appendix D1, May 2020 Air Dispersion Modeling Report and Health Risk Assessment, Prepared by Trinity Consultants (Table 2-1, pdf p. 495; see pdf pp. 490-491). They are also the same as the values for "Updated 2018 Baseline" in PR-DEIR Table 5-8, for "Alternative 8" (p. 5.65), and with values for "Baseline Emissions Based on SCAQMD AER 2018" in Appendix C.2 (pdf p. 599). One can conclude therefore that the information at pdf p. 599 accurately sets forth the per-unit emissions that underlie the "Updated 2018 Baseline" for the two project options.

L21-43 The first observation is procedural: it should not be this difficult to ferret out the source of the baseline values presented in Table 5-2. An environmental review document should provide information, not hide it and require readers to search through multiple appendices to identify such a basic piece of information.

L21-44

<u>LFG Combustion Not Removed from Baseline</u>

It is apparent that the updated baseline is inconsistent with the PR-DEIR's claim that the baseline was updated to reflect the change in circumstances when LFG stopped being combusted at Grayson: The values in the "Baseline Emissions Based on SCAQMD AER 2018" table show that emissions from combustion of LFG in Boilers 4 and 5 are included in these values. This means that the claim made on page xiv of the PR-DEIR is misleading or inaccurate.

L21-45 Moreover, **the selection of this "updated" baseline is illogical and unsupported**. The point of a baseline is to compare a project's impacts against the environmental setting at the time the project is contemplated—in this case, that means updating the baseline is meant to account for the fact that the emissions at the project site do not include LFG emissions.

L21-46 The PR-DEIR's use of an updated baseline from a time when LFG was combusted at Grayson is also **inconsistent with the treatment of the baseline for greenhouse gas emission impacts for**

L21-46 **"Alternative 8"**[7]. While the PR-DEIR itself does not include any information about a baseline for greenhouse gases, Appendix C.2 indicates a calculation of baseline emissions that excludes LFG emissions, "because these emissions are counted toward Biogas Renewable (Scholl Canyon) Project" (pdf p. 623). If emissions were counted toward that project for greenhouse gases, it is reasonable to assume the same is true for criteria pollutants and air toxics. The analysis of air quality impacts should also exclude LFG combustion from its baseline but does not (compare pdf p. 599 with pdf p. 623). If there is a sound reason why these impact areas are treated differently, the City should explain it.

L21-47

Different Baseline in Appendix C.1

A further problem with the PR-DEIR's treatment of air quality baselines is that the appendix meant to support the air quality analysis uses a different baseline than the PR-DEIR's updated baseline, and in fact argues against a 2018 baseline.

The PR-DEIR's Appendix C.1, Foulweather Consulting's revised SCAQMD permit application for Wartsila version of the project (either "Alternative 6" or "Alternative 7"), presents and attempts to justify a different baseline period than is used in the PR-DEIR's main text (see pdf p. 398).

L21-48

<u>Hypothetical Baseline</u>

Appendix C.1 utilizes a 2016-2017 average baseline, claiming it is more representative of long-term boiler operations than 2018 and 2019 (pdf p. 399). It then adjusts the actual emissions reported to the SCAQMD in a number of ways, leading to the use of a hypothetical baseline rather than a true representation of the environmental setting against which an EIR's analysis of a project's impacts should be measured.

L21-49 Boiler emissions of NOx were adjusted to reflect current maximums for new equipment (pdf p. 400). Emissions of VOC, SO2, and PM10/PM2.5 were not adjusted (pdf p. 400). At that time, a considerable portion of gas used to fuel the boilers was landfill gas (Figure 3, pdf p. 400). Use of landfill gas was discontinued in April 2018. Thus, reductions in air emissions asserted in this analysis may be at least partially due to elimination of landfill gas in favor of cleaner burning natural gas to fuel the boilers.

L21-50 For the existing turbines, NOx and VOC emissions were adjusted using BACT emission rates, while SO2 and PM10/PM2.5 emissions were not (pdf p. 400).

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7 As discussed below, we found no information about a baseline for greenhouse gas emissions in the analysis for "Alternative 7."

L21-51 After these adjustments were made, the AERs were further adjusted and reduced by various factors based on the number of days the equipment was operated (pdf pp. 400-401, including Table 18; see also Appendix C.1's Appendix E, pdf pp. 570-573).

Thus, instead of a baseline reflecting actual emissions, or even actual emissions adjusted to reflect a change in fuel, **the analysis is based on a hypothetical baseline**, which very well may not lead to an accurate portrayal of changes in emissions due to the proposed project. This approach has been rejected under CEQA because it can result in illusory comparisons and mislead the public and decision makers about the true impacts of a project, subverting the EIR's informational purpose.

Undermined Baseline

L21-52 Beyond the issue of an improper hypothetical baseline, the baseline discussion in Appendix C.1 also undermines the updated baseline used in the PR-DEIR. The 2016-2017 baseline is justified partly because Appendix C.1 claims that 2018-2019 operations were not representative of "normal plant operations" (pdf p. 398).

The selection of an older baseline for Appendix C.1 is problematic from a CEQA standpoint because the justification is that the actual baseline conditions at the time of the analysis didn't represent historical use. But **a baseline is not meant to represent what has happened in the past**—it should represent the conditions that will be changed by the project.

L21-53 **This discussion in fact supports the need for an updated baseline that represents conditions in 2019 or later.** As shown in Figure 3 on pdf p. 400, landfill gas was still being used in 2018 and there was significantly less heat input (i.e., combustion of gas) in 2019 compared with prior years.[8] The year 2019 is not an anomaly to be disregarded—rather, it appears more representative of the current amount of emissions against which the project's air quality impacts should be compared.

L21-54 The discussion in Appendix C.1 points up yet another issue with the justification for baselines: It uses equipment failures to partly justify use of a 2016-2017 baseline, but half of the units discussed were down for at least part of 2017, so **rejecting 2018 and 2019 because of equipment outages while using 2017 is illogical** (pdf p. 399).

In short, the discussion in Appendix C.1 undermines the "Updated 2018 Baseline" in the PR-DEIR in several ways.

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8 Appendix C.1's Appendix E shows with even more detail the fact that significant amounts of LFG were included in the 2016-2017 baseline calculations (pdf pp. 572-573). This is entirely inconsistent with the PR-DEIR's claim that its updated baseline represents the LFG being flared at Scholl rather than burned at Grayson.

Inconsistencies

L21-55 Yet another problem with the PR-DEIR related to baselines is that its inconsistencies themselves undermine the analysis and the conclusions regarding air quality impacts. Baselines are fundamental to sound analysis of impacts in CEQA, and an EIR needs to be clear about those baselines to fulfill its informational purpose. Yet here, **the PR-DEIR uses a baseline that is different from the main technical document attached as support of the PR-DEIR's conclusions**. And the inconsistency extends beyond that: **Appendix C.1's main text is inconsistent with its own Appendix D1**, which uses a 2018 baseline even though Appendix C.1 rejected such a baseline (pdf p. 495). What is the reason for this inconsistency?

L21-56 The many issues with the air quality baselines presented in the PR-DEIR lead to a lack of confidence in the analysis and cause us to doubt that the true impacts of the project options have been disclosed in a way that is understandable and that can guide sound decision making.

We ask that in responding to comments, the City include information about the baseline emissions in 2019, and also include information about 2020 emissions, and emissions in 2021 to the extent they are available, so that the public and decision makers can know whether the level of emissions remained steady compared with 2019 or declined even farther. This information would provide full disclosure and aid in evaluating impacts and guiding decision making. Even if the City believes the 2018 updated baseline is appropriate, the City should provide additional information about emissions in the time since then, in order to more fully inform the public and decision makers and provide a greater understanding of the circumstances surrounding this important decision.

Thresholds

L21-57 The air quality section of the PR-DEIR does not compare emissions against thresholds of significance (see pp. 5.46-5.47, 5.65-5.66, and Tables 5-2 and 5-8). The prior EIR has discussion of significance determination based on mass daily thresholds, but no comparable analysis appears in the PR-DEIR for either current project option. (See FEIR pp. 4.3.33-4.3.34 and Table 4-26.)

By not comparing air quality impacts to significance thresholds, the PR-DEIR makes it difficult to understand whether the current project options will have significant impacts based on the relevant significance criteria.

L21-58 Furthermore, on p. 5.47, the PR-DEIR states that for VOCs, "Alternative 7" emissions are lower than the original project's emissions and "will be offset through the application of emissions reductions credits pursuant to SCAQMD requirements ***if warranted***" (emphasis added). Similar language appears at page 5.66 for "Alternative 8." This conclusory and uninformative statement fails to disclose whether these impacts are significant. By comparison, the discussion of health risks plainly shows a comparison to thresholds of significance (Tables 5-3 and 5-9). The failure

L21-58 to do the same for criteria pollutants is a failure to disclose impacts and provide information needed to evaluate these alternative versions of the project.

Sensitive Receptors

L21-59 Appendix C.1 contains a discussion of sensitive receptors as part of its section on consistency with laws, ordinances, regulations and standards, on pdf pages 411-412. Page 411 states that Table 25 lists sensitive receptors within a mile of the project. **This statement and Table 25 give a misleading impression of the sensitive receptors in the vicinity.**

Table 25 is titled "Schools and Childcare Facilities in Project Area." The closest receptor listed is 0.49 mile from the project. Yet page 411 notes that the nearest residential receptor is approximately 694 feet from emission sources, and the nearest worker/commercial receptor is located approximately 572 feet from emission sources. These receptors are both much closer to the project site (0.13 mile and 0.11 mile, respectively) than any of the receptors listed in the table. The discussion should not present information suggesting these nearby residential and worker/commercial receptors are not among the closest sensitive receptors, as Table 25 does.

Health Risk Assessment

L21-60 PR-DEIR Table 5.3 (p. 5.47) summarizes health risks to residential receptors for "Alternative 7." The identified measurement for the maximum individual cancer risk is 0.5. **That value appears to be inconsistent with values in the technical appendix.** The Health Risk Assessment in Appendix C.1 contains the following values: pdf p. 527, Table D-1, shows cancer risk values of 2.0, 1.5, and 1.0 in a million for the PMI, MEIR, and MEIW, respectively. The MEIW appears to be the applicable value. In the Air Dispersion Modeling and Health Risk Assessment Alternative 6 and 7 Addendum, Table 4-4 on pdf p. 555 indicates a cancer risk of 1.71 in one million for the MEIR. Table B-1 on pdf p. 564 and B-7 on pdf p. 567 appear consistent with these numbers. None of these values are the 0.5 in one million value shown in PR-DEIR Table 5-3.

L21-61 For "Alternative 8," Health Risk Assessment materials are provided at pdf pages 603-621. These materials include several pages of data tables, followed by several pages of maps. The maps are identified as "showing the locations of modeling results." The appendix does not contain any explanation of why those locations were selected for modeling. Also, results are presented as representing residential risks and worker risks. For cancer risk, chronic output, and chronic 8-hour modeling, the residential and worker modeling locations are identical. For acute risks, there are two modeling locations each for residential and worker risks—one of the residential modeling locations is in the same location as the location for all cancer and chronic risk modeling, but the comparable worker modeling location is closer to the project site. No explanation is given to explain (1) the use of the same modeling location for residential and worker risks for most scenarios, (2) the use of a different modeling location for one worker risk measure but not for the others, and (3) the inclusion of a second modeling location for each of

L21-61 the acute risk scenarios but not for the cancer and chronic risk scenarios. By comparison, for "Alternative 7," Appendix C.1 shows different locations for residential and worker risks. (See pdf pages 523-525 and 556-558.) **This appears to be an analytical inconsistency for the two project options.**

Maximum Operating Hours Assumptions

L21-62 Analysis of air quality emissions for "Alternative 7" presents different assumptions about how many hours the equipment would operate. This is confusing and misleading, making the analysis inadequate.

Inconsistencies in Assumptions

L21-63 The assumptions underlying the air quality analysis are unclear and appear to fluctuate in different parts of the PR-DEIR document.

For "Alternative 7," Appendix C.1 states that the analysis of criteria pollutant emissions was based on assumptions that each engine would operate "a total of 1120 hours per year with up to 280 startups/shutdowns per year, and remaining operations at full load" (pdf p. 392). **This phrasing suggests that the 1120 hours per year includes the hours for startups/shutdowns, but it is not entirely clear.** Additionally, pdf p. 392 refers to Appendix C.1's Appendix B for detailed calculations, and pdf p. 395 states that the emissions during normal operations exclude emissions from commissioning and startup periods. Appendix C.1's Appendix B's Appendix Table B-4 sets for the operating schedule for the analysis. It shows 1120 normal/full load operating hours listed separately from cold starts, warm starts, and hot starts (pdf p. 483). This suggests that the total of 1120 hours per year in Appendix C.1 excludes the hours for startups/shutdowns, so that the engines would actually operate more than 1120 hours per year. **This is an apparent inconsistency with the statement on pdf page 392.**

L21-64 Additionally, the PR-DEIR analyzes startup emissions separately from normal operating emissions because the former are higher (pdf p. 393). Tables 9 and 12 in Appendix C.1 (pdf pp. 394 and 395) note that for each startup hour, 30 minutes are treated as emitting at the startup rate and 30 minutes are treated as emitting at the full-load operation rate. If these values are used, then the total assumed hours per year are 1120 + 280 x 0.5, or 1260 hours. Also, the analysis assumes a total of 1120 hours per year of normal/full load operations. It is unclear whether that includes the 30 minutes from each startup hour or only full hours of normal/full load operation, or whether those 30 minutes in startup hours are unaccounted for, so that the total hours would be above 1260. **Did this analysis in fact assume 1260 hours, or a higher number?**

L21-65 A different set of numbers appears in another part of Appendix C.1: Appendix C.1's Appendix D1, Trinity Consultants' May 2020 Air Dispersion Modeling Report and Health Risk

L21-65 Assessment (see pdf pp. 490-491). Appendix D1 has its own Appendix A, in which Appendix Table A-1 presents project emissions based on assumptions that each unit would operate 980 hours per year at normal conditions and 280 hours per year in startup mode (pdf p. 514, Table A-1, note B). The total, 1260, is the same as one scenario noted above, but the startup hours is double that in Appendix C.1, raising **the possibility that the higher emissions in startup/shutdown mode are overcounted in one analysis or undercounted in the other. The discrepancy should be explained.**

L21-66 For "Alternative 8," Appendix C.2's first page of data shows an operating schedule that assumes 1200 hours (pdf p. 597).[9] The second page shows "Annual Op. hours: 1,200" and shows the number of normal operating hours per year as 1035.40 and the hours of startups/shutdowns per year as 156, suggesting the *total* hours assumed for "Alternative 8" is 1191.4, approximately 1200 hours, different from 1120 and 1260 (pdf p. 598).[10] **This is yet another inconsistency in assumed operating hours.**

L21-67 We were not able to find an explanation for these inconsistencies in assumptions. In the absence of an explanation, the PR-DEIR's analysis is called into question. If an explanation appears within the document, please provide page references.

Inconsistencies Between Assumptions and Potential Equipment Operations

L21-68 Appendix C.1 shows that GWP seeks to run the equipment longer than the time assumed for the analysis of air quality impacts. As stated below, Appendix C.1 states that the analysis of criteria pollutant emissions was based on assumptions that each engine would operate a total of 1120 hours per year with up to 280 startups/shutdowns per year, and with operations at full load. The next sentence states, **"These assumptions are not intended to be imposed as permit limitations"** (pdf p. 392).

L21-69 Additionally, application forms submitted as part of the application package to SCAQMD list the operating schedule as follows (pdf pp. 427, 437, 447, 457, 467):

Normal:	up to 10 hours/day; up to 5 days/week; up to 50 weeks/yr
Maximum:	24 hours/day; 7 days/week; 52 weeks/yr

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[9] We presume this refers to hours, but the units are not disclosed.

[10] The information in the tables on pdf p. 598 is not clear. The number of normal operating hours per year is listed in the table showing emissions, but the number of startup/shutdown hours per year are not listed there. It is therefore unclear whether the Annual PTE values represent only normal operating hours or are inclusive of startup/shutdown operations. Since the values in the far right column match those in the summary table, which appears to be the source of the values in Table 5-8 on PR-DEIR page 5.65, <u>please explain how the data tables show how the startup/shutdown hours per year are included in the total values</u>.

L21-69 The assumed number of hours in the analysis, although not entirely consistent, is generally in the range of 1120 to 1260 hours, or only 13-14% of the maximum operating schedule in the application forms. **The analysis was based on this assumed range of hours, and is not valid if the units may run for a higher number of hours.**

If there is in fact a potential for operating more than the amount for which analysis was done, the analysis must be updated. It is very likely that if the units are run much more than the amount assumed in the present analysis, the new analysis will conclude that there are significant air quality impacts.

L21-70 On the other hand, if this analysis is carried through to the final environmental review document, then there must be conditions placed on operation of the plant to ensure that the units are operated within the limit of the operating schedule on which the analysis was based. **These conditions must be included both in the SCAQMD permit and as binding conditions of approval by the City Council. The CEQA analysis cannot be used as the basis for approving this project unless it is definitively established that the gas-combusting units will not run longer than the amount in the analysis.**

Needed Corrections in PR-DEIR

L21-71

The PR-DEIR incorrectly states the difference between the generation capacity of "Alternative 8" and the original project. Rather than 172 MW difference, the difference is 161 MW. The error leads to potential confusion as readers compare "Alternative 7" and "Alternative 8."

L21-72 The PR-DEIR causes further confusion by explaining, in the paragraph above Table 5-8, that criteria pollutant and GHG emissions were estimated for the "Tesla/Wartsila Repowering Project" and that the table summarizes the emissions for the "Tesla/Wartsila Repowering Project"—in other words, for "Alternative 7," not "Alternative 8."

Greenhouse Gases

L21-73 The PR-DEIR discusses greenhouse gas (GHG) emission impacts for each of the two project options in about one-half page (pdf pp. 156-157, 176). **Half a page of analysis is not adequate for one of the most crucial potential impacts of a power plant—its contribution to climate change.** This itself is a serious flaw, but that is compounded by other flaws discussed below.

GHG Emission Baseline

L21-74 **Baseline Hidden in Appendices**

The PR-DEIR states that it uses an updated greenhouse gas (GHG) emissions baseline, like for air quality, with the landfill gas flared at Scholl Canyon rather than combusted at Grayson (p.

L21-74 xiv). The PR-DEIR itself does not compare emissions with—or even provide—a baseline. Because the baseline was updated, this comparison is an important but missing part of the analysis in the PR-DEIR. To locate it, the reader must hunt through the appendices.[11]

Inconsistency with Air Quality Baseline

Once found, the baseline calculation shows another issue. The baseline calculation in Appendix C.2 shows a breakdown of emissions by gas-burning unit (pdf p. 623). Although the table shows
L21-75 landfill gas was burned in Boilers 3 through 5, emissions are shown as zero. A note explains that GHG emissions from LFG combustion were excluded from the baseline because those emissions were counted toward the Scholl Canyon project. **This is inconsistent with the air quality analysis, as noted previously. Air quality and greenhouse gas impacts are closely related, and should be treated the same way in the PR-DEIR.**

Inadequate Disclosure and Support for Baseline

The selection of the baseline is problematic, and as we discussed for air quality, inconsistencies and inadequate justifications for the selected baselines are a significant flaw of the PR-DEIR. In the case of greenhouse gas emissions, the lack of disclosure means that the public can't even
L21-76 evaluate the appropriateness of the selected baseline and look for inconsistencies—because **no information is provided to identify when these emissions occurred** (pdf p. 623). This is a substantial gap that must be remedied with sufficient time for the public and decision makers to examine the assumptions underlying this baseline. Please provide information regarding the source of the information in Appendix C.2 regarding the GHG emission baseline.

Flaws in Analysis

First, there are internal inconsistencies and weaknesses in the GHG emissions analysis.

L21-77

For "Alternative 7," there are inconsistent values for emissions. The PR-DEIR states that the emissions of greenhouse gases (CO_2e/year) for "Alternative 7" will be 54,063 $MTCO_2e$/year (pdf p. 157). In Appendix C.1, there is a page setting out the emission estimate, with the 54,063 $MTCO_2e$/year value (pdf p. 398). The reader is referred to Appendix B for detailed calculations. Appendix Table B-5 is the only relevant table (pdf p. 484). **The total $MTCO_2e$/year shown is 54,075—close to the 54,063 in the PR-DEIR, but not the same. The inconsistency is not explained.** We were unable to find another source for the 54,063 value. If one exists in the document, please provide page references.

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11 We were also unable to find a baseline identified in Appendix C.1. That appendix refers the reader to Appendix C.1's Appendix B for detailed calculations (see pdf p. 398). Appendix Table B-5 is the only relevant table in Appendix B (pdf p. 484). No baseline is shown. A baseline calculation does appear in Appendix C.2, at pdf p. 623.

L21-78 For "Alternative 8," the PR-DEIR states that the GHG emissions would be 66,925 MTCO2e/year (pdf p. 176). Appendix C.2's single page of GHG emissions data (pdf p. 623) shows this value as only one component of the total project GHG emissions. **The total is 67,195 MTCO2e/year. There is no explanation of why the PR-DEIR does not use that value.** As the calculated total, it is the better value to disclose in the PR-DEIR.

Second, **there are several inconsistencies between the way the analysis is done for the two project options**. There does not appear to be any good reason for analyzing these two project
L21-79 options differently, and the inconsistencies impede the ability to draw direct comparisons.

- The analyses for the two project options are based on different numbers of operating hours: For "Alternative 7," the analysis is based on 1260 hours of equivalent full-load operation; for "Alternative 8," the analysis is based on 1200 annual operating hours (compare pdf p. 484 with pdf p. 623).
- As already observed, "Alternative 7" emissions are not compared with a baseline, but "Alternative 8" emissions are.
- Also as already noted, the "Alternative 7" analysis considers only direct emissions from the gas-burning units, whereas the "Alternative 8" analysis includes other emissions—from facility occupants.

Third, both of these analyses assume a number of total operating hours over a year that is low compared with the potential maximum run time (again, the analysis for "Alternative 7"
L21-80 assumes 1260 equivalent full-load operating hours per year, and the analysis for "Alternative 8" assumes a total of 1200 annual operating hours [pdf pp. 484, 623]; there is evidence showing that GWP does not intend to limit operations to that schedule [pdf p. 392, pp. 427, 437, 447, 457, 467). **As for the air quality analysis, unless it is guaranteed that the gas-combusting units will not run longer than the respective amount for the selected project option, this analysis cannot be used as a basis for approval of the project**.

Fourth, the analysis is limited to only some sources of GHG emissions, and **other emission sources are improperly omitted**.

- For "Alternative 7," the first missing information is emissions from facility occupants, which was included for "Alternative 8."
- For both, the analysis omits mention of the switching station and Tesla BESS, so it is
L21-81 undisclosed whether those would emit GHGs or not.
- No construction-related emissions are disclosed.
- There is no analysis of GHG emissions from project-related use of off-road equipment and vehicle trips.
- The PR-DEIR does not analyze GHG impacts related to energy produced outside Glendale but used to charge the Tesla BESS (see above section on Project Description).

Compare the original project's FEIR, section 4.5, which shows analysis of emission sources other than the gas-burning equipment itself. Moreover, a fair comparison of the two project options

L21-81

must include emissions from all sources for both, accounting for differences between the options.

L21-82

Piecemealing

Concerned residents of Glendale have noted repeatedly that the City should have considered the impacts of the Grayson Repowering and Scholl Canyon Biogas Projects together. This is one example of possibly improper piecemealing of environmental analysis. While the PR-DEIR acknowledges the potential for a power generation facility at Scholl Canyon, anticipated emissions are not presented or discussed. At a minimum, the total emissions for the two projects must be presented and analyzed in the discussion of cumulative impacts. As part of that discussion, **the analysis must account properly and logically for the flaring of LFG as part of the baseline emissions, without double counting or otherwise misleading analysis**.

L21-83

Also, as noted before, the source of the power for charging the Megapack storage has been left up in the air. **All emissions associated with charging the batteries must be identified**, whether or not they are generated in the South Coast Air Basin. This is doubly important for greenhouse gases.

An off-site area may be used for storage during construction. Impacts to the off-site area are not addressed at all, and should be.

All of the above actions are facets of the proposed project and will assist in achieving the stated project objectives. As such, they must be identified, quantified, and analyzed in one EIR.

L21-84

Alternatives

The City should consider and present analysis for alternatives that reduce the amount of gas-burning equipment compared with the current project options, which both involve approximately 100 MW of gas capacity. For example, "Alternative 7" includes 5 ICE units. In 2019, when the Wartsila engines were first proposed to City Council, **council members expressed a strong desire for staff to work toward reducing or eliminating the need for the 5 units**, including by exploring additional distributed energy resources and additional transmission capacity. The PR-DEIR does not present any new project alternatives that accomplish that goal.

L21-85

GWP will have access to more transmission than previously expected since the 2019 IRP report and alternatives were discussed. This includes 72 MW more transmission available in 2027. The PR-DEIR acknowledges this change in circumstances, **but this transmission is not sufficiently addressed through consideration of new alternatives**. This also includes 25 MW of transmission associated with the Eland project beginning in 2024, which the PR-DEIR appears not to mention at all. The analysis of alternatives should be updated to account for these changes in the circumstances for Glendale's energy planning.

L21-86 The original EIR's Alternative 2, which is discussed in PR-DEIR at pages 5.9 to 5.17, is a potentially viable starting point for an alternative that eliminates gas-burning investments, but the PR-DEIR does not use this opportunity to explore its potential. The PR-DEIR did not update the discussion of Alternative 2 to account for increased transmission. The analysis states that the City would use a total supply of 287 MW composed of 48 MW from Unit 9, 39 MW form Magnolia, and 200 MW imported over transmission lines (p. 5.10). But the City has obtained additional transmission rights, as noted above. This is material because the City rejected this alternative at least in part because of inadequate transmission to import electricity to charge the batteries to serve daytime load, and also because the PR-DEIR states that the power supply would be less than the City's peak loads but that appears to not be the case with the increased transmission. **The increased transmission should be reflected in the PR-DEIR's discussion of Alternative 2. It is also unclear whether the additional transmission was included in the analysis of the N-1-1 contingency on p. 5.12.**

L21-87 The information about Alternative 2 in the PR-DEIR is also confusing and inconsistent, because much of the discussion appears to suggest that the storage system would need to be extremely large compared with the current Tesla BESS-based project options (large enough to store 2940 MWh of energy), but in the table on page 5.74, the amount of energy storage for Alternative 2 is listed as 161 MW. **Please clarify the size of battery system under consideration for Alternative 2.**

L21-88 The PR-DEIR's reasons for rejecting the energy-storage alternative appear to be based on several assumptions that are in question, particularly given evolving technology and cost reductions. Reasons given in the PR-DEIR for rejecting the energy-storage alternative that should be revisited include, but are not limited to, the following (see pp. 5-12-5:15):

- PR-DEIR: The storage system would need to be capable of storing and supplying 2,940 MWh. The PR-DEIR does not clearly explain why this is the amount of stored energy that would be needed to meet load during a four-day period. Although shortfalls are cumulative, some amount of energy will be available to recharge the batteries each day; the PR-DEIR does not offer any calculations to justify the 2,940 MWh value.
- PR-DEIR: The amount of storage needed is too large to be placed at Grayson. The PR-DEIR limits its consideration to placing storage at this single site, and should consider distributing storage
- PR-DEIR: The cost of 2,940 MWh is approximately $588,000,000 based on the Clean Energy proposals received by GWP (approx. $200,000/MWh and higher). First, the need for 2,940 MWh should be re-examined. Second, the Clean Energy proposals were received in 2018. Third, it is clear that the City did not conduct any research for updated costs of energy storage, and relied solely on values from a single RFP from 2018, despite

L21-85

significant cost reductions since then. BloombergNEF shows that costs have been falling and are expected to continue to do so, with a 2020 price of $137/kWh.[12]

L21-88

- PR-DEIR: Batteries have a finite life and require periodic augmentation, and maintenance contract costs could be several million dollars per year. This information is stated conclusorily, with no factual support. However, it should be obvious that gas-burning equipment also has a finite life and requires maintenance and repair over ***its*** lifetime. Without full disclosure of costs for all potential projects, it is impossible for the public and decision makers to evaluate all alternatives' comparative costs and benefits and make informed decisions.
- PR-DEIR: The costs for the energy storage alternative do not include the cost to produce and transmit the energy to charge the batteries. A fair comparison would provide the cost to fuel the gas-burning engines in the current project options, as well as the costs to produce and transmit the energy to charge the Tesla BESS.

L21-89

Options with greater battery storage than proposed in "Alternative 7" and "Alternative 8" were dismissed in the Ascend Analytics 100% Clean Energy by 2030 Feasibility Study (March 1, 2021, https://glendaleca.primegov.com/Portal/viewer?id=2735&type=2) for financial reasons; however, **options with greater storage capacity should have been pursued thoroughly in the PR-DEIR, either in Alternative 2 or in new alternatives**, so that when the costs of the various projects are presented, different alternative pathways to clean energy are available to compare. Higher costs alone do not render a project alternative infeasible and are not sufficient reason to decline to analyze a potential alternative.

L21-90

Moreover, in considering costs, they should be looked at over decades, and must include escalating costs for gas and carbon offset credits, costs to convert any potential gas units to green hydrogen, and other costs associated over the life of the project. Decisions about which project alternatives to pursue because of cost considerations must take all direct and indirect costs into account in order to provide a complete and fair disclosure of information for decision makers.

L21-91

Other potential alternatives that could be feasible and reduce the project's environmental impacts include one posed in the 2019 IRP, as scenario F: 56 MW ICE and 100 MW BESS (see PR-DEIR p. ix, and Integrated Resource Plan, 7/23/2019, https://www.glendaleca.gov/home/showdocument?id=51814, p. 51.) The City should consider alternatives based on this scenario and also taking into account the additional transmission on the SWAC line (72 MW in 2027) and the additional transmission from the Eland Project (25 MW in 2024). Additionally, the IRP explains that the amount of imported renewable

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[12] BloombergNEF, The Spectacular Energy Storage Growth, May 12, 2021, attached as **Attachment 4**, and available at https://www.climateinvestmentfunds.org/sites/cif_enc/files/knowledge-documents/thespectacular_energy_storage_growth.pdf, p. 3.

L21-91

resources was limited to the amount above local clean energy and load reduction that would be needed to meet SB 100 RPS goals (see IRP at p. 37). This suggests that it may be feasible to add more imported renewable resources to reduce the need for thermal generation. The City should consider that as part of examining potential alternatives based on the scenario F framework. Note that at least some additional imported renewable resources must be feasible, because the IRP presented two other scenarios that included 140 MW each of imported solar and wind than scenario F did (see IRP at p. 51). Rather than stopping with meeting the RPS requirement, the City should aim to maximize clean, carbon-free energy sources for a portfolio that will make Glendale a leader in the new energy future.

Conclusion

L21-92

We seek the best outcome for Glendale's energy future. We do not believe that the current project options represent that best outcome, and we urge the City to do what the City Council and residents have been requesting since 2017: develop an energy plan that accelerates progress toward 100% clean energy, and that avoids new investments in gas-burning equipment and locked-in greenhouse gas emissions and local air pollution for years to come. Transitioning is necessary given the accelerating impacts of the climate crisis and the city's moral imperative to stop contributing to that crisis.

L21-93

We also ask that the City conduct a more searching analysis of the current project options, rather than the abbreviated analysis that was enabled by treating the project as mere alternatives to a project that Glendale walked away from almost 4 years ago.

L21-94

We request that the final environmental review document for the Grayson project be released at least 30 days before it is presented to the GWP Commission and Sustainability Commission. Commissioners, who are volunteers serving the public in their personal time, will need time to fully review and consider the information in the final document. Members of the public, who also will be making time to review the EIR in their personal time, are concerned and wish to have a meaningful opportunity to review additional disclosures in the final environmental review document. Releasing the final document according to the statutory minimum timeline will not give the public sufficient opportunity to review the document and communicate remaining concerns to commission and City Council members before the commissions and Council deliberate and make their decisions regarding the Grayson project. Glendale should provide a full and complete opportunity for public participation in the process for making this consequential decision.

Sincerely,

Glendale Environmental Coalition steering committee members

Monica Campagna	Jane Potelle	Kate Unger
Elise Kalfayan	Paul Rabinov	

L21-A

CITY OF GLENDALE, CALIFORNIA
REPORT TO THE CITY COUNCIL

AGENDA ITEM

Report: Amendment of Contracts with Stantec Consulting Services, Inc. and Black & Veatch Corporation for Additional Professional Services Pertaining to the Limited Notice to Proceed Phase of the Proposed Grayson Repowering Project Alternatives

1) Motion authorizing the Interim City Manager, or his designee, to execute an Amendment to Contract No. 8000053 with Stantec Consulting Services, Inc. to increase the contract amount by $570,000 to provide additional professional services for the Limited Notice to Proceed Phase of the proposed Grayson Repowering Project Alternatives.

2) Motion authorizing the Interim City Manager, or his designee, to execute an Amendment to Contract No 8000847 with Black & Veatch Corporation to increase contract amount by $350,000 to provide additional professional services for the Limited Notice to Proceed Phase of the Proposed Grayson Repowering Project Alternatives.

3) Resolution of Appropriation

COUNCIL ACTION

Item Type: Action Item

Approved for December 15, 2020 **calendar**

ADMINISTRATIVE ACTION

Submitted by:
Stephen M. Zurn, General Manager, Glendale Water and Power

Prepared by:
Mark Young, Deputy General Manager/Power Management

Reviewed by:
Michele Flynn, Director of Finance
Michael J. Garcia, City Attorney

Approved by:
Roubik R. Golanian, P.E., Interim City Manager

RECOMMENDATION

Glendale Water & Power (GWP) respectfully recommends that the City Council authorize the Interim City Manager, or his designee, to execute Amendments to Professional Services Agreements with Stantec Consulting Services, Inc. and Black & Veatch Corporation for additional professional services pertaining to Limited Notice to Proceed Phase of the proposed Grayson Repowering Project Alternatives. The additional professional services include environmental analyses and reviews, permitting support, technical studies and assessments, and engineering support and plans. It is further recommended that the City Council adopt a Resolution of Appropriation to fund the above-referenced amendments and other limited notice to proceed activities, such as South Coast Air Quality Management District (South Coast AQMD) permit application fees for the proposed Grayson Repowering Project Alternatives.

BACKGROUND/ANALYSIS

On July 23, 2019, the City Council adopted the GWP 2019 Integrated Resource Plan (IRP). The IRP identified a preferred energy supply portfolio that included, among other things, the following resources selected from a 2018 Request for Proposals for Local and Regional Renewable, Low-Carbon, and Zero Carbon Resource Options to Serve the City of Glendale (the Clean Energy RFP): (1) a 75 megawatt (MW) / 300 megawatt-hour (MWh) battery energy storage system (BESS) of which 50 MW / 200 MWh would be installed in the near term, followed by an additional 25 MW / 100 MWh BESS to be installed in the future; (2) 93 MW of reciprocating internal combustion engine (ICE) generators; and (3) up to 50 MW of clean distributed energy resources.

At the July 23, 2019 meeting, the City Council authorized GWP to proceed with the Limited Notice to Proceed (LNTP) phase, or study and development phase, for the proposed BESS and ICE unit alternative at the Grayson Power Plant. The Council authorized Professional Services Agreements with Tesla, Inc. (Tesla) and Wartsila North America, Inc. (Wartsila) for preliminary engineering and planning services for the proposed 50 MW / 200 MWh of BESS and up to five ICE generators (93 MW of capacity). Additionally, the City Council authorized amendment of an existing Professional Services Agreement with Stantec Environmental Services, Inc. (Stantec) for environmental review of the proposed BESS and ICE alternative.

On March 10, 2020, following a request for proposal process, the City Council authorized a Professional Services Agreement with Black & Veatch Corporation (Black & Veatch) for Owner's Engineering services during the LNTP phase of the proposed Grayson Repowering Project Alternative. Black & Veatch's services include technical studies, engineering plans, development of specifications, financial analysis, support for environmental analysis, and engineering consulting services as needed for the proposed project alternative.

Pursuant to the City Council's direction, the City has undertaken engineering, technical studies, and environmental reviews of the proposed BESS/ ICE project alternative. The proposed new project Alternative, termed "Alternative 6" for the Environmental Impact Report, is comprised of the following:

1. Decommissioning, demolition, and removal of Grayson Units 1-8 including the "Boiler Building" that houses the existing Units 1-5 steam plant and, the decommissioning and removal of the existing 34.5 kilovolt (kV) switchyard;

2. Engineering, procurement, and construction (EPC) of a BESS (with a 50 MW BESS to be installed now, and an additional 25 MW BESS to be installed under a separate contract in the future) and a 93 MW ICE generator plant;
3. A new control room and office spaces for operations;
4. Separation of Grayson Unit 9 from the existing Grayson infrastructure that would be demolished; installation of temporary infrastructure to support continued operation of Unit 9 during the demolition and construction phase, then reintegration of Unit 9 into the overall Grayson Power Plant after the proposed Alternative 6 project is completed;
5. Protection-in-place of existing Grayson water wells 1 and 2 for future use by the GWP Water Department;
6. EPC of a new 34.5/69 kV switchyard (referred to as the Glendale Switching Station) to replace the existing 34.5 kV switchyard and increase the resilience of GWP's electrical system; and,
7. Other balance-of-site EPC work, such as a new water treatment system, station service substation, warehouse/workshop for plant maintenance, storm water system, and the replacement of existing water main and plant potable/fire suppression water systems.

In July of 2020, GWP learned that the California High Speed Rail Authority (Rail Authority) had concluded in a Historic Architectural Survey Report for the EIR associated with the California High Speed Rail (Burbank to Los Angeles Section), that the L.W. Grayson Steam-Electric Generating Station (i.e. the Boiler Building at the Grayson Power Plant) was potentially eligible for listing in the National Register of Historic Places. The conclusions of the Rail Authority differed from the 2016 Architectural Resource Evaluation prepared for the Grayson Repowering Project EIR, which found that the existing structures at the Grayson site are not eligible for listing on national, state or local historic registers. Discussions with the Rail Authority's consultant confirmed that the Rail Authority's findings were based on a much more limited review and no access to the site or the Boiler Building itself.

On November 4, 2020, the Rail Authority notified the City of Glendale and the State Historic Preservation Officer that it considers the L.W. Grayson Steam-Electric Generating Station to be ineligible for listing in the National Register of Historic Places, and the State Historic Preservation Officer has concurred with this determination.

Project Alternatives 7 and 7A

Due to the assertion that Boiler Building may be historic, GWP commenced evaluation of a project alternative ("Alternative 7") that would retain the Boiler Building in place and move the ICE and BESS power islands to a different location on the Grayson site.

Based upon preliminary evaluation, retaining the Boiler Building would delay construction of the BESS as more demolition work would be needed in order to clear space where the BESS power island would be located. Additionally, taller exhaust stacks with more extensive foundations would be required if the Boiler Building were to be retained. Retaining the Boiler Building carries an opportunity cost as it would also eliminate space that was envisioned for additional energy storage facilities in the future (beyond the 75 MW). On the other hand, based upon a preliminary assessment, the new layout would reduce the number of old existing piles that must be removed for the new ICE power island and could reduce the number of piles required.

While the Boiler Building is not a historic resource, GWP proposes to evaluate the new alternative layout in the EIR, both with and without the Boiler Building. This proposed new layout for the BESS/ ICE plant would be designated in the Grayson Repowering Project EIR as Alternative 7 (new layout retaining the Boiler Building) and Alternative 7A (new layout without the Boiler Building).

To fully assess Alternatives 7 and 7A, additional studies are needed that were not included within the scope of the original Stantec and Black & Veatch Professional Services Agreements. The reconfiguration of the site necessitates that various studies that are dependent upon the physical arrangement of the equipment (such as noise and air quality studies) must be re-studied. Additionally, given the age of the Boiler Building, more work is needed to understand what modifications would be needed to extend the building's life and/or comply with mandatory upgrades, if the Boiler Building were to be retained. Therefore, an amendment to the Professional Services Agreements is needed to complete the work.

Alternative 8 – Extend the Life of Units 8A and 8BC

As another alternative to the proposed Grayson Repowering Project, GWP is also evaluating an option that would retain combustion turbine generator Units 8A and 8BC. This alternative would result in extending the lives of these units by refurbishing the gas turbine generators and replacing other elements of the units with new equipment. The result would be units that are more reliable, efficient, capable of meeting a ten-minute to full load start requirement, and capable of meeting new South Coast AQMD emission requirements set to take affect January 1, 2024. This new option is being evaluated in the proposed Grayson Repowering Project EIR as Alternative 8.

In addition to extending the life of Units 8A and 8BC, Alternative 8 would include the 75 MW / 300 MWh BESS that is also part of Alternatives 6, 7, and 7A. As with Alternatives 6, 7 and 7A, with Alternative 8, the Grayson Units 1-5 steam plant and related facilities would be demolished, and the new Glendale Switching Station would be added. This Alternative could support both the demolition or retention of the Boiler Building.

The work needed to study and evaluate this alternative was not in the Professional Services Agreements with Stantec and Black & Veatch for the LNTP Phase for Alternative 6. This additional work includes plant configuration studies, conceptual designs, engineering cost estimates, environmental reviews, and air modeling. Therefore, an amendment to the Professional Services Agreements would be required to evaluate this Alternative.

Alternative 6 – Additional Required Studies

In addition to the above costs associated with the analysis of Alternatives 7, 7A, and 8, an Amendment to the Professional Services Agreement with Stantec is needed for additional work that was not included in the original scope of work for the LNTP phase for Alternative 6. The additional work includes noise and visual impact evaluations related to Confluence Park; a quantitative analysis of potential air quality impacts of a potential BESS thermal event; a quantitative assessment of construction noise; demolition engineering support; and a Phase II study of the existing 34.5 kV switching station. Work that is common to other proposed alternatives will not be duplicated.

FISCAL IMPACT

Staff is requesting a Resolution of Appropriation to transfer funds from Net positions, Electric Fund Balance (27900-5810-0000) to Contractual Services, Electric Depreciation Fund, GWP Projects (43110-5830-GWP-0020-P0000-T0000-Various FERCs) in the amount of $1,255,000, asfollows:

<u>Stantec Consulting Services, Inc.</u>
To amend existing Professional Services Agreement No. 8000053 with Stantec Consulting Services, Inc. to increase the contract amount by $570,000 to fund the additional scope of work pertaining to the evaluation of Alternatives 6, 7, 7A and 8. Funds for this project will be made available from the Grayson Repower Project (P13748). Therefore, staff is requesting a Resolution of Appropriation to transfer funds from Net positions, Electric Fund Balance (27900-5810-0000) to Contractual Services, Electric Depreciation Fund, GWP Projects, Admin General Plant Allocation FERC (43110-5830-GWP-0020-P0000-T0000-F3890; Munis PL P13748-CNTRCSVCS-F3991) in the total amount of $570,000 to fund the cost associated with this Professional Services Agreement.

<u>Black & Veatch Corporation</u>
To amend existing Professional Services Agreement No. 8000847 with Black & Veatch Corporation to increase the contract amount by $350,000, to fund the additional scope of work for pertaining to the LNTP phase of the proposed modernization of the Grayson Power Plant. Therefore, staff is requesting a Resolution of Appropriation to transfer funds from Net positions, Electric Fund Balance (27900-5810-0000) to Contractual Services, Electric Depreciation Fund, GWP Projects, Owner's Engineering Services for Grayson Power Plant (43110-5830-GWP-0020-P0000-T0000-F3000 and F3500; Munis PL GWP00170CN-CNTRCTSVCS-F3437 & F3510) in the amount of $350,000 to fund the cost associated with this Professional Services Agreement.

<u>Additional LNTP Costs</u>
Staff anticipates that there will be costs associated with additional LNTP phase, including South Coast AQMD permit application fees for the additional alternatives and legal services associated with the preliminary development and permitting, estimated at $335,000. Therefore, staff is requesting a Resolution of Appropriation to transfer funds from Net positions, Electric Fund Balance (27900-5810-0000) to Contractual Services, Electric Depreciation Fund, GWP Projects, Admin. General Plant Allocation FERC (43110-5830-GWP-0020-P0000-T0000-F3890; Munis PL P13748-CNTRCSVCS-F3991) in the total amount of $335,000 for above mentioned activities.

ALTERNATIVES

Alternative 1: The City Council may choose to authorize the Interim City Manager, or his designee, to execute the proposed amendments as recommended herein to cover the costs of completing the evaluation and development of Alternative 6 and evaluating and developing Alternatives 7, 7A, and 8.

Alternative 2: The City Council may choose to authorize the Interim City Manager, or his designee, to execute Amendments to cover the cost of additional work to evaluate some, but not all, of the Alternatives.

Alternative 3: The City Council may consider any other alternative not proposed.

CAMPAIGN DISCLOSURE

The completed Campaign Disclosures for Black & Veatch Corporation and Stantec Consulting Services, Inc. are attached as Exhibit 1.

EXHIBIT(S)

Exhibit 1: Campaign Finance Disclosure Information for Black & Veatch Corporation and Stantec Consulting Services, Inc.

L21-B

Search Results

Start Range 2019-01-01
End Range 2021-11-12
Lead/Public Agency Burbank, City of
County Los Angeles

Edit Search

Download CSV

18 document(s) found

SCH Number	Type	Lead/Public Agency	Received	Title
2021050436	NOP	City of Burbank	9/22/2021	Burbank Downtown Transit Oriented Development Specific Plan
2021040181	NOD	City of Burbank	7/19/2021	Burbank Operable Unit (BOU) Remediation System Upgrades Project
2021070154	SCA	City of Burbank	7/9/2021	Burbank Aero Crossings Project
2021050436	NOP	City of Burbank	5/20/2021	Burbank Downtown Transit Oriented Development Specific Plan
2021040181	MND	City of Burbank	4/7/2021	Burbank Operable Unit (BOU) Remediation System Upgrades Project
2021040010	NOP	City of Burbank	4/1/2021	3700 Riverside Drive Mixed-Use Project
2021020393	NOP	City of Burbank	3/17/2021	Burbank Housing Element Update and Associated General Plan Updates
2021020393	NOP	City of Burbank	2/22/2021	Burbank Housing Element Update and Associated General Plan Updates
2020110213	NOE	City of Burbank	11/13/2020	Concurrence in the Issuance of a New Solid Waste Facilities Permit for Burbank Recycle Center in Los Angeles County, SWIS No. 19-AA-1149

SCH Number	Type	Lead/Public Agency	Received	Title
2020089016	NOP	City of Burbank	8/12/2020	Golden State Specific Plan Project
2019129091	MND	City of Burbank	12/27/2019	Burbank Water and Power Campus Stormwater Improvement Project
2019110032	NOP	City of Burbank	11/4/2019	2500 N. Hollywood Way - Dual Brand Hotel Project
2019090516	NOE	City of Burbank	9/20/2019	Burbank Recycle Center Findings for Exemption
2018041012	EIR	City of Burbank	7/1/2019	777 North Front Street Project
2019068084	NOE	City of Burbank	6/20/2019	Providence St. Joseph Medical Center ~ Emergency Department and Urgent Care Project
2018041012	EIR	City of Burbank	3/22/2019	777 North Front Street Project
2018011049	NOD	City of Burbank	1/30/2019	Media Studios Ten-Year Development Agreement Extension Project
2018011049	NOD	City of Burbank	1/15/2019	Media Studios Ten-Year Development Agreement Extension Project

L21-C

Search Results

Start Range 2019-01-01

End Range 2021-11-12

Lead/Public Agency Glendale, City of

County Los Angeles

Edit Search

Download CSV

47 document(s) found

SCH Number	Type	Lead/Public Agency	Received	Title
2021100301	NOE	City of Glendale	10/19/2021	Brand Park Reservoir Slope Repair Project, Specification No. 3871 and Plan No. 6926-E
2021100016	NOE	City of Glendale	10/1/2021	East End Studios - New Soundstage (Production) Project
2021090591	NOE	City of Glendale	9/30/2021	Glendale Heights Water Tank Replacement Project
2021080215	NOE	City of Glendale	9/27/2021	New 340-Unit Residential Density Bonus & Affordable Housing Project
2021090507	NOE	City of Glendale	9/27/2021	DENSITY BONUS & INCLUSIONARY HOUSING PLAN NEW 22-UNIT MIXED-USE BUILDING
2021090088	NOE	City of Glendale	9/7/2021	DENSITY BONUS & INCLUSIONARY HOUSING PLAN_NEW 17-UNIT RESIDENTIAL BUILDING
2021090018	NOE	City of Glendale	9/1/2021	DENSITY BONUS & INCLUSIONARY HOUSING PLAN_NEW 17-UNIT RESIDENTIAL BUILDING
2021080215	NOE	City of Glendale	8/12/2021	New 340-Unit Residential Density Bonus & Affordable Housing Project
2016121048	EIR	City of Glendale	8/9/2021	Grayson Repowering Project, Partially Recirculated Draft Environmental Impact Report.

SCH Number	Type	Lead/Public Agency	Received	Title
2021080140	NOE	City of Glendale	8/9/2021	Pedestrian Crossing Flashing Beacons Installation Project, Project No. HSIPSL-5144(076)
2017081062	FIN	City of Glendale	8/3/2021	City of Glendale Biogas Renewable Generation Project
2021070448	NOE	City of Glendale	7/23/2021	Parcel Map Waiver - Central Park Block
2020050044	NOD	City of Glendale	7/13/2021	New Single-family Residence
2021060219	NOP	City of Glendale	6/9/2021	1642 SOUTH CENTRAL AVENUE PROJECT
2021050123	NOE	City of Glendale	5/28/2021	New 127-Unit Residential Density Bonus Affordable Housing Project
2021050124	NOE	City of Glendale	5/25/2021	New 40-Unit Residential Density Bonus Affordable Housing Project
2021050131	NOD	City of Glendale	5/6/2021	New Multi-Family Development
2021050124	NOE	City of Glendale	5/6/2021	New 40-Unit Residential Density Bonus Affordable Housing Project
2021050123	NOE	City of Glendale	5/6/2021	New 127-Unit Residential Density Bonus Affordable Housing Project
2021030594	NOE	City of Glendale	3/25/2021	New 18-Unit Residential Mixed Use Developed/Density Bonus & Affordable Housing Project
2020100595	NOD	City of Glendale	3/24/2021	Glendale Citywide Pedestrian Plan
2021030293	NOE	City of Glendale	3/11/2021	New 34-Unit Residential Mixed Use Developed/Density Bonus & Affordable Housing Project
2021030250	NOP	City of Glendale	3/9/2021	1420 Valley View Road Project
2020120158	NOE	City of Glendale	12/9/2020	Ordinance Pertaining to Accessory Dwelling Units and Junior Accessory Dwelling Units
2020110069	NOE	City of Glendale	11/4/2020	Amendments to Title 30 of the Glendale Municipal Code, 1995, regarding Design Review for Projects in the DSP, Murals, Rebuilds Following Natural Disaster, and R
2020100595	MND	City of Glendale	10/30/2020	Glendale Citywide Pedestrian Plan
2020060208	NEG	City of Glendale	9/18/2020	Amendment to FY 2019-2020 Community Development Block Grant ESG-CV2

SCH Number	Type	Lead/Public Agency	Received	Title
2020070417	NOE	City of Glendale	7/22/2020	Local Urgency Ordinance to Extend Planning Entitlements in Response to Impacts Due to COVID-19 Emergency Orders
2017081062	EIR	City of Glendale	7/3/2020	Biogas Renewable Generation Project
2017081003	EIR	City of Glendale	6/25/2020	Wilson Middle School Multi-Purpose Field Project
2020060557	NOE	City of Glendale	6/25/2020	Amendments to Titles 2, 15, and 30 of the Glendale Municipal Code
2020060292	NOE	City of Glendale	6/15/2020	Citywide Guardrail Updates Project, Specifications No. 3830
2020060291	NOE	City of Glendale	6/15/2020	Colorado Street & Columbus Avenue Rehabilitation Project, Specifications No. 3629
2020050044	NOD	City of Glendale	6/15/2020	New Single-family Residence
2020060209	NOD	City of Glendale	6/10/2020	FY 2020-2021 CDBG, ESG and HOME Programs
2020060208	NOD	City of Glendale	6/10/2020	Amendment to FY 2019-2020 Community Development Block Grant
2020060188	NOE	City of Glendale	6/10/2020	New 137 Room Hotel Project
2020050343	NOE	City of Glendale	5/15/2020	Amendment to permit for Glendale Water Treatment Plant (GWTP) to remove PFAS
2020050044	MND	City of Glendale	5/1/2020	New Single-Family Residence
2019120315	NOE	City of Glendale	12/12/2019	Ordinances amending Titles 4, 5 and 30 of the Glendale Municipal Code, 1995, and General Plan Downtown Specific Plan (DSP) to prohibit vacation rentals, and per
2019120314	NOE	City of Glendale	12/12/2019	Urgency Ordinance Pertaining to Accessory Dwelling Units and Junior Accessory Dwelling Units
2019120239	NOE	City of Glendale	12/10/2019	25-Year Power Sales Agreement (PSA) with the Southern California Public Power Authority (SCPPA)
2019120134	NOE	City of Glendale	12/5/2019	Contract award to start the Glendale Land Use, Housing and Circulation Element Updates, Transportation Impact Fee, and Senate Bill (SB) 743 Implementation
2019100447	NOE	City of Glendale	10/23/2019	Authorizing the Submission of Application for California Department of Housing and Community Development (HCD) SB2 Grant

SCH Number	Type	Lead/Public Agency	Received	Title
2019100062	NOE	City of Glendale	10/2/2019	West Glendale Sustainable Transportation & Land Use Study Contract Award
2017081062	NOP	City of Glendale	3/21/2019	Biogas Renewable Generation Project
2018061015	NOD	City of Glendale	3/14/2019	Glendale Wastewater Change Petition WW0097

L21-D

The Spectacular Energy Storage Growth

Keeping the Power On: Sparking Energy Storage Solutions in Developing Countries

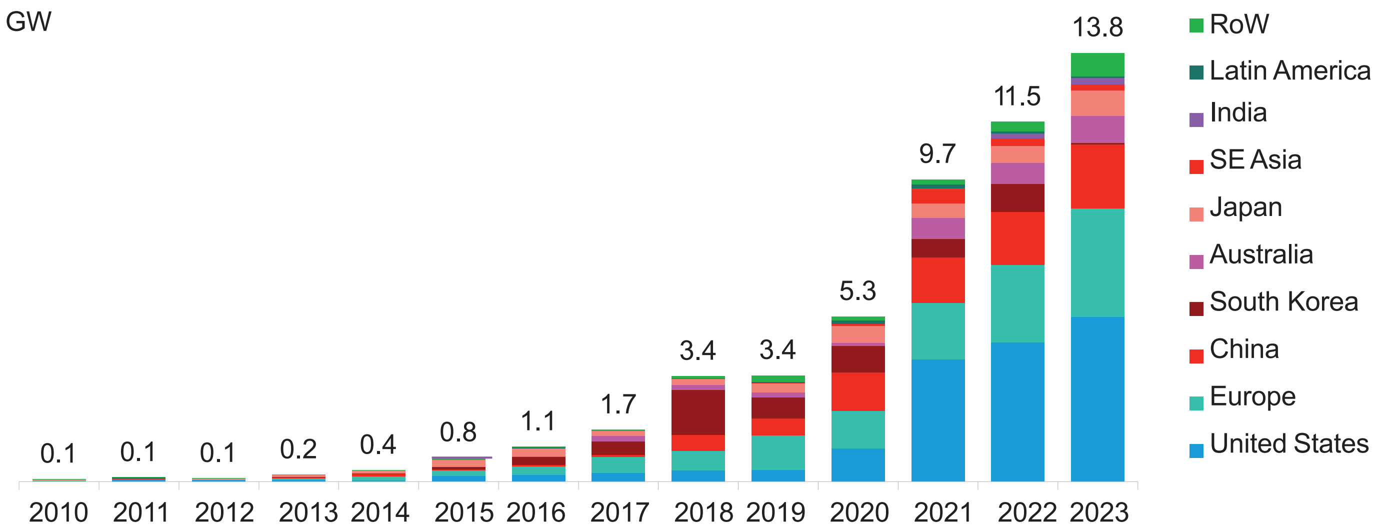
Yayoi Sekine

May 12, 2021

BloombergNEF

Global energy storage market on a record-setting spree

Global energy storage build

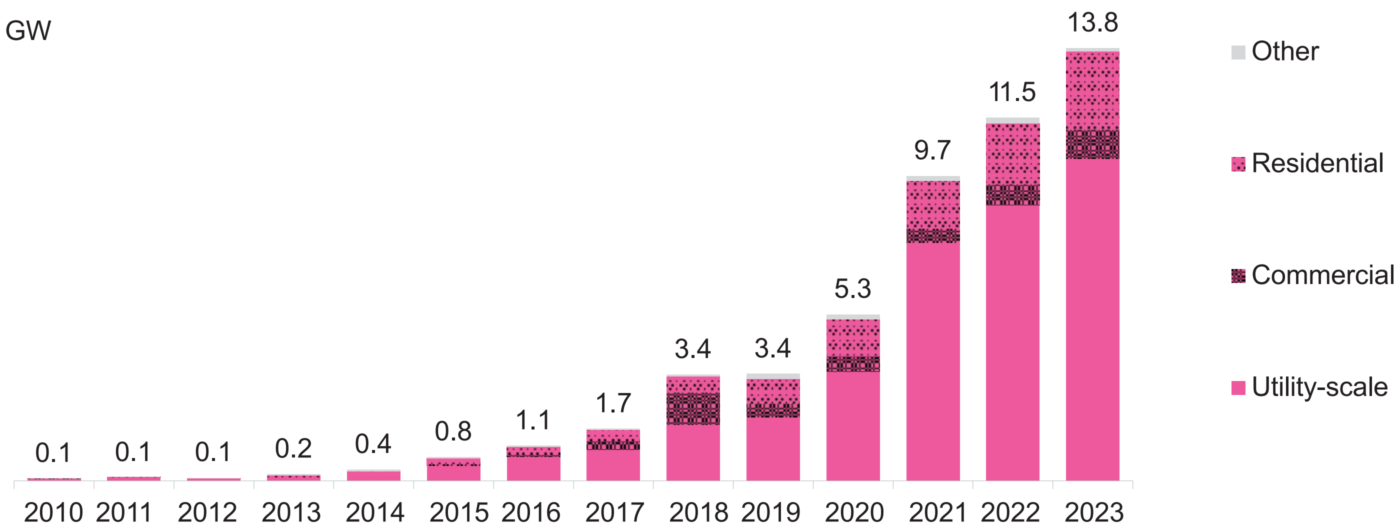


Source: BloombergNEF

BloombergNEF

Global energy storage market on a record-setting spree

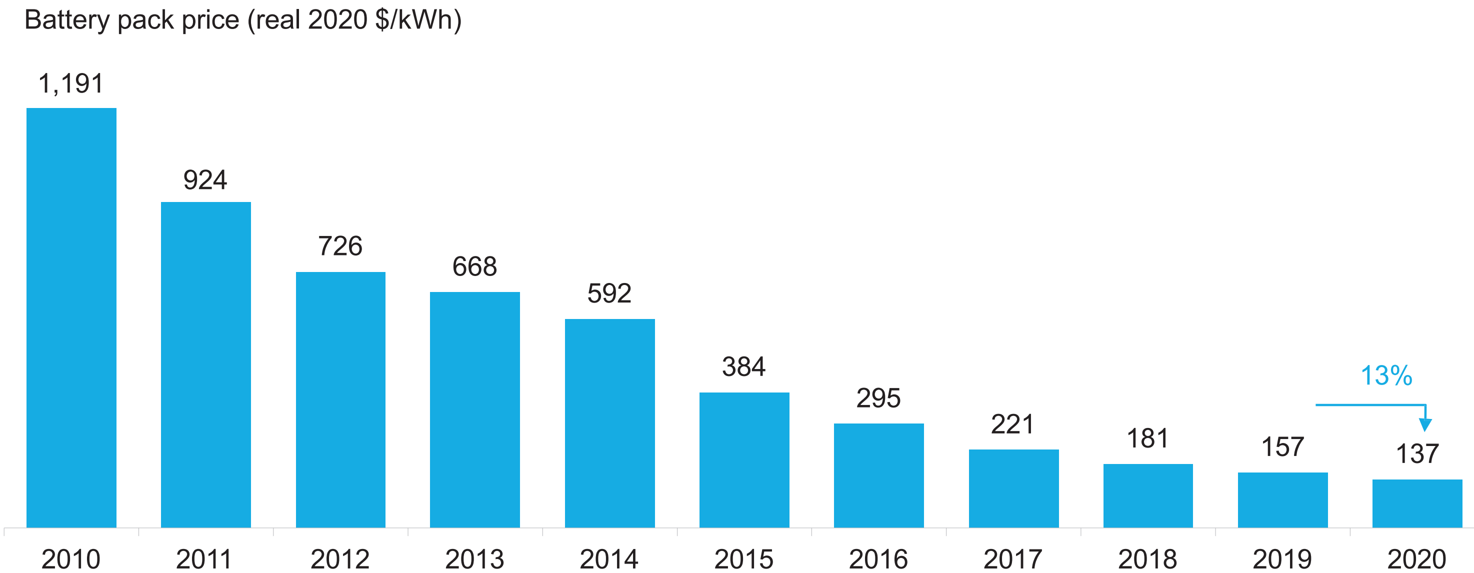
Global energy storage build



Source: BloombergNEF

Falling costs have been crucial

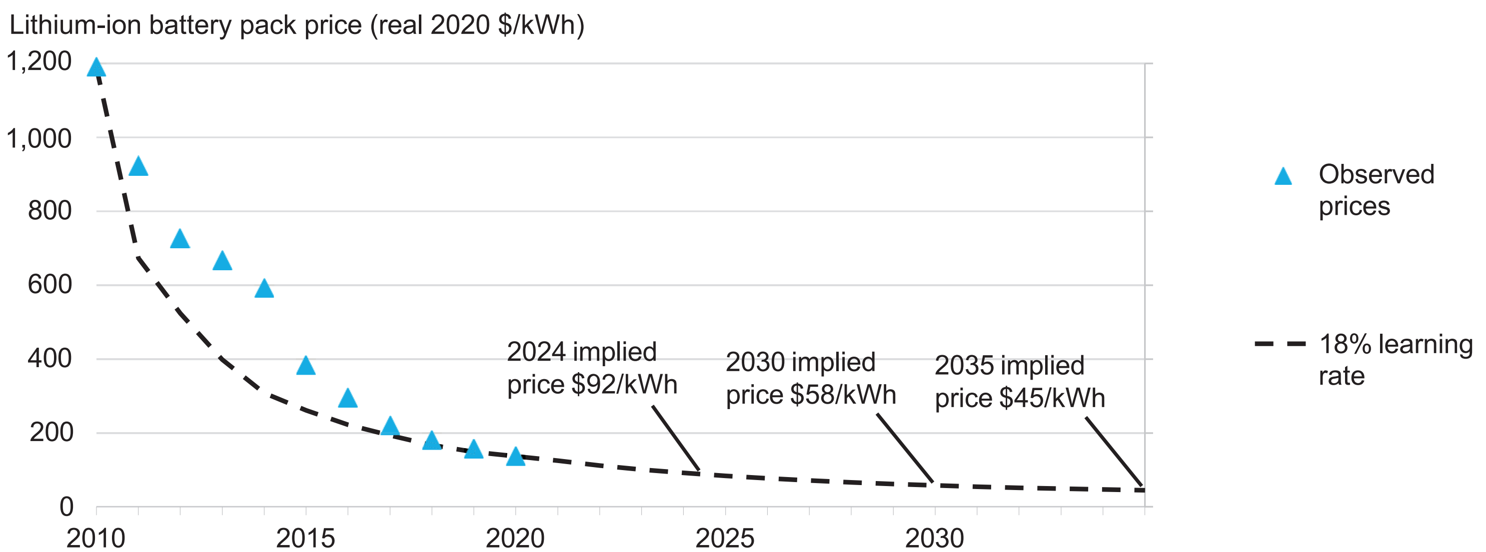
Lithium-ion battery price survey results (volume-weighted average)



Source: BloombergNEF Note: This is based on the 2019 Battery Price Survey. The 2020 results shown here are a projection.

Costs will continue to fall to new lows

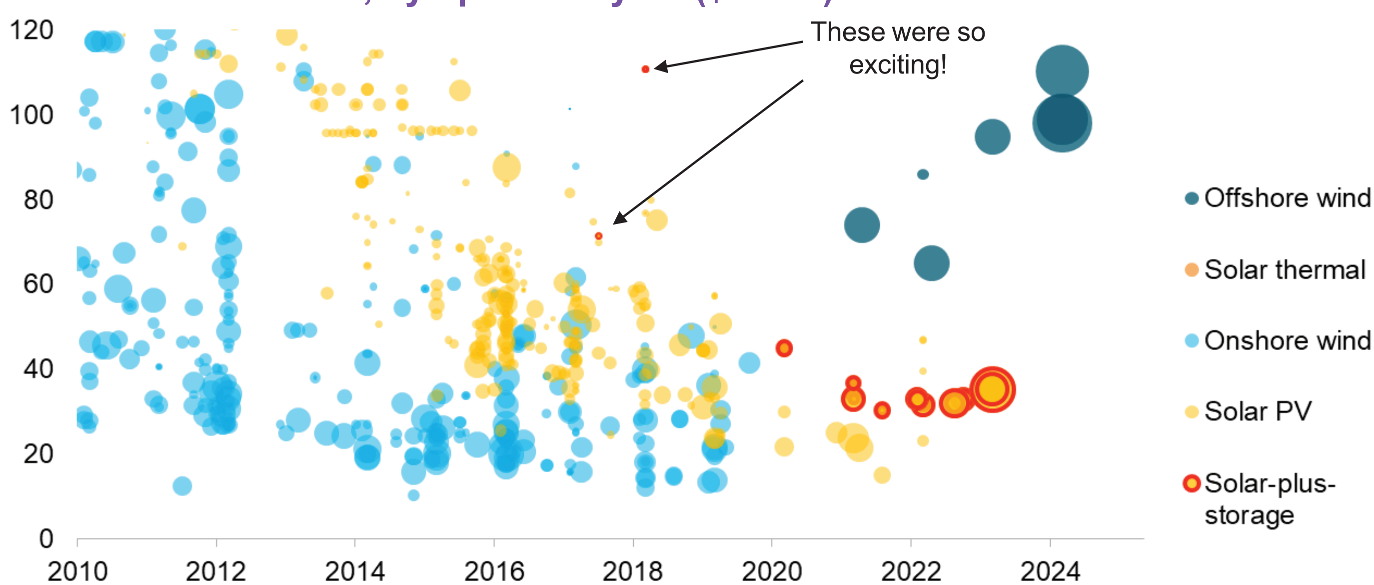
Lithium-ion battery price outlook



Source: BloombergNEF Note: This is based on the 2019 Battery Price Survey.

This had helped lead to significant drop in contract prices

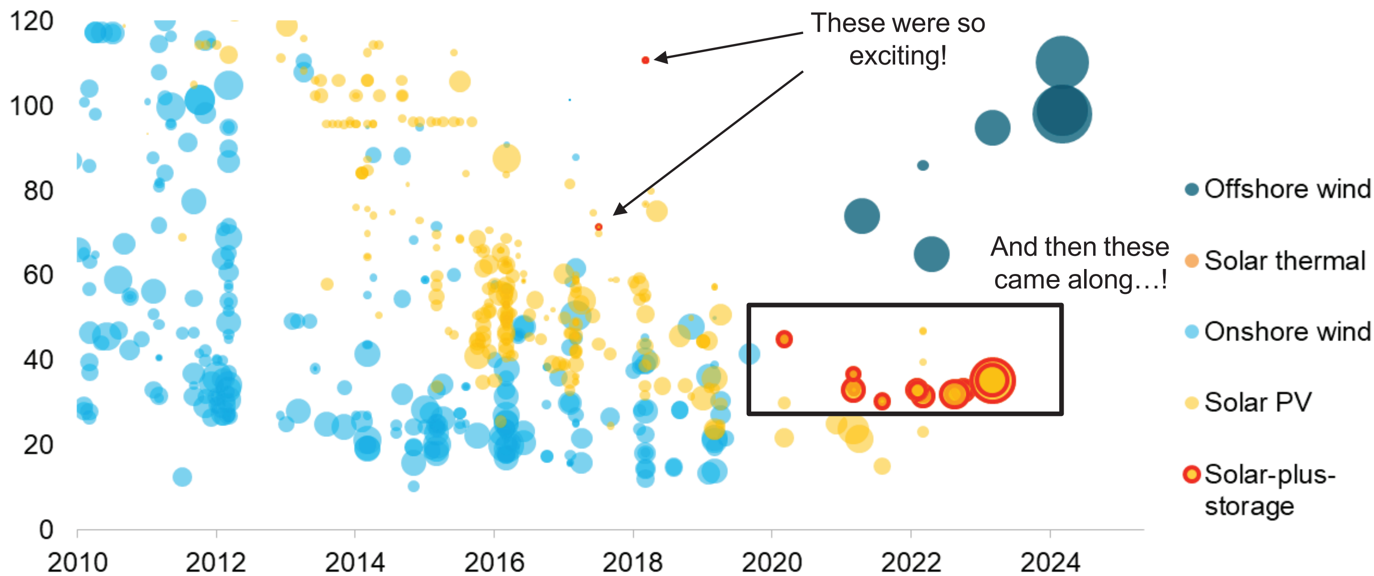
U.S. renewable PPAs, by operation year ($/MWh)



Source: FERC, BloombergNEF

This had helped lead to significant drop in contract prices

U.S. renewable PPAs, by operation year ($/MWh)

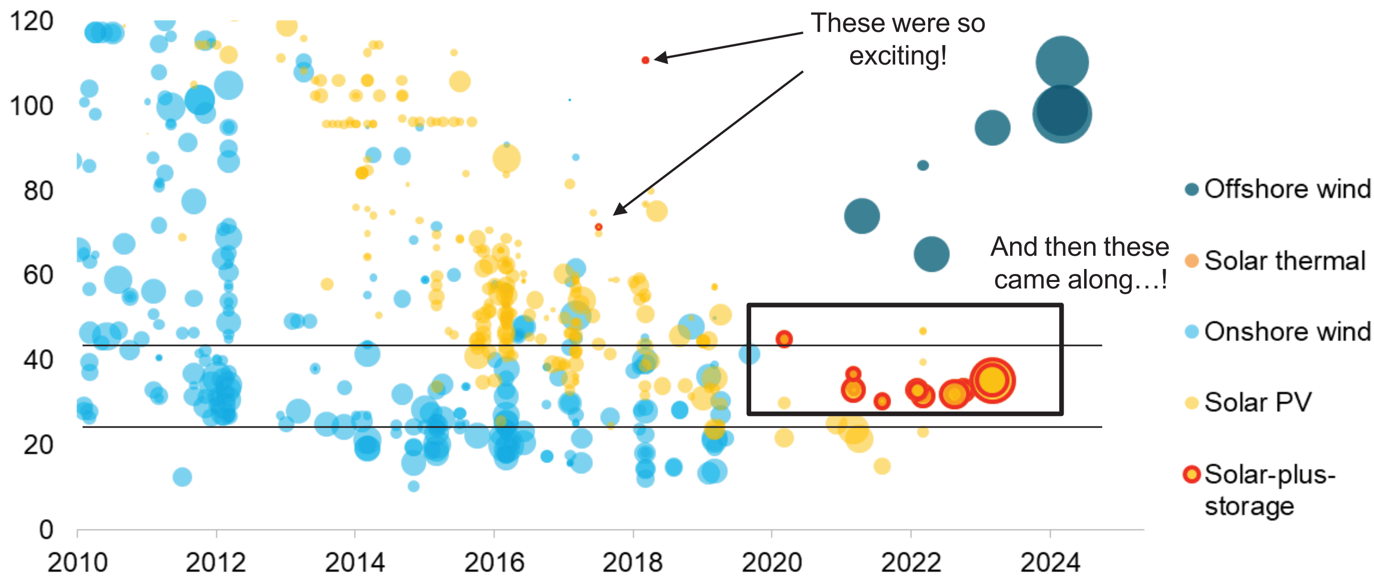


Source: FERC, BloombergNEF

BloombergNEF

This had helped lead to significant drop in contract prices

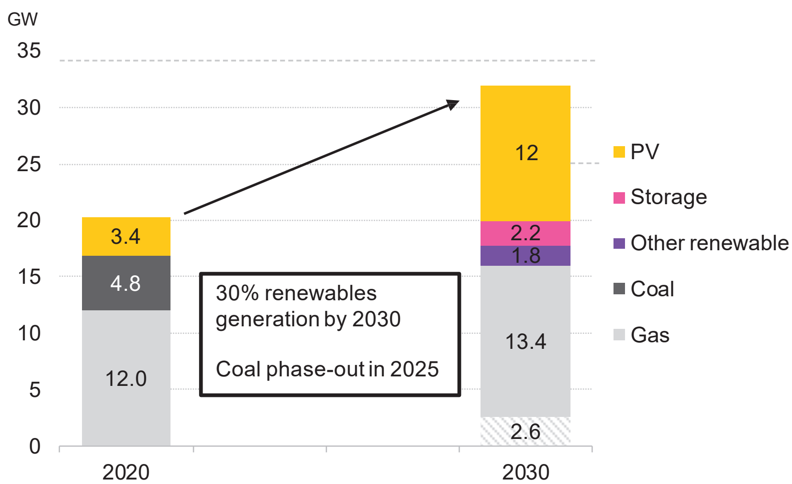
U.S. renewable PPAs, by operation year



Source: FERC, BloombergNEF

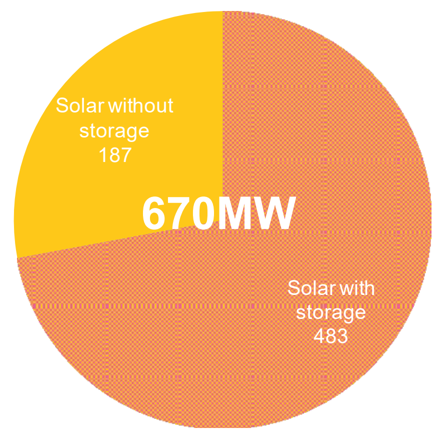
Solar-plus-storage auctions and RFPs is helping to scale market rapidly

Change in Israel's electricity generation capacity mix, 2020 - 2030



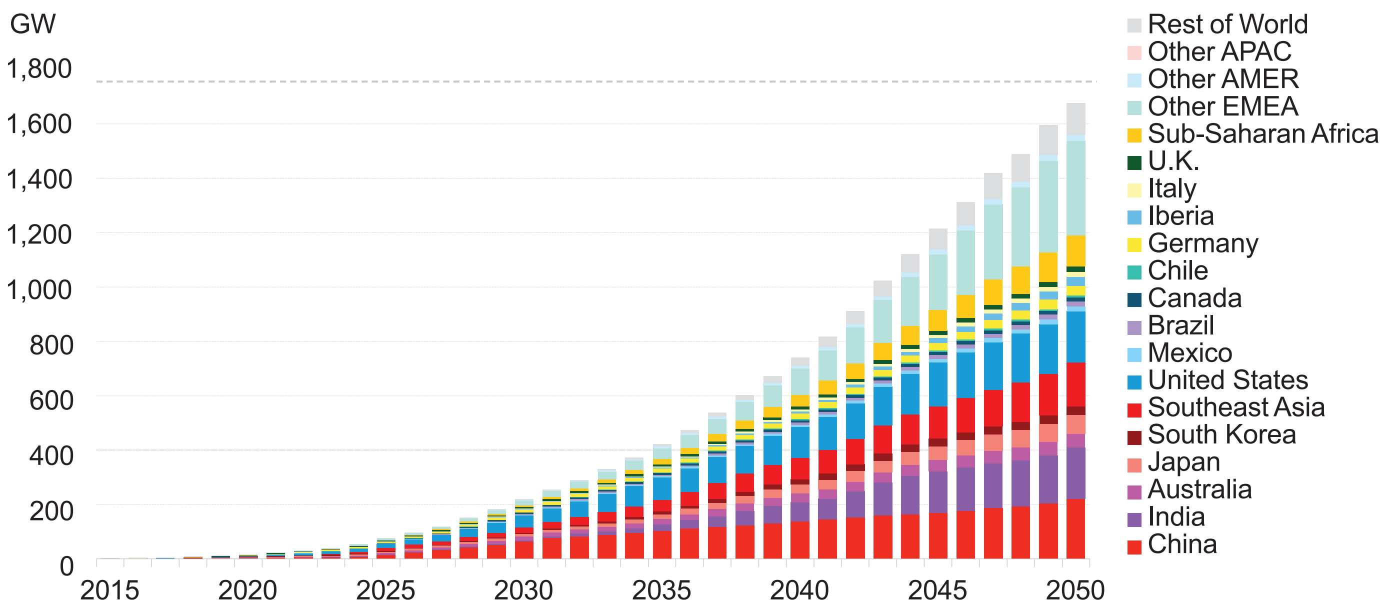
Source: BloombergNEF

Portugal auction contracts awarded by technology



Source: BloombergNEF. Note: At least 20% of 483MW awarded to solar plus storage must be battery capacity, amounting to at least 96MW

Opportunities will continue to grow over coming decades



Source: BloombergNEF

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L22

From: Francesca Smith
To: Krause, Erik
Cc: Devine, Paula; Kassakhian, Ardashes; Brotman, Daniel; Agajanian, Vrej; Najarian, Ara; Adjemian, Aram; John Schwab-Sims; julianne.polanco@parks.ca.gov; Cindy Woodward; lucinda.woodward@parks.ca.gov; Chris Cragnotti; Alek Bartrosouf
Subject: Grayson Repowering Project PR-DEIR (Glendale, CA)
Date: Monday, November 15, 2021 11:24:39 AM
Attachments: Smith- Comments on PR-DEIR 11 15 21.pdf
Attachment 1.pdf
Attachment 2.pdf
Attachment 3.pdf
Attachment 4.pdf

L22-1

Hi Erik *et al.*,
I hope all is well.
Please find my husband's and my letter regarding the Grayson Repowering Project PR-DEIR (http://graysonrepowering.com/#pr-draft-eir).
We copied the Mayor, Council, City Clerk and each of the others listed. Please confirm receipt of this message, the attached letter and the four attachments as soon as you are able.
Thanks for the opportunity to comment on this important project.
Best wishes,
Francesca Smith

LEE & FRANCESCA SMITH

November 15, 2021

Mr. Erik Krause, Deputy Director of Community Development
City of Glendale
Community Development Department
633 East Broadway, Room 103
Glendale, CA 91206
Sent via e-mail to ekrause@glendaleca.gov

RE: Comments on Partially Recirculated- Draft Environmental Impact Report, Grayson Repowering Project

Dear Mr. Krause:

L22-2 We took the time to review the Partially Recirculated- Draft Environmental Impact Report, Grayson Repowering Project (PR-DEIR, August 6, 2021) and note quite a few significant shortcomings, errors and omissions and disagreements with CEQA compliance in the new document. Those problems include the lack of any discussion of a reuse alterative, the lead agency's failure to intensively re-evaluate the entire property for local and California Register eligibility to understand its significance,

L22-3 The most important cultural resources-related inadequacies are the lack of an updated technical report that would have intensively evaluate the property for historic significance, unclear description of one-sided discussions with The Glendale Historical Society (TGHS) and results, unnecessary repetition of the description of the property as a "'discretionary' historical resource," the fact that the PR-DEIR and previous editions of the DEIR fail to analyze or even address alternatives to the proposed project that would retain the historical resources, the City's (Lead Agency's) elaborate, sequestered circumvention to reverse the property's status as a historic property and a historical resource, its lack of consideration of Cultural Resources mitigation measures prepared for the City at staff's request, the missing identification of character-defining features, not agenizing the proposed project, including demolition and identification of character-defining features for review and consideration by City's Historic Preservation Commission, constricted, excessively selective cumulative impacts analysis and does not address the expected loss of embodied energy that would be caused by the project.

L22-4 Absence of supplemental or updated Cultural Resources Technical Report

While the lead agency has, after more than six months of discussion with TGHS (see following pages), at long last conceded that the Grayson Power Plant Boiler Building is a historical resource for the purposes of CEQA, no updated technical report was prepared to support those findings. Without a thorough and impartial "good faith" evaluation of the entire property, which would include its direct connection to the Glendale Switch Rack which was constructed roughly concurrently with the Boiler Building both the identification of historical resources, the analysis of impacts on the historical resource are inadequate. Without a complete identification of historical resources on the property as well as its consideration as a potential historic district, L22-4 directly connected to the establishment and development of Glendale as an independent city and as a Pre-War power plant, the analysis of impacts has no basis.

Because the PR-DEIR is not even partially based on the results of a supplemental or updated Cultural Resources Technical Report because none was prepared, its conclusions regarding Cultural Resources impacts is not supported. We strongly recommend that the City comply with CEQA as it relates to cultural resources in that that future environmental clearance documents for this and other projects would include preparation of reliable, unbiased supplemental, updated or any Cultural Resources Technical Reports that would re-evaluate the entire property for historic significance, including as a historic district. Such a technical report
L22-5 would rely on a more balanced approach, and its conclusions would not be not predicated on alterations, fully considering the effect the independent power source had on the widespread development of the community as well as its architecture, engineering and novel earthquake resistant design.

<u>"Collaboration" or meetings between the Lead Agency and The Glendale Historical Society</u>
We note that partially because there is no updated or supplemental Cultural Resources Technical Report, there is no clear discussion of the meager coordination that took place with TGHS. It is incorrectly described as "collaboration" in the PR-DEIR which would have meant that the Lead Agency did not pick or chose what its employees would consider to reduce the considerable Cultural Resources problem in the proposed project. The few paragraphs describing those meetings with representatives of TGHS notably contains without no records when those meetings took place, who attended, what was discussed and what, if anything, was
L22-6 agreed. That information is germane to this project's decision makers and must be included in more complete detail in future and or final environmental clearance documents for this project. TGHS provided reasonable Mitigation Measures to the City that would have ensured that problems of this magnitude relating to City-owned historic resources were not repeated in the future (see Attachment 4 and page 8 of this letter, Cultural Resources Mitigation Measure B-Historic Resources Survey of City-Owned Properties).

On December 15, 2020 the Glendale City Council discussed an Amendment of Contracts with Stantec Consulting Services, Inc. and Black & Veatch Corporation for Additional Professional Services Pertaining to the Limited Notice to Proceed Phase of the Proposed Grayson Repowering Project Alternatives. [1] During that item's public testimony at least one officer of TGHS and two members provided information in that recorded meeting by telephone to decision makers explaining the elaborate circumvention of the eligibility determination by High-Speed Rail (HSR) for Grayson Power Plant.

Grayson Power Plant was determined eligible for the National Register of Historic Places in 2019. Despite the fact that the City of Glendale (City or Lead Agency) was copied on all technical reports as a by-right consulting party, staff took no action until August 31, 2020 after a TGHS member let them know via e-mail, that Lead Agency prepared a letter to HSR outlining
L22-7 the reasons that Grayson Steam-Electric Power Plant should not in City staff's opinion be considered a historic property. The 25-page justification included photographs of structures that are not part of the main Boiler Building and notably omitted a map or diagram that would have clarified the locations of those structures (Attachment 1, pages 3-33). In that letter, the City notably excluded discussion the opinions of TGHS, its members, who are part of the public

[1] Item 8C form the Agenda at https://glendaleca.primegov.com/Portal/Meeting?compiledMeetingDocumentFileId=30739.

L22-7 including qualified judgment that was provided, constituting "expert disagreement" that would have proven that the main Boiler Building was historically significant at both state and local levels (Attachment 2, pages 4-16).

L22-8 In Attachment 2, TGHS reminded the Lead Agency that "CEQA strongly encourages early consultation with interested or affected parties, which includes local historic advocacy groups. No consultation efforts were made with TGHS. We were asked for information early in the process [December 2015] but have not otherwise been consulted on the project" (page 17). No consultation effort with TGHS was made by the Lead Agency until January 2021 and the few months following. Rather than a collaboration it could better be described as a one-way street, where the City offered carrots but proffered only sticks.

Despite TGHS demonstrated interest in the proposed project as described above, the non-profit and its representative were not copied on the Lead Agency's Attachment 2 letter to HSR requesting the property's National Register determination be overturned. Based on the unnecessarily secretive information provided by the City in Attachment 1, and absent any information and professional opinions to the contrary provided by TGHS regarding the subject property's historic significance, the State Historic Preservation Officer (SHPO) concurred with the opinion provided by the City of Glendale based on alterations to separate Cooling Tower structures (1, 2, 3, 4 and Units 8A-C) ,that the Boiler Building was not eligible for listing in the National Register. TGHS was not ever apprised of the request for reversal of the property's determination of eligibility until that City Council Meeting Agenda was posted for the December 15 meeting despite demonstrated interest in letters regarding its historic significance. Notably as well, in that December 15th City Council Meeting, City Attorney staff member Gillian van Muyden incorrectly asserted to Council that the California Register finding for the Grayson Steam-Electric Plant was overturned as well in the SHPO concurrence letter. It was not, see Attachment 3, pages 1 and 2. Also in that meeting, the adopted City Council motion included the provision that City staff meet with TGHS to address the historic significance of the Boiler Building and voted to move forward, excluding consideration of "Alternative 7" which would have retained the Boiler Building in place.

L22-9 We note that the Glendale Switch Rack, which dates from the same year as the Boiler Building (1941) and was central to the property's operation as a power plant should be considered historically significant as well (see Figure 1 on page 4).

L22-9

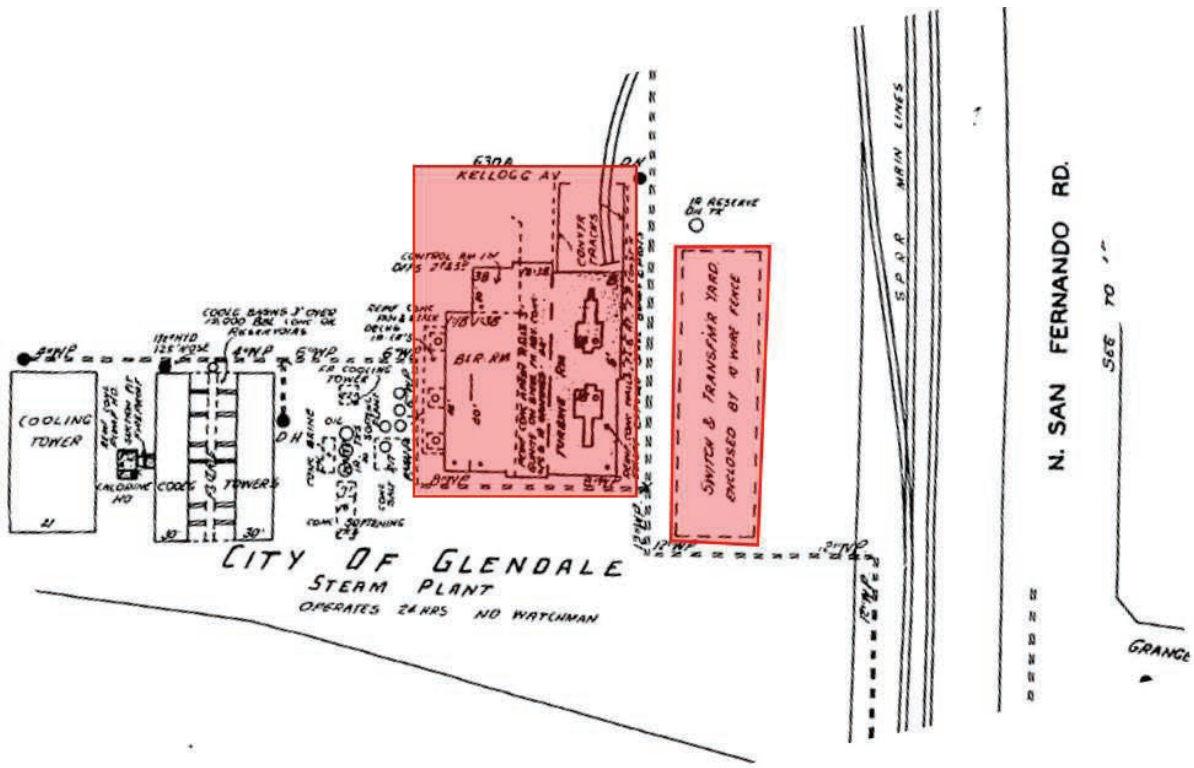

Figure 1: Annotated excerpt of Sanborn Fire Insurance Co. map of Grayson Power Plant in 1950. Note the irregularly configured Boiler Building on the left side with three exhaust stacks which remain and extant Glendale Switch Rack on right. Both are highlighted in red. Source: Sanborn Fire Insurance Co. "Maps of Glendale, CA" Volume 2, updated to October 1950, sheet 299B.

Figure 1, above depicts the Boiler Building and the functionally-related, and currently extant Glendale Switch Rack in 1950. Review of aerial photographs from the same time period reveal the same relationship between the Boiler Building and Glendale Switch Rack. If the property had been appropriately, impartially evaluated for historic significance impacts and effects we believe the Glendale Switch Rack and likely other part of the property would likely have been identified as contributing features of what may likely be a historic district.

We asset that in failing to re-evaluate the property it was not analyzed for its engineering significance either. In the first addition to the Boiler Building, its architect, Daniel A. Elliott, AIA extended the main rectangular form and repeated the original bay configuration to the northwest. The Lead Agency should know that addition notably included "the first hydrogen-cooled turbine generation for outdoor use," which was made possible by the "prevailing
L22-10 moderate weather."[2] The then-novel use of hydrogen to power the turbines allowed the plant to maintain its original design program of a narrow block-like building which housed generating units served by exterior turbine engines. Hydrogen is more efficient transferring heat than air is because it can absorb heat and can thus transfer it another medium. Challenges include maintaining the pure hydrogen, ensuring the pure gas has no air leaks and safety. According to industry news, hydrogen cooled generators became the industry standard which makes that early instance of its use in Glendale all the more important. [3]

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[2] *Electric Light and Power*, Volume 18, 1940: 74.

[3] Spring, Nancy. "Hydrogen Cools Well, But Safety is Crucial" *Power Engineering*. June 1, 2009 and Covertel Power. "How H^2 Is Used to Cool Electric Generators" at

At the time of the installation of the unique exterior turbine, the subject of making personnel work outside was the subject of wide debate among professionals in the field. Factors in its favor included reducing the necessary size of the main plant buildings (like the Boiler Building) and the obvious benefits of natural ventilation. Minor drawbacks were the requirement for a deep "basement" as is present in the turbine deck, the excessive noise generated inside small turbine covers and the exposure of employees to the elements. In the 1940s, an industry
L22-10 publication held a competition to assess the practicality of such outdoor turbines. Although the mechanical engineer who received the top award for his essay was not in favor of the new concept, the fact that exterior turbines are now common and hydrogen cooling remains the most widely used application seems to ultimately close the discussion. [4]

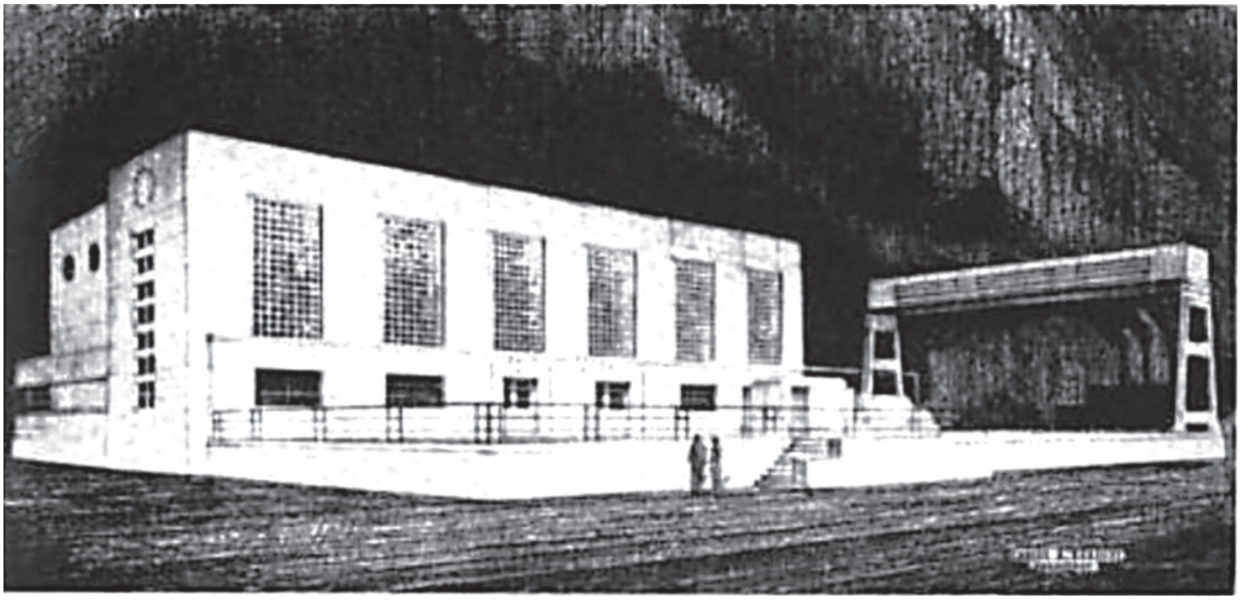

Figure 2: Daniel A. Elliott's' early rendering of Glendale Power Plant, with one turbine above steps and the crane at left. The rendering was published in *Electric Light & Power* with the caption: "Architect's sketch of the Glendale (Calif.) plant where the first hydrogen cooled turbine for outdoor operation will be installed." Source: *Electric Light & Power,* Volume. 18 July 1940: 72.

The regional Postwar residential boom in Glendale was enabled, in part, by the fact that the City had an independent power plant. [5] The City could not have developed as rapidly or as widely as it did in the years after 1941 without its own power plant.

CEQA ensures full public disclosure of the likely impacts of significant projects and provides
L22-11 part of the system through which community members can participate in a meaningful way in environmental review.

https://covertelpower.com.au/products-and-services/electrolysers/how-h2-cools-generators/ accessed on June 24, 2021.

[4] Maddock, Bill. M.E. "Is the Outdoor Installation Here to Stay?" *Power Plant Engineering*. United States: Technical Publishing Company, October 1943.

[5] *Power Plant Engineering*. (United States, Technical Publishing Company, 1944): np.

"Discretionary" Historical Resource

We note as well that in the PR-EIR text, every mention of the single identified historical resource is diluted by repetition of the modifier "discretionary." That thinly veiled language mannerism, which is repeated more than 30 times in the PR-DEIR is intended to lead non-professionals (which will include most of the public, the mayor and city council members) into believing that the significance of the Boiler Building is somehow in doubt, which it is not.

L22-12

Page xv in the PR-DEIR ambiguously states "the City agreed to treat the Boiler Building as a discretionary historical resource under CEQA." That description notably passes ore the reasons the Lead Agency agreed to treat the property as a historical resource and whether it was based on its proven California Register or local register eligibility.

It would have been understandable if the Lead Agency had defined the term "discretionary historical resource" in the text. It is when the Lead Agency *determines that a resource meets the criteria for listing in the California Register of Historical Resources* (California Code of Regulations or CCR Section 15064.1.a.3); *or the Lead Agency uses its discretion to consider any resource as historic for the purposes of CEQA* (CCR Section 15064.1.a.4).

The document need only explain that detail once. It can be in a footnote, and should explain that its historic significance was clearly proven based on "substantial evidence" as defined in CEQA.

Alternatives Analysis

According to CEQA, the contents of an EIR must describe a reasonable range of alternatives to a proposed project that could feasibly attain most of the basic project objectives and would avoid or substantially lessen any of the proposed project's significant effects (CEQA Guidelines Section 15126.6(e)). Grayson Power Plant Boiler Building is a historical resource for the purposes of CEQA as described in the PR-DEIR.

L22-13

A build alternative such as the 2020 Alternative 7 that would have avoided demolition of the Grayson Power Plant Boiler Building and Glendale Switch Rack would have included but not been limited to different locations for the proposed project, a smaller or reduced project, and at the very least, consideration of rehabilitation of the Boiler Building in accordance with the Secretary of the Interior's Standards for Rehabilitation.

L22-14

Alternative 3 "The Alternative Energy Project Alternative" is entirely conjectural. Its undeveloped description e.g. "some combination of photovoltaic or wind power production with energy storage and transmission lines" in not sufficiently developed to adequately analyze the impacts. The description is overly vague, devoid of clear information. The conclusion that "the Alternative Energy Project Alternative reduces local potential air quality, cultural resources, energy, greenhouse gas emissions, hydrology and water quality, and noise impacts local to the Grayson Power Plant site" is unfounded. The Alternative is further described as "it increases off-site impacts to aesthetics [how?], agriculture and forestry resources [where?], biological resources [without explanation], cultural/tribal cultural resources [also not specified but apparently would somehow both reduce and increase such impacts and is variously describe as only Tribal and in other places Cultural Resources impacts], environmental justice [no corroboration description], geology and soils [without justification], land use and planning [even though its wind farm and solar fields locations are unspecified], and population and housing impacts [again, where, exactly] due to the need for increased transmission as well as the large area [not demonstrated or disclosed in the PR-EIR] needed for a wind farm or solar field." The analysis concludes that the alternative is not viable "This determination is reinforced

by the results of the Clean Energy RFP, the 2019 IRP, and the 100% Clean by 2030 study" which
L22-14 demonstrates that an infeasible alternative was brought forth as a CEQA "Trojan horse" or
untruthful alternative (PR-DEIR "Alternative Energy Project Alternative – Alternative 3" page
XX, see also CEQA Guidelines Section 15126.6(e)).

The omission of this important component of the alternatives analysis, which would have
meaningfully considered a reuse alternative for the historical resource, a different location or a
smaller project is significant and problematic is under the law. While an EIR need not consider
every conceivable alternative to a project, alternatives must include consideration of those that
would avoid or substantially lessen the significant environmental effects of the project. The PR-
DEIR did not include describing any rationale for the selection or rejection of the absent reuse
alternative or of any clear information on which the Lead Agency relied in not making that a
L22-15 viable alternative under consideration. While City Council may have voted not to analyze an
alternative that would have retained the historical resource in December of last year with staff
standing by, such local, and unfortunately not fully informed decisions would not supersede
the requirements in CEQA which is a state law.

The PR-DEIR should have clearly identified alternatives considered but rejected as infeasible during the scoping process and briefly explained the reasons for the exclusions. Alternatives may be eliminated from detailed consideration in an EIR if they fail to meet most of the project objectives, are infeasible, or do not avoid any significant environmental effects, however it is legally required that they be described. See additional information under the Mitigation Measures section in this letter, in the following pages.

We have been told that reuse of the Boiler Building would be impossible numerous times.
Power plant buildings have been successfully reused for a numerous purposes throughout the
United States and abroad.[6] Reuse of power plant facilities is not impossible, as has been implied
in meetings with staff and their consultants (February 2, 9 and 16, March 4, 2021) as well as in
public meetings regarding the proposed project. A fair amount of guidance on the subject of
reusing power plants exists, including: "Repurposing Retired Power Plants Into Green
L22-16 Neighborhood Centers" (Smart Cities Dive, Kaid Benfield), "Repurposing Legacy Power Plants:
Lessons for the Future" (American Clean Skies Foundation) and "Interpreting The Secretary of
the Interior's Standards for Rehabilitation No. 30: Reusing Special Use Structures" (National
Park Service). If reuse of power plants for other purposes were impossible as implied by City
staff , then how and why would the described guidance and examples exist?

The description of alternatives in the PR-DEIR fails to provide the necessary information for
stakeholders and decision-makers to understand whether or not the historical resource could, or
L22-17 could not be reused under any of the considered alternatives. Because no such reuse alternative
was considered, the alternatives analysis is incomplete and is deficient. The PR-DEIR is legally
inadequate in its description of existing conditions (without a supplemental technical reports, as
well as in its analysis of alternatives.

[6] Examples of successful power plant reuse projects include Barksdale Power Station (London, UK), City Hospital; Power Plant (Chicago, IL), Pier 4 Power Plant (Baltimore, MD), RJ Reynolds Tobacco Co. Power Plant (Winston Salem, NC), Seaholm Power Pant (Austin, TX), Sears & Roebuck Power Plant (Chicago, IL), South Street Station (Providence, RI) and the State Department West Heating Plant (Washington, D.C.). Additional power plants have been converted other uses in Portland, OR; Queens, NY, and Beloit, WI.

The Lead Agency is using the PR-DEIR as a *post hoc* rationalization for its predetermination that
the majority of Grayson Power Plant, which may be a collection of unrelated historical resources
L22-18 or more likely is a locally and a California Register historic district, should be demolished
wholesale. The PR-DEIR should instead have considered feasible alternatives that would
include new construction in some combination with adaptive reuse of the historical resource or
resources.

<u>Mitigation Measures</u>

During that December 15, 2020 City Council Meeting, Councilman Ardashes Khassakhian
spoke about the importance of the City completing "all remaining" historic surveys. If the
mitigation measure prepared and submitted to the Lead agency by THGS, which was for a
Historic Resources Survey of City-Owned Properties had been implemented before the Grayson
Repowering Project was considered, it is assumed that the property would have been identified
L22-19 as a historical resource and could have avoided this years-long dispute with TGHS regarding its
significance.

Attachment 4, the April 25, 2021 three-page attachment sent via e-mail by TGHS to the Lead Agency directed: "The environmental document prepared for the Grayson Electric-Steam Power Plant must study and analyze historical resource impacts. The Grayson Electric-Steam Power Plant is eligible for listing in the California Register of Historical Resources."

It stated:

> The alternatives analysis component will be especially critical in this this document. It must evaluate the No Project alternative as well as a "reasonable range" of feasible alternatives that would retain the Grayson Electric-Steam Power Plant as described in CEQA Guidelines Section 15126.6(e)).
>
> There must be an essential nexus (*i.e.* connection) between the mitigation measure and a legitimate governmental interest… Nollan v. California Coastal Commission, 483 U.S. 825 (1987). The mitigation measure must be "roughly proportional" to the impacts of the project. Dolan v. City of Tigard, 512 U.S. 374 (1994). TGHS… believes that the below-listed mitigation measures would be both connected to the expected loss of the Grayson Electric-Steam Power Plant and are relational to the expected loss of that structure to the community. The addition of signage on San Fernando Road near the current location of the Grayson Electric-Steam Power Plant and the future retention and display of components of equipment from the Grayson Electric-Steam Power Plant shall be added to these mitigation measures.
>
> Mitigation of impacts must lessen or eliminate the physical impact that the project will have on the historical resource. This is often accomplished through redesign of a project to eliminate objectionable or damaging aspects of the project. Relocation of a historical resource may constitute an adverse impact as well. However, in situations where relocation is the only feasible alternative to demolition, relocation may mitigate the impact below a level of significance provided such that the new location is compatible with the original character and use of the historical resource and the resource retains its eligibility for listing in the California Register (14 CCR §4852(d)(1)).
>
> <u>C[ultural] R[esources] M[itigation] M[easure] B- Historic Resources Survey of City-Owned Properties</u>
>
> The City shall prepare or cause to be prepared comprehensive Historic Resources Survey of (all) City-Owned Properties (Survey) with improvements constructed before

L22-19 1990, unless the property has previously been evaluated (with a written record of that evaluation) within the past five years or are expected to be evaluated in the planned East-West Survey. All survey work shall conform to the Secretary of the Interior's Standards for Archaeology and Historic Preservation, which include Standards for Evaluation, Identification, and Registration. The survey shall be prepared in accordance with "National Register Bulletin: Guidelines for Local Surveys: A Basis for Preservation Planning" and the California Office of Historic Preservation's latest guidance. The Survey shall commence within 90 days of the adoption of the environmental clearance document for the Proposed Grayson Power Plant Repowering Project. The survey shall be completed within one-calendar year, be subject to a draft and final survey review and recommendation by the City's Historic Preservation Commission and adoption by City Council.

The resulting survey shall include, at minimum:

A Summary, enumerating the total number of surveyed resources and districts with levels of significance.

A Project Description, that clearly describes the purposes of the survey, sources of funding, its overall parameters, a description and map of the survey area and property types.

A Summary of Previous Identification Efforts that clearly describes any previous survey of identification efforts, local designations, National and California Register listings and determinations of eligibility, California Historic Landmarks and California Points of Historic Interest listings and designations and any other related historic preservation planning efforts. It shall include and describe the contents of a current, records search at the South Central Coastal Information Center at California State University Fullerton and provide the final survey and all known Glendale surveys to the Information Canter upon completion, in accordance with the Information Center's requirement.

A Context Statement prepared in compliance with The Secretary of the Interior's Standards for Preservation Planning, "Standard I. Preservation Planning Establishes Historic Contexts," "Standard II. Preservation Planning Uses Historic Contexts To Develop Goals and Priorities for the Identification, Evaluation, Registration and Treatment of Historic Properties" and the California Office of Historic Preservation-prepared "Writing Historic Contexts" guidance. The Context Statement shall establish clear registration requirements for eligibility.

A clear Methodology section that describes field work techniques and research methods used to conduct the survey, a description of how historic districts are identified in the survey, references to previous surveys, and methodology for re-survey completed as part of this project. It will clearly describe efforts made to contact and involve members of the community and organizations with particular interests in historic properties.

Recommendations for future preservation activities, including: potential updates and/or amendments to existing National, California and Glendale Register designations, as applicable; designation recommendations for potential local historic districts, as applicable; and potential economic development, heritage tourism, and other preservation planning activities;

L22-19

Survey results shall enumerate the total number of surveyed resources in appropriate categories, tables listing the property types and architectural styles identified, as well as narrative defining the results, with information regarding the levels of integrity and condition of resources, describes character-defining features, past and current development trends.

Appendix 1: Two-page DPR 523 series forms for each City-owned property unless the property is vacant or a paved parking lot which shall be noted in the survey results tables by Los Angeles County Assessor's Parcel Identification Numbers and address (where assigned). The DPRs shall be fully completed in accordance with the latest edition of the OHP-prepared "Instructions For Recording Historical Resources." They shall include whether or not the evaluation is an update, assign California Register Status Codes and describe other listings in the header blocks and include at least one clear digital photograph and a sketch map. If a property is California Register Status Code 1-6L, it shall include a complete architectural description, construction history, related features and under significance, describe why the resource is significant within a the relevant historic context and identify character-defining features.

Appendix 2: A survey map that delineates the survey area with all previously identified properties including local landmarks and historic districts and the results of the City owner-Properties Survey.

The results of the final or adopted survey shall be provided to the [California] Office of Historic Preservation, submitted in the specified formats to the Information Center and the result, including the DPR series 523 forms shall be posted, by property in the City's Glendale Information Property Portal or its successors and in its entirely on the City's website until it is updated by a subsequent survey, within no more than 90 days of its substantial completion or adoption.

The thoroughly described, recommended mitigation measure for a Historic Resources Survey of City-Owned properties was not included in the PR-DEIR, despite TGHS's preparation, when asked by the City to prepare mitigation measures, Councilman Khassakian's clear direction to complete the City's historical resources survey , the recommended mitigation measure's direct connection to a legitimate governmental interest (maintaining a complete city survey), the recommended mitigation measure's approximate proportionality to the historical resources impacts of the project and the relation to the expected historical resources loss to the community. Based on this project's years-long difficulty recognizing that the subject property is a historical resource, there is a "nexus" linking the project's expected impact to need for the city-wide survey. The proposed Grayson Repowering Project would serve the entire City of Glendale, thus the recommended Historic Resources Survey mitigation measure would be "roughly proportional" to its impact (i.e., fair share of total impact). Future environmental clearance documents for this project must incorporate the recommended city-wide survey mitigation measure in full.

L22-20

Identify existing conditions and present to Historic Preservation Commission

In addition, the City is either consciously or accidentally making an effort to sidestep compliance with its own Historic Preservation Ordinance. That recently updated ordinance specifically states in Chapter 15.20 under "Identification of character-defining features" (15.20.035) that

L22-20

> the character-defining features of a designated historic resource, a potential historic resource, or a protected interior may be identified at the time of designation or in survey documentation and reflect the existing condition of the property at such time. *To the extent that one (1) or more character-defining features are not specifically identified at the time of designation or in survey documentation, there is a rebuttable presumption that features that conform to the definition of "character-defining feature" included in Section 15.20.020 of this chapter and that date to the property's original construction and/or to any subsequent historically-significant alteration, will be treated as character-defining features and will be identified as such by the director of community development pursuant to Section 15.20.030 of this chapter.* (emphasis added, Ord. 5931 Section 4, 2019)

L22-21 Consequently and in full conformance with the Historic Preservation Ordinance, at minimum, all components of the Boiler Building, including its boilers, turbines, mechanical systems, crane and other appurtenances, as well as the Glendale Switch Rack and any other components of shall be considered by the City to be character-defining features.

L22-22

Furthermore, there is no mention in the PR-DEIR of the requirements in the Glendale Municipal Code which addresses demolition of potential historical resources. The ordinance clearly directs under "Demolition clearance and demolition permit required for demolition of designated historic resources and potential historic resources" (15.20.080):

> A. No person shall completely demolish a designated historic resource or a potential historic resource without first obtaining a demolition clearance and demolition permit, pursuant to Chapter 15.22 of this code.
> B. In the event any designated historic resource or potential historic resource is completely demolished or partially demolished without demolition clearance and issuance of a demolition permit, the provisions of Section 15.20.090 of this chapter shall apply.
> C. In the case of a property listed in the Glendale Register of Historic Resources, upon completion of any environmental review required by CEQA and issuance of a demolition permit, the matter will be referred to the historic preservation commission and city council to commence the process of deleting the demolished property for deletion from the Glendale Register of Historic Resources pursuant to Sections 15.20.055 and 15.20.060 of this chapter. (Ord. 5949 § 10, 2020; Ord. 5784 § 11, 2012; Ord. 5110 § 16, 1996; prior code § 21-04).

No demolition clearance or demolition permit for Grayson Power Plant has, to date, been presented to the City of Glendale Historic Preservation Commission (HPC) for consideration.

L22-23

The Powers and Duties of the HPC are clearly set forth in the Glendale Municipal Code as "the following acts"

> A. *To consider and recommend to the city council additions to and deletions from the Glendale Register of Historic Resources*;
> B. To keep current and publish a register of historic resources;
> C. To make recommendations to the planning commission, and the city council on amendments to the Historic Preservation Element of the city General Plan;
> D. *To grant or deny applications for permits for demolition, or major alterations of historic resources*;
> E. To grant or deny appeals from decisions of the director of community development as specified in Section 15.20.040 of this code;

L22-23

F. To encourage public understanding of and involvement in the unique historical, architectural and environmental heritage of the city through educational and interpretative programs;
G. *To explore means for the protection, retention and use of any historic resource, historic district, or potential historic resource* or district;
H. To make recommendations to the city council on applications for properties to be included in the Mills Act property tax incentives program which may be subject to historic property contracts as set forth in Section 15.20.070 of this code;
I. To encourage private efforts to acquire property and raise funding on behalf of historic preservation; however, the commission is specifically denied the power to acquire any property or interest therein for or on behalf of itself or the city;
J. *To recommend and encourage the protection, enhancement, appreciation and use of structures of historical, cultural, architectural, community or aesthetic value which have not been designated as historic resources but are deserving of recognition*;
K. *To encourage the cooperation between public and private historic preservation groups*;
L. *To advise city council and city boards and commissions as necessary on historic preservation issues;*
M. *To make recommendations concerning, and render decisions on, design review applications affecting designated historic resources, resources pending designation as historic resources, potential historic resources*, protected interiors, and protected landscape features as defined in Section 15.20.020 of this code, and affecting existing or proposed buildings, structures, or objects in designated and pending historic district overlay zones, as defined in Section 30.25.030(C) of this code and pursuant to Chapter 30.47of this code;
N. To perform any other functions that may be designated by resolution or motion of the city council;
O. *To make environmental determinations under the California Environmental Quality Act on any discretionary project applications the historic preservation commission considers for approval.* (emphasis added, Ord. 5949 § 1, 2020; Ord. 5888 § 4, 2016; Ord. 5803 § 10, 2013; Ord. 5783 § 10, 2012; Ord. 5535 § 4, 2006; Ord. 5425 § 3, 2004; Ord. 5110 § 5, 1996; Ord. 4986 § 1, 1992: prior code § 3-139)

Unfortunately, and notably, review of the proposed project by the HPC has to date, not taken place and has not been mentioned in any of environmental clearance documents for the proposed project, most notably in the PR-DEIR, which should have incorporated any HPC findings or opinions regarding the proposed demolition of the historical resource, which would encourage public understanding of the project, particularly with historic preservation groups, explore possible means for protection, retention and future use of the subject property historic resource.

If HPC's role, as stated, is "recommending and encouraging the protection, enhancement, appreciation and use of structures of historical, cultural, architectural, community or aesthetic value which have not been designated as historic resources, encouraging cooperation for this project with historic preservation groups, advising city council and other city boards and commissions" regarding the proposed project, which is a historic preservation issue, and most importantly, to make recommendations concerning, and render decisions on, design review applications affecting designated historic resources, resources pending designation as historic resources, potential historic resources, then the proposed project must be presented to the HPC for consideration and recommendation to City Council. Any such hearings to address or coordinate with the HPC after the project FEIR was adopted, would be too late to make any

L22-23 findings or recommendations that would be considered for the proposed project. Without HPC's express participation, this action and environmental clearance of this project would violate the City's own established, adopted and recently updated Historic Preservation Ordinance.

By-passing the City commission whose stated role is to make decisions regarding historical resources and to advise city council on such matters is not only unconscionable, it will, no doubt make the environmental review process take longer than expected, which seems to be of greater importance to the Lead Agency than making informed decisions on the proposed project or compliance with applicable state laws and local ordinances.

L22-24

Cumulative Impacts and Effects

The PR-DEIR also failed to adequately analyze the cumulative impacts and effects of currently proposed future and recent projects with the proposed project. The assertion that "There are no known related projects that are expected to impact other previously identified historic resources which are examples of the municipal power property type in Glendale" is an overly restrictive view of the expected cumulative impacts in currently proposed future and recent projects. Historical resources impacts in the City of Glendale are not limited to those caused by the City to city-owned properties, such impacts can be caused by any project proponent and would cumulatively affect the community.

L22-25 A bold and agonizing example was the recent demolition of the 1908 residence and garage at 1420 Valley View Road, which occurred without the incorporation of or adoption of mitigation measures. It may not have been a "municipal power property type," but a historical resource was undeniably permanently lost by the community. How many properties within that narrow context of the "municipal power property type" have been evaluated for historic significance? Is there an adopted historic context regarding Glendale's municipal water and power system? CEQA ensures that the myriad of content-specific state environmental laws are considered in a holistic context that includes cumulative impacts.

L22-26 For example, what are the expected CEQA impacts expected to be caused by the current Glendale Water & Power "Western Reservoir & Bel Aire Electric Substation Improvements" to the Bel Aire Electric Substation Pump House? If that Pump House had been evaluated for historic significance in a city-wide survey as proposed by TGHS, that answer would be known. Is the Pump House a historical resource? Has it been intensively evaluated? Was it historically connected to a black metal fence as proposed? Was its setting historically in a grove of trees as currently proposed or was it surrounded by lawn? Implementation of the proposed historic resource mitigation measure would serve to guide future projects of that type and should avoid future problems like this. Refer to the discussion in the previous pages regarding Mitigation Measures and the preparation of a related context statement.

L22-27 To bring a finer point to the matter, how would the Lead Agency or the public know whether or not a city-owned property was historically significant in the absence of the TGHS-recommended intensive historic resources survey of those properties? The Lead Agency's justification is both exceedingly inward-looking, restricting the analysis of identified historic resources which are known examples of "the municipal power property" type in Glendale and moreover is circular. If the City of Glendale does not identify city-owned properties that are historically significant to avoid situations like the proposed project, where TGHS has presented a fair argument for its historic significance, then only unreasonably limited opportunities to analyze historical resources impacts to those properties will exist.

L22-28 Because the PRDEIR did not consider a comprehensive list of recent and expected future projects that would affect historical resources, the combined impacts of those projects considered with the proposed project has not been properly analyzed. An analysis of the severity and extent of those impacts is required by CEQA. It is common for a lead agency to conclude that a project would not cause significant cumulative impacts because it is assumed that the project's incremental effect is not cumulatively considerable, *i.e.,* the impacts of the project would be a drop in the bucket compared to the overall view. The requirement for an adequate cumulative impact analysis as it relates to historical resources must be properly prepared to ensure the fullest possible protection of the environment as it relates to historical resources.

L22-29 <u>Embodied Energy</u>

We further note that in a City that maintains an established Sustainability Commission, there is no discussion or calculations in the PR-DEIR regarding the expected loss of embodied energy that would be caused by the proposed project. "Examples of embodied energy include: the energy used to extract raw resources, process materials, assemble product components, transport between each step, construction, maintenance and repair, deconstruction and disposal. As such, it is important to employ a whole-life carbon accounting framework in analyzing the carbon emissions in buildings."[7] Using of embodied-energy calculations as a basis for evaluating the relative environmental benefits of any building strategy, whether it is reuse and rehabilitation or new construction, has validity and merit. It is particularly appropriate for historic buildings like the Boiler Building with its 20-foot deep basement, and can be expected to possess high embodied energy. Comparing the benefit of reusing a building versus the construction of an entirely new building, the embodied energy savings would be considerable.

L22-30 The recommended study of reuse of the Boiler Building and any other structures that were identified as potentially reusable rather than being wholesale demolished for the sake of simplicity could make the proposed restudied project a model of sustainability for other communities.

L22-31 It is strongly recommended that the Lead Agency include and consider embodied energy calculations in future environmental clearance documents for this project and consult with the Sustainability Commission on the subject. It is their responsibility "to make advisory recommendations to Council on ways to promote progress toward sustainability in the Greener Glendale Plan, Climate Action Plans, on issues relating to the environment and recommend priorities to promote regional leadership in sustainability." [8] The Commission is tasked with working "in conjunction with City departments regarding the development, implementation and evaluation of sustainability programs." The consideration of the proposed project's embodied energy loss presents an abundant opportunity for Glendale to make strides toward our sustainability goals.

[7] Ibn-Mohammed, T., *et al*. "Operational vs. Embodied Emissions In Buildings—A Review of Current Trends" *Energy and Buildings*. November 1. 2013..

[8] Glendale, City of. Boards & Commissions. Sustainability Commission. "Duties" https://www.glendaleca.gov/government/boards-and-commissions/sustainability-commission

We appreciate the opportunity to comment and look forward to working with the Lead Agency in a more constructive and comprehensive way to avoid future problems with CEQA compliance as it relates to historical resources, including the Grayson Repowering Project.

L22-32

Very truly yours,

Lee Smith Francesca Smith

Lee W. Smith Francesca Smith

Attachments:

L22-33 Attachment 1 Letter from High-Speed Rail Authority to Julianne Polanco, State Historic Preservation Officer regarding "High-Speed Rail Program, Burbank to Los Angeles Project Section – additional information and request for review and concurrence on revised determination of National Register of Historic Places eligibility for Grayson Steam-Electric Generating Station (Grayson Power Plant)" November 3, 2020 (pdf pages 1-2); with letter from Erik Krause, City of Glendale to Mark McLoughlin, High-Speed Rail Authority, August 31, 2020 (pages 3-7) and California DPR 523 dated August 17, 2015 and revised 2017 (pages 8-33).

L22-34 Attachment 2 Letter from The Glendale Historical Society to Erik Krause "Comments on Proposed Grayson Repowering Project Draft Environmental Impact Statement" November 17, 2017.

L22-35 Attachment 3 Letter from Julianne Polanco, State Historic Preservation Officer to Brett Rushing regarding "High-Speed Rail Program, Burbank to Los Angeles Project Section, Additional Information and Request for Review and Concurrence on Revised National Register of Historic Places Determination of Eligibility for Grayson Steam-Electric Generating Station (Grayson Power Plant)" December 2, 2020.

L22-36 Attachment 4 "Grayson Electric-Steam Power Plant Mitigation Measures" transmitted by The Glendale Historical Society to the Lead Agency dated April 25, 2021. Note: the date may be incorrect, the document may have been transmitted on March 25, 2021.

cc: Mayor Paula Devine and all council persons
Aram Adjemian, City Clerk
Julianne Polanco, State Historic Preservation Officer
Lucinda Woodward, Supervisor Cultural Resources Program, California Office of Historic Preservation
John Schwab-Simms, Vice President of Advocacy, The Glendale Historical Society
Alek Bartrosouf, Chair, City of Glendale Sustainability Commission
Chris Cragnotti, Chair, City of Glendale Historic Preservation Commission

L22-A

CALIFORNIA
High-Speed Rail Authority

November 3, 2020

Julianne Polanco
State Historic Preservation Officer
Attention: Tristan Tozer
Office of Historic Preservation
1725 23rd Street, Suite 100
Sacramento, CA 95816

OHP Project #FRA_2017_0516_001

Subject: High-Speed Rail Program, Burbank to Los Angeles Project Section – additional information and request for review and concurrence on revised determination of National Register of Historic Places eligibility for Grayson Steam-Electric Generating Station (Grayson Power Plant)

Dear Ms. Polanco:

The California High-Speed Rail Authority (Authority) is continuing consultation with the State Historic Preservation Officer (SHPO) and other consulting parties regarding the Burbank to Los Angeles Project Section of the California High-Speed Rail (HSR) Program. This consultation is undertaken in accordance with the 2011 *Programmatic Agreement Among the Federal Railroad Administration, the Advisory Council on Historic Preservation, the California State Historic Preservation Officer, and the California High-Speed Rail Authority* (PA). In support of this consultation, the Authority is providing the enclosed documentation:

Updated California Department of Parks and Recreation Site Record Form (DPR 523) for Grayson Power Plant, 2015 (revised 2017)

City of Glendale Community Development Department Comment Letter on the California High-Speed Rail Program Burbank to Los Angeles Project Section Draft Environmental Impact Report/Environmental Impact Statement, August 31, 2020

On December 12, 2016, the Authority provided your office and consulting parties the Burbank to Los Angeles Project Section Historic Architectural Survey Report, which evaluated the eligibility of properties for listing in the National Register of Historic Places (NRHP). In a letter dated May 2, 2019, you concurred with the Authority's findings, including the Authority's determination that the Grayson Steam-Electric Generating Station (Grayson Power Plant) in Glendale was eligible for listing in the NRHP.

On August 31, 2020, in response to the circulation of the Burbank to Los Angeles Project Section Public Draft EIR/EIS, the Glendale Community Development Department provided the Authority additional information on the Grayson Power Plant.

The information provided included an updated DPR form for the Grayson Power Plant recommending the power plant ineligible for listing in the NRHP. The DPR form provided information previously unknown to the Authority including documentation of substantial physical alterations to the power plant that have diminished its integrity and ability to convey its historical significance. The Authority has reviewed the additional information, has reevaluated its previous NRHP eligibility determination, and now considers Grayson Power Plant ineligible for listing in the NRHP.

REQUEST FOR CONCURRENCE

The Authority is requesting SHPO concurrence with the determination that Grayson Power Plant is ineligible for listing in the NRHP. While the PA does not specify review duration for NRHP reevaluations, we respectfully request your response **within 30 days** of receipt of this submittal.

By copy of this letter, this report is also being transmitted to the Burbank to Los Angeles Consulting Parties for review and comment. If you require any additional information, please contact Jeff Carr by phone at (213) 443-7458 or by email at jeff.carr@hsr.ca.gov. Thank you very much for your ongoing assistance with this undertaking.

Sincerely,

Brett Rushing
Cultural Resources Program Manager
California High-Speed Rail Authority
(916) 403-0061
brett.rushing@hsr.ca.gov

Encl: Updated California Department of Parks and Recreation Site Record Form (DPR 523) for Grayson Power Plant, 2015 (revised 2017)

City of Glendale Community Development Department Comment Letter on the California High-Speed Rail Program Burbank to Los Angeles Project Section Draft Environmental Impact Report/Environmental Impact Statement, August 31, 2020

cc: Stephanie Perez, Federal Railroad Administration
Sarah Stokely, Advisory Council on Historic Preservation
David Navecky, Surface Transportation Board
Danielle Storey, U.S. Army Corps of Engineers, Los Angeles District
Claudia Harbert, Caltrans District 7
Ken Bernstein, Office of Historic Resources, Los Angeles Department of City Planning
Steve Fox, Southern California Association of Governments
Adrian Scott Fine, Los Angeles Conservancy
Erik Krause, City of Glendale Community Development Department

CITY OF GLENDALE, CALIFORNIA
Community Development
Planning

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August 31, 2020

Mr. Mark McLoughlin
California High-Speed Rail Authority
770 L Street, Suite 620 MS-1
Sacramento, CA 95814
Info@hsr.ca.gov

On behalf of the City of Glendale (City), we are providing comments on the California High Speed Rail (HSR) Authority's "California High-Speed Rail Project, Burbank to Los Angeles Project Section Draft EIR." (Project).[1] We understand, GPA Consulting prepared a Historic Architectural Survey Report (Report) for the Project which was completed in March 2019. Using the HSR Section 106 Programmatic Agreement in the Cultural Resources Technical Memorandum #1, GPA defined the Project Area of Potential Effect (APE) based on the November 2018 footprint. Through delineation of the APE, the City of Glendale's Grayson Power Plant (Power Plant) was included within the defined APE.

We recognize the Power Plant had no listings for previous studies and no historical determination under any criteria for either the National Register of Historic Places (NRHP) or California Register of Historical Resources (CRHR). Therefore, the Power Plant was surveyed and recorded by GPA on a DPR-523 Series Form in which they identified the boiler building as being constructed in 1941. GPA recommended

> "…the main building located at 901 Fairmont Avenue[2] meets the criteria for listing in the [NRHP] and the [CRHR] as a locally significant example of a property associated with developmental history of power generation in Glendale under NRHP Criterion A and CRHR Criterion 1, with a period of significance of 1941-1955 (its years of operation prior to the redevelopment of the Grand Central Air Terminal to the Grand Central Industrial Center)."

We understand that, based on this recommendation, the EIR considers the Power Plant to be an historical resource for the purposes of CEQA. GPA's prepared DPR-523 Form included a detailed physical description of the Power Plant, as well as, a short historic context, brief property history, historical photographs, and aerials, limited contemporary photographs from the public right-of-way, and full evaluation per the NRHP and CRHR criteria. Based on their data, GPA considered the Power Plant a California Historical Resource Status Code of 2S2, which represents "Individual property determined eligible for [NRHP] by a consensus through Section 106 process. Listed in the [CRHR]."

On October 9, 2018, the "California High-Speed Rail Authority, Burbank to Los Angeles Project Station Historic Architectural Survey Report" was submitted to the California State Historic Preservation Officer (SHPO) for review. The report was reviewed and revised multiple times, in October 2018, March 2019,

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[1] California High-Speed Rail Project, Burbank to Los Angeles Project Section, State Clearing House 2014071073, https://ceqanet.opr.ca.gov/2014071073/2 (accessed 8/29/2020).
[2] The correct address is 800 Air Way.

and on April 3, 2019, for a final SHPO review and concurrence.[3] On May 2, 2019, Kathleen Forrest, acting on behalf of California SHPO Julianne Polanco , concurred with the findings presented in the April 2019 submittal. This included the finding that the Grayson Power Plant is eligible for the NRHP as a locally significant example of a property associated with developmental history of power generation in Glendale under NRHP Criterion A.[4]

In 2016, prior to the High Speed Rail Study, the City of Glendale contracted, Stantec Consulting Services Inc. to prepare a Historic Resources Inventory and Evaluation Report (attached) and DPR-523 Forms for Grayson Power Plant in support of an EIR (Grayson Repowering Project) on the Grayson Power Plant. In 2018, this report was revised to reflect comments received during the public review of the draft EIR and preparation of the final EIR. The report documents the entire property, rather than just the boiler buildings. The 2018 revised report included an introduction with the project location and description, identified APE for the redevelopment project, team qualifications, research and field methods, and an in-depth historic context which covers the history of electricity in California, steam generation in Los Angeles County, Glendale history, and the history and evolution of the power plant. Additionally, the report included an in-depth discussion of the power plant, boiler building, boiler units, cooling towers, switchyards, as well as adjacent and new construction. The extensive written documentation was supported by photographic documentation, crucial for identification of property modifications and included tables chronologically illustrating modifications, citing building information provided by the City and through aerial photography to show change over time. The property includes an evaluation of potential eligibility for the NRHP, CRHR, and the City of Glendale Register based upon full evaluations per the applicable significance criteria.

The 2018 effort recommended the Grayson Power Plant <u>not</u> eligible for listing on the NRHP, CRHR, or the Glendale Register of Historic Resources. The report found the Grayson Power Plant significant under Criteria C and 3; however, it lacks sufficient integrity to convey that significance. The report states:

> "The Grayson Power Plant property as first constructed in 1941 represented the designs of the 1920s, this was soon realized as the plant underwent numerous upgrades and additions through the 1940s, 1950s, 1960s, 1970s, and 1980s to keep pace with the larger, semi-outdoor boiler types that proliferated across California in the 1950s and 1960s. Therefore, Grayson Power Plant is ineligible, under NRHP Criteria A, CRHR Criterion 1 and GRHR as it is not associated with important events in national, state, or city history, or exemplifies significant contributions to the broad cultural, political, economic, social, or historic heritage of the nation, state, or city. Rather, the plant is a continuation of electrical generation themes in a city that had been using electricity for 32 years…. There is no evidence that Grayson Power Plant has any important association with any person or persons who made significant contributions to history at the local, state, or national level. The power plant is not eligible

[3] Brett Rushing, Cultural Resources Program Manager for the California High-Speed Rail Authority to Kathleen Forrest, State Historic Preservation Officer California Office of Historic Preservation re: "High-Speed Rail Program, Burbank to Los Angeles Project Section (FRA_2017_0516_001), request for review and concurrence on revised Historic Architectural Survey Report; Notification of Modification to the Area of Potential Effects," April 3, 2019.
[4] Julianne Polanco, SHPO to Brett Rushing, Cultural Resource Program Manager for the California High-Speed Rail Authority, re: "Historical Architectural Survey Report (HASR) Burbank to Los Angeles Project Section High-Speed Train Project, County of Los Angeles, California," FRA_2017_0516_001, May 2, 2019.

> under NRHP Criteria B, CRHR Criterion 2 or for the GRHR… An article noted its design as earthquake resistant meaning its generators were located outside on a concrete foundation that was resistant to earthquakes with metal coverings to protect it from weather. R.R. Martell noted earthquake engineer consulted on the project stating the generator could be constructed outside the main boiler building. Through time the power plant has withstood earthquakes, as have other power plants with varied designs. This design is important in the greater advancement of power plant designs. Unfortunately, multiple additions and modifications have degraded its integrity and it can no longer convey this significance under NRHP Criteria C or CRHR Criterion 3. As noted, before, the GRHR does not assess integrity. The evolution of earthquake resistant power plant is important to the context of power plant design in California, however it is within the context of Glendale is lessened… The property does not appear likely to yield significant informational associations under NRHP Criteria D, CRHR Criterion 4 or the GRHR as the plant does not yield information important to archaeological pre-history or history of the nation, state, region, or city.[5]

It continues, through

> …numerous building additions and continued evolution of the property there has been a loss of integrity of design, materials, workmanship, and feeling. The property retains integrity of location, setting, and association. The power plant has not moved, the overall setting has remained industrial, and it maintains its association as a power plant. However, numerous alterations have removed its integrity of design to the original plant conceived by Elliott, materials as the building materials, while similar are different in type and massing from the original section. The plant has lost its association of workmanship as the additions have fundamentally altered the physical characteristics of the building as original constructed in 1941 and finally the plant has lost its original feeling. Aside from the numerous building additions continued addition of non-attached boiler units with modern cooling towers and ancillary buildings have removed the original feeling of the property. Therefore, the building has lost integrity coupled with lack of significance the building is not eligible for the NRHP or CRHR under any criterion.[6]

These findings were preliminary and were included in, and frame the discussion in, the City's EIR for the proposed redevelopment Grayson Repowering Project. The EIR concluded that the proposed Project would not result in potentially significant and unavoidable environmental impacts relating to historical resources.

The City has recognized some data gaps and/or inaccuracies in the GPA preparation; of importance is that the GPA study mischaracterized the period of significance, 1941-1955, as it correlates to the identified historic property. The earliest iteration of the boiler building dates to 1941; however, the building identified by GPA was constructed between 1941 and 1964, with a significant portion of the building constructed between 1959 and 1964. This is relevant because the modifications, would constitute a loss of integrity as most of the building was constructed after 1955.

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[5] Stantec Consulting Services (Stantec), Historic Resources Inventory and Evaluation, Grayson Power Plant, City of Glendale, California 2016, (revised 2018).
[6] Stantec, Historic Resources Inventory and Evaluation, Grayson Power Plant (revised 2018).

The map in the DPR-523 Building, Structure, Object (BSO) Form identifies the "NRHP-Eligible Historic Property Boundary highlighted in white." GPA expands stating "The boundaries of the historic property are limited to the main building. The later additions, such as the modern buildings and infrastructure as well as the replaced steam turbines, do not contribute to the property because they were most likely constructed outside the period of significance, 1941-1955, at which point the Grand Central Air Terminal was redeveloped as the Grand Central Industrial Center. This redevelopment incited major alterations throughout the subject property, bust most noticeable the northern portion of the property which was formerly part of the airfield."

The challenge is, the identified property was constructed between 1941 and 1964, not 1955. The original boiler building which housed Unit 1 was completed in 1941, with Unit 2 added in 1948. In 1953 the building was expanded to accommodate Unit 3, with the design remaining consistent with the original building. Between 1959 and 1964 a multi-story addition on the north end of the building was added to accommodate Unit 4 in 1959 and Unit 5 in 1964. Additions to the property continued with Unit 6 in 1972 and Unit 7 in 1974, they were separate structures constructed north of the main boiler building.

Up until 1959, the Power Plant remained a single-story-structure. In 1959, the addition of Unit 4 and 5 resulted in the much larger and taller structure which remains today. Despite these alterations, GPA inaccurately states that the "main building marked by signage stating 'City of Glendale Public Service Department Steam Electric Generating Plant,' retains integrity of location, materials, design, workmanship, feeling, and association; however, the integrity has been diminished by ongoing development on the site and in the area since the property's construction according to historic aerials maps."

GPA provides that the entire building identified dates from 1941 to 1955 and that it retains the integrity of a building competed in 1955, when in actuality a significant portion of the building dates from 1959 to 1964. These modifications should have been identified as a loss of integrity as the building clearly no longer retains the design, materials, and workmanship of a building constructed between 1941 and 1955. With this, the loss of four of the seven aspects (setting, design, materials, and workmanship), they could have concluded the building was significant under Criteria A and 1, but because of a loss of integrity unable to convey this significance and thusly ineligible for the NRHP and CRHR.

Additionally, the historic context considered in the GPA study does not address the significance of this end date. By choosing 1955, it would suggest that the Power Plant's significance is derived to its association with the Grand Central Air Terminal. However, there is no historic context to support this assertion; the airfield was developed in 1928, whereas the Power Plant was constructed 13 years later. In addition, the report states that it retains all aspects of integrity, despite the Power Plant having undergone multiple additions since the original plan construction in 1941. Most notably, the GPA report does not include the fact that the two story-addition was added in 1959, with ongoing work occurring into 1964. Given this, the structure cannot convey its significance from 1941 through 1955 since the northernmost portion of the building is an addition constructed outside the identified period of significance, 1941-1955.

A detailed review of the 2016 DPR revealed the evaluation conducted GPA does not address several key aspects in developing a proper historic resource evaluation, as outlined in *National Register*

Bulletin No.15. Primarily, the historic context included in the DPR-523 Form is largely incomplete, and does not provide sufficient information to form the basis for an accurate historical significance evaluation of the property, specifically under Criterion A/1 for the property's association with the Grand Central Air Terminal, nor does it fully support the assertion that construction of a steam plant benefited the region. It does not explain the history of electrical generation in the region or place the construction of the Grayson Power Plant within that context. Second, the GPA report does not provide a well-developed analysis of historical integrity. While the report does provide a cursory list of alternations, which appear to be based upon the included historic aerials, it does not identify or account for many of the modifications to the property, which largely occurred outside the period of significance. This does not adhere to the integrity analysis outlined in N*ational Register Bulletin No.15.*

We ask the HSR Authority, given this new information, to reconsider the previous determination. We ask that, based on the lack of integrity through multiple additions from 1959 through 1964, outside the GPA period of significance, the authority find Grayson Power Plant ineligible for listing on the CRHR and as a historical resource for the purposes of CEQA. Further, we ask the Authority reconsult with SHPO regarding the property's status on the NRHP.

Sincerely,

Erik Krause
Deputy Director of Community Development

State of California - The Resources Agency
DEPARTMENT OF PARKS AND RECREATION
PRIMARY RECORD

Primary #
HRI #
Trinomial
NRHP Status Code 6Z

Other Listings
Review Code Reviewer Date

***Resource Name or #:** (Assigned by recorder) Grayson Power Plant

P1. Other Identifier:

***P2. Location:** ☐ **Not for Publication** ☒ **Unrestricted** ***a. County** Los Angeles

and (P2c, P2e, and P2b or P2d. Attach a Location Map as necessary.)

b. USGS 7.5' Quad Burbank, CA

Date 2015 **T** 1N; **R** 13W **Sec** 7 S.B. **B.M.**

c. Address 800 Air Way City Glendale Zip 91201

d. UTM: (Give more than one for large and/or linear resources) Zone, 10S 382154 mE/ 3780132 mN

e. Other Locational Data: (e.g., parcel #, directions to resource, elevation, decimal degrees, etc., as appropriate)

From downtown Glendale, travel 2.3 miles west on Elk Avenue to San Fernando Road, proceed northwest of 2.8 miles on San Fernando Road to Flower Street. Travel southwest on Flower Street to Air Way, the power plant is located on Air Way at the convergence of the Los Angeles River and Fairmont Avenue. APN: 5593-003-906.

***P3a. Description:** (Describe resource and its major elements. Include design, materials, condition, alterations, size, setting, and boundaries)

Glendale Water and Power's Grayson Power Plant is a steam electric power plant located in Glendale, CA. The approximately 11-acre property is bounded by Union Pacific Railroad tracks and San Fernando Road to the northeast, Fairmont Avenue to the southwest, south, and southeast. The property contains numerous elements of power generating infrastructure including a boiler building with nine boilers, generators, five cooling towers, two switch yards, and multiple auxiliary buildings amounting to approximately 17 permanent buildings and structures (**Photograph 1**) (see Continuation Sheet).

***P3b. Resource Attributes:** (List attributes and codes) HP8 – Industrial Building, HP11 – Engineering Feature

***P4. Resources Present:** ☒ Building ☒ Structure ☐ Object ☐ Site ☐ District ☐ Element of District ☐ Other (Isolates, etc.)

P5a. Photograph or Drawing (Photograph required for buildings, structures, and objects.)

P5b. Description of Photo: (view, date, accession #)
Photograph 1: Grayson Power Plant, camera facing southwest, August 17, 2015.

***P6. Date Constructed/Age and Source:**
☒ Historic ☐ Prehistoric ☐ Both
1941, Glendale Water and Power

***P7. Owner and Address:**
City of Glendale, Glendale Water and Power
800 Air Way
Glendale, CA 91201

***P8. Recorded by:** (Name, affiliation, and address)
Meagan Kersten and John Terry
Stantec, Inc.
555 Capitol Avenue, Suite 650
Sacramento, CA 95814

***P9. Date Recorded:** August 17, 2015

***P10. Survey Type:** (Describe) Intensive

***P11. Report Citation**: (Cite survey report and other sources, or enter "none.")
Historic Resource Inventory and Evaluation Report, Grayson Power Plant, Glendale, CA, Stantec, 2015 (Revised 2017)

***Attachments:** ☐NONE ☐Location Map ☒Continuation Sheet ☒Building, Structure, and Object Record ☐Archaeological Record ☐District Record ☐Linear Feature Record ☐Milling Station Record ☐Rock Art Record ☐Artifact Record ☐Photograph Record ☐ Other (List):

State of California - The Resources Agency Primary #
DEPARTMENT OF PARKS AND RECREATION HRI#

BUILDING, STRUCTURE, AND OBJECT RECORD

***Resource Name or #** (Assigned by recorder) Grayson Power Plant ***NRHP Status Code** 6Z

B1. Historic Name: Glendale Public Service Department, Steam Electric Generating Plant

B2. Common Name: Grayson Power Plant

B3. Original Use: Power Plant B4. Present Use: Power Plant

***B5. Architectural Style:** Streamline Moderne

***B6. Construction History:** (Construction date, alterations, and date of alterations) Grayson Power Plant was constructed in 1941 with additions added to the main boiler building in 1952, 1963, 1972, and 1977. The site has continuously evolved as technology changed and more units were brought online (see detailed history below)

***B7. Moved?** ☒**No** ☐**Yes** ☐**Unknown Date:** ________ **Original Location:** ________

***B8. Related Features:** **none**

B9a. Architect: Daniel A. Elliott b. Builder: Glendale Public Service Department

***B10. Significance: Theme** n/a **Area** n/a

Period of Significance n/a **Property Type** n/a **Applicable Criteria** n/a (Discuss importance in terms of historical or architectural

This intensive level survey and evaluation finds that Grayson Power Plant, while significant, lacks integrity to convey this significance for listing in the National Register of Historic Places (NRHP), California Register of Historical Resources (CRHR) or Glendale Register of Historic Resources (GRHR). The property has been evaluated in accordance with Section 15064.5(a)(2)-(3) of the California Environmental Quality Act Guidelines (CEQA), using the criteria outlined in Section 5024.1 of the California Public Resources Code and does not appear to be a historical resource for the purpose of CEQA (see continuation sheet).

B11. Additional Resource Attributes: (List attributes and codes) ________

***B12. References:** See footnotes

B13. Remarks:

***B14. Evaluator:** Corri Jimenez and Garret Root, Stantec Inc.

***Date of Evaluation:** December 2015 and December 2017

This space reserved for official comments.

P3a. Description (Continued):

Grayson Power Plant's boiler building faces southeast, on a northwest-southeast axis and massing is predominantly rectangular divided into three levels and each elevation asymmetrical (**Photograph 2** and **3**). Architecturally, the boiler building is 2-3-stories high and is framed with structural steel set on a poured concrete pier foundation (**Photograph 4**). The lower floor extends up a floor level on a poured concrete structure with a steel-framed superstructure set on top of the concrete walls; a second steel-framed structure is set on the northwest corner, which houses Unit 3. Streamline Moderne character-defining details are evident as linear lines in the cementitious paneling, illuminating stringcourses on the building's upper southeast corner addition, added during a 1953 expansion to building for Unit #3.

The building has a flat roof with metal coping at the top. The exterior of the building is clad with multiple building materials that include horizontal asbestos siding and horizontal metal sheathing that are bolted to the steel framing. The cementitious siding are visible on the interior of the building as well. A Streamline Moderne style-rolling directional crane, which services the boilers, turbines, and generators, is located on the northeast elevation. Each of the five turbines is covered with a Streamline Moderne enclosure (**Photograph 5**). Copper box lettering in the same style are located on the corner and state: "CITY OF GLENDALE/PUBLIC SERVICE DEPARTMENT/STEAM ELECTRIC GENERATING PLANT" (see Figure 20-21). The northeast elevation of the building has a dock with boilers and equipment located on the northwest elevation (**Photograph 6**). The northwest elevation is where all the mechanical equipment and numerous boiler stacks for Boilers 1, 2, and 3. New equipment is evident for Boiler Unit #3 on the northwest corner.

Multiple openings punctuate the elevations of the boiler building on all elevations. The boiler building retains its original windows, which include structural glass blocks on the northeast elevation and metal-framed industrial awning windows on the southeast elevation (**Photograph 7**). Currently the building houses six boilers and is centrally located near the control room. The interior of the building is open with a catwalk or mezzanine floor of metal grating constructed on the west wall in operating the power equipment that include the boilers above and turbines, which attached to the concrete floor platforms. The corresponding boiler stacks and scrubbers are located on the exterior of building along the west wall (**Photograph 8**).

The Grayson Power Plant had eleven boiler units with seven intact. Units 1 and 2 are located within the boiler building and have been mothballed. Units 3, 4, and 5 are located along the southwest elevation of the boiler building. Units 6 and 7, built between 1972-1974, have since been demolished. Units 8A, 8B, and 8C, were constructed in 1977 and Unit 9, built in 2003. Units 1 through 4 are housed in the main boiler building with additions. Structures 8A, 8B, 8C, and 9 are located within utilitarian metal structures (**Photograph 9** and **10**).

Located west of Grayson Power Plant's boiler units are five cooling towers. Each cooling tower correlates to one boiler. The cooling towers consists of a sub grade water tank is enclosed by two-to-three-foot-thick concrete walls. Each cooling unit has a series of vent stacks. Cooling Towers 1 and 2 are designed with four stacks, which has splayed concrete sidewalls, while Cooling Tower 3 is constructed with six stacks, Cooling Tower 4 has eight stacks, and Cooling Tower 5 with five stacks (**Photograph 12, 13,** and **14**). Additional features of the cooling towers include a louvered wall, which provides air circulation to cool the water from the boilers and wooden roof decks. There are two switching yards, east of the boiler building and are labeled as Kellogg and the Glendale switching yards. The yards are not historic and are not part of this inventory. Five miscellaneous utilitarian buildings are located on the property northwest of the boiler building. These buildings were not inventoried or evaluated as part of this study.

B10. Significance (Continued):

Historic Context

The Glendale Public Service Department steam electric generation plant, renamed Grayson Power Plant in 1972, was constructed in Glendale in 1941, Since construction the power plant has undergone numerous alterations and expansions. The Streamline Moderne boiler building has more than tripled in size since originally conceived by architect Daniel A. Elliott. Fuel fired steam electric units have been common power generators in California since the 1920s. The design and power output changed dramatically by the end of World War II as municipalities and utilities moved towards semi-outdoor fuel fired steam plant. This reduction in building material cost drove exponential growth in the post-war years, becoming common fixtures across California. The Grayson Power Plant represents a transition in fuel fired power plant design that is more associative with the early 1920s designs rather than the more prominent post-war designs.

Electricity in California

California's growth in the first half of the twentieth century was due in part to the development of ambitious hydroelectric systems. Long-distance transmission lines linked the power generating mountainous regions with valley farms, coastal centers, and distant cities, allowing a pace and scale of development that was previously unimaginable. By the 1920s, this intricate system of hydroelectric facilities, coupled with a growing number of fuel-fired steam plants, fed into long distance transmission lines and a series of substations that transferred and distributed power to locations throughout the state for widespread public use (Root and Herbert 2013: 1; Department of Energy 2015). Within this burgeoning energy context, the long-distance transmission lines were of vital importance, serving as the nexus between the state's abundant hydro supplies and the distant urban and agricultural markets. The technological advancement and development of transmission technology enabled greater and greater supplies of readily available energy, occurring with striking rapidity during the period (Root and Herbert 2013: 1-2).

In the late nineteenth century and into the twentieth, electrical transmission covered small distances, typically limited to tens of miles. During this period, the technological debate raged between two key concepts: Direct Current (DC), championed by General Electric and Thomas Edison, and Alternating Current (AC), championed by Westinghouse and electrical engineer Nikola Tesla (Department of Energy 2015; Williams 1997: 90). The critical limitation to DC was its inability to be transmitted over great distances, as the current could not be converted to higher and lower voltages and rapidly lost energy along any distances. In contrast, Tesla's AC stepped up voltage for transmission and stepped down voltages for local distribution, creating a system that avoided the energy seepage of DC. Ultimately, Tesla's vision of AC prevailed and soon transmission lines could carry more power over greater distances, a development that undergirded much of the state and nation's early twentieth century growth. Rapid innovation during the first decades of the twentieth century allowed for increasingly higher voltages, with heavier insulators, multi-phase lines, and other mechanical methods adapted to carry greater supplies more efficiently, following the adoption of AC. By the early-1910s, California's hydroelectric industry was carrying hundreds of kV of electrical power over hundreds of miles (**Figure 1**) (Root and Herbert 2013: 1-3; Hayes 2014: 237-270).

In the 1880s, hydroelectric plants provided small-scale electrical development to only isolated companies, such as Standard Consolidated Mining Company in Bodie, CA and other localized concerns (Hubbard 2006).

However, by the early 1890s AC technological advancement allowed for a more effective means of transmitting electricity over ever-increasing distances. At the outset of this development, the San Antonio Light and Power Company constructed a 13 mile, 5,000-volt, transmission line in 1892, with PG&E constructing the Folsom Hydroelectric Plant's 22 mile, 11,000-volt transmission line in 1895 (Coleman 1952: 138-140). These distances soon gave way to ever larger transmission capability, with Pacific Light and Power Company's Big Creek Hydroelectric Project running at 150 kV by 1913. Several small companies began constructing independent and local power plants a transmission systems (JRP 2004).

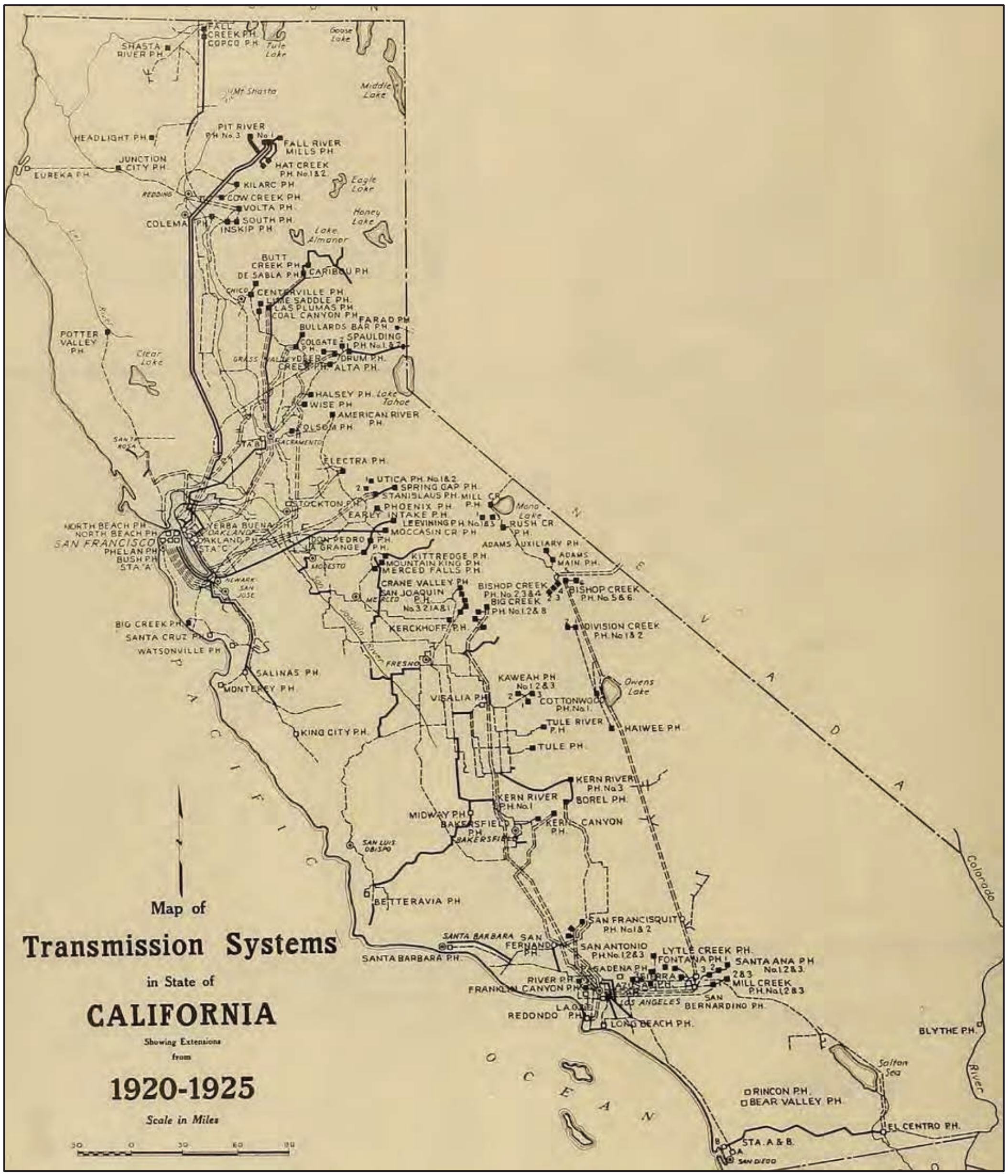


Figure 1. A 1925 map depicting the growth of the transmission system (Vincent 1925).

Rise of Fuel-Fired Steam Electric

British designer Sir Charles Parsons built the first steam turbine-generator in 1884. At the beginning of the twentieth century, engineers designed steam turbines to replace the aging steam engine power plants. Aegidius Elling of Norway is credited in 1903-1904 as being the first to apply the method of injecting steam into the combustion chambers of a gas turbine engine (Termuehlen 2001: 11, 21-28; Beck and Wilson 1996: 30). The greater Los Angeles region had multiple examples of early fuel fired steam plants including the Banning Street Electrical Plant in Los Angles completed in 1883, Los Angeles Steam Plant No. 1 constructed in 1896, Pacific Light and Power Company's steam plant in Redondo Beach was completed in 1902 and the Glenram Power Plant constructed in Pasadena in 1906 (Water and Power Associates 2017; City of Pasadena 2015). Within a relatively short time, the technology and capacity of these engines to supply power and electricity grew exponentially. These advances brought electricity to a wide range of industrial and domestic applications; however, the materials needed to withstand the high temperatures of modern turbines were not yet available. Improvements in steam turbines advanced throughout the 1920s and 1930s, leading to a generation of more efficient turbine power plants in the 1950s. During this time, utilities closed or replaced many of the older steam-electric plant generators and constructed more modern units (Myers 1984: 8).

Steam power generation was part of California's power production throughout the twentieth century, though it declined considerably in the period leading up to World War II as large hydroelectric generating plants came online throughout the state. As early as 1920, hydroelectric power accounted for 69% of all electrical power generated. In 1930, that figure had risen to 76%, and by 1940 hydroelectric sources provided 89% of California's electricity. After World War II this trend reversed and construction of steam-powered electric generating units grew, accounting for most of the new construction. By 1950, hydroelectricity accounted for only 59% of the total power generated, falling to 27% in 1960. Some new hydroelectric plants were built during the 1960s, chiefly associated with federal and state water projects, but by 1970, hydroelectric plants accounted for only 31% of all electricity generated in California. A combination of drought, discovery and tapping of natural gas, and lack of new hydroelectric sites led to its decline (Williams 1997: 374).

A persistent drought in California caused the major utilities to question the reliability of systems dependent on abundant water flows, like hydroelectricity. This drought began in 1924 and continued, on and off, for a decade. Concurrently, in the 1920s new natural gas discoveries were made and provided both Northern and Southern California with ample fuel for steam electric power generation. The confluence of these various factors – drought, new steam generator technologies, and new supplies of natural gas – prompted California utilities to begin constructing large steam plants. Steam plants built across the state shared design characteristics including locations close to load centers to reduce transmission costs, easy and efficient access to fuel supplies, near a water supply, on inexpensive land, and on geological formations that could provide a good foundation (Steele 1950: 17-21). By 1920, the cities of Burbank, Pasadena, Los Angeles, and Glendale restructured their original charters to allow municipality owned power generation facilities and distribution lines (Williams 1997:261; Water and Power Associates 2015; Electrical West 1929). In 1928, LA Gas and Electric Corporation constructed the Seal Bach Power Plant and PG&E constructed Station C in Oakland. In 1929, Great Western Power Company built a large steam plant on San Francisco Bay, near the Hunters Point shipyard, fitted with two 55 MW generators. In 1930, fuel-fired steam power plant accounted for more than half of all new plants under construction in California. The fuel-fired steam generation capacity jumped from 1924 at 407,000 kW to over 1 million kW a mere six years later. (Williams 1997: 279-280; City of Pasadena 2015; Burbank Water & Power 2015; Water and Power Associates 2017; Spencer 1961). These factors prompted many municipalities, like Glendale to construct power plants of their own.

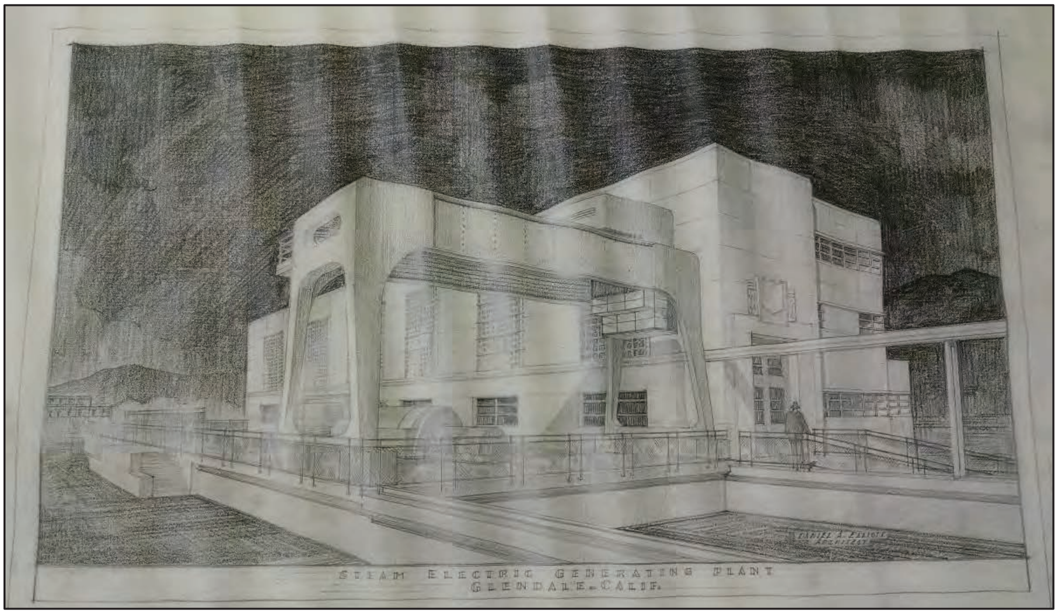
Early Glendale History

By the turn of the twentieth century, Glendale had already experienced rapid growth resulting, in part, from the promotional efforts of Edgar D. Goode and Dr. D. W. Hunt and their Glendale Improvement Society in 1902 (City of Glendale 2012a). The growth continued with the opening of the Pacific Electric Railroad in 1904, connecting Glendale to Los Angeles (City of Glendale 2012a). Glendale incorporated in 1906 and by 1910 had a population of 2,742 residents (Glendale News-Press 1953c; Los Angeles Almanac 2015). Power generation in the City of Glendale began in earnest early when the citizens voted in favor of a $60,000 bond to create the Glendale Public Service Division that purchased the Glendale Light & Power Company generating facility in 1909. By 1910, the system was already strained as power output was a mere 107,000 kilowatts. To supplement, the city purchased additional electricity from Pacific Power & Light, now part of the Southern California Edison Company (Glendale Public Service Commission 1951).

By 1920, Glendale began annexing neighboring communities boasting the city's population to over 13,000 residents (City of Glendale 2012b; Los Angeles Almanac 2015). From 1930 to 1952, Glendale added Whiting Woods and Verdugo Mountains to their city limits a total of 23.6 square miles; two major annexations included New York Avenue (in the La Crescenta area) and Upper Chevy Chase Canyon, and several smaller annexations, which enlarged the city to 29.2 square miles by 1952. By 1950 the population was over 95,700 residents and was considered at the time to be "the fastest growing city in America" (City of Glendale 2012b; Los Angeles Almanac 2015). However, by the late 1930s the Glendale Public Service Commission, Electric Division could not keep pace with the population increases (Glendale Public Service Commission 1951). Prior to 1937, Glendale purchased their power from Southern California Edison Company. This supply was supplemented with completion Hoover Dam however, continued growth indicated another plant would be necessary to supplement demand [Glendale News-Press 1953a; Glendale Public Services Department 1974).

Glendale Steam Electric Generating Plant

Building off the success of the 1920s and early-1930s and seeing the impending probability of an outbreak of hostilities, utilities and municipalities began constructing a series of fuel-fired steam plants across California. Northern California PG&E began construction of three, fuel-fired steam -plants located adjacent to oil refineries, in 1939. Southern California municipalities, in Burbank, Glendale (study property), and San Diego each completed power plants, in 1941 (Williams 1997: 279-280). The City of Glendale began planning for construction of a new power plant in 1937. However, the city's plans were met with immediate opposition by Los Angeles Bureau of Power and Light and the Southern California Edison Company, both which supplied the city with electricity and claimed had surplus electricity which could be sold to the city (Los Angeles Times 1938). Despite these assertions, the city, led by industrial entities pushed forward with their plan for construction of a $1.8 million-dollar plant. The City secured the services of Architect Daniel A. Elliott to design the power plant, referred as the "Glendale Power & Light" or "Steam Electric Generating Plant" (**Figure 2**) (LA Conservancy 2015).



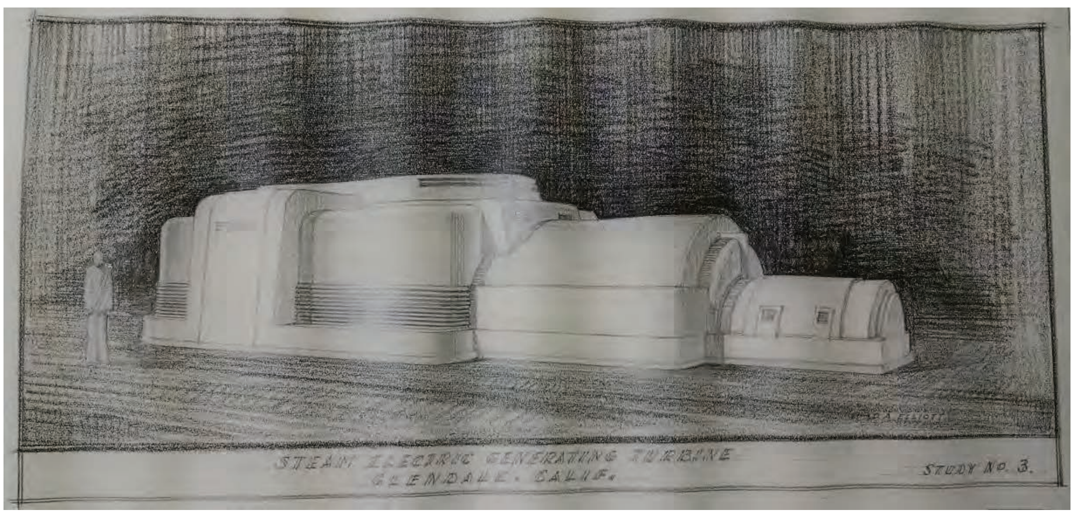


Figure 2. Original Daniel Elliott renderings show the exaggerated streamline moderne details, much of which did not make it onto the building.

Elliott designed the boiler structure in the Streamline Moderne-style, built to house two boilers (Boilers 1A and 1B). Located outside on a full length concrete pedestal were the generators, manufactured by Combustion Engineering Company Inc., New York and with Streamline Moderne detailing. Elliott was born in Las Vegas, New Mexico in 1898. He attended University of California at Berkley, earning an architecture degree in 1925. From 1925 through 1932 he served as a designer at the Los Angeles architecture firm of Gilbert Stanley Underwood before getting his architecture license and becoming an architect at the Metropolitan Water District of Southern California. He remained at the water district from 1932 through 1939. During World War II he worked at Hoover and Montgomery, a firm that specialized in water-related construction projects. Following the end of the war he formed his own architecture practice, one he maintained until his retirement in 1962. Principle examples of his work are water focused designs most notably the Colorado River Aqueduct Pumping Plants and F.E. Weymouth Memorial Water Softening and Filtration Plant completed in 1939 (**Figure 3**) and the Burbank Water & Power administrative building in 1949 (LA Conservancy 2015; AIA 1956: 155).

Elliott's original design laid claim to being the world's first earthquake-proof plant, with a 22 foot deep concrete basement, turbo-generator on an uncovered open deck with a metal covering over the generator from to protect from inclement weather, and a building shell built of light steel and stucco filler walls (Los Angeles Times 1940). At its start-up in 1941, the plant produced 20,000 kilowatts of power. The city had already secured funding for a second unit set to be added in 1945 (Lost Angeles Times 1941; Glendale Public Service Commission 1951). To meet increasing demands for electricity, a second unit was added in 1947, which included an additional 20,000-kilowatt generator and single boiler increasing the plant's combined kilowatt capacity of 40,000 kilowatts (Glendale News Press 1953e; Glendale News Press 1953f; and Glendale Public Service Commission 1951).

Figure 3. Top, the 1939 Metropolitan Water District of Southern California Water Softening Plant in La Verne and below the Burbank Water Light and Power Administration building built in 1949.

As demand increased a third unit were added in 1953, which constituted the first of several additions to the boiler building on its north end; the third unit at the plant was completed at a cost of over $3 million. The integral furnace boiler and superheater steam boiler was manufactured by the Babcock & Wilcox Company and the turbine generator by General Electric. The company of Foster & Wheeler constructed the cooling tower and provided the condenser for Unit 3. Unit 3 also utilized the most up-to date engineering replicated in fuel-fired plants across California. The turbine for Unit 3 is located outside the main building under a removable housing (Glendale News Press 1953e).

California utility companies' steam generating capacity expanded during the period of 1950 through 1970. PG&E operated 15 steam electric plants in 1950. Conversely, Southern California utilities built large steam plants at a much slower rate than with Northern California, constructing the Valley Steam Plant in 1953 and Scattergood Steam Plant in 1957. By the late 1970s, there were more than 20 fossil fuel steam-generating plants in California owned by various power companies and clustered near urban areas such as San Francisco Bay, the greater Los Angeles area, San Diego County, along with a few interior plants in San Bernardino, Riverside, and Imperial Counties. Happening concurrently, in the mid-1960s large scale intertie projects such as the 500 kV California Oregon Intertie (also known as Path 66) were completed. Additionally, utility companies began to pool their resources, creating a larger interconnected grid. Dictated by Federal power policy, utility companies came together to form bulk transmission entities. In 1967, the Western Systems Coordinating Council formed, consisting of 40 power systems located in western states and remained in existence until 2002 when it merged with three regional transmission associations forming the Western System Coordinating Council (WSCC). In addition to WSCC in the mid-1960s was the California Power Pool. This entity gave rise to the current California Independent Service Operator (CAISO). These large intertie projects brought the death of independent, locally sourced electricity as CAISO and its predecessors controlled operation of the various plants (Transmission Agency of Northern California 2017; Water and Power Associates 2017); Southwest Builder and Contractor 1962).

Between 1953-54, the plant generated a total of 122,649,440 kilowatts per hour, supplemented by electricity generated at Hoover Dam, supplied all the power needed for the City (Glendale Public Service Commission 1951). Five more units were constructed after 1953 including Unit 4 (1959), Unit 5 (1964), Unit 6 (1972), and Unit 7 (1974). The boiler for Unit 4 was manufactured by Riley Stoker Corporation; Unit 6 was manufactured by General Electric; and Unit 7 by the Curtiss-Wright Company. Units 1 through 3 maintain Elliott's the style aesthetics, however the structure shape and detailing shifts with the addition of Units 4 & Unit 5, to a significantly taller, less detailed utilitarian structure that we see to the north. As the building was expanded north, lower level fenestration of the first three phases was repeated but without the vertical glass block panels. Little significant architectural detail was included in Unit 4 & Unit 5's building expansion. In 1972 The plant was renamed the "L.W. Grayson Steam-Electric Generating Station" after the City of Glendale General Manager and Chief Engineer, Lauren W. (L.W.) Grayson who at the time was the longest serving employee. Grayson accepted a position at the City of Glendale in 1951 (City of Glendale 1972; Glendale News-Press 1972). His most notable achievement was in bringing power to Southern California through the Pacific Northwest Intertie (Glendale News-Press 1972).

Unit 8 (Unit 8A, 8B, and 8C) was constructed in 1977 and was one of the last to be installed at the power plant and the most efficient of the group while producing fewer emissions than the earlier generators at the plant (Cook 1977). Initially, it was called a "combined cycle repowering unit" in producing more energy and fewer emissions with conventional units that provide better combustion controls and higher efficiency

(Cook 1977). The new system cost $20 million dollars and at the time, lessened air pollution (Ralph 1977). Further environmental improvements to the plant resulted from the construction of a phosphate removal and treatment plant in 1978. The treatment plant was connected to the steam plant by a pipeline, which directly pumps the reclaimed water into the Grayson Power Plant's cooling towers (Rees 1978). In addition, since 1994 the plant has utilized methane gas from the Scholl Canyon Landfill mixed with natural gas to generate power in Units 3, 4, and 5 (Scholl Canyon Landfill 2015).

Continuous improvements in efficiency and power generation capacity have been one of the priorities at the Grayson Power Plant throughout its history including the construction of a new 50 megawatt power generator was completed in 2004, at a cost of $33.5 million dollars, replaced two of the older, outdated units. The new structure consists of a generator, a gas turbine and compressor, and an emissions control tower to filter out pollutants throughout the system. The generator runs entirely on computers and operates during peak hours (Moskowitz 2004).

In July 2010, a fire at Cooling Tower 3 caused severe damage to the structure, although service was not effected (Wells 2010). Repairs to other portions of the plant included the replacement of the superheater tubes in Boiler No. 4 in 2001, wall tubes in Boiler No. 4 in 2011, an upgrade of the burner management and boiler control systems, also in Unit 4 in 2011, among other updates (City of Glendale 2011). According to the City of Glendale, California Report to the City Council in April 2014, the boilers for Units 1 and 2 have been mothballed (City of Glendale 2014). In 2015, the Glendale City Council commissioned plans to upgrade Grayson Power Plant to make the plant more efficient, reliable and cost effective. According to the June article in the Glendale News-Press, seven of the eight turbines would be decommissioned and replaced by 4 more efficient turbines, which would be able to produce power more quickly (Mikailian 2015). Currently the power plant generates approximately 18% of the power needed for the City of Glendale with the remaining power coming from a combination of both local and remote generation (owned and leased), coupled with spot market purchases from a variety of suppliers throughout the Western United States (Mikailian 2015).

Evaluation

Glendale's Grayson Power Plant served as a regional power source since construction. While the power plant has maintained this role, it has not directly contributed to the early growth of the city, further it only supplemented electricity supplied by other utilities and by the 1937 constructed Hoover Dam. The power plant did supply the region with localized power, however, it is just a continuation of existing power supplies. By the time the power plant came online, in 1941, the city had been electrified for 32 years. Further, articles exaggerated the need for a localized power plant to sustain growth. Supply was high, the city, understandably preferred control of their own power supply. California, like much of the west had begun interconnection a series of previously independent transmission systems into an interconnected grid. When originally conceived, the plant would provide a localized source of power, however by the 1940s the state had already begun interconnection. Further, fuel-fired steam plants were well established across California by 1941, that utilized proven technologies. The Grayson Power Plant as first constructed in 1941 represented the designs of the 1920s, this was soon realized as the plant underwent numerous upgrades and additions through the 1940s, 1950s, 1980s, 1970s, and 1980s to keep pace with the larger, semi-outdoor boiler types that proliferated across California in the 1950s and 1960s. Therefore, Grayson Power Plant is ineligible, under NRHP Criteria A, CRHR Criterion 1 and GRHR as it is not associated with important events in national, state, or city history, or exemplifies significant contributions to the broad cultural, political, economic, social, or historic heritage of the nation, state, or city. Rather, the plant is a continuation of electrical generation themes in a city that had been using electricity for 32 years.

There is no evidence that Grayson Power Plant has any important association with any person or persons who made significant contributions to history at the local, state, or national level. It was designed to supplement and create a localized power source that involved several key institutions and individuals. Research did not reveal any notable figures specifically associated with the alignment or its related infrastructure, and research did not indicate the potential for significant associations in this regard. While the power plant is currently named Grayson Power Plant for L.W Grayson, a longtime Glendale employee. The name change, occurred in 1972, was in recognition of Grayson 19 years of service to the city. Grayson was important in management of the city but had no association with development, construction, or early operation of the plant. The power plant is not eligible under NRHP Criteria B, CRHR Criterion 2 or for the GRHR.

The subject property is not eligible for NRHP Criteria C, CRHR Criterion 3 nor the GRHR. Grayson Power Plant when originally constructed as a small, two-unit boiler house with Streamline Moderene styling. Since originally constructed, the power plant main boiler building has undergone numerous additions and alterations. These additions, mimic Elliott's design but with each addition are farther removed from the original (**Figure 4** and **5**).

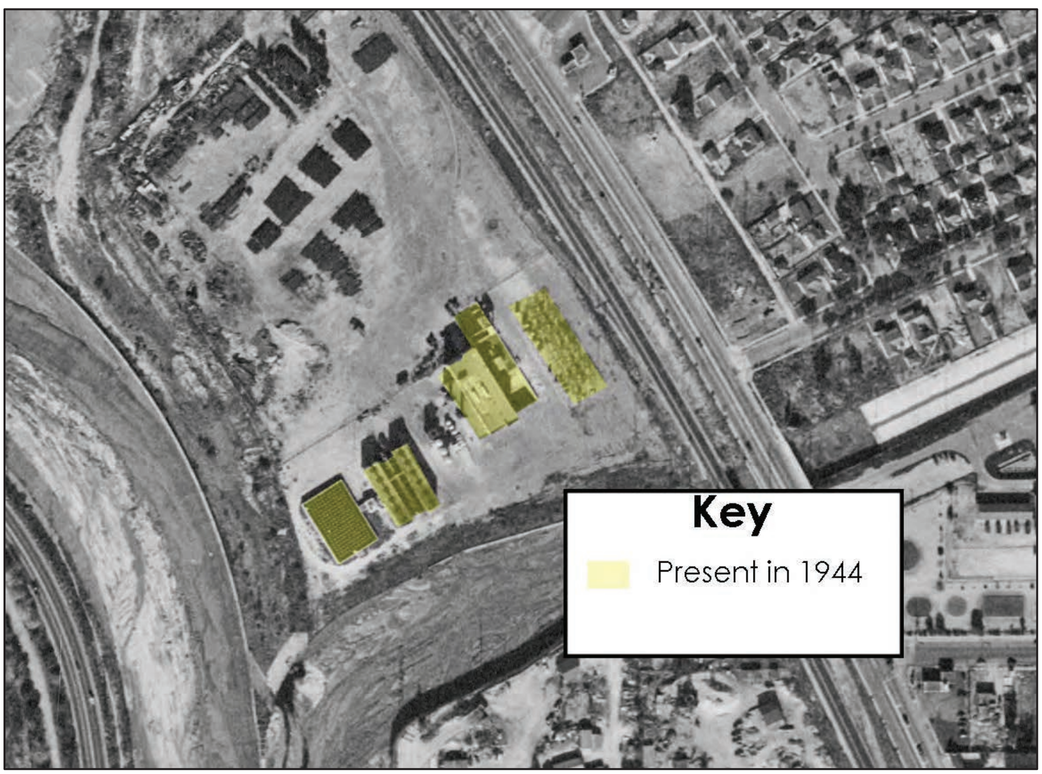


Figure 4. Glendale Steam Electric Power Plant Property in 1944.

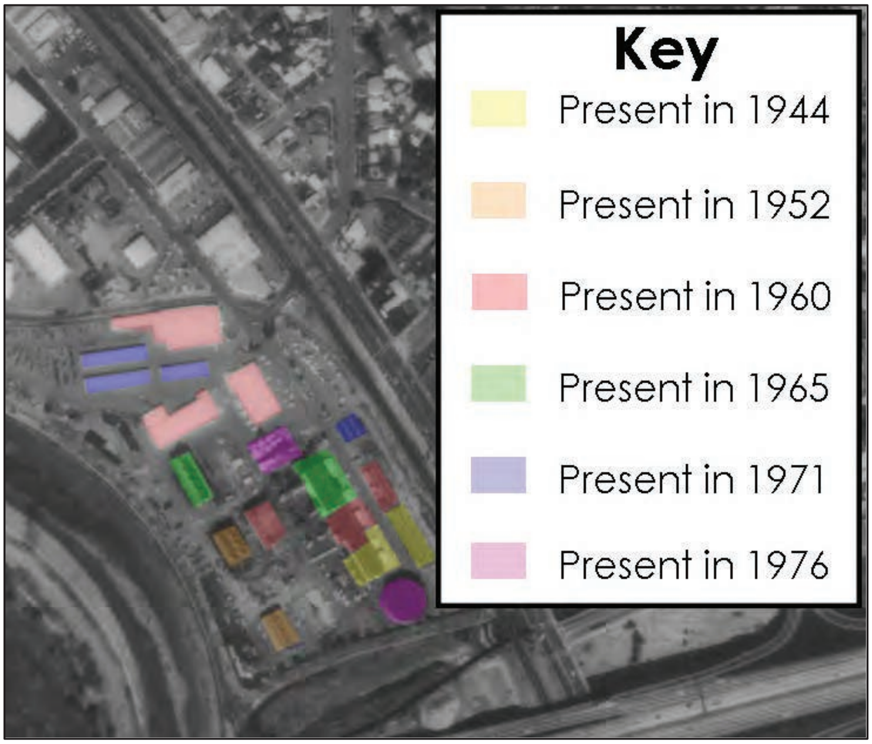


Figure 5. A graphic showing the numerous plant modifications since construction in 1941. The information is overlaid on a 1976 aerial with changes noted on historic aerials in 1944, 195, 1960, 1965,1971, and 1976.

Daniel Anthony Elliott, who is arguably a master architect. His noteworthy designs focus on water related infrastructure including the Colorado River Aqueduct Pumping Plants and F.E. Weymouth Memorial Water Softening and Filtration Plant completed in 1939 (**Figure 3,** above) and later the Burbank Water & Power administrative building in 1949. The F.E. Weymouth Memorial Water Softening and Filtration Plant is the earliest extant example of Elliott's work, further it is the best example of monumental water and power architecture. Built in a Spanish Revival design, this building exemplifies the style, prominent of the time and best showcases Elliott's ability to make infrastructure into beautiful architecture. They original design of the Grayson Power Plant followed these design tenants. Elliott used prominent architectural styles on infrastructure. Elliott's design followed established power plant and substation design principles emblematic of the 1910s and 1920s. Power company architects designed substations and powerhouses in prominent public-building architectural styles like Beaux-Arts and Classical Revival. Urban power houses and substations housed the electrical equipment within buildings in order to accommodate the congested urban surroundings and to buffer the public from the sounds and activities associated with operation. The power plants and substations were constructed to meet both aesthetic and functional mandates (Frickstad 1916). Elliott's design of the Streamline Moderne power plant is a 1940s continuation of these design principles. Further, the 1941 building designed by Elliott has been manipulated and changed beyond his original vision through multiple building modifications. Further, the F.E. Weymouth Memorial Water Softening and Filtration Plant is far more intact example of his early designs.

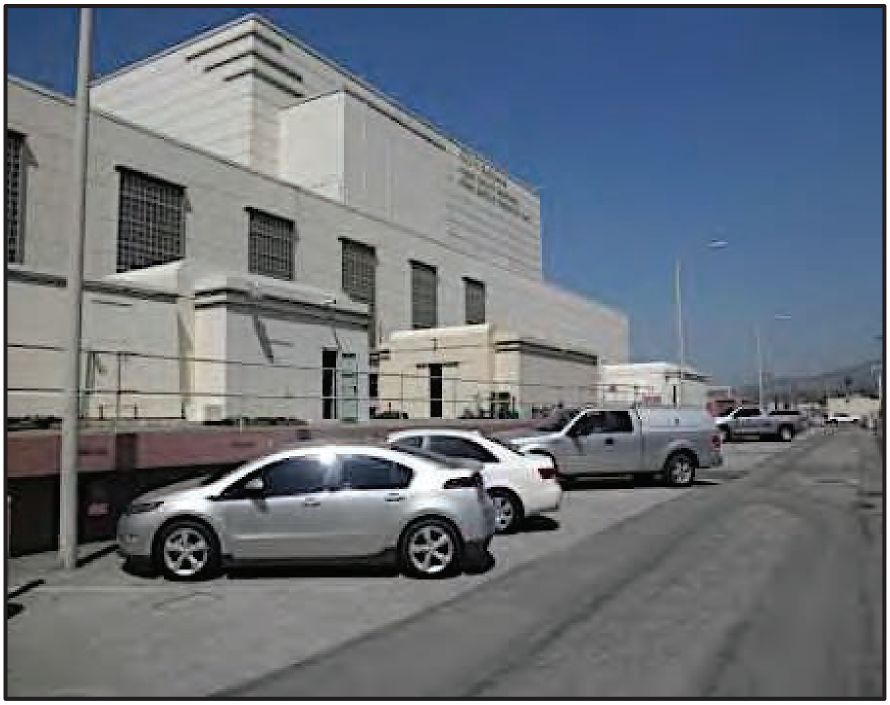
An article noted its design as earthquake resistant meaning its generators were located outside on a concrete foundation that was resistant to earthquakes with metal coverings to protect it from weather. R.R. Martell, noted earthquake engineer consulted on the project stating the generator could be constructed outside the main boiler building. Through time the power plant has withstood earthquakes, as have other power plants with varied designs. This design is important in the greater advancement of power plant designs. Unfortunately, multiple additions and modifications have degraded its integrity and it can no longer convey this significance under NRHP Criteria C or CRHR Criterion 3. As noted before, the GRHR does not assess integrity. The evolution of earthquake resistant power plant is important to the context of power plant design in California, however it's within the context of Glendale is lessened.

The property does not appear likely to yield significant informational associations under NRHP Criteria D, CRHR Criterion 4 or the GRHR as the plant does not yield information important to archaeological pre-history or history of the nation, state, region, or city. In contrast, the extant archival record regarding the site presents a wealth of specific and informative material, including maps, photographs, aerials, and building permits that provides significant material for interpretation. Thus, the extant physical structures of the site do not convey significant informational material that would inform the rather robust archival record regarding the Grayson Power Plant.

The Grayson Power Plant was constructed approximately 60 years after the early development of the City of Glendale and 35 years after the City incorporated electricity in 1906. Due to this passage of time it is not associated with the early heritage of the City and not eligible for listing on the GRHR.

While the GRHR does not account for integrity, both the NRHP and CRHR do. Due to numerous building additions and continued evolution of the property there has been a loss of integrity of design, materials, workmanship, and feeling. The property retains integrity of location, setting, and association. The power plant has not moved, the overall setting has remained industrial, and it maintains its association as a power plant. However, numerous alterations have removed its integrity of design to the original plant conceived by Elliott, materials as the building materials, while similar are different in type and massing from the original section. The plant has lost its association of workmanship as the additions have fundamentally altered the physical characteristics of the building as original constructed in 1941 and finally the plant has lost its original feeling. Aside from the numerous building additions continued addition of non-attached boiler units with modern cooling towers and ancillary buildings have removed the original feeling of the property. Therefore, the building has lost integrity coupled with lack of significance the building is not eligible for the NRHP or CRHR under any criterion.

Photographs (Continued):



Photograph 2. Grayson Boiler Building, View Looking Northwest (Photo by J. Terry).

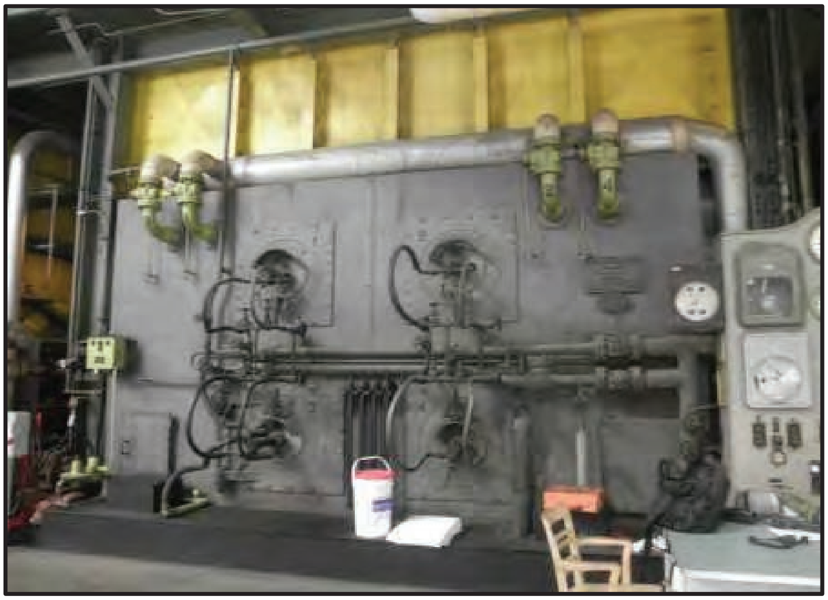
Photograph 3. Grayson Boiler Building, View Looking Northwest (Photo by J. Terry).

Photograph 4. Grayson Boiler Building, View Looking Southwest (Photo by J. Terry).

Photograph 5. Grayson Boiler Building, View Looking Southeast (Photo by J. Terry).

Photograph 6. Boiler Stacks (Boilers 1 and 2 Center Rear of Photograph; Boiler 3 to Left), View Looking South. (Photo by J. Terry).

Photograph 7. Overview of Basement Floor Level, View Looking North (Photo by J. Terry).



Photograph 8. View of Boiler 1B, Looking West (Photo by J. Terry).

Photograph 9. Unit 8A, Looking West (Photo by J. Terry).

Photograph 10. Units 8A & 8B, View Looking Northeast (Photo by J. Terry**).**

Photograph 12. Cooling Tower No. 2 (No. 1 in background), View Looking Southeast (Photo by J. Terry).

Photograph 13. Cooling Tower No. 3 (No. 5 in Background), View Looking Northwest (Photo by J. Terry).

Photograph 14. Cooling Tower No. 4, View Looking Northeast (Photo by J. Terry).

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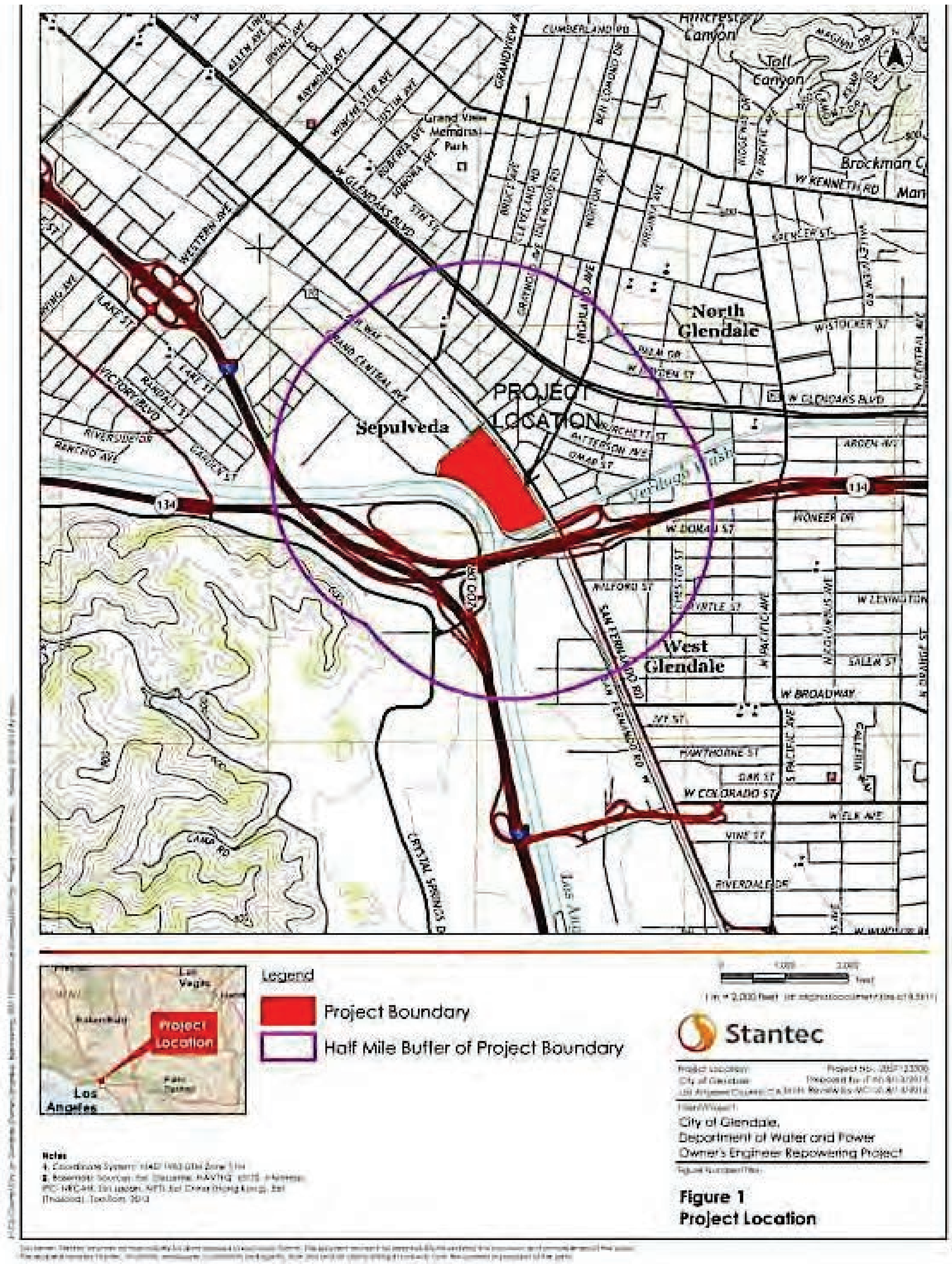
State of California - The Resources Agency
DEPARTMENT OF PARKS AND RECREATION

LOCATION MAP

Primary#
HRI#
Trinomial

Page 25 **of** 25 ***Resource Name or #** (Assigned by recorder) Grayson Power Plant

***Map Name:** Grayson Power Plant Location Map ***Scale:** 1:24,000 ***Date of map:** 2015



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THE GLENDALE HISTORICAL SOCIETY

CONSERVING OUR HERITAGE

P.O. Box 4173 Glendale CA 91202
www.GlendaleHistorical.org

November 19, 2017

Mr. Erik Krause
Interim Deputy Director of Community Development
City of Glendale Community Development Department
633 E Broadway, Room 103
Glendale CA 91206

RE: Comments on Proposed Grayson Repowering Project Draft Environmental Impact Statement

Dear Mr. Krause:

On behalf of the Board of Directors of The Glendale Historical Society (TGHS), I would like to thank you for the opportunity to comment on the draft Environmental Impact Report (DEIR) for the Proposed Grayson Repowering Project. Established in 1979, TGHS is a non-profit organization with more than 700 members dedicated to the preservation of Glendale's history and architectural heritage through advocacy and education.

We disagree with the findings that the Grayson Steam Electric Power Plant is not a historical resource as defined in CEQA. We believe that the consultant's assessment of historic significance is fundamentally flawed and we question whether the City's qualified experts have critically reviewed the built environment or archaeological findings. TGHS believes that the Grayson Steam Electric Power Plant may be eligible for listing in the National Register and that it is eligible for listing in the California and Glendale Registers for its associative as well as for its design and engineering significance. We also believe the DEIR is flawed in other important ways described in detail below.

<u>Tribal Cultural Resources</u>

We note that the "Tribal Cultural Resources" chapter of the DEIR is incorrectly titled among other more deficiencies. The inaccurate title demonstrates a lack of basic understanding of the intent of the section and the task by preparers and reviewers. The purpose of what is normally called a Cultural Resources chapter in an EIR is to identify and evaluate the potential for a project to effect paleontological, archaeological and historical resources. Resources of concern include fossils, prehistoric and historic artifacts, burials, sites of religious or cultural significance to Native American groups and historical resources.

Its essential questions should be:

> Is there a historical resource that may be affected by the proposed project; and
>
> Will the project result in a substantial adverse change to the extent that the resource's historical value is materially impaired or lost?

Evaluations for historic significance are not normally "negative" as stated in the document, historical resources either exist or they do not. Negative findings are an archaic term that was used in solely archaeological investigations and do not apply to the built environment. That paragraph, along with the section title, the evaluation and analysis contained therein alerts informed readers to the fact that the entire section may have been prepared primarily by archaeologists practicing outside of their fields of expertise.

The Tribal Cultural Resources title implies that only archaeological resources and tribal concerns were considered. Under CEQA, Initial Studies and EIRs address Cultural Resources, not merely "Tribal Cultural Resources."

Preparer Qualifications

The preparer qualifications presented in the Initial Study (1.4 Cultural Resources Project Staff Qualifications) do not demonstrate that any staff meet the Secretary of the Interior's Professional Qualifications Standards. A statement in the closing paragraph claims "The Stantec Cultural Resources *Program Manager* and *Senior Architectural Historians* directing the survey meet the Professional Qualification Standards of the Department of the Interior" but provides no particulars regarding degrees attained and more importantly does not identify any staff members' fields of expertise (emphasis added). Each provides numbers of years preparing reports but none of the brief biographies provides evidence to corroborate meeting the Secretary of the Interior's Professional Qualifications Standards codified in CFR Part 61.

The guidance in Archeology And Historic Preservation: Secretary of the Interior's Standards and Guidelines [as Amended and Annotated] directs "The qualifications define minimum education and experience required to perform identification, evaluation, registration, and treatment activities. In some cases, additional areas or levels of expertise may be needed, depending on the complexity of the task and the nature of the historic properties involved". The website for the Historical Architect responsible for the report states that he specializes "in custom residential architecture, and also do[es] commercial projects" (http://www.johnterryarch.com/Introduction-1). Enumerated experience on that website includes two "renovations" but no rehabilitations or restorations are listed. No evidence of a year or more of graduate study or of professional experience including "detailed investigations of historic structures, preparation of historic structures research reports, and preparation of plans and specifications for preservation projects" as cited in the Professional Qualifications Standards is provided. We submit that this evaluation for historic significance is a complex case, and that the preparers provide no evidence of additional levels or areas of expertise and shows no demonstrated experience with successful evaluations for the National, California or Glendale Registers.

Archaeologists are not normally qualified to prepare built environment evaluations, and historians are not interchangeable with historic architects. In the FEIR revised cultural resources technical report all preparers' professional qualifications should be clearly stated otherwise the reviewers suspect that it was prepared by staff who have generated reports for specific numbers of years rather than persons with demonstrated expertise necessary to perform the tasks required for this evaluation of historic significance and analysis of effects.

<u>Laws, Ordinances, Regulations and Standards</u>

The introductory "Laws, Ordinances, Regulations and Standards (LORS)" section is fatally flawed. The applying LORS enumerated are not demonstrated to have any specific application to the project. If federal regulations apply to the proposed project, then Section 106 of the National Historic Preservation Act (as amended) would pertain to the project. If the project has *any* federal nexus, the proper environmental document would likely be an Environmental Impact Statement/Environmental Impact Report (EIS/EIR) rather than merely an EIR.

It is not clear that Section 106 of the National Historic Preservation Act does or does not apply to the proposed project. We expect that a project of this type requires federal permits, licenses or other approvals. If so, Section 106 applies and the appropriate clearance document may be an Environmental Impact Study and well as an Environmental Impact Report.

The federal Environmental Protection Agency (EPA) promulgated the Steam Electric Power Generating Effluent Guidelines and Standards (40 CFR Part 423) in 1974, and amended the regulations in 1977, 1978, 1980, 1982 and 2015. *The regulations cover wastewater discharges from power plants operating as utilities.* The steam electric regulations are incorporated into National Pollutant Discharge Elimination System (NPDES) permits. If a NPDES permit or any other federal approval or license is required for the proposed project, *there is a federal nexus and Section 106 applies*.

Further, the EPA released a final rule to limit greenhouse gas emissions from new power plants on August 3, 2015. The final "Carbon Pollution Standard for New Power Plants" establishes New Source Performance Standards to limit emissions of carbon dioxide from fossil fuel-fired power plants. If the "Carbon Pollution Standard for New Power Plants" applies to the proposed project or any other federal approval or license is required for the proposed project, *there is a federal nexus and Section 106 applies*.

Please explain how the National Environmental Policy Act would or would not apply to the proposed project. Can the proposed project be considered a major federal action that would be determined to significantly affect the quality of the human environment?

The "Applicable Federal, State, Local LORS for Tribal [*sic*] Cultural Resources" table and section notably contains no discussion of whether or not the listed LORS apply and why, which is an obvious necessity in such documents. Merely listing the language in LORS does not inform the public or decision-makers in making their decisions regarding the proposed project.

In the "Applicable Federal, State, Local LORS for Tribal [*sic*] Cultural Resources" table, there are significant errors and omissions. The administering agency column is incorrect *in each entry*. For instance, Section 106 is not administered by the Code of Federal Regulations (CFR). CFR is not and has never been an administering agency; it is codification of the general and permanent rules and regulations (or administrative law) published in the Federal Register by the executive departments and agencies of the federal government. Applicable Federal Agency Programs administer Section 106 with the Advisory Council on Historic Preservation. If that table, which provides no of information of value to the analysis, remains, it must be corrected in the Final EIR or a supplemental EIS/EIR. We strongly recommend that it be completed (most of it is blank) and corrected to list correct administering agencies.

Further, where each of the LORS is enumerated in the narrative sections below, applicable language was merely cut-and-pasted into the document. There is notably no description of how the listed LORS apply to the proposed project, and why, or what it means to the project or analysis, which is critical to understanding what the document is and why preparers came to whatever conclusions they did. Absent this information, the "Tribal Cultural Resources" section of the document is useless, devoid of worthwhile information for decision makers and the public. Reviewers are left wondering what laws, ordinances and regulations apply to the proposed project, why and how that fits into the analysis at hand.

Archaeology
Neither the "Existing Conditions" section nor the other parts of the larger "Tribal Cultural Resources" [*sic*] chapter make reference to an archaeological surveys being performed, presenting the property only above-ground when whatever does or does not exist below grade is undeniably part of the subject property's cultural resources existing conditions. No reference was made to any archaeological surveys being performed for the proposed project, of the likelihood for encountering archaeological resources or what the expected impacts of effects would be on those resources.

Review of the Initial Study, where the technical reports are sequestered, provides an overview of archaeological surveys being performed in 2003 and 2016, providing no further details. What methods were used? How much of the subject property was surveyed? More importantly, who at the City of Glendale has the appropriate credentials (meeting the Secretary of the Interior's Professional Qualifications Standards in Archaeology) to critically review the reports that ostensibly resulted? Was a subcontractor engaged to review whatever reports resulted from those surveys? Provide the name and professional qualifications of the archaeologist who reviewed the confidential section of the Initial Study.

The archaeological survey reports were requested of the City by Francesca Smith, a cultural resources professional who is approved by the South Central Coastal Information Center to perform records searches and to review archaeological surveys. It was denied pending City Attorney review. Subsequently, the same request was made on behalf of a professionally qualified archaeologist, but no response has been received to date. The archaeological surveys on which the "Tribal Cultural Resources" section and Initial Study conclusions were based should be made available to qualified reviewers on request. TGHS, the public and decision makers can't provide any comments on the adequacy of those studies without being provided those reports for review.

Methodology
The "Methodology" section of the EIR is inadequate as well. The two sentences describing Senate Bill 52 efforts is not equivalent to what should be a description of how project Cultural Resources procedures were carried out. Inserting words that do not apply into a section does not satisfy the requirements of CEQA. The methodology section is intended to explain how the evaluation and analysis were prepared that lead the preparers to arrive at the conclusions they did.

Evaluation for Historic Significance
We additionally submit that because the evaluation of the subject property's historic significance is not included in the document or the appended technical reports, decision makers cannot review the evaluation. Because of that omission, decision-makers and the public cannot make their own conclusions based on information presented as to whether or not the Grayson Steam-Electric Power Plant is historically significant. In addition, because that information is not provided,

decision-makers and public are not able to judge whether substantial adverse change to a historical resources would be materially impaired or entirely lost. The California Code of Regulations (CCR) directs under Technical Detail:

> The information contained in an EIR shall include summarized technical data, maps, plot plans, diagrams, and similar relevant information sufficient to permit full assessment of significant environmental impacts by reviewing agencies and members of the public. *Placement of highly technical and specialized analysis and data in the body of an EIR should be avoided through inclusion of supporting information and analyses as appendices to the main body of the EIR.* Appendices to the EIR may be prepared in volumes separate from the basic EIR document, but shall be readily available for public examination and shall be submitted to all clearinghouses which assist in public review (emphasis added, CCR Section 15147).

The applicable cultural resources analysis is not contained in the technical report section, or in an appendix, but was secreted in the Notice of Preparation. Once TGHS was able to locate the "Architectural Resource Evaluation of The Grayson Power Plant For City of Glendale, California" it was reviewed for adequacy by a professional qualified under the Secretary of the Interior's Qualifications Standards in both history and architectural history and was found not to be correct in its conclusions.

Other EIR reviewers will not know where to find the evaluation for historic significance. Because that analysis is not "readily available for public examination" it does not "assist in public review" as required. We strongly stress that the conclusion, that the Grayson Steam-Electric Power is not historically significant is was made in error and that the revised, corrected evaluation should be a technical appendix to the FEIR and that the FEIR should address alternatives to the project that would retain the historical resource and or mitigate its loss if it were proven not to be feasible, based on facts.

Like the archaeological investigation, no evidence is provided of any lead agency review of the conclusions in the report being performed by qualified staff or consultants for the City of Glendale. The conclusions the EIR that are based in incorrect finding in the Initial Study must be peer-reviewed for accuracy by professionally qualified professionals with demonstrated expertise in the applicable fields.

Reconnaissance Survey

The evaluators note in the survey type on the DPR form that the evaluation is an "Architectural Inventory and Evaluation *Reconnaissance* Survey." We strongly assert that an intensive evaluation must be prepared by local qualified architectural historians with has clear understanding of the Grayson Steam-Electric Power Plant's place in local and regional history and who has demonstrated experience in applying the criteria for Glendale Register of Historic Resources to evaluations for significance. We assert that the property's National, California Register and local significance were not properly considered and that its conclusions are incorrect.

National Register guidance prepared by the Department of the Interior provides a definition in "Guidelines for Local Surveys A Basis For Reservation Planning: "*Reconnaissance* may be thought of as a 'once over lightly' inspection of an area, most useful for characterizing its resources in general and for developing a basis for deciding how to organize and orient more detailed survey efforts."

Likewise directions in "The Secretary of the Interior's Guidelines for Identification" state

> Reconnaissance survey might be most profitably employed when gathering data to refine a developed historic context—such as checking on the presence or absence of expected property types, to define specific property types or to estimate the distribution of historic properties in an area… *In most cases, areas surveyed in this way will require resurvey if more complete information is needed about specific properties*" (emphasis added, Archaeology and Historic Preservation: Secretary of The Interior's Standards and Guidelines, as Amended and Annotated, 48 Federal Register 44716, effective 1983).

We believe a reconnaissance survey, buried in the Initial Study was not the correct level of evaluation and should rightly be an intensive survey in a technical appendix to the EIR that would allow reviewers the opportunity to consider the logic of a full evaluation for historic significance.

Is the Grayson Steam-Electric Plant a Historical Resource?

The "Tribal Cultural Resources" [*sic*] EIR section commences with a statement where the authors refute their own justification for finding the Grayson Steam-Electric Power not to be historically significant:

> While the [Grayson Steam-Electric Power] Plant does possess potential significance under the… [California Register] and Glendale Register of Historic Resources Criterions [*sic*] 1, 2, 3, and 4, a lack of integrity under all aspects of integrity recognized by the… [California Register], and implemented for the City of Glendale Register… *which is silent on aspects of integrity*, undermines the property's ability to convey importance/significance for either the state or local registers.

The Glendale Register has no requirement for integrity. Finding a property not eligible for the Glendale Register because of supposed alterations is not supported in the stated requirements for designation on the local register. Because the Glendale Register has no specific requirements for integrity a property's significance should not be dismissed because of alterations, particularly when the facility being evaluated remains absolutely recognizable to its original appearance.

When properties are significant for associations with the development of the community or with important persons they need not retain the same aspects or level of integrity as a property that is significant only for its design. That concept is a fundamental principle in evaluating properties for historic significance and was markedly not recognized by the document preparers. Furthermore, the addition of separate cooling towers, maintenance and storage buildings, oil tanks and trailers over time would be essential to its continued use as a power plant and would be well-known to qualified, experienced practitioners.

The inadequate evaluation in the Initial Study does not make clear where the described, overly emphasized alterations are, or how they would collectively reduce the property's integrity of design. Table 4 in the Initial Study curiously lists more than 57 building permits (only post 1964), but after review, it is discovered that few, if any are actual alterations to the Grayson Steam-Electric Power Plant that would affect its integrity. The document states "Some of the projects associated with these permits are visible in the aerials…" but no connection between listed building permits and actual alterations that would affect the ability of the property to convey its significance, which is central to the claim of the property not being eligible has been made.

Supposed alterations such as “Constructed a new concrete block chemical pump house with concrete roof” (1964), “Constructed one metal shed” (1970) and “Constructed a foundation (only) for a temporary modular trailer” (2012) demonstrate the consultant’s lack of understanding of the crux of an evaluation for historic significance. Does the property have historic significance and if it does, is it recognizable, depending on the type of significance?

None of those predominately separate actions described as alterations in the Initial Study table or annotated aerials affected the design, location, materials, workmanship, feeling or association of the power plant. Its setting may have changed since it was completed, but its setting in an industrial yard is not as essential to its significance as would the setting of other buildings such as a barn in an open field or adjacent to a barnyard. The subject property remains in a utility yard setting as it has been historically. The additional small buildings and other structures and objects that have been added to the subject property are located on the northwest and southwest, non-character-defining, secondary and rear sides of the plant as demonstrated in Figure 1.

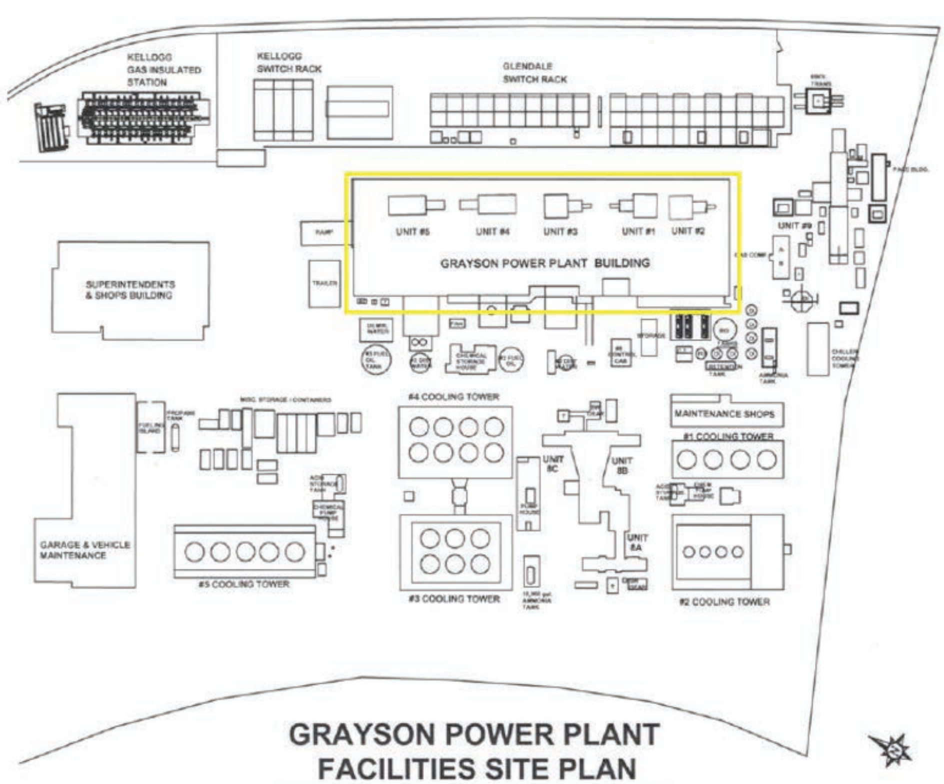

Figure 1: Excerpted and annotated from Architectural Resource Evaluation of The Grayson Power Plant For City of Glendale, California, showing only a ramp and trailer on the northwest (left-hand) side of the main building and various additional facilities at the back or southwest side of the Grayson Steam-Power Plant Building. Note that very few alterations in this figure are connected to the main, Grayson Steam-Power Plant Building, which is highlighted in yellow.

Figure 1 makes evident the fact that there are no alterations on the façade or northeast side, none are shown on the southeast end wall (a carport was added sometime after 1950 that does not affect its integrity), various small additions on the non-character-defining southwest side and only a ramp was added on the northwest side.[1] Further text will describe why other small changes do not affect its integrity. The building's principal cladding materials remain, its original ribbon, hopper-type and glass block, multi-story windows remain, the original metal sign on stand-outs and the distinctive, staggered, horizontal corner fillets remain intact. An experienced architectural historian would have exercised appropriate professional judgment and omitted items that were not alterations that affected the actual resource under consideration. The Grayson Steam-Electric Power Plant structure retains more than adequate integrity to its original design by Daniel A. Elliott, AIA, and remains recognizable.

Grayson Steam-Electric Power Plant Significance

The Grayson Steam-Electric Power Plant is significant for its association with the development of the community, for its direct association with Lauren W. Grayson, likely for its Streamline Moderne-Stripped Classicism design, as the work of a master architect and as the first earthquake-proof power plant. Its integrity of design remains, clearly visible from nearby streets, the large, metal and stucco-clad building is visible and is the inventive, original design remains easily distinguishable.

Association with the Development of the Community

The power plant's connection to the development of Glendale is reasonably straightforward and is undeniable. Almost immediately after Glendale's incorporation, locals recognized the importance and costs savings of establishing independent utilities. Once street lighting became an issue, the new city government took action to establish a "light and power" entity, holding a bond election to acquire and construct an electric works system for the city by 1909 (Winston W. Crouch and Beatrice Dinerman, *Southern California Metropolis: A Study of Development of a Government for a Metropolitan Area* 1964). An expanded distribution service and the establishment of the Glendale Light and Power Company were the part of the consequences of that election. Without the existence of the subject property power plant, the community would not have had the necessary utility capacity to grow as it did after the second World War. In 1938, the *Los Angeles Times* substantiated the assertion that the power plant made development of the community possible, reporting "City officials have maintained steadily that there are no available sources of power and that erection of the generating plant is necessary" ("City Officials Deny Charges in Glendale Power Plant Plan" 26 May 1938:14). The resulting power plant was built at an estimated cost of $1.5 million.

In the two decades spanning its construction, the population of modern Glendale increased by more than 50 percent between 1930 and 1950, from approximately 63,000 to 96,000 (U.S. Census). Neighboring Pasadena and other comparable communities' populations did not grow by nearly as great a percentage as Glendale's unfettered growth during that period. The stratospheric evolution of Glendale as a population and business center was spurred partly by annexation but as much by its increased ability to independently provide inexpensive power to newly expanding and establishing businesses and the thousands of new homes and apartments that were built during that time. That tendency continued "between 1980 and 2000, Glendale grew significantly more than neighboring areas" (City of Glendale, Government Departments, Economic Development, "Great Demographics," "Top 10 Reasons You Want Your Business in

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[1] An "addition to boiler room" at the southwest corner is noted in the Initial Study Figure 15 annotated aerial photographs incorrectly as being added around 1979 (Aerial 4). That small addition is clearly evident in Aerial 2, the 1964 aerial photograph.

Glendale" at http://www.glendaleca.gov/government/departments/glendale-economic-development-corporation-/top-10-reasons-you-want-your-business-in-glendale/analytic-information). Sustaining that trend that was made partly possible by the existence of an independent power source, the population of Glendale soared by nearly 40 percent during that 20-year period, significantly more than any other single city in Los Angeles County and more than the county itself. Without an autonomous power source providing economical electricity, the unbridled population growth and expansion of Glendale after World War II would not have been possible. The power plant shaped that development rather than merely reflecting it. Because of that direct connection between Glendale's growth and the Grayson Steam-Electric Power Plant, it is eligible for listing in the California and Glendale Register under each Criterion 1 for its essential role making the Postwar development of the community possible.

Distinctive Stripped Classicism Design, Work of a Master and Engineering Significance
Stripped Classicism was a twentieth century architectural style that reduced all, or nearly all superfluous ornamentation. It was favored primarily by government agencies for public building designs and was widely used by the Works Progress Administration during the Depression. The style embraced simplified but recognizable classicism in its overall massing, scale and proportions while eliminating traditional decorative detailing.

The significance of the design by architect Daniel Anthony Elliot, A.I.A. for the main building remains plainly visible and recognizable is not adequately explored in the reconnaissance level evaluation. The original, remaining design placed a large amount of equipment inside a metal-clad, deftly stepped shell that articulated a large volume from what could have been an ungainly multi-street block shape into human-scaled units, reducing its apparent mass and creating an elegant solution to what could well be an entirely utilitarian facility. In addition the electrical turbines, which are entirely functional apparatuses used to drive generators to transform mechanical energy into electrical energy by electromagnetic induction are cloaked in cleverly designed covers that supplement the large scale Stripped Classicism design elements of the facility into smaller units. At least three pencil-drawn renderings were made to demonstrate design alternatives that would camouflage the practical features.

It would be helpful to reviewers to understand the architect's remarkable career. He was a designer for Gilbert Stanley Underwood, a recognized master architect, between the years 1925 and 1932, was a contributor to the Colorado Aqueduct Project (1932-'41) and Elliott was responsible for the designs of various other water and power plants (see "Experience Record," Daniel A. Elliott, AIA, Architect at http://dbase1.lapl.org/webpics/calindex/documents/04/515676.pdf). Elliott designed the Burbank Water & Power Building (1949, 164 W. Magnolia Bl, Burbank) which is a noted example of Late Moderne design, as illustrated by the Los Angeles Conservancy on its website (Explore LA, Historic Places <https://www.laconservancy.org/locations/burbank-water-and-power>). His utility portfolio was described in the "Public Imagery and Its Uses" section of *Los Angeles In the Thirties: 1931-1941,* which considered an expert source on local architecture during that period (Gebhard and Von Bretton 1989).

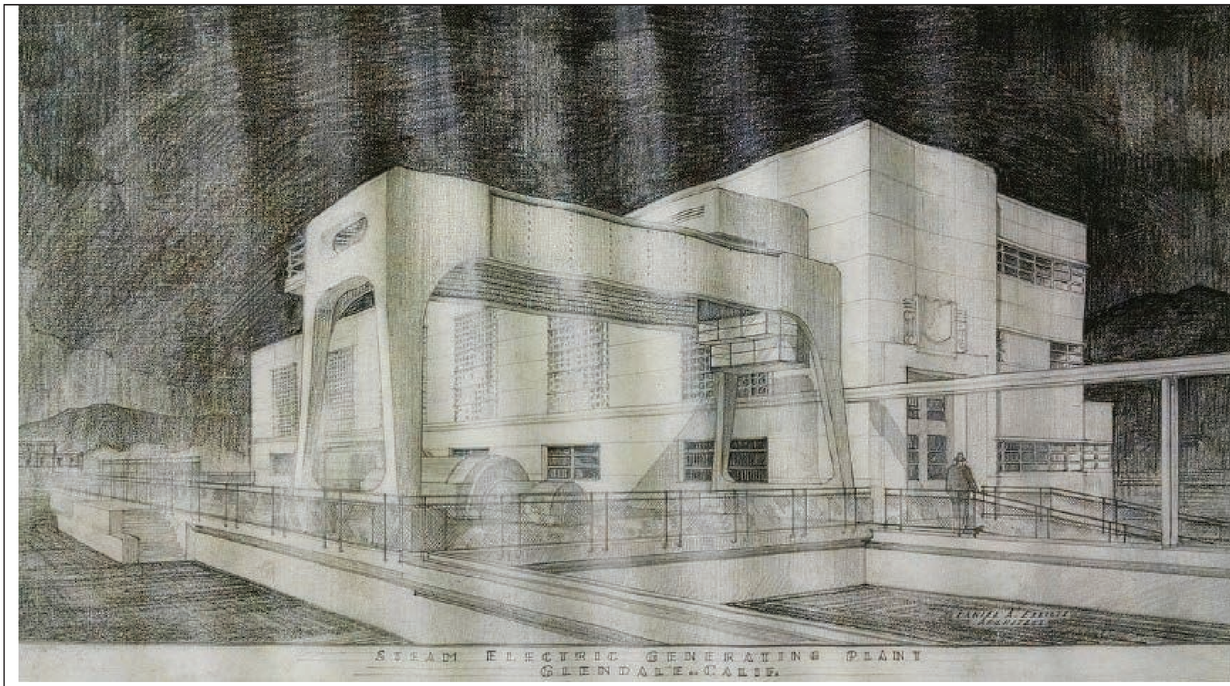

Figure 2: Pencil rendering of Glendale "Steam Electric Generating Plant" by Daniel A. Elliott, AIA excerpted from Initial Study, Architectural Resource Evaluation of The Grayson Power Plant For City of Glendale, California, Figure 9 (page 4.5). Compare with the recent photograph in Figure 3 that shows a series of multi-story, glass block windows in the boiler building portion of the Grayson Steam-Electric Power Plant building. If the crane in the foreground was at the south rather than the north end, the rendering and the power plant as it exists today would appear nearly the same, clearly expressing its distinctive Stripped Classicism design. The design treatment for the endwall in the above rendering was ultimately executed without the cartouche or the inset entrance. It is mistakenly called an "architectural drawing" rather than a rendering in the Initial Study.

The still-recognizable, Stripped Classicism design of the Grayson Steam-Electric Power Plant is understated, exquisitely proportioned and was undeniably futuristic for its time. The three staggered, dimensioned green, horizontal strokes that wrap around the southeast corner skillfully punctuate the otherwise staid building composition and assert the Modernism of the design. At the north façade, left-justified bronze letters on stand-outs primly identify the facility: "City of Glendale Public Service Department Steam Electric Generating Plant." Most power plans in the 1930s and now have no architectural design imposed reducing their aesthetic effects on the community, which is part of the significance of the Grayson Steam-Electric Power Plant's design.

Figure 3: Excerpted, cropped photograph from Initial Study, Architectural Resource Evaluation of The Grayson Power Plant For City of Glendale, California, Figure 18 (page 6.6). View is of the northwest, main façade, no date (estimated 2016). Note the staggered green horizontal bands at the left corner, the sign at the right side, sets of multi-story glass block windows of the boiler portion of the building, original, riveted "Cyclops" crane at left foreground and Units 3, 2 and 1 (left-to-right) in the foreground. The turbine covers for Units 1-3 have radiused roof-wall connections on the main volumes at each endwall, modulating the appearances of otherwise entirely utilitarian structures. Double fillet bands wrap around their lower cornices and corners, emphasizing the carefully expressed scale and proportion.

At the cornice of the main volume, a simple, dimensioned band interposes the roof-wall junctions. The band motif is repeated in pairs on the turbine covers for Units 1-3, the small, utilitarian structures in the foreground on the main elevation. In the design for the Grayson Steam-Electric Power Plant, different volumes are manipulated using varying scale and proportion strategies. The factory-painted, metal exterior of the main tower is clad in small rectangles that together form a grid. The lower, "Boiler Building" main portion of the plant is divided by stacked horizontal scoring lines. The turbine covers for Units 1-5 are painted metal, single-story housings with curved ends and lower, filleted endwalls. The Initial Study cultural resources evaluation mistakenly identified the exterior metal panel material as asbestos, which is likely incorrect as well as needlessly alarming (Figure 20, 6.7). Nearly 15 years after its completion, the unique exterior shell on the turbine covers at Glendale Power Plant was described in *Power Plant Management,* "the housing is fabricated of steel and is lifted in a piece from over the turbine- generator"(Robert Henderson Emerick 1955). We assert that the Stripped Classicism design of the power plant is an outstanding example of a rare type of architecture, the architect-designed power plant. The Stripped Classicism design should be considered the work of a master architect, Daniel A. Elliot, AIA (1998-1978). California Register Criterion 3 includes properties that "…represent… the work of an important creative individual." The Grayson Steam-Electric Power Plant is eligible for listing

in the California and Glendale Register under each Criterion 3 for Stripped Classicism design and as work of master architect, Daniel Anthony.
The subject property is further significant for its engineering and construction methods. The Grayson Steam-Electric Power Plant was described in the *Los Angeles Times* as "the world's first completely earthquake-proof … plant… Among its unique features is the location of the huge turbo-generator on an uncovered deck… the only building is a shell built of light steel and stucco filter walls that will more or less cover the unsightly appearance of boilers."[2] R.R. Martel, a Caltech professor and widely recognized international authority on seismic engineering collaborated on the design. Martel (1890-1965) was among the first engineers in the nation to concentrate on earthquake-resistant buildings and is considered the first in California.[3] He was one of two founders of the Earthquake Engineering Research Institute, an independent, nonprofit organization which was established "to promote research on safe and economical earthquake resistant structures" worldwide and continues to thrive, providing that service on an international scale to this day.

Its earthquake-proof structure was prescient for the late 1930s. An engineering periodical by the Earthquake Engineering Research Institute focused on seismic safety "Earthquake Spectra: The Professional Journal of the Earthquake Engineering Research Institute" ran numerous articles specifically describing earthquake-related damage to power plants in the greater Los Angeles area fifty years later, between 1987 and 1994. While the Glendale's Power Plant is listed in data and tables with plants that sustained significant damage, no damage to Grayson Steam-Electric Power Plant from those events is enumerated. Similarly, "Seismic Experience Data--Nuclear And Other Plants: Proceedings Of A Session" prepared by the American Society of Civil Engineers describes Glendale's Power Plant remaining "on-line" during the 1971 earthquake, despite its proximity to Sylmar, which was considered the epicenter (1985). We are not saying the subject property building can withstand all earthquakes; in the past it demonstrated superior seismic strength compared to its peers in the Los Angeles area. The Grayson Steam-Electric Power Plant was designed to be "earthquake-proof" before any other facilities of its type were which is overridingly consequential in California engineering. The property possesses significance as the earliest known example of an earthquake-proof power plant in California or anywhere else.

Both the California and the local register recognize construction and engineering innovation. California Register Criterion 3 states "It embodies the distinctive characteristics of a type, period, region, or *method of construction*; represents the work of an important creative individual." The Grayson Steam-Electric Power Plant is eligible for listing in the California and Glendale Registers under Criteria 3 and C for its method of early earthquake proof construction. None of those avenues of its significance was addressed in the reconnaissance level survey prepared for the Grayson Steam-Electric Power Plant.

Direct Association with Lauren W. Grayson

The significance of Chief Engineer and General Manger Lauren W. Grayson (1907-1972) is also not adequately evaluated. When Grayson retired in 1970, he had served the city for nearly two decades, expanded water and power capacity by 400 percent and the budget by an even higher percentage during his tenure ("Public Services Head in Glendale to Retire" *Los Angeles Times.* 25 January, 1970: SG-B2). The visionary civil servant was responsible for bringing together other agencies for collaboration with other such agencies in the northwest. That joint power alliance was considered monumental in the field, and brought electrical capacity diversification, as well as lower costs, to Glendale-based users. He oversaw both water and power utilities, constantly interpreting and planning for future community needs.

[2] "Power Plant Built In Open: Glendale Will Have First Completely Quake-Proof Setup." *Los Angeles Times*. June 30, 1940: A10.

[3] "R. R. Martel, Professor of Structural Engineering Staff" *Engineering and Science*, Volume 19, 1956: 22-24.

Lauren Grayson was responsible for the addition of cleaner technologies, including a steam-electric generating unit (1965) and the nation's first gas turbine peaking unit in his final year. Grayson served as president of American Water Works and California Municipal Utilities associations and was elected American Water Works Man of the Year (1959). He was considered a national leading authority on public utilities and delivered academic papers on a wide variety of utility-based subjects throughout his career. Grayson was published on subjects ranging from visionary long-range planning to the unique needs of car wash and drive-in usage in a number of national and regional industry periodicals, including *The American City*, *Engineering News & Record*, *Western City* and *Aqueduct News*. Under his leadership, Glendale was one of the first local communities to require subterranean power lines. The *Times* succinctly described his career at retirement as an "outstanding achievement in the field of water and power" (Don Snyder "Glendale Official: Public Service Chief to End Long Career" *Los Angeles Times.* 6 July 1970:B9). It was named in his honor in 1972. Mr. Grayson lived in Glendale after 1951 was buried at Forest Lawn. The Grayson Steam-Electric Power Plant is eligible for listing in the California and Glendale Registers under each Criteria 2 for its direct association with Lauren W. Grayson during his period of significant, local utility-related achievements.

The period of significance of the Grayson Steam-Electric Power Plant commenced in 1941 when it was completed and ended in 1970, when Loren W. Grayson retired. Neither the California nor the Glendale Register has requirements that a property be completed more than 50 years ago. For the purposes of National Register eligibility, the period of significance would end in 1967, because it does not meet the requirements in Criterion Consideration G for properties that have achieved exceptional significance in the past 50 years.

Because the California Register Technical Assistance Bulletin 7, is currently under review for updates and revisions, there is no current state guidance for nominating California Register properties and National Register of Historic Places guidance is used in its place. In the National Park Service-prepared National Register Bulletin: "How to Prepare the National Register Criteria for Evaluation" under "Determining the Relevant Aspects of Integrity" for properties associated with important events or persons it states:

> A property important for association with an event, historical pattern, or person(s) ideally might retain *some* features of all seven aspects of integrity: location, design, setting, materials, workmanship, feeling, and association. *Integrity of design and workmanship, however, might not be as important to the significance,* and would not be relevant if the property were a site. A basic integrity test for a property associated with an important event or person is whether a historical contemporary would recognize the property as it exists today.

Grayson Steam-Electric Power Plant retains integrity to its location. The building remains on the original site where it was completed in 1940. The power plant building's original Stripped Classicism design is intact, the painted metal panels that camouflage day-to-day operations of the facility, including the three staggered, green bands that wrap around the southeast corner and original signage are visible and recognizable to the general public from the public right of way. Its setting in an essentially flat yard among other large utility apparatuses has changed over time, reflecting upgrades, increases in capacity and new technologies, but continues to be the basic, recognizable surroundings of a power plant. Its distinctive painted metal exterior materials endure, as do other visible elements from its original design including multi-story glass block banks of windows, awning-type steel sash windows, decorative fillets, metal sign letters, decorative turbine covers and the essential building configuration. The condition of those materials reflect the passage of 77 years, as should be expected. The fit, finish and connections of those original materials remains impeccable, revealing its inventive, Depression-era workmanship. Because the other aspects of integrity remain intact, the feeling and associations of the Grayson Steam-Electric Power Plant, while somewhat reduced by the additions of new outbuildings and facilities remains. The property maintains its original, intended use, and judging by publicly visible portions of the building, it building retains essential qualities that evoke its aesthetic and historic senses it would have had in 1941 when it was completed.

Despite the enumeration of every new building and feature ever built at the larger surrounding property, National Register guidance clearly states "A property that has lost some historic materials or details can be eligible *if* it retains the majority of the features that illustrate its style in terms of the massing, spatial relationships, proportion, pattern of windows and doors, texture of materials, and ornamentation." The Grayson Steam-Electric Power Plant retains its original inventive massing, its essential spatial relationship with the larger yard, the carefully designed proportions, the original, visible, main fenestration, the textures of painted metal, stucco and other materials and its distinctive, austere ornamentation (Figures 2-5)

The exhaustive, improperly prepared evaluation for historic significance in the Initial Study expended an inordinate amount of research to justify the misguided point that the power plant has impaired integrity because of alterations. The architect-designed power plant is the resource in question- not the not the entire surrounding yard. The Initial Study ardently describes the addition of switching yards, additional units, cooling tanks and towers, sheds, a warehouse, storage buildings and a garage which are not connected to the Grayson Power Plant and are immaterial to the evaluation of the building. Those non-contributing features comprise the setting of the subject property and do not affect its integrity or significance. To the average reader, hurrying through the document to achieve a basic understanding, their assertion that the power plant is not historically significant would seem well justified. Professionally qualified reviewers who are experienced as performing such evaluations arrive at entirely different conclusions as described in this letter.

We assert that if Lauren W. Grayson, for whom the property was named were able to see the subject property today, he would plainly recognize the Grayson Steam-Electric Power Plant. Whether or not a person associated with the property during its period of significance is among the National Register thresholds for integrity. It remains clearly recognizable to its original appearance. The addition of buildings, cooling towers, fuel tanks and other equipment is typical of and are necessities to continuously operating a power plant, particularly in a community where its existence made population growth possible. It can be assumed that no public power plant dating from 1941 that remains in operation would be devoid of any alterations made since its completion. Keeping up with requirements, particularly those for life safety require inevitable alterations to buildings and structures. Comparison between the photographs in Figures 3 and 4 as well as others validates that the building is absolutely recognizable to its original design and claims of its loss of integrity are exaggerated and not based in facts.

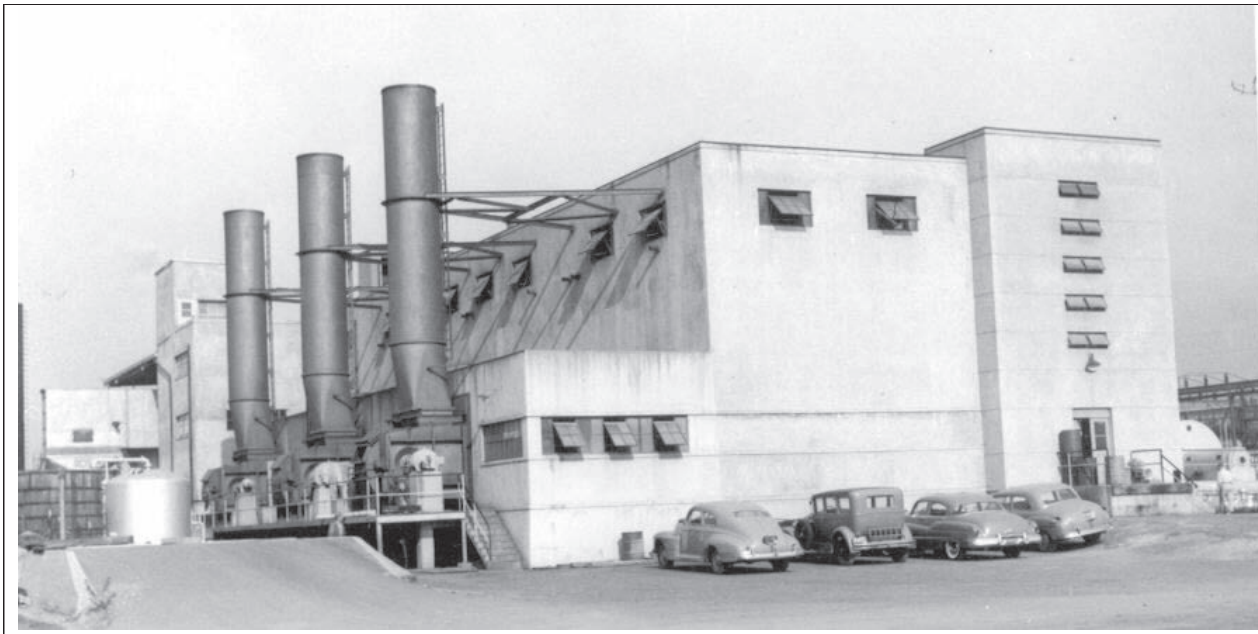

Figure 4: Grayson Steam-Power Plant Building, view northwest of south endwall, circa 1950s. Source: https://commons.wikimedia.org/wiki/File:Grayson_Power_Plant.jpg, not for publication.

Figure 5: Excerpt from Initial Study, Architectural Resource Evaluation Of The Grayson Power Plant For City of Glendale, California, undated photograph estimated 2016,(Figure 26 Grayson Boiler Building page 6.10, same view as Figure 4 above). Note all visible awning-type, steel sash windows, exterior materials, the building configuration and Stripped Classicist design remain recognizable. Carport at lower center is an addition (year unknown). Note the stucco scoring bands at the right-hand boiler building tower and the dimensioned continuous sill and header on the left-hand bank of ribbon windows that enunciate the endwalls, providing visual interest and relief. Other than the carport, no alterations are visible.

A brief review of National Register-listed power plants in the United States revealed that all remaining in use contain non-contributing buildings and structures and that nearly all of the main buildings had been altered.[4] In Pasadena, the Glenarm Power Plant was determined eligible for the National Register for its associative and design significance, despite hundreds of alterations made to the building and larger power plant complex over time and numerous changes to the building since it was completed in 1928. The very visible, east facing, rear side of the Glenarm Power Plant is entirely concealed by alterations made in the past 20 years. Comparison against like types is one of many tests for significance and the Grayson Steam-Power Plant stacks up favorably against its significant peers in terms of it importance to the development of the community, its design significance, and its retention of integrity. We believe that the Grayson Steam-Electric Power Plant is eligible for listing in the National Register as well as the California and local registers, but the property is not publicly accessible to make site visits and perform a complete, intensive evaluation of its significance.

While the 29-page DPR does provide a narrative paragraph on "Locational Data," which are normally reserved for properties that have no street addresses, such as archaeology sites in the desert, the evaluation notably does not address the engineering importance of the Grayson Steam-Electric Power Plant.

Previously Recorded Resources

In the Initial Study, the preparers included a list of "previously recorded" built environment resources, mistakenly applying what is normally archaeological methodology to the built environment. Not only does the section not inform the evaluation, it demonstrates their misunderstanding of the task. The absence or presence of built environment resources within a half a mile is not a predicator as it can be in archaeology, of whether or not built environment resources can be expected to be encountered. Moreover, the list provided does not enumerate whether or not the studied properties were found to be significant or not rendering it even less useful.

The only "previously recorded resources" that should be considered in this evaluation would be on the subject property (including any previous evaluations), or would be other power plants against which this property should rightly have been compared. See National Register guidance on "Comparing Similar Properties" in "VIII. How to Evaluate The Integrity of A Property" (National Park Service, "How to Apply the National Register Criteria For Evaluation")

Project Description

We note that the Grayson Steam-Electric Power Plant has a 22-foot deep basement as described in the 1940 *Los Angeles Times* article, while the proposed project description cites only an eight-foot-depth of disturbance. As described, the additional 14-foot depth of remaining concrete, rebar and whatever other other materials would remain should be proposed removed, which would probably result in an approximately 23 to 25-foot depth of disturbance. The project description and all applicable analyses must be revised accordingly.

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[4] National Register-listed power plants include: Adams Power Plant Transformer House (Niagara Falls, NY); American Falls Power Plant Transformer House (American Falls, IA); Moran Municipal Generating Station (Burlington, VT); Murray City Diesel Power Plant (Murray City, UT); Pratt Street Power Plant (Baltimore, MD); Power Plant No. 1 (McPherson, KS); Seaholm Power Plant (Austin, TX) and Spaulding Power Plant and Dam (Greely City, NB). The Adams Power Plant Transformer House is no longer is use; its contributing buildings are notably no longer extant. Seaholm Power Plant contained a non-contributing structure when it was listed in the National Register. It has since been redeveloped and is no longer used as a power plant.

CEQA strongly encourages early consultation with interested or affected parties, which includes local historic advocacy groups. No consultation efforts were made with TGHS. We were asked for information early in the process but have not otherwise been consulted on the project.

Predicated on the facts and issues presented above, TGHS believes that the Grayson Steam-Electric Power Plant must be re-evaluated for historic significance in a supplementary document and that the Cultural Resources section of the environmental document must be revised to reflect a good faith and more reasoned analysis of the property's historic significance. We have presented "substantial evidence" for the lead agency to change its conclusion and find that the Grayson Steam-Eclectic Power Plant building is a historical resource for the purposes of CEQA.

Thank you for your consideration.

Sincerely,

Greg Grammer

President
The Glendale Historical Society

1 L22-C

State of California • Natural Resources Agency
Gavin Newsom, *Governor*

DEPARTMENT OF PARKS AND RECREATION
OFFICE OF HISTORIC PRESERVATION
Lisa Ann L. Mangat, *Director*

Julianne Polanco, State Historic Preservation Officer
1725 23rd Street, Suite 100, Sacramento, CA 95816-7100
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December 3, 2020 Reference Number: FRA_2017_0516_001

Submitted Via Electronic Mail

Brett Rushing
Cultural Resources Program Manager
California High-Speed Rail Authority
770 L Street, Suite 620
Sacramento, CA 95814

Re: High-Speed Rail Program, Burbank to Los Angeles Project Section, Additional Information and Request for Review and Concurrence on Revised National Register of Historic Places Determination of Eligibility for Grayson Steam-Electric Generating Station (Grayson Power Plant)

Dear Mr. Rushing:

The California High-Speed Rail Authority (Authority) is continuing consultation with the State Historic Preservation Officer (SHPO) regarding the Burbank to Los Angeles Project Section of the High-Speed Rail (HSR) Project. This consultation is undertaken in accordance with the *Programmatic Agreement Among the Federal Railroad Administration, the Advisory Council on Historic Preservation, the California State Historic Preservation Officer, and the California High-Speed Rail Authority* (PA 2011). In support of this consultation, the authority has provided following documentation:

Updated California Department of Parks and Recreation Site Record Form (DPR 523) for Grayson Power Plant, 2015 (revised 2017)

City of Glendale Community Development Department Comment Letter on the California High-Speed Rail Program Burbank to Los Angeles Project Section Draft Environmental Impact Report/Environmental Impact Statement, August 31, 2020

In a letter dated May 2, 2019, SHPO concurred that the Grayson Power Plant was eligible for listing on the National Register of Historic Places (NRHP) under Criteria A at the local level of significance for its association with power generation in Glendale. Subsequently, new information on the history of the Grayson Power Plant has come to light: a comprehensive 2018 evaluation undertaken for an Environmental Impact Report by Stantec Consulting Services for the City of Glendale found that the property did not retain sufficient integrity to considered eligible for listing on the NRHP under all criteria. Having considered this information, the Authority agrees with the conclusions with the 2018 evaluation and request SHPO concurrence with the revised determination of eligibility.

Having reviewed your submittal, SHPO concurs that the Grayson Power Plant is ineligible for listing on the NRHP under all criteria for the reasons outlined in the revised DPR 523 form.

If you have any questions, please contact State Historian Tristan Tozer at (916) 445-7027 or Tristan.Tozer@parks.ca.gov.

Sincerely,

Julianne Polanco
State Historic Preservation Officer

The Glendale Historical Society
4/25/2021

The environmental document prepared for the Grayson Electric-Steam Power Plant must study and analyze historical resource impacts. The Grayson Electric-Steam Power Plant is eligible for listing in the California Register of Historical Resources.

The alternatives analysis component will be especially critical in this this document. It must evaluate the No Project alternative as well as a “reasonable range” of feasible alternatives that would retain the Grayson Electric-Steam Power Plant as described in CEQA Guidelines Section 15126.6(e)).

There must be an essential nexus (*i.e*. connection) between the mitigation measure and a legitimate governmental interest. Nollan v. California Coastal Commission, 483 U.S. 825 (1987). The mitigation measure must be "roughly proportional" to the impacts of the project. Dolan v. City of Tigard, 512 U.S. 374 (1994). The Glendale Historical Society (TGHS) believes that the below-listed mitigation measures would be both connected to the expected loss of the Grayson Electric-Steam Power Plant and are relational to the expected loss of that structure to the community. The addition of signage on San Fernando Road near the current location of the Grayson Electric-Steam Power Plant and the future retention and display of components of equipment from the Grayson Electric-Steam Power Plant shall be added to these mitigation measures.

Mitigation of impacts must lessen or eliminate the physical impact that the project will have on the historical resource. This is often accomplished through redesign of a project to eliminate objectionable or damaging aspects of the project. Relocation of a historical resource may constitute an adverse impact as well. However, in situations where relocation is the only feasible alternative to demolition, relocation may mitigate the impact below a level of significance provided such that the new location is compatible with the original character and use of the historical resource and the resource retains its eligibility for listing in the California Register (14 CCR § 4852(d)(1)).

Although in most cases the use of drawings, photographs, and/or displays do not mitigate the physical impact on the environment caused by demolition or destruction of a historical resource (14 CCR Section 15126.4(b)). However, CEQA requires that all feasible mitigation be undertaken even if they do not mitigate to below a level of significance. In this context, recordation would serve a legitimate archival purpose.

Cultural Resources Mitigation Measure A (CR MM A)- Historic American Engineering Record (HAER) documentation

If the preferred alternative is demolition, Historic American Engineering Record (HAER) documentation shall be prepared for the Boiler Building, including the boilers and all additions, the turbine deck and turbine units 1-9. That documentation will include preparation of a written narrative, large format photography and drawings that meet the latest requirements in HAER History, Photography and Drawing Guidelines (at https://www.nps.gov/hdp/standards/haerguidelines.htm). Archival and electronic full copies of that completed documentation shall be submitted to the HAER program in accordance with the most recent edition of “Preparing HABS/HAER/HALS Documentation For Transmittal,” the Glendale Public Library and posted on the City’s main website for no less than 10 years. No fewer than a total of eight, full-size archivally printed and framed, full size (or larger) copies of those HAER drawings and six enlarged large format photographs, also archival printed and framed, shall

be displayed in the lobby or foyer of the of the replacement Operations and Maintenance building (or a more publicly accessible location subject to written approval to The Glendale Historical Society).
That HAER documentation, as described, shall be complete and accepted by the HAER program before any demolition or dismantling of the Boiler Building, its contents, the turbine deck or turbines 1-8 can commence.

If the City of Glendale maintained a comprehensive, up-to-date, historic resources survey of City-Owned Properties, the Grayson Steam-Electric Power Plant would previously have been identified as a historical resource and there would be no need for the years of disagreement on that important subject. Based on the absence of such a survey, a comprehensive, intensive survey is proposed as a mitigation measure to avoid these situations in the future.

As directed in the National Register Bulletin "Guidelines for Local Surveys: A Basis for Preservation Planning,"

> The success of planning a community survey, as well as conducting it and using the results, will depend on a broad base of local interest and involvement. Vital support for the survey, and for historic preservation in general, can be generated if a carefully planned campaign is mounted to involve the public and obtain their participation. Such a campaign can also identify valuable local sources of information and special expertise. Public involvement should begin at the earliest stages of survey planning.

CR MM B- Historic Resources Survey of City-Owned Properties
The City shall prepare or cause to be prepared comprehensive Historic Resources Survey of (all) City-Owned Properties (Survey) with improvements constructed before 1990, unless the property has previously been evaluated (with a written record of that evaluation) within the past five years or are expected to be evaluated in the planned East-West Survey. All survey work shall conform to the Secretary of the Interior's Standards for Archaeology and Historic Preservation, which include Standards for Evaluation, Identification, and Registration. The survey shall be prepared in accordance with "National Register Bulletin: Guidelines for Local Surveys: A Basis for Preservation Planning" and the California Office of Historic Preservation's latest guidance. The Survey shall commence within 90 days of the adoption of the environmental clearance document for the Proposed Grayson Power Plant Repowering Project. The survey shall be completed within one-calendar year, be subject to a draft and final survey review and recommendation by the City's Historic Preservation Commission and adoption by City Council.
The resulting survey shall include, at minimum:

> A <u>Summary</u>, enumerating the total number of surveyed resources and districts with levels of significance.
> A <u>Project Description</u>, that clearly describes the purposes of the survey, sources of funding, its overall parameters, a description and map of the survey area and property types.
> A <u>Summary of Previous Identification Efforts</u> that clearly describes any previous survey of identification efforts, local designations, National and California Register listings and determinations of eligibility, California Historic Landmarks and California Points of Historic

Interest listings and designations and any other related historic preservation planning efforts. It shall include and describe the contents of a current, records search at the South Central Coastal Information Center at California State University Fullerton and provide the final survey and all known Glendale surveys to the Information Canter upon completion, in accordance with the Information Center's requirement.

A Context Statement prepared in compliance with The Secretary of the Interior's Standards for Preservation Planning, "Standard I. Preservation Planning Establishes Historic Contexts," "Standard II. Preservation Planning Uses Historic Contexts To Develop Goals and Priorities for the Identification, Evaluation, Registration and Treatment of Historic Properties" and the California Office of Historic Preservation-prepared "Writing Historic Contexts" guidance. The Context Statement shall establish clear registration requirements for eligibility.

A clear <u>Methodolog</u>y section that describes field work techniques and research methods used to conduct the survey, a description of how historic districts are identified in the survey, references to previous surveys, and methodology for re-survey completed as part of this project. It will clearly describe efforts made to contact and involve members of the community and organizations with particular interests in historic properties.

<u>Recommendations for future preservation activities</u>, including: potential updates and/or amendments to existing National, California and Glendale Register designations, as applicable; designation recommendations for potential local historic districts, as applicable; and potential economic development, heritage tourism, and other preservation planning activities;

<u>Survey results</u> shall enumerate the total number of surveyed resources in appropriate categories, tables listing the property types and architectural styles identified, as well as narrative defining the results, with information regarding the levels of integrity and condition of resources, describes character-defining features, past and current development trends.

<u>Appendix 1:</u> Two-page DPR 523 series forms for each City-owned property unless the property is vacant or a paved parking lot which shall be noted in the survey results tables by Los Angeles County Assessor's Parcel Identification Numbers and address (where assigned). The DPRs shall be fully completed in accordance with the latest edition of the OHP-prepared "Instructions For Recording Historical Resources." They shall include whether or not the evaluation is an update, assign California Register Status Codes and describe other listings in the header blocks and include at least one clear digital photograph and a sketch map. If a property is California Register Status Code 1-6L, it shall include a complete architectural description, construction history, related features and under significance, describe why the resource is significant within a the relevant historic context and identify character-defining features.

<u>Appendix 2:</u> A survey map that delineates the survey area with all previously identified properties including local landmarks and historic districts and the results of the City owner-Properties Survey.

The results of the final or adopted survey shall be provided to the Office of Historic Preservation, submitted in the specified formats to the Information Center and the result, including the DPR series 523 forms shall be posted, by property in the City's Glendale Information Property Portal or its successors and in its entirely on the City's website until it is updated by a subsequent survey, within no more than 90 days of its substantial completion or adoption.

L23

From:	Lupe Ruelas
To:	Krause, Erik
Cc:	bchan@earthjustice.org; ameszaros@earthjustice.org
Subject:	Comments on Grayson Repowering Project PR-DEIR
Date:	Monday, November 15, 2021 1:37:40 PM
Attachments:	2021-11-15 Grayson PR-DEIR Comments and Exhibits.pdf

CAUTION: This email was delivered from the Internet. Do not click links, open attachments, or reply if you are unsure as to the sender.

SUBMITTED VIA ELECTRONIC MAIL

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L23-1 Dear Mr. Krause,

On behalf of the Sierra Club, Earthjustice submits the attached comments on the Grayson Repowering Project PR-DEIR.

Please acknowledge receipt of the attached comments.

Best Regards,

Lupe Ruelas *(she/her)*
Litigation Assistant
Earthjustice Los Angeles Office
707 Wilshire Blvd, Suite 4300
Los Angeles, CA 90017
T: 213-766-1092
earthjustice.org

EARTHJUSTICE

EARTHJUSTICE

November 15, 2021

VIA ELECTRONIC MAIL

Erik Krause
Deputy Director of Community Development
City of Glendale
Community Development Department
633 East Broadway, Room 103
Glendale, CA 91026-4386
ekrause@glendaleca.gov

RE: Comments on the Partially Recirculated Draft Environmental Impact Report

Dear Mr. Krause:

L23-2 Pursuant to the California Environmental Quality Act ("CEQA"), we submit these comments on behalf of the Sierra Club on the Partially Recirculated Draft Environmental Impact Report ("PR-DEIR") for the Grayson Repowering Project ("Grayson Project"). Previously, we submitted extensive comments and testimony on both the Draft Environmental Impact Report and the Final Environmental Impact Report ("FEIR") for the Grayson Project.[1] Given that the PR-DEIR incorporates those environmental impact reports, our prior comments and testimony remain relevant and demand proper responses in accordance with CEQA.[2]

L23-3 One of the primary objectives of the Grayson Project is "to provide reliable, cost effective, and flexible generation capacity for [Glendale] to serve its customer load."[3] When Glendale Water and Power ("GWP") presented the FEIR for the Grayson Project to the Glendale City Council on April 10, 2018, GWP claimed that the only way to achieve this objective was to demolish the whole Grayson Power Plant, except for Unit 9, and replace it with 278 Megawatts ("MW") of fossil-fired generation. Ultimately, the Glendale City Council declined to certify the FEIR and directed GWP to consider clean energy alternatives to meet Glendale's energy needs.

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[1] Citations to "SC" refer to the Bates-stamped Exhibits 1–10 submitted concurrently with these comments, which include Sierra Club's comments on the DEIR and FEIR.
[2] Cal. Pub. Res. Code § 21091(d).
[3] City of Glendale Water and Power, Partially Recirculated Draft Environment Impact Report, at 5.1 (PDF p. 110) (Aug. 6, 2021) [hereinafter PR-DEIR].

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L23-4 GWP now presents an energy portfolio that reduces the amount of proposed fossil-fired generation from 278 MW to 93 MW while still "meet[ing] all Project objectives."[4] The energy portfolio's ability to provide "reliable, cost effective, and flexible generation capacity," even with 65 percent less fossil-fired generation than originally proposed, demonstrates the availability of clean energy technologies and strategies to meet Glendale's energy needs.

L23-5 Although GWP has moved in the right direction towards clean energy technologies and strategies, it has failed to move far enough. This failure stems from GWP's continued reliance on fundamental errors and flawed analysis in its PR-DEIR that violates CEQA's requirements. In particular, GWP continues to claim incorrectly that it is subject to a reserve obligation that dramatically inflates Glendale's energy needs. GWP sizes the Grayson Project to meet this inflated energy need while planning to produce and sell excess fossil-fired energy to neighboring regions. L23-6 Further, GWP omits discussion of the impending closure of the Aliso Canyon gas storage facility ("Aliso Canyon") from its project description. The closure of Aliso Canyon would significantly impact the availability of natural gas to the Grayson Project and force GWP to seek natural gas from other sources that could result in environmental impacts and potentially higher energy prices. L23-7 Finally, GWP arbitrarily dismisses feasible clean energy alternatives that could move Glendale beyond fossil-fired generation. GWP's fundamental errors and flawed analysis contravene the fundamental goal of CEQA—to protect the environment through informed decision-making. Accordingly, the PR-DEIR is legally deficient and unfit for certification under the California Environmental Quality Act.

L23-8

I. The project's description is inaccurate and incomplete because it arbitrarily inflates Glendale Water and Power's reserve obligation, fails to disclose the sale of energy from the Grayson Project to neighboring regions, and overlooks the Grayson Project's environmental impacts from the closure of Aliso Canyon

L23-9 An accurate project description, including the project's objectives, "is the *sine qua non* of an informative and legally sufficient EIR," while an inaccurate or incomplete project description "draws a red herring across the path of public input."[5] A California court will reject an EIR with an inaccurate or incomplete project description.

[4] PR-DEIR, at 5.80 (PDF p. 189).
[5] *County of Inyo v. City of L.A.*, 71 Cal. App .3d 185, 193, 198 (1977).

L23-10 The project description underpinning GWP's proposal for 93 MW of fossil-fired generation is fatally flawed for three reasons. First, GWP misstates its reserve obligation to justify the inclusion of fossil-fired generation in GWP's energy portfolio. Second, GWP hides from decisionmakers that its proposal for 93 MW of fossil-fired generation includes plans to produce and sell excess fossil-fired energy to neighboring regions. Third, GWP fails to include and evaluate the Grayson Project's environmental impacts from the closure of Aliso Canyon.

L23-11

a. Glendale Water and Power's reserve obligation

GWP incorrectly asserts that North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") reliability standards and its Balancing Authority Area Services Agreement ("BAASA") with the Los Angeles Department of Water and Power ("LADWP") require GWP to carry contingency reserves that meet an N-1-1 reserve obligation.[6] GWP claims that its N-1-1 reserve obligation is 148 MW.[7]

L23-12 Neither NERC/WECC reliability standards nor the BAASA imposes an N-1-1 reserve obligation on GWP. GWP is a "load-serving entity" within the balancing authority managed by LADWP.[8] NERC/WECC reliability standards apply at the balancing authority (LADWP) level, not at the "load-serving entity" (GWP) level.[9] This dynamic is confirmed by the Federal Energy Regulatory Commission's approval in 2015 of NERC's proposal "to eliminate the load-serving entity as a registered function subject to the Reliability Standards."[10] In accordance with NERC/WECC reliability standards, LADWP carries full reserves for its own N-1-1 contingencies, which cover reserves for GWP.

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[6] PR-DEIR, Project Objective No. 3, at 5.2 (PDF p. 111); PR-DEIR, Alternative 7 Consistency Evaluation with Objective No. 3, at 5.52 (PDF p. 161).
[7] City of Glendale Water and Power, 2019 Integrated Resource Plan, at 30 (July 23, 2019) [hereinafter 2019 GWP IRP].
[8] *Load-Serving Entity*, Glossary of Terms Used in NERC Reliability Standards, at 16 (Updated June 28, 2021), https://www.nerc.com/files/glossary_of_terms.pdf. (SC_000352).
[9] WECC Reliability Standards, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-3.pdf. (SC_000324–000336).
[10] *N. Am. Energy Reliability Corp.*, No. RR15-4-001, 153 FERC ¶ 61,024, at 11 (Oct. 15, 2015). (SC_000323).

L23-13

The BAASA between GWP and LADWP, rather than NERC/WECC reliability standards, determines GWP's reserve obligation.[11] According to the BAASA, GWP is required to purchase reserves of 80 MW from LADWP at a specified tariff rate but has the contractual right to self-supply all or any portion of this obligation from its own resources.[12] Whether GWP decides to purchase reserves from LADWP or self-supply its reserve obligation, GWP's reserve obligation remains 80 MW. GWP is not subject to any reserve obligation outside of the 80 MW outlined in the BAASA. As the BAASA states, "this Agreement shall satisfy GWP's obligations under the Existing Agreements to provide spinning reserves, supplemental reserves . . . or any other contingency reserves."[13]

L23-14

Although the BAASA limits GWP's reserve obligation to 80 MW, GWP insists in its 2019 Integrated Resource Plan that it must maintain sufficient reserves to cover an N-1-1 event (148 MW) because "termination of the BAASA would cause GWP to automatically become its own [balancing authority]."[14] This assertion does not justify GWP's inflated reserve obligation for several reasons. First, termination of the BAASA would not cause GWP to "automatically become its own [balancing authority]." LADWP, GWP, and Burbank Water and Power ("BWP") negotiated the current BAASA in 2015.[15] The BAASA replaced the prior balancing authority agreement known as the Southern California Utility Power Pool ("SCUPP"). LADWP cancelled the SCUPP in 2011 because the agreement did not reflect modern industry practice, costs, or cost-allocation.[16] Despite the lack of a balancing authority agreement between 2011 and 2015, GWP and BWP continued to participate in the LADWP balancing authority.[17] The cancellation of the SCUPP did not cause GWP to "automatically become its own [balancing authority]." GWP provides no evidence that termination of the BAASA would result in a different outcome. Second, potential termination of the BAASA is a future political decision

[11] Balancing Authority Area Services Agreement Between Los Angeles Department of Water and Power and Glendale Water and Power (Nov. 18, 2015), Ex. 3 to Sierra Club Comment on FEIR [hereinafter BAASA]. (SC_000048–000109).
[12] BAASA, Schedules 5 & 6, at 30–35. (SC_000077–000082). GWP's reserve obligation under the BAASA consists of 40 MW of spinning reserves (Schedule 5) and 40 MW of supplemental reserves (Schedule 6).
[13] BAASA, art. 2.2.2, at 6. (SC_000053).
[14] 2019 GWP IRP, at 30 fn.11.
[15] BAASA, at 2. (SC_000049).
[16] City of Burbank Water and Power, 2019 Integrated Resource Plan, at 108 (adopted by Burbank City Council on Dec. 11, 2018) [hereinafter 2019 Burbank IRP].
[17] 2019 Burbank IRP, at 108.

L23-14

that does not impact GWP's current reserve obligation of 80 MW. If LADWP or GWP are planning to terminate the BAASA, despite the immense benefits they derive from the agreement, then GWP must clearly state so in the PR-DEIR. In the absence of such a clear statement, GWP misinforms decisionmakers and the public by claiming that it is currently subject to a reserve obligation of 148 MW that necessitates fossil-fired generation.

L23-15

Burbank Water and Power's reserve obligation also confirms that GWP's reserve obligation is 80 MW under the BAASA. Like GWP, BWP is a "load-serving entity" within the LADWP balancing authority.[18] Accordingly, BWP is a signatory to the same BAASA that GWP signed with LADWP.[19] Unlike GWP, however, BWP does not claim that it has an N-1-1 reserve obligation. Instead, BWP states in its 2019 Integrated Resource Plan:

> As part of the BAASA, BWP also negotiated the opportunity to purchase all of its reserve obligations from LADWP, instead of using BWP's own assets and limited market access to provide for the reserves. BWP reserve obligations were determined during and through negotiation of the BAASA as 40 MW of spinning capacity and 40 MW of supplemental capacity for a total of 80 MW of reserve capacity.[20]

BWP, like GWP, has a reserve obligation of 80 MW under the BAASA. To meet this obligation, BWP decided to purchase reserves from LADWP instead of self-supplying its reserves from its own resources. GWP can self-supply its reserve obligation of 80 MW under the BAASA—what GWP cannot do is misstate its reserve obligation. Such a misstatement renders the PR-DEIR unlawful because it misinforms decisionmakers and the public about Glendale's energy needs and the feasibility of clean energy alternatives.

L23-16

b. Energy sales from the Grayson Project

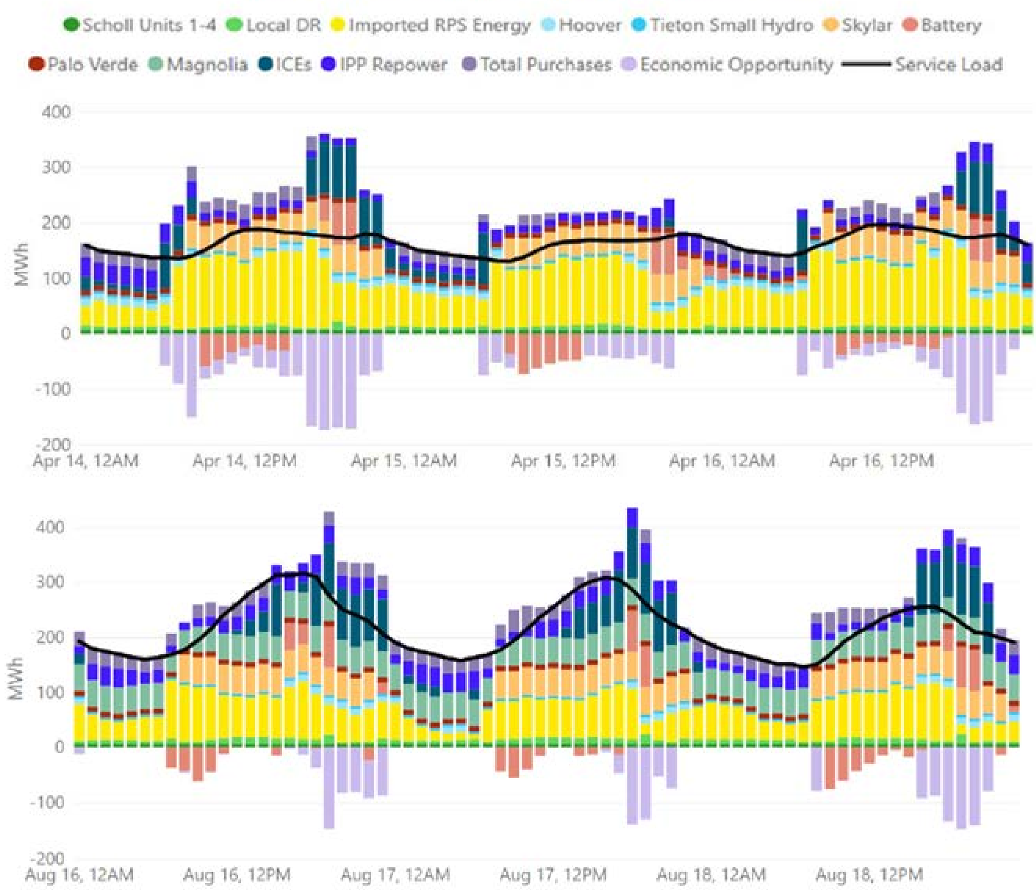
Based on an incorrect and inflated reserve obligation, GWP claims in the PR-DEIR that 93 MW of fossil-fired generation are necessary just to meet Glendale's energy needs. A review of

[18] 2019 Burbank IRP, at 106
[19] 2019 Burbank IRP, at 108.
[20] 2019 Burbank IRP, at 108.

L23-16 GWP's 2019 Integrated Resource Plan, however, reveals that GWP's proposal for 93 MW of fossil-fired generation is actually meant to provide GWP with excess energy that GWP proposes to sell to neighboring regions during periods of peak energy demand.

L23-17 GWP's 2019 Integrated Resource Plan includes graphs on the performance of GWP's energy portfolio on an hourly level based on modeling projections for a span of three days in the spring and summer of 2035.[21] In the graphs, "bars plotted against the negative axis represent energy leaving [GWP's energy] system either through the charging of batteries or through sales to market," while "bars plotted against the positive axis represent incoming energy used to serve load."[22]

Figure 16: Hourly Dispatch in the Spring and Summer of 2035



Example dispatch over the course of three days in the Spring and Summer of 2035. Total load is shown with a black line.

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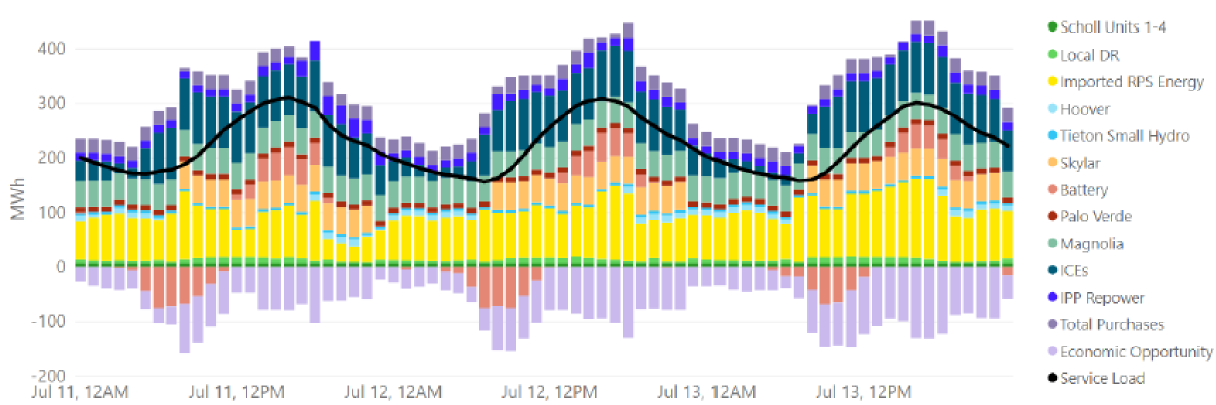
[21] 2019 GWP IRP, at 46–47 figs.16 & 17.
[22] 2019 GWP IRP, at 45.

L23-17 In its explanation of the graphs, GWP notes the presence of "Economic Opportunity" to sell excess energy during peak load hours.[23] GWP highlights such potential sales in the lavender bars plotted against the negative axis. The lavender bars in the top graph reveal that during the spring, GWP's proposed energy portfolio will consistently produce excess energy for sale. The lavender bars in the bottom graph reveal that even during the summer, when peak energy loads are highest, GWP's energy portfolio will continue to produce excess energy for sale. In both graphs, periods of "Economic Opportunity" largely coincide with periods when GWP plans to run the Grayson Project's fossil-fired generation units ("ICEs"), indicated by the dark teal bars on the positive axis. Thus, the excess energy for potential sales to neighboring regions primarily comes from fossil-fired generation.[24]

L23-18 The availability of "Economic Opportunity" is most pronounced in GWP's modeling for a three-day period in the summer of 2036 during an outage of the Pacific DC Intertie. GWP asserts that an outage of the Pacific DC Intertie represents its single largest continency ("N-1").[25] Even with an outage of the Pacific DC Intertie during the summer, the lavender bars in GWP's modeling show that the Grayson Project continuously produces excess energy from fossil-fired generation (indicated by the dark teal bars) that far surpasses Glendale's energy needs.

Figure 17: Hourly Dispatch in the Summer of 2036 when the Pacific DC Intertie is out



Example hourly dispatch over the course of three days in the Summer of 2036 when the Pacific DC Intertie is out. ICEs become critical to serving load and are running around the clock, battery storage also becomes increasingly important during peak load hour.

[23] 2019 GWP IRP, at 46.
[24] 2019 GWP IRP, at 47.
[25] 2019 GWP IRP, at 31.

L23-18 The presence of "Economic Opportunity" during peak load hours reveals that GWP's proposed energy portfolio is sized to produce a significant amount of excess energy even when Glendale's energy needs are greatest. In fact, the proposed fossil-fired generation units will produce excess energy even if their long-term average capacity factor is limited to 14 percent.[26] Nevertheless, GWP fails to disclose its consideration of "Economic Opportunity" in its project description. As a result, the additional environmental impacts beyond those that would occur if the Grayson Project was sized only to meet Glendale's own energy needs remain hidden. The PR-DEIR's omission of this important consideration violates CEQA because it prevents the public and other decisionmakers from making an informed decision about the Grayson Project.

c. The Grayson Project's environmental impacts from the closure of Aliso Canyon

L23-19 The availability of natural gas from Aliso Canyon directly affects operations at the Grayson power plant. GWP notes that between November 2018 and April 2019, "[s]torage restrictions at [Aliso Canyon] resulted in significant natural gas price increases that led to an unprecedented seasonal facility shutdown of the entire [power plant]."[27] Despite its reliance on Aliso Canyon for the Grayson power plant, GWP does not discuss or acknowledge the future closure of Aliso Canyon and the resulting consequences for the Grayson Project. GWP's omission results in an incomplete project description that overlooks significant environmental impacts from the Grayson Project.

From October 2015 until February 2016, a massive leak at Aliso Canyon expelled more than 100,000 metric tons of natural gas, or methane, into the atmosphere.[28] Methane is a potent greenhouse gas that "can warm the atmosphere 80 times as fast as carbon dioxide in the short term."[29] Following the environmental disaster at Aliso Canyon, then-Governor Brown directed the Public Utilities Commission to undertake an orderly phase out of Aliso Canyon by 2027.[30]

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[26] 2019 GWP IRP, at 48.
[27] Updated Air Quality Technical Report, at 25 (June 2021), Appendix C to PR-DEIR (PDF p. 399).
[28] Editorial, *A Billion-Dollar Settlement Can't Erase the Aliso Canyon Methane Blowout*, L.A. Times (Sept. 29, 2021), https://www.latimes.com/opinion/story/2021-09-29/aliso-canyon-settlement. (SC_000394).
[29] Lisa Friedman, *Biden Administration Moves to Limit Methane, a Potent Greenhouse Gas*, N.Y. Times (Nov. 2, 2021) https://www.nytimes.com/2021/11/02/climate/biden-methane-climate.html. (SC_000398).
[30] Editorial, L.A. Times (Sept. 29, 2021). (SC_000395).

Governor Newsom reaffirmed that decision in 2019.[31] A recent decision by the Public Utilities Commission to increase the capacity at Aliso Canyon has not affected the agency's plan to "reduce or eliminate the use of Aliso Canyon by 2027 or 2035, or anytime in between."[32]

L23-19 CEQA mandates GWP to discuss the significant environmental impacts from the Grayson Project that will result from the closure of Aliso Canyon. Such impacts include the Grayson Project's inevitable reliance on other sources of natural gas that are also prone to leaks. For example, in 2018, research published in the journal *Science* found that the U.S. gas supply chain leaked on average 2.3% of all U.S. gas produced, 60% higher than the EPA's official estimate.[33] Closure of Aliso Canyon and demand for natural gas from the Grayson Project will force Glendale to rely on other sources of natural gas that are part of this leaking supply chain. By neglecting to discuss the environmental impacts from these other sources of natural gas in the PR-DEIR, GWP presents an inaccurate and legally inadequate project description that violates CEQA.

II. The PR-DEIR fails to evaluate and improperly dismisses feasible alternatives to the Grayson Project

CEQA requires a lead agency to select and evaluate a reasonable range of alternatives in its
L23-20 Environmental Impact Report.[34] The range of alternatives considered in an EIR should be designed to foster informed decision-making and public participation.[35] In addition, "an agency may not approve a project unless it finds the alternatives are infeasible, a finding that must be supported by substantial evidence in the record."[36]

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[31] Editorial, L.A. Times (Sept. 29, 2021). (SC_000395).
[32] Olga Grigoryants, *6 Years After Disastrous Aliso Canyon Gas Leak, Officials Vote Unanimously to Expand Facility*, L.A. Daily News (Nov. 4, 2021), https://www.dailynews.com/2021/11/04/6-years-after-disastrous-aliso-canyon-gas-leak-officials-vote-unanimously-to-expand-facility/. (SC_000401-000402).
[33] Ramon A. Alvarez et al., Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain, 361 Science 186, 186–188 (July 13, 2018), https://science.sciencemag.org/content/361/6398/186. (SC_000389–000391).
[34] 14 Cal. Code Regs. §15002(f).
[35] 14 Cal. Code Regs. §15126.6(a)–(f); *See Bay Area Citizens v. Ass'n of Bay Area Gov'ts*, 248 Cal. App. 4th 966, 1017 (2016); *Federation of Hillside & Canyon Ass'ns v. City of L.A.*, 83 Cal. App. 4th 1252, 1263 (2000).
[36] *Save Panoche Valley v. San Benito County*, 217 Cal. App. 4th 503, 521 (2013); Cal. Pub. Res. Code § 21081.5.

L23-20 The PR-DEIR fails to consider and improperly rejects several alternatives that would avoid or substantially lessen the Grayson Project's environmental impacts.[37] First, the PR-DEIR arbitrarily dismisses the potential for LADWP to supply additional energy to GWP while it transitions away from fossil-fired generation. Second, the PR-DEIR omits analysis of widely available and cost-effective energy programs to manage projected load growth. Finally, the PR-DEIR dismisses an interconnection to the California Independent System Operator ("CAISO") based on a factual error that renders the PR-DEIR's alternatives analysis unlawful.

a. Obtaining an energy commitment from LADWP

L23-21 Glendale is not an energy island. Glendale is interconnected to a variety of non-local energy resources that travel along several transmission lines into the city.[38] In addition, GWP is part of the LADWP balancing authority.[39] Through this relationship, LADWP already works closely with GWP to maintain reliable generation and transmission resources. For example, as mentioned above, LADWP assumes "full obligation" to provide GWP with "full contingency reserve[s]" under the BAASA.[40] Building off this relationship, LADWP has already committed to assist GWP in meeting its electrical loads during the decommissioning of the existing Grayson units.[41] Specifically, LADWP has agreed to provide GWP with 75 MW during peak period hours and up to 25 MW during off-peak hours, in addition to the transmission access that LADWP already provides.[42] This energy supply would come from within the LADWP balancing authority area and "would not be transmitted over GWP's transmission assets."[43] Thus, GWP's transmission entitlements "would be preserved to supply additional power to Glendale."[44]

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[37] *Laurel Heights Improvement Ass'n v. Regents of Univ. of Cal.*, 47 Cal. 3d 376, 403–405 (1988).
[38] 2019 GWP IRP, at 20.
[39] 2019 GWP IRP, at 93.
[40] BAASA, scheds. 5–6, at 30–35. (SC_000077–000082).
[41] City of Glendale Water and Power, Draft Environmental Impact Report, at 2.11 (PDF p. 47) (Sept. 15, 2017) [hereinafter DEIR].
[42] DEIR, at 2.11 (PDF p. 47).
[43] City of Glendale Water and Power, Final Environmental Impact Report, Response to Comments: Topical Response No. 3, at 9.49–9.50 (PDF pp. 25–26) (Mar. 1, 2018) [hereinafter FEIR Topical Response No. 3].
[44] FEIR Topical Response No. 3, at 9.49–9.50 (PDF pp. 25–26).

LADWP's commitment to support GWP's energy needs during the Grayson Project is a concrete foundation for further discussions to transition away from fossil-fired generation and advance clean energy in Glendale. But GWP dismisses such discussions with the conclusory statement that "LADWP cannot be relied on as a feasible long-term solution to the Project."[45]

L23-21

GWP does not need to rely on LADWP as a long-term solution to successfully develop and pursue clean energy options and strategies. For example, GWP could request that LADWP extend its existing commitment to provide 100 MW during the decommissioning of the existing Grayson units. Extending that commitment for six additional years would provide a reliable stopgap measure until GWP acquires an additional 72 MW from the Southern Transmission System in 2027.[46] LADWP's commitment of 100 MW would take the place of GWP's proposed 93 MW of fossil-fired generation. During those six additional years, GWP could procure more local clean energy resources by issuing Requests for Proposals ("RFPs"). GWP's clean energy RFP from 2018 required all proposed projects to be "developed, designed, constructed/installed and commissioned for service by no later than April 2021."[47] Despite this short timeline for project completion, GWP received and accepted several clean energy proposals that are now included in its energy portfolio. A commitment from LADWP to provide 100 MW for six additional years would allow GWP to issue additional RFPs that invite a greater range of proposals based on a longer timeline for project completion. Potential projects include targeted energy efficiency, demand response, and behind-the-meter renewable and storage programs to reduce GWP's projected need.

Ultimately, the relationship between LADWP and GWP provides a significant opportunity for GWP to move beyond fossil-fired generation and pursue clean energy resources. LADWP's existing commitment to support GWP's energy needs demonstrates the feasibility of engaging LADWP to extend that commitment so that both utilities can work together to develop reliable and clean energy solutions. GWP's dismissal of this alternative to the Grayson Project is conclusory and fails to provide the objective analysis that CEQA requires.[48]

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[45] DEIR, at 2.11 (PDF p. 47).
[46] PR-DEIR, at xi–xii (PDF p. 12–13).
[47] City of Glendale Water and Power, Request for Proposal for Local and Regional Renewal, Low-Carbon, and Zero Carbon Energy and Capacity Resource Options to Serve the City of Glendale, at 4 (May 4, 2018) [hereinafter 2018 GWP RFP].
[48] *Laurel Heights Improvement Ass'n v. Regents of Univ. of Cal.*, 47 Cal. 3d 376, 404 (1988).

b. Managing projected load growth

L23-22 GWP fails to thoroughly evaluate alternatives to manage projected load growth. GWP forecasts rising peak loads in its 2019 Integrated Resource Plan.[49] Prior to its 2019 Integrated Resource Plan, GWP had never forecasted rising peak loads. For example, GWP's 2015 Integrated Resource Plan showed peak loads falling from 350 MW in 2017 to 300 MW in 2035.[50] GWP largely attributes rising peak loads in its 2019 Integrated Resource Plan to an increase in electric vehicle adoption.[51] Based on this forecast, GWP proposes an energy portfolio that includes 93 MW of fossil-fired generation. In doing so, GWP overlooks feasible alternatives to manage such growth without fossil-fired generation.

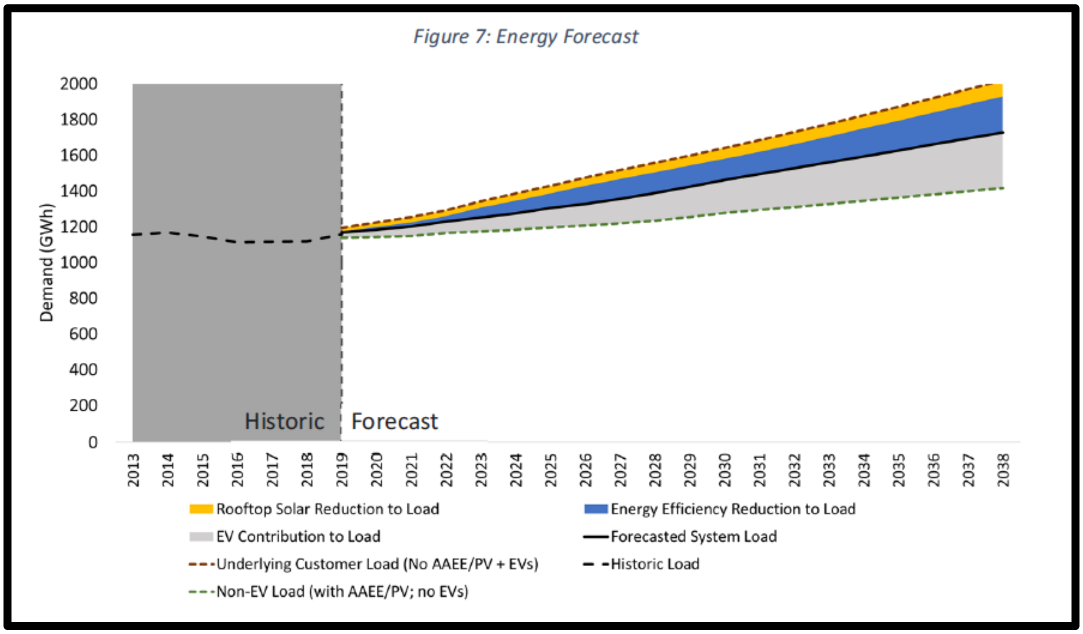
Table 8: Peak Demand Forecast of Customer Load + EV Load 2019-2038

(MW)	2018*	2019	2020	2021	2022	2023	2025	2030	2035	2038
P5 Peak	336	267	285	317	308	318	307	307	356	351
Median Peak	336	352	332	332	338	329	348	358	370	385
Mean Peak	336	342	344	343	343	345	347	362	376	386
P95 Peak	336	425	428	377	378	400	388	412	405	422

For example, GWP neglects to meaningfully evaluate alternatives to encourage electric vehicle charging during off-peak hours. Additional loads from charging electric vehicles are the perfect use case for demand-management programs, like time-of-use rates and demand response. Although GWP claims to have considered time-of-use rates, such consideration is not reflected in GWP's energy forecast.[52]

[49] 2019 GWP IRP, at 29.
[50] Glendale Water and Power, 2015 Integrated Resource Plan Report, at 12 (June 30, 2015) [hereinafter 2015 GWP IRP].
[51] 2019 GWP IRP, at 24, 27–28.
[52] 2019 GWP IRP, at 24 fig.7.

L23-22



Unlike GWP, BWP forecasts no future load growth despite its acknowledgement of rapidly increasing vehicle electrification.[53] Using the same California Energy Commission EV Forecast Tool that GWP used to calculate electric vehicle load, BWP anticipates powering approximately 5,000 electric vehicles by 2038.[54] Through a variety of load management strategies, BWP expects that increasing vehicle electrification will "help achieve new environmental goals, integrate renewable energy, and maintain grid reliability."[55] BWP outlines a variety of load management strategies to achieve these environmental and reliability benefits. For example, BWP initiated a managed charging pilot program in 2017 for large commercial customers.[56] The program incentivizes customers to use EV chargers during daylight hours to better integrate with renewable resources.[57] BWP can reduce EV charging levels "during outages or a limited number of peak demand or other load management events."[58]

While GWP and BWP manage different energy portfolios that inevitably possess local characteristics, both are part of the same energy landscape within the LADWP balancing authority and face the same electric vehicle transformation. In addition, both GWP and BWP

[53] 2019 Burbank IRP, at 40.
[54] 2019 Burbank IRP, at 140.
[55] 2019 Burbank IRP, at 64.
[56] 2019 Burbank IRP, at 140.
[57] 2019 Burbank IRP, at 140–141.
[58] 2019 Burbank IRP, at 141.

L23-22 rely on largely the same transmission lines to import energy into their electrical systems.[59] BWP's ability to manage increasing demand from vehicle electrification suggests that GWP has foregone alternatives that would do the same. GWP can and should pursue focused incentives like those envisioned and implemented by BWP to incorporate more electric vehicles without increasing Glendale's energy needs.

L23-23

c. Interconnecting to CAISO

GWP rejects several alternatives to the Grayson Project, in part because those alternatives would require additional transmission. Although GWP could obtain such additional transmission by interconnecting to CAISO, GWP falsely claims that interconnecting to CAISO is infeasible because GWP would have to first become part of the CAISO balancing authority.[60] GWP's false claim forecloses informed decision-making at the heart of the CEQA process.

Interconnecting to CAISO would allow GWP to make purchases or sales of energy with any member of CAISO or any other entity interconnected to CAISO.[61] GWP previously determined that such an interconnection was feasible and could provide an additional 150 MW to Glendale. Specifically, GWP's 2015 Integrated Resource Plan contains an interim screening report titled "New Interconnection Options for the City of Glendale Water and Power."[62] In the report, GWP contracted with consultants to assess four locations for a potential interconnection to CAISO. The consultants determined that GWP could interconnect to CAISO at Eagle Rock.[63]

Nevertheless, GWP claims it "cannot interconnect to [CAISO] because it is not a member of the CAISO Balancing Authority."[64] But GWP is not required to become a member of the CAISO Balancing Authority to directly interconnect to CAISO.[65] For example, LADWP is not a member

[59] 2019 GWP IRP, at 21; 2019 Burbank IRP, at 176–180.
[60] PR-DEIR, at 5.23 (PDF p. 132).
[61] 2015 GWP IRP, at 10; Memorandum from James Caldwell to Evan Gillespie re Glendale Contingency Reserve Obligations, at 4 (Apr. 18, 2018), Ex. 4 to Sierra Club Comment on FEIR [hereinafter Jim Caldwell Comments]. (SC_000114).
[62] 2015 GWP IRP, at 102.
[63] 2015 GWP IRP, at 108.
[64] FEIR Topical Response No. 3, at 9.43 (PDF p. 19).
[65] Jim Caldwell Comments, at 4. (SC_000114).

L23-23 of CAISO, but it is robustly interconnected to CAISO.[66] LADWP executes interconnection agreements with CAISO and routinely makes purchases and sales with CAISO members.[67] According to the 2015 Integrated Resource Plan, GWP's interconnection to CAISO would cost approximately $66 million for 150 MW.[68] This value is far greater than the $126 million for 93 MW of fossil-fired generation that GWP is proposing for the Grayson Project. Further, interconnecting to CAISO could save GWP money by providing GWP with additional options for both long-term energy contracting and short-term energy purchases.

L23-24 Ultimately, GWP acknowledges that Glendale will need additional transmission beyond 2030 to meet its obligations under Senate Bill 100.[69] Senate Bill 100 requires local, publicly owned electric utilities to supply 100 percent zero-emission electricity by 2045.[70] Nevertheless, GWP proposes to invest hundreds of millions of dollars to build 93 MW of fossil-fired generation that will become obsolete in or before 2045, instead of pursuing opportunities for additional transmission that GWP must obtain.[71] GWP's dismissal of interconnecting to CAISO defies common sense and violates CEQA's mandate for thorough consideration and analysis of feasible alternatives.

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L23-25 Glendale Water and Power's PR-DEIR does not meet the clear informational requirements of the California Environmental Quality Act. Although the PR-DEIR proposes less fossil-fired generation than the originally proposed 278 MW, the PR-DEIR remains legally inadequate because it still relies on fundamental errors and flawed analysis. GWP uses such fundamental errors and flawed analysis to justify a project that continues to greatly exceed Glendale's energy needs, while failing to disclose significant environmental impacts and dismissing feasible clean energy alternatives.

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[66] Jim Caldwell Comments, at 4. (SC_000114).
[67] Jim Caldwell Comments, at 4. (SC_000114).
[68] 2015 GWP IRP, at 108.
[69] 2019 GWP IRP, at 87; PR-DEIR, at xii (PDF p. 13).
[70] California Energy Commission, Programs: SB 100, https://www.energy.ca.gov/sb100 (last accessed Nov. 11, 2021). (SC_000386–000388).
[71] 2019 GWP IRP, at 43.

L23-26 Thus, GWP must correct its errors in the PR-DEIR and present an accurate report of the Grayson Project in accordance with CEQA's goals of environmental protection, transparency, and informed decision-making.

Respectfully submitted,

Byron Chan

Angela Johnson Meszaros

EXHIBITS IN SUPPORT OF SIERRA CLUB'S COMMENTS ON GRAYSON PR-DEIR

Index Of Exhibits

	Exhibit No.	Description	Bates Nos.
L23-27	1	Sierra Club's Comments on Grayson DEIR (Nov. 20, 2017)	SC_000001–SC_000019
L23-28	2	Sierra Club's Comments on Grayson FEIR (Apr. 10, 2018)	SC_000020–SC_000312
L23-29	3	*North American Reliability Corporation*, 153 FERC ¶ 61,024, Order on Compliance Hearing (Dkt. No. RR15-4-001) (Oct. 15, 2015)	SC_000313–SC_000323
L23-30	4	NERC, WECC Regional Reliability Standard BAL-002-WECC-3 (Contingency Reserve) (Adopted June 28, 2021)	SC_000324–SC_000336
L23-31	5	NERC, Glossary of Terms Used in NERC Reliability Standards (June 28, 2021)	SC_000337–SC_000385
L23-32	6	California Energy Commission, SB 100 Webpage (2021)	SC_000386–SC_000388
L23-33	7	Ramón A. Alvarez et al., *Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*, 361 Science 186–188 (July 13, 2018)	SC_000389–SC_000392
L23-34	8	Editorial, *A Billion-Dollar Settlement Can't Erase the Aliso Canyon Methane Blowout*, L.A. Times (Sept. 29, 2021)	SC_000393–SC_000397
L23-35	9	Lisa Friedman, *Biden Administration Moves to Limit Methane, a Potent Greenhouse Gas*, N.Y. Times (Nov. 2, 2021)	SC_000398–SC_000400
L23-36	10	Olga Grigoryants, *6 Years After Disastrous Aliso Canyon Gas Leak, Officials Vote Unanimously to Expand Facility*, L.A. Daily News (Nov. 4, 2021)	SC_000401–SC_000403

EXHIBIT 1

Sierra Club's Comments on Grayson DEIR

EARTHJUSTICE

November 20, 2017

VIA ELECTRONIC MAIL

Erik Krause
Interim Deputy Director of Community Development
City of Glendale
Community Development Department
633 East Broadway, Room 103
Glendale, CA 91026-4386
ekrause@glendaleca.gov

Re: Comments on the Draft Environmental Impact Report for the Grayson Repowering Project

Dear Mr. Krause:

In accordance with the California Environmental Quality Act (CEQA), we submit these comments on behalf of the Sierra Club on the Draft Environmental Impact Report (DEIR) for the Grayson Repowering Project (Grayson Project).

The Glendale Department of Water and Power (GWP) proposes a project that demolishes the whole Grayson Power Plant, including all its ancillary buildings, with the exception of the recently constructed Unit 9. Following demolition, GWP proposes to build an entirely new 278 Megawatt (MW) natural gas-fired power plant.[1] This new power plant will consist of four separate turbine blocks as well as an array of support and ancillary buildings and equipment. This new power plant will be 43 MWs larger than the current power plant and is a significant expansion beyond the plant currently at the site. For context, the California Independent System Operator (CAISO) estimates that 43 MWs is enough energy for 32,250 households.[2] There were roughly 71,500 households in the City of Glendale in the 2011-2015 time period.[3]

[1] Stantec, Draft Environmental Impact Report Grayson Repowering Project, September 15, 2017, at 2.2 (hereinafter "DEIR").
[2] California ISO, Glossary http://www.energy.ca.gov/glossary/ISO_GLOSSARY.PDF
[3] United States Census Bureau, Quick Facts: Glendale, CA https://www.census.gov/quickfacts/fact/table/glendalecitycalifornia/HSD410215#viewtop. The DEIR notes that GWP has "88,100 electric customers." DEIR 2.8.

With the addition of the new Grayson Project, GWP will have a total generation capacity of 328 MWs at the Grayson site.[4]

While it seems cost of this undertaking has not yet been finalized, the current estimate is half-a-billion dollars ($500,000,000). This estimate is already $160,000,000 more than the highest estimated provided by GWP in 2015 when it sought approval from the City Council to proceed with a new 250 MW power plant at the Grayson site.[5] Further, it is unclear how accurate this half-a-billion dollar cost estimate is because GWP would not provide details about how the estimate was constructed, about what is included in the estimate, we do not know how accurate assigned costs are.[6] While the cost of the power plant is not an environmental impact, understanding the projected cost is critically important here because cost is used as a basis for rejecting cleaner alternatives to the Grayson Project.

Overall, the DEIR reveals that GWP has failed to undertake the type of through analysis required by CEQA prior to approving this project. Instead, this DEIR minimizes the real and significant environmental harms that will result from building this power plant in order to make it easier to avoid scrutiny from the public and to get approval from the Glendale City Council.

In contrast to the process unfolding here, the fundamental goal of CEQA is to ensure that decisionmakers, including the public, have complete information about the environmental impacts of a proposed project before its approval. This core informational aspect of the DEIR is important to ensure the long-term protection of the environment. At the core of this effort is the Environmental Impact Report that the Courts describe as "an environmental alarm bell whose purpose it is to alert the public and its responsible officials to environmental changes before they have reached ecological points of no return."[7] Here, the DEIR fails to meet this core requirement as it proposes to build a massive fossil-fueled power plant, claiming that doing so is the only possible way to meet Glendale's energy need and claiming that the brand new

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[4] "As shown in Table 2-1, the Project includes replacing 235 MW gross (219 MW net) of generation capacity with 278 MW gross (262 MW net) of generation capacity. The Project would increase the total Grayson Power Plant generation capacity from 286 MW gross (267 MW net) to 328 MW gross (310 MW net), for a net increase of 42 MW gross (43 MW net)." DEIR 2.2.

[5] City of Glendale, Report to the City Council, Agenda Item: Integrated Resource Planning Report, June 2, 2015, at 4 (hereinafter June 2015 Report to Council).

[6] Letter from Christine A. Godinez to Angela Johnson Meszaros dated November 8, 2017, stating that "the budget estimate for the Grayson Repowering Project is $500 Million" but declining to provide details of the estimate, stating "Please be advised that preliminary drafts, notes, or interagency or intra agency memoranda are withheld pursuant to California Government Code § 6254(a)."

[7] *County of Inyo v. Yorty,* (1973) 32 Cal.App.3d 795, 810

Grayson Power Plant will have no significant environmental impacts. Such a determination flies in the face of facts about environmental and health impacts of fossil fueled energy. Further, the DEIR rejects clean energy alternatives that could meet the city of Glendale's energy needs without adequately exploring the feasibility of those alternatives.

CEQA does not mandate any particular outcome, but it does require that decisionmakers are fully aware of the environmental consequences of the decision being made. CEQA also requires that GWP avoid or reduce environmental damage whenever feasible by requiring changes in a project through the use of alternatives or mitigation measures. It is, therefore, unlawful for an Environmental Impact Report (EIR) to hide or conceal environmental impacts of a proposed project. Similarly, it is unlawful for an EIR to stack the deck in favor of project approval by obscuring the true scope of the project and its environmental impacts. The DEIR runs afoul of both the spirit and the law regarding disclosure of environmental impacts.

I. The project's description is inaccurate because it fails to disclose that Grayson has been sized to allow Glendale Water and Power to sell energy to the energy market.

An accurate project description, including the project's objectives, "is the *sine qua non* of an informative and legally sufficient EIR," while an inaccurate or incomplete project description "draws a red herring across the path of public input."[8] The court will reject an EIR with an inaccurate or incomplete project description.

The Grayson DEIR lists nine objectives for the Project, all of which focus on meeting Glendale's energy needs. For example, objective number two is "Utilize current and reliable technology and control systems to provide reliable, cost effective, and flexible generation capacity for the City to serve its customer load."[9] Purportedly, the Grayson DEIR's proposal of a new 278 MW power plant is based upon Glendale's need. However, it is clear from looking at information developed prior to the Grayson DEIR that the DEIR is hiding from the public important information necessary for understanding the massive size of this fossil fueled project: selling the energy produced by an over-sized power plant.

In 2015, the City of Glendale developed an Integrated Resource Plan Report (IRP). The IRP purported to "provide a roadmap for future resource decisions for GWP."[10] The document also included many references to the fact that rebuilding Grayson will cause the GWP to have more energy than needed to serve Glendale's energy needs. The IRP suggests that excess energy could be sold to offset the financial risk associated with the overbuild.

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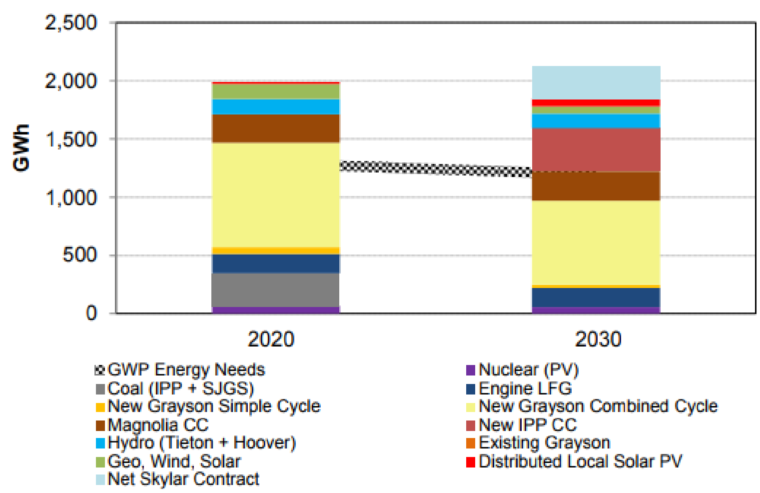
[8] *County of Inyo v. City of L.A.* (1977) 71 Cal.App.3d 185.
[9] DEIR 2.15.
[10] Pace Global, 2015 Integrated Resource Plan Report, June 30, 2015, at 6 (hereinafter "IRP"). This is the most recent IRP that GWP has developed.

For example, a graph showing the "projected portfolio energy resources over time" demonstrated that in 2020 and in 2030 GWP's "energy needs" will be far, far below the proposed energy portfolio that includes a 250 MW Grayson power plant.[11] Indeed, the IRP specifically points out that "notably, GWP's energy resources are projected to be greater than its needs, meaning that excess sales opportunities are likely to be available."[12]

Exhibit 2: Projected Portfolio Energy Resources over Time



Note that the "Net Skylar Contract" and refers to Skylar's obligation to deliver to GWP minus GWP's obligation to deliver back to Skylar. Further detail on this contract is provided in the GWP Situation Assessment chapter of this report.

Source: Pace Global analysis

Indeed, the IRP summarized the "preferred resource plan strategy" related to Grayson as:

> Proceed with a re-powering of the natural gas-fired Grayson Power Plant with a combination of simple cycle and combined cycle combustion turbines totaling around 250 MW, pending further engineering study. Find a long-term municipal partner to contract for a share of the new plant's capacity and energy in order to reduce market exposure associated with potential excess energy sales.[13]

And the "summary of key metrics for preferred resource plan" noted in the "risk" section that "since there is a larger reliance on excess energy sales, a partner for long-term offtake of

[11] Of course, the proposed Grayson Project is for 262 MWs, even more than was contemplated in the IRP.
[12] IRP at 7.
[13] IRP at 6.

capacity or energy is recommended in order to mitigate the risk of relying on short-term, spot markets."[14]

In conducting the portfolio analysis to compare various Grayson repower options, the IRP writes:

> As can be seen, the portfolios with new combined cycles at Grayson have the capability to produce more energy than is required for meeting GWP's native system needs, opening up the opportunity for revenues from sales of surplus power.[15]

Then, the IRPs "summary of portfolio analysis findings" reports under "risk" performance metric that "the 250D portfolio offers a hedge against high market prices, but relies heavily on market sales, suggesting that a long-term offtake agreement may be recommended."[16] And under the "financial flexibility" metric that "the 250D portfolio requires the highest capital expenditures and new debt. However, a contract arrangement with an offtaker could provide security in future revenue."[17]

In its final summary of the portfolio analysis, the IRP notes "the 250D MW option has the highest capital investment but lowest range of costs; it has highest reliance of off-system sales in order to keep costs down."[18] Another way the IRP summarized this was to say: "the larger capacity additions at Grayson require more capital and potentially pose a risk to GWP's financial stability."[19]

It is strikingly clear from the IRP that the 250 MW option produces far more energy than is needed to meet the GWP's energy needs. It is also clear that under the "environmental stewardship assessment" metrics—which looked only at emissions of CO2—the 250 MW scenario was the worst environmental performer—as would be expected. For example, the IRP

[14] IRP at 8.
[15] IRP at 47.
[16] IRP at 52.
[17] IRP at 52.
[18] IRP at 52.
[19] It is not at all clear who the buyer of all of this surplus fossil energy could be or whether the price, if a buyer were to be found, would be sufficient to justify the high capital cost of the new fossil facilities at Grayson. Indeed, both the California Public Utilities Commission and the California Independent System Operator have found that a large surplus of natural gas plants currently exists and that this surplus will only grow in the future as the state increases its use of renewable resources. See, e.g., Ivan Penn and Ryan Menezes, Californians are paying billions for power then don't need, Los Angeles Times, February 5, 2017, (http://www.latimes.com/projects/la-fi-electricity-capacity/). *See, generally*, California's electricity glut, Los Angeles Times (http://www.latimes.com/projects/la-fi-electricity-glut/)

acknowledges that "portfolios with more energy generation…also produce larger amounts of CO2."[20] And the "summary of portfolio analysis findings" notes for "environmental stewardship: Portfolios with more local generation have the highest CO2 emission footprint."[21]

Interestingly, the DEIR confirms the fact that all the energy from the Grayson Project is not critical to meeting Glendale's energy need by providing two pieces of information: Grayson's construction schedule and plans for contracting with the Los Angeles Department of Water and Power (LADWP) during construction. The DEIR explains:

> The demolition at the Grayson Power Plant would commence in the second quarter or early in the third quarter of 2018, and be completed in the first quarter of 2019. Construction of the Project is scheduled to commence during the first quarter of 2019.
>
> In order to facilitate the Repowering of Grayson, Los Angeles Department of Water and Power (LADWP) has agreed to assist GWP during the repower Project in accordance with the following terms; Term – up to eight years beginning January 1, 2015, Delivery at Air Way receiving station, *Quantity up to 75 MW during peak period hours and up to 25 MW during off-peak hours, to ensure that the City will have sufficient electrical energy to serve its customers.*[22]

Here, the project description is inadequate because the DEIR fails to explain that the project has been sized to do more than simply ensure that that Glendale can meet its energy needs, rather, its size is driven by the ability to sell excess energy from the power plant.[23] Further, despite the IRP's conclusion that a 250 MW power plant would exceed Glendale's energy need,

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[20] IRP at 52.

[21] IRP at 52.

[22] DEIR 3.45. (emphasis added)

[23] The DEIR argues extensively that GWP has an obligation under federal law to generate enough energy to serve all of Glendale's need at a level of the highest peak usage plus 100 MW to allow for the loss of the single largest source of energy, which is loss of a power line. *See, e.g.* DEIR 2.11. However, this requirement actually applies to the Balancing Authority within which Glendale sits—the LADWP Balancing Authority—not to Glendale. As the City acknowledged in response to a question posed seeking clarification about these purported requirements:

> With respect to the single largest contingency (also known as the "most severe single contingency") and balancing authority obligations, the applicable federal reliability standard is WECC Standard BAL-002-WECC-2a. This standard requires the Balancing Authority to maintain a minimum amount of contingency reserves. GWP operates as a metered subsystem within the LADWP Balancing Authority Area. As a metered subsystem, *GWP must either self-provide or purchase from LADWP or other[] regulation and balancing services to balance the loads and resources within its metered subsystem* (i.e. within GWP's service area).

Letter from Christine A. Godinez to Angela Johnson Meszaros, October 26, 2017, at 2. (emphasis added)

GWP proposed a 278 MW power plant with no explanation for the increased size, while construction planning makes clear that without Grayson a maximum of 75 MWs is needed "to ensure that the City will have sufficient electrical energy to serve its customers.

GWP is proposing to build a power plant that is bigger than is needed to meet the City of Glendale's native energy requirements. Building and operating this large power plant will result in increased environmental impacts beyond what would occur if the DEIR's project was sized to only meet the City's native load. Further, GWP overstatement of Glendale's need facilitates the rejection of clean energy alternatives that would easily meet the actual need had it been properly stated. Because the DEIR hides this underlying objective, the public and other decisionmakers are unable to make an informed decision about the Grayson Project—and resulting environmental impact—rendering the DEIR unlawful.

II. The DEIR improperly rejects feasible alternatives that would reduce environmental impacts while meeting the project's stated objectives

The DEIR "must consider a reasonable range of potentially feasible alternatives that will foster informed decisionmaking and public participation."[24] The DEIR "*shall* include sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison with the proposed project."[25] The DEIR has failed to meet this basic legal standard because it constructed alternatives that do not truly inform the decisionmakers and the public about reasonable, feasible, and available clean energy alternatives that would significantly reduce or eliminate environmental impacts of the Grayson Project. Further, the DEIR failed to support important assertions of fact including assertions about the costs of alternatives as compared to the project's cost and the purported need to build more transmission capacity to use less polluting energy alternatives.

a. Clean Energy can provide feasible alternatives to the Grayson Project

There was a time, perhaps only a few years ago, when building a new massive fossil fueled power plant seemed proper for meeting energy needs. That time has passed. Now, the reality that clean energy choices can reliably and cost-effectively meet both capacity and peaking needs has been established. As a result, a DEIR that dismisses clean energy alternatives with the scant consideration given here fails to meet the information requirements of CEQA was well as the environmental protection goals that CEQA mandates.

[24] Guidelines 15126.6(a).
[25] Guidelines 15126.6(d). (emphasis added)

First, because the DEIR overstates Glendale's energy need, all of the alternatives are improperly drawn. The alternatives available to meet a 75 MW peak need are very different from those available for a 278 MW project to meet Glendale's energy need and to sell energy.

Second, recent changes in California law combined with three recent examples in the Southern California region highlight the reality of the shift to clean energy.[26] California's adoption of SB 350 in 2015 requires utilities to get 50 percent of their energy from renewable energy sources and double energy efficiency savings by 2030.[27] Of critical importance here, all of the IRP scenarios modeled Glendale's alternatives based upon reaching a 33 percent renewables mandate by 2030, not the 50 percent mandate established by SB 350.[28] This mistake alone requires the DEIR to completely reanalyze all the alternatives at 50 percent renewables. Also, last year, the legislature nearly passed SB 100, which would have established at 100 clean energy target by 2045 and accelerated SB 350's 50 percent mandate to 2026 and changed the 2030 mandate to 60 percent. SB 100 will be taken up again in 2018. All indications are that California will only increase and accelerate its renewable mandates and the Grayson Project will hinder, rather than support, Glendale's efforts to comply with these mandates.

i. The California Energy Commission is proposing the reject a fossil fuel power plant license application because the identified energy need can be met with clean energy.

In 2015, NRG submitted an Application for Certification for the proposed Puente Power Project (P3). The 271 MW power plant was to be located on the existing site of the aging Mandalay Generating Station. NRG sought certification for the project after P3 had been chosen by Southern California Edison to fill a local capacity need identified by the California Independent System Operator (CAISO) for the Ventura/Santa Barbary County region. After more than two years of an intense licensing proceeding before the California Energy Commission (CEC), the Commissioners conducting the proceeding issued a statement

[26] GWP's assertions in the DEIR that building Grayson increases, rather than decreases, its ability to integrate renewables is unsupported by any analysis and conflicts with the analysis in the DEIR about Glendale's energy portfolio. In particular, the DEIR shows that if GWP builds Grayson it alone would be sufficient to meet Glendale's energy needs almost every day of the year. This means that almost every day of the year *every* MW of renewable energy will be in excess of Glendale's energy need. Put another way, almost every day of the year Glendale's ratepayers will be paying for energy that they do not need, cannot use, and Glendale will not be meeting California's mandate to meet its energy need with renewable energy.
[27] Clean Energy and Pollution Reduction Act of 2015 (https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350); see also California Public Utilities Commission, Implementation of SB 350 (http://www.cpuc.ca.gov/sb350/)
[28] IRP at 47.

informing the parties that "it intended to issue a [proposed decision] that recommends denial of the Project."[29] This proposed denial came after CAISO released a study[30] demonstrating that clean energy resources, including battery storage and other clean energy resources "are technologically feasible to meet local capacity requirements" in the area.[31] CAISO also pointed out that the only way to really know the cost of deploying feasible clean resources is by putting out a Request for Offers to receive bids for providing those resources.[32] As a result, the CEC has granted NRG's request to suspend the P3 project application for six-months pending the outcome of a new process by Southern California Edison and the Public Utilities Commission to identify available, cost-effective clean energy resources to meet the energy need in the local area.

This stunning shift from meeting an identified energy need with Puente's 271 MW fossil fueled power plant to a process to identify clean energy sources to meet that need shows how dramatically the energy landscape has changed. California energy regulators understood that moving forward with P3 in the face of the state's focused efforts to address climate change and move the state to clean energy means making choices today that do not lock us into more fossil fuel powered energy.

ii. *The Los Angeles Department of Water and Power has paused its plans to rebuild its natural gas plants to fully explore how to meet energy needs with clean energy.*

The Los Angeles Department of Water and Power (LADWP) has known since 2010, when the State Water Resources Control Board approved the policy to eliminate the use of ocean water to cool power plants, that it would no longer be able to avoid the need to retire its aging coastal power plant fleet. It determined that it would replace every megawatt of the existing energy capacity with a new fossil fueled fleet of power plants and began a $2.2 billion capital effort.[33] This year, LADWP decided to "put on hold all planned local repowering projects until a

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[29] California Energy Commission, Committee Statement Regarding the State of the Presiding Member's Proposed Decision (http://docketpublic.energy.ca.gov/PublicDocuments/15-AFC-01/TN221401_20171005T173308_Committee_Statement_re_PMPD_Status.pdf)
[30] California Independent System Operator, Moorpark Sub-Area Local Capacity Alternative Study, August 16, 2017. (http://docketpublic.energy.ca.gov/PublicDocuments/15-AFC-01/TN220813_20170816T165328_Moorpark_SubArea_Local_Capacity_Study.pdf)
[31] Letter from California Independent System Operator to the California Energy Commission, September 29, 2017. (http://docketpublic.energy.ca.gov/PublicDocuments/15-AFC-01/TN221345_20170929T153404_CAISO_Comments_regarding_Puenete_Power_Project.pdf)
[32] Ibid.
[33] Los Angeles Department of Water and Power, 2016 Briefing Book at 12. (https://www.ladwp.com/cs/idcplg?IdcService=GET_FILE&dDocName=OPLADWPCCB423407&RevisionSelectionMethod=LatestReleased)

system-wide, in-depth, and independent study/analysis is conducted to analyze the necessity for repowering [and to] identify all viable alternatives to repowering."[34]

iii. Southern California Edison launched a successful Preferred Resources Project to avoid building a natural gas plant to serve the energy need of more than 250,000 residential and 30,000 commercial customers

In 2015, Southern California Edison launched a project to meet a projected 300 MW of load growth in Orange County without building a fossil fueled power plant.[35] The first phase of this plan, called the "Preferred Resource Pilot" secured roughly 40 percent of this target with a mix of "Preferred Resources"--including battery storage, demand response, and solar—to "meet the needs of a metropolitan area, delivering the energy that is needed, when it is needed, and for as long as it is needed."[36] More solicitations are planned.

b. The DEIR improperly rejected the alternatives

CEQA requires an in-depth discussion of each alternative and its impacts in a way that the public and decisionmakers can undertake a meaningful comparison with the proposed project. "An agency may not approve a project unless it finds the alternatives are infeasible, a finding that must be supported by substantial evidence in the record."[37]

The DEIR proposes four alternatives in addition to a "No Project" alternative required by CEQA. The four alternatives are Energy Storage Project Alternative (Storage Project), Alternative Energy Project Alternative (Alternatives Project), 150 MW Project Alternative (150 Project), and the 200 MW Project Alternative (200 Project).[38] Ultimately, the GWP rejected each alternative by arguing, that it "failed to meet the Project objectives to the same extent as the Project."[39] The standard for consideration, however, is not whether the alternative meets the

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[34] Los Angeles Department of Water and Power, L.A.'s Clean Energy Future, June 6, 2017. Slide 6. (http://clkrep.lacity.org/onlinedocs/2016/16-0243_misc_8-1-17.pdf)
[35] Southern California Edison, Preferred Resources Pilot, August 17, 2015. Slide 2. (http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-07/TN205728_20150813T151843_Preferred_Resources_Pilot_by_Caroline_McAndrews_of_SCE.pptx)
[36] O.C. Pilot Tests Whether Clean Energy Resources Can Meet Growing Needs of Major Metro Area: SCE contracts for 125 megawatts of power, including batter storage and solar, September 9, 2016. (https://www.insideedison.com/stories/orange-county-pilot-tests-whether-clean-energy-resources-can-meet-major-metro-needs)
[37] PRC § 21081.5; *Save Panoche Valley v. San Benito County*, 158 Cal.Rptr.3d 719.
[38] DEIR 5.3 – 5.4.
[39] DEIR 5.15.

objective "to the same extent as the Project" but whether the alternative would meet the basic objectives of the project while reducing environmental impacts.

While the DEIR goes out of its way to argue why each alternative purportedly does not meet certain objectives, it does not find that any of the alternatives are infeasible. Indeed, as outlined above, the state of California mandates the use of clean energy to meet energy needs and using clean energy to meet the need previously served by fossil fuel power plants is feasible.

The DEIR rejects each alternative without adequate evidence to support key assumptions underlying the basis for the rejection. For example, the DEIR provides no support for its bare assertions that there would not be sufficient energy available to recharge the batteries in the Storage Project, which is the primary reason for rejecting that alternative[40], nor is there analysis to support the assertion that new transmission lines are required for the Alternatives Project[41] and the 150 Project, [42] which is the primary reason for rejecting those alternatives. In fact, a recent planning study conducted by the California Natural Resources Agency, called "RETI 2.0," concluded that "confirm[ed] that existing transmission capacity is available to interconnect a substantial amount of new renewable generation in several areas of the state."[43]

The DEIR rejected the 200 Project after acknowledging it would have less environmental impact and "meet most of the Project objectives" because it purportedly is "a higher cost option

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[40] "The Energy Storage Project Alternative is completely dependent on excess energy being available to charge the batteries, primarily through daily imports over the transmission systems. During high load periods, there will not be sufficient excess capacity to charge the batteries thus compromising the ability of this Alternative to reliably serve the residents and customers of the City. While this Alternative, using batteries alone, does have reduced local environmental impacts, it does not meet several critical project objectives with regards to assuring reliability of supply at reasonable cost." DEIR 5.30.

[41] "The Alternative Energy Project Alternative produces less potential air quality, greenhouse gas emissions, hydrology and water quality, and noise impacts than the proposed Project, but it would create greater impacts in several other resource categories because this Alternative requires additional development of transmission facilities on remote site(s); it requires a significantly greater amount of land to be disturbed in connection with development of new transmission line routes." DEIR 5.30.

[42] "This Alternative would create
greater impacts in several resource categories described above because it would require a significantly greater amount of land to be disturbed for the development of new transmission line routes." DEIR 5.30.

[43] Renewable Energy Transmission Initiative 2.0 Plenary Report, California Natural Resources Agency, February 23, 2017, at 9.

than the proposed project."[44] However, the DEIR does not provide sufficient information to support the claim that the 200 Project option is "higher cost" and seems to reach that conclusion by adding "the impact of the cost of periodic battery replacement as well as the need to dispose/recycle the batteries when they reach end of life."[45] This is improper because there is no support for the cost numbers that are included in the DEIR for the 200 Project. Further, the DEIR does not provide *any* information at all about the cost of the proposed Grayson Project, and includes no information about the ongoing operation costs for the proposed fossil fueled power plant. Therefore, not only is a cost comparison between the 200 Project (or any of the alternatives) and the Grayson Project not possible, it seems the DEIR is rejecting the 200 Project on the basis of costs of both construction and operation. This approach adds costs to the 200 Project that are not disclosed for either the Grayson Project or any other alternative rendering this cost approach completely without basis and therefore unlawful.

In comparing the potential environment impacts of the alternatives as compared to the project, the DEIR finds that *every* alternative, *including the no project alternative*, would have similar or less environmental impact than the Grayson Project, unless a new transmission line is built.[46] However, the DEIR does not provide any meaningful analysis to establish that a new transmission line would be needed and merely speculates about environmental impacts of a transmission line. These unsupported assertions and speculations do not meet the informational requirements found in CEQA law and are not substantial evidence to support the rejection of the alternatives. Strangely, after finding that the 200 Project would have less environmental impact compared to the project, the DEIR declared the Grayson Project to be "the Environmentally Superior Alternative."[47] That declaration, too, is unsupported by evidence in the record.

III. The DEIR Improperly Asserts That Air Quality, Geology & Soils, and Greenhouse Gas Emissions of the New Power Plant Will Be Less Than Significant

a. The air emissions are significant

As the lead agency, GWP is responsible for determining whether this power plant will have significant air quality impacts. To make that determination, GWP is required to identify a significance threshold against which to compare the emissions from the power plant. In the DEIR, GWP choose to use the South Coast Air Quality Management District's (SCAQMD) daily

[44] DEIR 5.30.
[45] DEIR 5.27.
[46] DEIR 5.29.
[47] DEIR 5.29.

significance thresholds for operations as the threshold.[48] Every air pollutant GWP analyzed will increase as a result of building this new power plant.[49] Two of the pollutants, Nitrogen Oxides (NOx) and Volatile Organic Compounds (VOCs) clearly exceed the SCAQMDs significance threshold. The significance threshold for both NOx and VOCs is 55 pounds per day, the power plant will have a net increase of 1,475 pounds per day for NOx and 102 pounds per day for VOCs. This exceedance of the significance threshold is clearly presented in the summary chart on page 4.3.34 of the DEIR:

Table 4-26 Project Maximum Net Daily Emissions

Pollutant	NO_x (lbs./day)	CO (lbs./day)	VOC (lbs./day)	PM10 (lbs./day)	PM2.5 (lbs./day)	SO_x Lbs./day
New turbines (without maint.)	648	623	179	173	173	101
New Turbines (with maint.)	1,570	1,017	191	173	173	101
New Emergency Engine	6	3	0.19	0.01	0.01	0.01
New Cooling Towers	0	0	0	5.4	5.4	0
Facility Occupancy	0.58	1.45	0.69	0.40	0.12	0.006
Less: Replaced Equipment (actual historic)	102	497	90	162	162	26
Net Increase (turbines without maint.)	**553**	**130**	**90**	**16**	**16**	**75**
Net Increase (turbines with maint.)	**1,475**	**524**	**102**	**16**	**16**	**75**
Sig. Thresholds (Operation)	55	550	55	150	55	150
Exceed Thresholds	YES	NO	YES	NO	NO	NO
Exceed Thresholds after New Source Review Offsets	NO	N/A	NO	NO	N/A	NO

Note:
1. The net emissions increase does not reflect emission offsets that will be required pursuant to SCAQMD Rule 1302. With the retirement of emission offsets to offset any emission increase of NO_x, VOC, PM10 and SO_x; the net increase of all pollutants will be below the significance thresholds.
2. CO and PM2.5 emissions are not required to be offset per SCAQMD Rule 1302 nor do they exceed the applicable SCAQMD daily mass emissions thresholds.

While it is clear that the significance thresholds are exceeded, the DEIR seeks to confuse the otherwise clear next step in the analysis. Under CEQA, once a project's impacts exceed the significance threshold the proponent must identify that impact as significant. The next step for the CEQA analysis is to seek feasible mitigation measures to avoid significant impacts. CEQA requires that feasible mitigation be adopted. If, after adopting all feasible mitigation, the identified impacts remain significant, then the agency can do a "statement of overriding

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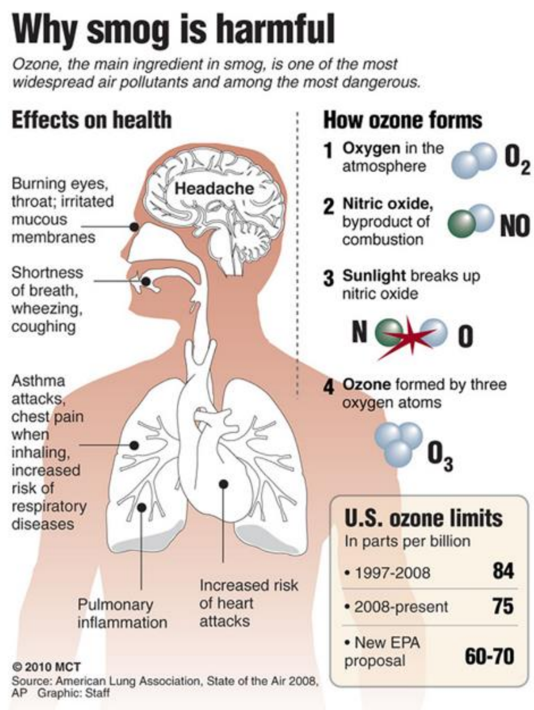
[48] DEIR 4.3.33 ("To evaluate the air quality impacts of the Project, maximum daily emissions from the new equipment were compared with the significance daily thresholds for operations.")
[49] This table also misses a key step in the SCAQMD process for determining significance thresholds by omitting the requirement to first reduce historic actual emissions from the existing Grayson power plant to current state of the art pollution control called "Best Available Control Technology" (BACT). This BACT discount significantly increases the "net increase" in emissions resulting from the project. Taking this BACT discount into account may result in PM also exceeding the significance threshold and, therefore, also requiring mitigation.

considerations" to explain to the public why the project will move forward despite its significant environmental impact.

Here, GWP inserted an unauthorized and deeply misleading sub-step to the significance finding: it argues that the project no longer exceeded the significance threshold "after New Source Review Offsets."[50] This sub-step short-circuits CEQAs required process of examining mitigation and alternatives for the significant air pollution that would be caused by the Grayson Project, and is therefore unlawful.

What the DEIR calls "New Source Review Offsets" are Emission Reduction Credits required by the Federal Clean Air Act as part of the Act's tools to edge the South Coast Air Basin toward meeting the health-based National Ambient Air Quality Standards. Glendale sits in an area that is unique in the United States: this area is the only one that has *never* met *any* of the Act's Ozone[51] standards. The first Ozone standard became effective in 1979. This region has not met that standard. Subsequent to the first standard, new standards were established in 1993, 1997, 2008, and 2015. None of those standards have been met. Failure to meet this standard has real and significant environmental and health impacts, and the Grayson Project's significant air pollution emission cause Ozone. Ozone is formed when NOx and VOC emissions combine with heat and sunlight. Ozone causes significant health problems from burning eyes to asthma and heart attack.

[50] DEIR 4.3.34
[51] Ozone is also known as "smog."



Because the South Coast Air Basin's Ozone is so bad, and because the environmental health impacts of ozone are so serve, the significance thresholds for NOx and VOCs are low. Those thresholds reflect the importance of facilities doing everything possible to reduce emissions at the source. In the context of CEQA, the thresholds reflect the requirement that facilities take seriously the environmental impacts of NOx and VOCs and identify and use all feasible mitigations and alternatives to avoid emitting them. Simply declaring that the NOx and VOC significance thresholds are not exceeded because Grayson will have Emission Reduction Credits reduces environmental protections required by CEQA to an empty exercise since all new sources of NOx and VOCs in the South Coast Air Basin require Emission Reduction Credits. Because overall emissions in the Los Angeles Basin must be reduced in order to meet these health-based standards, supply of these Emission Reduction Credits is extremely limited, and, even if available, come at a very high price. Although a small "reserve bank" of offsets is available for "essential public services," the Project would not be eligible to tap this reserve because market sales of surplus energy do not qualify as an essential public service.

b. The greenhouse gas emissions are significant

The DEIR uses an approach to analyzing the significance of greenhouse gases (GHG) that is similar to the improper approach used for analyzing air pollution. In this section, the DEIR calculates the total GHG emission from the Grayson Project as 476,406 Metric Tons per year

(MT/year) of CO2e[52] and the net increase after subtracting the current emissions from Grayson as 415,832 MT/year of CO2e.[53] This amount of GHG emissions is significant both because of its impact on the environment and because it clearly exceeds the significance threshold of 10,000 MT/year. Since the Grayson Project's GHG emissions exceed the significance threshold, GWP is obligated to consider all feasible mitigation measures and alternatives. If, after all feasible mitigation is adopted, Grayson's GHG emissions still exceed the threshold then GWP may do a statement of overriding considerations. What GWP cannot do, however, is simply assert that the emissions are not significant because Grayson will be part of California's cap-and-trade program.

First, the increase in GHGs caused by the Grayson Project are significant in terms of their environmental impacts. The climate crisis is real. "Scientists have high confidence that global temperatures will continue to rise for decades to come, largely due to greenhouse gases produced by human activities."[54] And we are already seeing the effects of climate change here. For example, in the Southwest "increased heat, drought and insect outbreaks, all linked to climate change, have increased wildfires. Declining water supplies, reduced agricultural yields, health impacts in cities due to heat, and flooding and erosion in coastal areas are additional concerns."[55]

The Grayson Project will *add* 415,832 MT/year of CO2e of GHG emissions. The United States Environmental Protection Agency has a tool that makes GHG emissions, which can be a little abstract, a little more concrete by giving examples of what they mean in every day terms such as how many cars driven, or how many miles by a passenger car, or how many barrels of oil consumed, or how much coal burned, or what it would take to sequester those emissions. For context, here are EPA's estimates for some equivalences of the added emissions from the Grayson Project:

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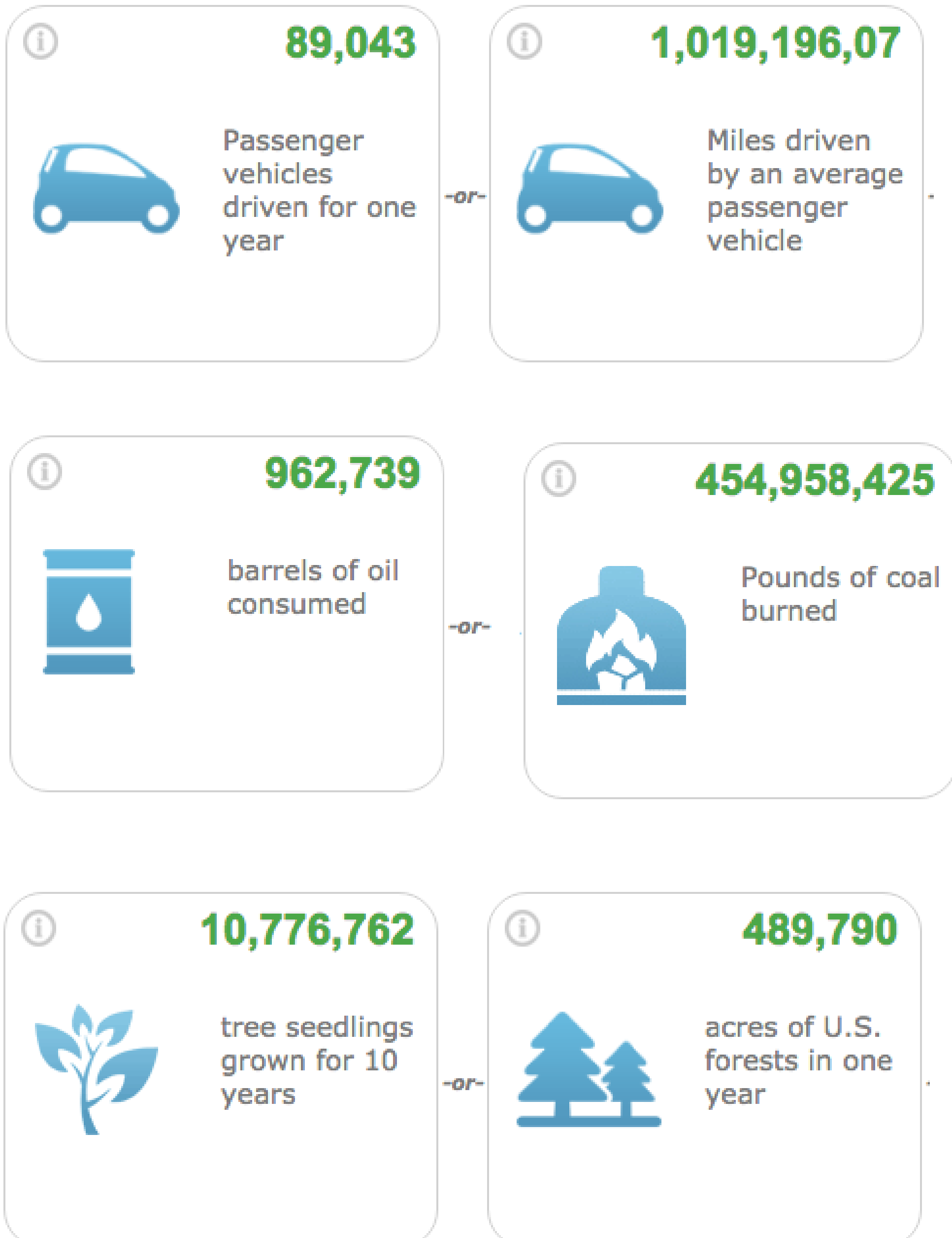
[52] DEIR 4.5.7.
[53] DEIR 4.5.7.
[54] NASA, Global Climate Change: Vital Signs of the Planet (https://climate.nasa.gov/effects/)
[55] Ibid.



The actual emissions from the Grayson Project are significant.

In addition to the real world significance, the Grayson Project exceeds the significance threshold of 10,000 MT/year of CO_2e. The DEIR explains:

> As shown in Table 4-37, the net increase of GHG emissions from the operation of the Project exceeds the significance threshold of 10,000 metric tons per year. The GHG emissions

> exceedance is solely contributed from operating the proposed combustion turbines and transformers.[56]

Despite the clarity of this statement, the DEIR then finds that the GHG emissions from the Grayson Project are "Less than significant" before mitigation.[57] This counterintuitive claim is based on the wrongful assertion that because the Grayson Project "is required to comply with the State cap and trade program" the GHG emissions are not significant. This is wrong. Participation in the cap and trade program does not reduce emissions from the Project, rather is simply requires a Project to buy carbon permits. Its purpose is to put a price on carbon to encourage people to figure out ways to reduce GHGs; the cap and trade program itself does not reduce emissions at a project.[58] Here, just as with its air pollution, GWP is required to explore mitigation and alternatives that would reduce or eliminate GHG emissions prior to approving the Grayson Project. If the GHG emissions cannot be reduced to a level below the significance threshold, then Glendale may disclose that fact and do a statement of overriding consideration. What Glendale cannot do is ignore its obligations under CEQA.

c. The risks to the power plant from an earthquake are significant

The DEIR identified a "moderate potential for surface rupture from the Verdugo fault and other nearby active faults during the design life of the proposed development."[59] Further, it is "expected" that strong ground shaking will occur at the Grayson Project site."[60] And, the Grayson Project site is in a known "liquefaction" zone.[61] Put another way, there is a significant chance that an active earthquake fault will cause earthquake near the Grayson site and when that happens, the soil can experience significant settlement—"approximately 11 inches."[62]

The DEIR establishes that the risk to the project requires mitigation because it is in an established liquefaction zone, writing:

> According to the State of California Seismic Hazards Zones – Burbank Quadrangle Map (released March 25, 1999), the Project area is located within a liquefaction zone, which is defined as an area where historic occurrence of liquefaction or where local geological,

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[56] DEIR 4.5.7.
[57] DEIR 4.5.7.
[58] Because State law requires that overall carbon emissions be reduced, the "cap" part of cap and trade will reduce the quantity of these permits available for purchase over time. The price of these permits will increase accordingly and add more costs to the Grayson Project over time.
[59] DEIR 4.4.6.
[60] DEIR 4.4.7.
[61] "Liquefaction occurs when loose, unconsolidated, water-laden soils are subject to ground shaking, causing the soils to lose cohesion." DEIR 4.4.7.
[62] DEIR 4.4.8.

> geotechnical, and groundwater conditions indicate a potential for permanent ground displacements *such that mitigation as defined in Public Resources Code Section 2693(c) would be required*.

Being in a mapped liquefaction zone establishes that the risk of liquefaction is significant. As such, as described above, the DEIR must identify the impact as significant and adopt all feasible mitigation or alternatives to reduce that impact below significance. Further, GWP may not simply assert that "the results of additional, forthcoming geotechnical assessments within the Project Area will be utilized to further evaluate potential engineering impacts and to design possible mitigation measures as they pertain to liquefiable soils."[63] CEQA does not allow the DEIR to shift mitigation identification and adoption to after approval as attempted here.[64]

IV. Conclusion

Glendale Water and Power's Draft Environmental Impact Report does not meet the clear informational requirements of the California Environmental Quality Act. It is clear that the Grayson Project is significantly larger than what is needed to meet Glendale's energy needs. The DEIR fails both to disclose the fact that the Grayson Project is oversized and fails to clearly establish the environmental impacts of this massive project. In addition, the massive size of the project resulted in flawed construction and analysis of alternatives to the Project. The alternatives analysis that was constructed is legally inadequate because it fails to inform meaningful consideration of feasible alternatives to the proposed project. Finally, the DEIR improperly hides the significant impacts of air pollution, greenhouse gas emissions, and earthquake risk and as a result fails to properly consider mitigation of and alternatives to the Grayson Project. Left uncorrected, each of these defects would render a Final Environmental Impact Report unlawful.

Respectfully submitted,

Angela Johnson Meszaros
Staff Attorney

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[63] DEIR 4.4.7 – 4.4.8.

EXHIBIT 2

Sierra Club's Comments on Grayson FEIR

EARTHJUSTICE

April 10, 2018

VIA ELECTRONIC MAIL

Erik Krause
Interim Deputy Director of Community Development
City of Glendale
Community Development Department
633 East Broadway, Room 103
Glendale, CA 91026-4386
ekrause@glendaleca.gov

Re: Comments on the Final Environmental Impact Report for the Grayson Repowering Project

Dear Mr. Krause:

We submit these comments in conjunction with Jim Caldwell[1] on behalf of the Sierra Club on the Final Environmental Impact Report (FEIR) for the Grayson Repowering Project (Grayson Project).

Glendale Water and Power's FEIR fails to address the deficiencies in the Draft Environmental Impact Report (DEIR) that were described at length in our letter of November 20, 2017. Glendale Water and Power (GWP) crows that it made only minor "editorial" revisions to the DEIR. As a result, the FEIR continues to provide a deeply flawed analysis of the Grayson Project. The FEIR is legally deficient and unfit for certification under the California Environmental Quality Act (CEQA).

I. The Project Description Rests on a Fatal Error.

The FEIR's flawed Project Description violates the fundamental goal of CEQA, which is to provide decision-makers and the public with information that allows them to balance the benefit of the project against its environmental impacts.[2] Central to the determination of the size of the project is the claim that the design of the Grayson Project is meant to "sufficiently

[1] Mr. Caldwell is an energy expert retained by Sierra Club. His resume is attached as Exhibit 1.
[2] See, e.g., *County of Inyo v. City of L.A.* (1977) 71 Cal.App.3d 185, 192-193 ["Only through an accurate view of the project may affected outsiders and public decision-makers balance the proposal's benefit against its environmental costs, consider mitigation measures, assess the advantage of terminating the proposal (i.e., the "no project" alternative) and weigh other alternatives in the balance."]

meet [Glendale's] peak load and reserve obligations."[3] The FEIR, however, misstates Glendale's reserve obligations, leading to incorrect analysis regarding the design of the Grayson Project.

The FEIR's failure stems from its erroneous understanding of Glendale's reserve obligations. GWP claims that North American Electric Reliability Corporation[4] (NERC) Reliability Standards[5] "require it to carry reserves equal to the loss of its single largest contingency (N-1 contingency), and its next largest contingency (N-1-1 contingency)."[6] Accounting for the loss of Glendale's two largest contingencies, GWP determines that Glendale "must replace 171 MW of 'lost' energy supply on a potentially on-going basis."[7] 171 MW is nearly 50% of Glendale's peak energy load, and more energy than Glendale uses for all but about 900 hours per year.[8] GWP uses this purported reserve obligation to justify the size of the Grayson Project.

GWP's calculation of its reserve obligation, however, is incorrect. The Balancing Authority Area Services Agreement (BAASA) between GWP and Los Angeles Department of Water and Power (LADWP), rather than NERC Reliability Standards,[9] determines Glendale's reserve obligation.[10] LADWP is the Balancing Authority subject to NERC Reliability Standards.[11] GWP is a "metered subsystem" approximately one-twentieth the size of LADWP contained within the LADWP Balancing Authority Area. GWP is contractually obligated under the BAASA to

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[3] FEIR Topical Responses 9.48.

[4] "The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid." https://www.nerc.com/AboutNERC/Pages/default.aspx.

[5] "NERC Reliability Standards define the reliability requirements for planning and operating the North American bulk power system and are developed using a results-based approach that focuses on performance, risk management, and entity capabilities." https://www.nerc.com/pa/Stand/Pages/Default.aspx.

[6] FEIR Topical Responses 9.46.

[7] FEIR Topical Responses 9.46.

[8] Based upon load profile data provided by the City of Glendale via Christine A. Godinez, February 20, 2018.

[9] The relevant standard for reserve obligation is set out in BAL-002-WECC-2a. See Reliability Standards for the Bulk Electric Systems of North America, North American Electric Reliability Corporation, updated February 15, 2018, at pp. 79-92. Attached as Exhibit 2.

[10] Balancing Authority Area Services Agreement Between Los Angeles Department of Water and Power and Glendale Water and Power, November 18, 2015 (BAASA). Attached as Exhibit 3.

[11] See generally, Western Interconnect Balancing Authorities, January 5, 2017. https://www.wecc.biz/Administrative/Balancing_Authorities_JAN17.pdf; see also, BAASA at p. 2. ["WHEREAS, GWP's System is currently located within the LADWP Balancing Authority Area"].

pay for its "fair share" of LADWP's reserve obligations. According to the BAASA, GWP is required to purchase reserves of 80 MW from LADWP at a specified tariff rate but has the contractual right to self-supply all or any portion of this obligation from its own resources.[12] This is a stark contrast to the 171 MW that GWP claims it is required to purchase.[13] In addition, even 80 MW of reserves is significantly larger than reserve policies in neighboring balancing authority systems.[14] GWP's factually incorrect assertion that it has a NERC-obligated 171 MW reserve requirement contaminates the analysis and alternatives development for the Grayson Project and deprives decision-makers and the public of a clear understanding of Glendale's energy needs.

Another stated purpose for repowering Grayson "is to provide [a] dispatchable source of power that can firm and shape GWP's renewable sources of power and ensure reliable operation of the City's electric supply."[15] Sierra Club strongly disputes GWP's unsubstantiated assertion that "firming and shaping" of renewable resources is required by modern utility practice. However, even if one accepts GWP's assertion, no such need has been documented in the FEIR. GWP's current "intermittent" renewables portfolio arrives in Glendale already "firmed and shaped"[16] and the FEIR contains no analysis of future proposed renewable resource purchases that require "firming and shaping."

II. The FEIR Improperly Rejects Feasible Alternatives.

The law requires an Environmental Impact Report (EIR) to identify and discuss alternatives to a proposed project. This requirement is based on the policy that agencies should adopt feasible alternatives that reduce a project's environmental impacts. GWP is obligated to provide a good faith and reasoned explanation for why it is rejecting a viable alternative[17] that would

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[12] BAASA Schedule 5 Operating Reserve – Spinning Reserve Service at pp. 30-34 and Schedule 6 Operating Reserve – Supplemental Reserve Service at pp. 35-39.
[13] See memorandum from energy expert Jim Caldwell to Evan Gillespie, April 9, 2018. ["In summary, GWP's need analysis for the Grayson Repowering Project is fundamentally flawed principally because it significantly and arbitrarily inflates GWP required planning reserve margin . . . ."] Attached as Exhibit 4.
[14] Generally accepted industry standard for "planning reserve margin" is 15% of a once in ten-year peak load. GWP's 1 in 10 peak load is 350 MW so industry standard planning reserves for GWP would be 350 x 1.15 minus 350 or 40.25 MW.
[15] FEIR Topical Responses 9.26.
[16] FEIR Topical Responses 9.27.
[17] See generally "Power Glendale with Renewable Energy" infographic (attached as Exhibit 5); presentation of Jim Caldwell at slide 15 (attached as Exhibit 6); expert testimony of Jim Caldwell restating previous testimony before the City Council, in conversations with City

meet the objective of providing the people of Glendale with reliable energy when Grayson is retired.[18] In particular, the FEIR must explain why a combination of solar, battery storage, energy efficiency, and demand response cannot meet Glendale's energy needs as proposed by numerous commenters.[19] GWP's conclusory response to comments regarding a clean energy alterative and the relevance of the Puente Power Project, LADWP's pause to study the availability of clean energy alternatives, and Southern California Edison's (SCE) preferred resources pilot unreasonably discounts the reality of California's changing energy landscape and the economic viability of clean energy alternatives. GWP simply notes that these projects are different than the Grayson Project. While these projects inevitably possess local characteristics that do not make them identical to the Grayson Project, all are part of the same energy landscape. These examples clearly demonstrate the availability of non-fossil fueled power to meet energy needs so as to significantly reduce—or completely eliminate—environmental impacts long associated with producing electricity. The examples also demonstrate that other energy providers addressing the same decisions as Glendale have identified and implemented energy alternatives that dramatically reduce environmental impacts. The law requires GWP to provide more than bare assertions of irrelevance; instead, it must explain why a combination of clean energy alternatives cannot serve Glendale's energy needs.

A clear example of this unfounded dismissal is GWP's description of the Puente Power Project that was proposed to be located in Southern California Edison's service territory. GWP argues that "not repowering Grayson would have a dramatically greater impact to the GWP system than not building the Puente Power Plant would have to the SCE system," because the Puente Power Plant only represents approximately 1% of SCE's peak load while Grayson

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Council members, and before the GWP Commission (included on the thumbdrive accompanying this letter).

[18] US Power Grid Can Run Well No Matter What Fuels It Uses: Reliability Official, S&P Global Platts, March 29, 2018 ["With the right policies and infrastructure, the US could get most of its electricity from renewable resources without hurting the performance of the power grid, according to an official who helps develop and oversee compliance with reliability standards."] https://www.platts.com/latest-news/electric-power/washington/us-power-grid-can-run-well-no-matter-what-fuels-10330144. Attached as Exhibit 7.

[19] During the GWP Commission meeting on April 2, 2018, Mr. Zurn indicated to the Commissioners that failure to move forward with the proposed project would result in the City forfeiting a $3,804,000 payment to Siemens Energy, Inc., to secure delivery of the power plant's Power Island Equipment. That payment was approved by the City Council on November 8, 2016 (attached as Exhibit 8.) It would be a clear violation of the law for this Council to have committed to completing the project prior to completion of proper environmental review.

represents almost 75% of GWP's peak load.[20] This statement is factually incorrect. The Puente Power Project was proposed to be a 271 MW fossil fired power plant located in a disadvantaged community (Oxnard). The proposed net capacity of the Grayson Project is 262 MW. The Puente Power Project was to be located in a transmission constrained portion of SCE's service territory that required up to 290 MW of new local generation to provide reliable electric service.[21] GWP is a 350 MW system. The Puente Power Project thus represents a much higher fraction of the reliability requirement in the Oxnard area than Grayson would be to Glendale. Yet, the California Energy Commission, in its role as the equivalent CEQA lead agency for permitting the Puente Power Project, indicated that it would recommend denial of the project's license because there are other clean energy alternatives available to meet the need.[22]

III. The FEIR Improperly Maintains that Impacts on Air Quality from the Grayson Project Will Be Less than Significant.

GWP continues to assert, improperly, that emission reduction credits and participation in the cap and trade program make the Grayson Project's air emissions and greenhouse gas emissions less than significant. To make such a claim, GWP misleadingly includes emission reduction credits and cap and trade permits as a project component in its significance determination. GWP, however, cannot rely on regulatory compliance to conclude that the Grayson Project will not have significant air emissions. The use of emission reduction credits and participation in the cap and trade program are—at best—possible mitigation measures that do not reduce emissions below the thresholds of significance. Improperly relying on these programs would mean that even a huge project like this would avoid a finding of significant air emissions and, consequently, an agency's obligation to consider alternatives and mitigation measures would seldom be triggered. This would contradict one of the central functions of CEQA which is to ensure that decision-makers and the public understand the impact of projects on the environment and take steps to reduce those impacts when feasible.

As a mitigation measure, emission reduction credits and cap and trade permits have no bearing on GWP's significance determination. Accordingly, GWP is required to find that the air emissions and greenhouse gas emissions from the Grayson Project are significant, and separately explore feasible mitigation and alternatives to address these emissions.

[20] FEIR Topical Response 9.113.

[21] California Public Utilities Commission D.13-02-015, February 13, 2013, at p. 73. Attached as Exhibit 9.

[22] California Energy Commission, Committee Statement re PMPD Status, October 6, 2017, Docket Number 15-AFC-01, TN# 221401. Attached as Exhibit 10.

IV. Environmental Justice Impacts Must Be Evaluated.

In its response to comments to the DEIR, GWP uses a flawed methodology to analyze environmental justice concerns that overlooks the potentially significant and harmful effects of the Grayson Project on surrounding environmental justice communities.

GWP makes several significant mistakes in its dismissal of environmental justice concerns. First, GWP analyzes an arbitrary and ineffective geographic area to determine whether the Grayson Project may potentially affect an environmental justice community. The relevant environmental justice communities to consider are those that live in proximity to the Grayson Project. In evaluating such communities, GWP should have followed the examples of other power plant projects that draw a six-mile radius around the project area and study the socio-economic make-up of communities within the radius.[23] This radius captures the communities most affected by the proposed project and, specifically, tracks the parameters for dispersion of air emissions from the project. In the case of the Grayson Project, a six-mile radius includes communities in both Los Angeles and Burbank that would suffer adverse effects from the Grayson Project and contains significant populations of low-income people and people of color. GWP's environmental justice analysis, however, only considers environmental justice communities within Glendale.[24] This decision is nonsensical because the Grayson Project is located on the northernmost border of Glendale. Impacts from the Grayson Project, such as air emissions, will inevitability affect communities outside of Glendale.

Second, GWP incorrectly concludes that the Grayson Project does not disproportionately impact minority or low-income communities because the Grayson Project does not result in significant environmental impacts on the general population. This conclusion is flawed because an impact that is not significant for the general population may still be significant for an environmental justice community due to special sensitivities within and cumulative impacts on such communities. Special sensitivities within environmental justice communities can make such communities susceptible to project harms, although the general public remains unaffected. For example, members of environmental justice communities may have significantly less access to healthcare and less financial security to cope with seemingly "minor" project impacts. Cumulative effects refer to a community's exposure to multiple environmental burdens that have significant interaction effects with other stressors such as pollution or unhealthy living

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[23] Puente Power Plant Final Staff Assessment, http://docketpublic.energy.ca.gov/PublicDocuments/15-AFC-01/TN214712_20161208T162906_PUENTE_POWER_PROJECT_FSA_PART_1.pdf. Attached as Exhibit 11.

[24] See maps developed by our office based upon 2012 U.S. Census Bureau data found on ArcGIS Online that show the median household income, tracts with greater that 50% people of color, and the distribution of tracts that are predominantly people of color. Attached as Exhibit 12.

conditions. Effects and stressors, together, may produce a disproportionately significant impact on environmental justice communities.

Consequently, GWP must undertake a more thorough and nuanced analysis of project impacts on environmental justice communities that specifically compares the different effects of project impacts on environmental justice communities and non-environmental justice communities.

V. Conclusion.

The FEIR's continuing informational deficiencies render it unlawful. GWP's responses to comments to the DEIR do not address the range of arguments against the adequacy of the DEIR, rather, the responses merely repeat unjustified conclusions set out in the DEIR. The Grayson Project continues to greatly exceed Glendale's energy needs because the project is based on an incorrect reserve obligation. In addition, the FEIR fails to provide meaningful analysis to address potential alternatives and significant air emissions. Finally, the FEIR improperly omits an environmental justice analysis by using flawed measurements and an incorrect understanding of project impacts on environmental justice communities.

Accordingly, the Grayson Project must be suspended until GWP is able to present a comprehensive and accurate report of the Grayson Project's scope, alternatives, and impacts.

Respectfully submitted,

Byron Chan

Byron Jia-Bao Chan
Angela Johnson Meszaros

Attorneys for Sierra Club

EXHIBIT 1

James H. Caldwell Jr.
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Sonoma, CA 95476
Phone: 707 939 1650
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James Caldwell is a renowned energy professional with fifty years experience in virtually all phases of energy production and public policy. He has Chemical Engineering and MBA degrees with an extensive plant operations and construction management background, as well as hands on corporate planning and finance experience. He has managed large organizations, been an officer of a Fortune 100 company, and started his own business. Relevant experience is as follows:

PRIVATE CONSULTING (October 2010 to Present)
For the past six years, Mr. Caldwell has used his expertise to leverage the achievement of California's goal for producing a large majority of its electricity from renewable resources with an interim goal of 33% of electric demand by 2020 while maximizing development of in-state renewable resources, managing customer bills through cost control of renewable development and grid integration, improving energy efficiency, and actively involving consumers through what is known as Demand Response. He serves as Senior Advisor for the Center for Energy Efficiency and Renewable Technologies (CEERT) in advocating this long term policy and near-term actions to achieve defined milestones before the California Public Utilities Commission, the California Energy Commission, the California Independent System Operator, the Legislature, Governor's Office, and other state and local government agencies. He also advises a number of renewable development companies on specific project matters typically involving grid interconnection, transmission and wholesale market issues.

SOLAR MILLENNIUM, LLC (February 2010 to October 2010)
Mr. Caldwell was an executive consultant to Solar Trust of America, a German owned manufacturer/developer of solar thermal technology, assisting them in permitting and interconnecting 2250 MW of solar projects in California and Nevada. He devised a transmission strategy to interconnect 1500 MW of these projects to the CAISO grid with over 90% of the required transmission upgrades funded by the interconnecting utility rather than the project developer. This strategy required two policy changes by the CAISO and favorable FERC and CPUC rulings.

He also functioned as President of Solar Millennium, LLC (the development arm of Solar Trust of America) in charge of permitting before the California Energy Commission and the Bureau of Land Management. This strategy resulted in receiving both State and Federal authorization to commence construction on 1500 MW of new solar thermal facilities covering more than 11,000 acres in the Eastern Mojave Desert. Formal agreements to support the projects were reached not only with State and Federal regulatory agencies, but also with Riverside County, Native American Tribes, labor unions, and five national and regional environmental groups.

LOS ANGELES DEPARTMENT OF WATER AND POWER (December 2006 to October 2009)
Mr. Caldwell joined the Los Angeles Department of Water and Power as a full time executive consultant reporting to the General Manager and the Board of Water and Power Commissioners. In March 2008, he was appointed Assistant General Manager of LADWP for Environmental

Affairs. He resigned from that position in October 2009. He managed corporate environmental affairs and advised the Department on its Power Integrated Resource Plan to dramatically increase the use of renewable energy, eliminate reliance on coal, engage the customer base in energy efficiency and clean distributed generation, and improve the efficiency and flexibility of the Department's natural gas generation. He also advised the Department on its Water Integrated Resource Plan to generate all new water resources for the City of Los Angeles from recycling and storm water capture while significantly reducing per capita water consumption. In addition to the Corporate Planning role for both the Water and the Power System Integrated Resource Plans, Mr. Caldwell had line responsibility for siting, permitting and obtaining California Environmental Quality Act approvals for the projects that made up the Department's Integrated Resource Plans. He also designed and implemented new City Planning ordinances for water conservation, customer based renewable energy development (called a "Feed In Tariff"), and low impact development.

PPM ENERGY (June 2004 to December 2006)
Mr. Caldwell joined PPM Energy (now Iberdrola Renewable Energy) as Director of Renewable Policy. At PPM, he was responsible for regulatory affairs, transmission policy, and wholesale market structure issues nationwide, and legislative affairs in California. PPM Energy has a wind project development pipeline of over 10,000 MW spread throughout the country. Mr. Caldwell was responsible for ensuring that state legislation, transmission tariffs, market rules, and transmission expansion projects are in place to facilitate the build-out of that pipeline. Much of this effort focused on implementation of ambitious Renewable Portfolio Standard programs in California, Colorado, Minnesota, New York, Iowa, and Texas.

AMERICAN WIND ENERGY ASSOCIATION (May 2001 to May 2004)
As Policy Director, Mr. Caldwell was responsible for AWEA's Transmission Initiative to integrate wind into the nation's wholesale electricity market structure and create regional grids capable of moving significant amounts of wind energy from resource rich areas to load centers. He led the wind industry effort at the Federal Energy Regulatory Commission to adopt balanced national market rules to facilitate entry of this unique technology into wholesale electricity markets while ensuring grid reliability and avoiding subsidies to wind and/or cost shifting onto other technologies and market participants. This effort led to a series of FERC Orders and adoption of innovative market rules at, for example, the Bonneville Power Administration, the California Independent System Operator, the Midwest Independent System Operator, the PJM Independent System Operator, ERCOT (Texas), the New York Independent System Operator, and the Western Area Power Administration. He advised AWEA's Legislative and Communications staff on all technical matters and served as liaison to regionally based environmental/energy company organizations (including CEERT in California) pursuing renewable energy development.

RENEWABLE RESOURCES (October 1980 to April 2001)
Mr. Caldwell is the former President of ARCO Solar Inc., the photovoltaic subsidiary of Atlantic Richfield Company. In that position, he was also a Vice President of Atlantic Richfield Company. As President of ARCO Solar, Mr. Caldwell took that company from a research organization with less than $3 million in revenue to an integrated worldwide manufacturing and marketing operation with over $30 million in sales. He created joint ventures in Japan and Germany, and partnered with ninety-six exclusive distributors selling ACRO Solar products in 126 countries. Prior to becoming President, Mr. Caldwell was the Senior Vice President for Manufacturing, Research, and Engineering where he constructed what, at the time, was the world's largest photovoltaic central station power plant, the 6.5 MW Carisso Plains project in Central California, as well as every large grid connected photovoltaic project constructed anywhere in the world prior to 1990. When Atlantic Richfield decided to sell ARCO Solar, Mr.

Caldwell left ARCO and attempted to purchase the company. He raised over $50 million in equity to purchase and fund the company's business plan, but was outbid by Siemens AG in July of 1989.

After leaving ARCO, Mr. Caldwell started his own consulting/project development business. He developed numerous power plant projects around the globe in partnership with Bechtel Enterprises and several European organizations. Projects included a 300 MW combined cycle gas fired power plant in Thailand, a 30MW gas turbine/water desalination cogeneration facility in an oil refinery on the island of Cyprus, a 10 MW waste wood fired power plant in northern California, and a 5 MW diesel generator/water desalination cogeneration facility in the Cape Verde Islands.

Mr. Caldwell's consulting clients included most of the national environmental organizations with a direct interest in energy policy including the National Resources Defense Council, the Sierra Club, Union of Concerned Scientists, and Environmental Defense. He also consulted for several independent power producers including Enron and PG&E's National Energy Group, and regional transmission organizations such as the California Independent System Operator.

ATLANTIC RICHFIELD COMPANY (August 1965 to September 1980)
Prior to his assignment with ARCO Solar, Mr. Caldwell held a variety of positions over a twenty-four year career with Atlantic Richfield. After graduating from college, he began employment with ARCO's predecessor, Richfield Oil Corporation, as a Refinery Process Engineer. A fourteen-year stint in refinery operations culminated in the position of Refinery Operations Manager at ARCO's Los Angeles refinery.

Mr. Caldwell was then assigned as Manager of Downstream Planning in ARCO's Corporate Planning Department. He oversaw ARCO's capital budget and worldwide strategic business plan for refining and marketing; petrochemicals; transportation including oil and gas pipelines and marine shipping; and ARCO's non-energy related diversification program. He led a corporate team that developed company investment and research policy for all synthetic fuels including coal gasification, coal liquefaction, biomass to energy, and concentrating solar power.

After leaving Corporate Planning and before assignment to ARCO Solar, he was the Project Manager and Owner's Representative for the Colony Oil Shale Development Company in Denver CO -- ARCO's primary venture into synthetic fuels. In addition, he managed ARCO's non-energy diversification effort into agricultural genetic engineering and vegetable seed production.

AFFILIATIONS
Mr. Caldwell is a former member of the Clean Air Act Advisory Committee for the Environmental Protection Agency, the Energy Modeling Committee of the Energy Engineering Board of the National Academy of Sciences, the Advisory Committee on Energy Policy for the Office of Technology Assessment, and the Advisory Board for the USAID Energy Training Program. He is a life member of the IEEE and the AIChE. Along with his wife, Jan McFarland and V. John White, in 1990 he helped found the Center for Energy Efficiency and Renewable Technologies in Sacramento, CA, and currently serves as Senior Advisor and At Large Member of the Board of Directors.

EDUCATION

Mr. Caldwell received a B.S. Degree in Chemical Engineering from Stanford University (1965) and an MBA from California State University at Long Beach (1978). He is married with three children and three grandchildren.

References on request.

EXHIBIT 2

EXCERPT FROM

HTTPS://WWW.NERC.COM/PA/STAND/RELIABILITY%20STANDARDS%20COMPLETE%20SET/RSCOMPLETESET.PDF

A. Introduction

1. **Title:** **Contingency Reserve**

2. **Number:** BAL-002-WECC-2a

3. **Purpose:** To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions.

4. **Applicability:**

   4.1 Balancing Authority

   4.1.1. The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group, in which case, the Reserve Sharing Group becomes the responsible entity.

   4.2 Reserve Sharing Group

   4.2.1. The Reserve Sharing Group when comprised of a Source Balancing Authority becomes the source Reserve Sharing Group.

   4.2.2. The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the sink Reserve Sharing Group.

5. **Effective Date:** See Implementation Plan.

B. Requirements and Measures

R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is: [*Violation Risk Factor: High] [Time Horizon: Real-time operations]*

1.1 The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

1.2 Comprised of any combination of the reserve types specified below:

- Operating Reserve – Spinning

- Operating Reserve - Supplemental
- Interchange Transactions designated by the Source Balancing Authority as Operating Reserve – Supplemental
- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service
- A resource, other than generation or load, that can provide energy or reduce energy consumption
- Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.
- All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.

1.3 Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).

1.4 An amount of capacity from a resource that is deployable within ten minutes.

M1. Each Balancing Authority and each Reserve Sharing Group will have documentation demonstrating its Contingency Reserve was maintained, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Part 1.1

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates its Contingency Reserve was maintained in accordance with the amounts identified in Requirement R1, Part 1.1, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Attachment A is a practical illustration showing how the generation amount may be calculated under Requirement R1.

- Where Dynamic Schedules are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1 may include, but is not limited to, documentation showing a reciprocal acknowledgement as to which entity is carrying the reserves. This transfer may be all or some portion of the physical generator and is not limited to the entire physical capability of the generator.

- Where Pseudo-Ties are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1, may include, but is not limited to, documentation accounting for the transfers included in the Pseudo-Ties.

Part 1.2

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.2. Evidence may include, but is not limited to, documentation that reserves were comprised of the types listed in Requirement R1, Part 1.2 for purposes of meeting the Contingency Reserve obligation of Requirement R1. Additionally, for purposes of the last bullet of Requirement R1, Part 1.2, evidence of compliance may include, but is not limited to, documentation that the reliability coordinator had issued an energy emergency alert, indicating that firm Load interruption was imminent or was in progress.

Part 1.3

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.3. Evidence of compliance with Requirement R1, Part 1.3 may include, but is not limited to, documentation that Contingency Reserve amounts are based upon load and generating data averaged over each Clock Hour and excludes Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464.

Part 1.4

Evidence of compliance with Requirement R1, Part 1.4 may include, but is not limited to, documentation that the reserves maintained to comply with Requirement R1, Part 1.4 are fully deployable within ten minutes.

R2. Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve identified in Requirement R1, as Operating Reserve – Spinning that meets both of the following reserve characteristics. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

2.1 Reserve that is immediately and automatically responsive to frequency deviations through the action of a governor or other control system;

2.2 Reserve that is capable of fully responding within ten minutes.

M2. Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates it maintained at least half of the Contingency Reserve identified in Requirement R1 as Operating Reserve – Spinning, averaged over each Clock Hour, that met both of the reserve characteristics identified in Requirement R2, Part 2.1 and Requirement R2, Part 2.2.

R3. Each Sink Balancing Authority and each sink Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M3. Each Sink Balancing Authority and each sink Reserve Sharing Group will have dated documentation demonstrating it maintained an amount of Operating Reserve, in addition to the Contingency Reserve identified in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, for the entire period of the transaction, except within the first sixty minutes following an event requiring the activation of Contingency Reserves, in accordance with Requirement 3.

R4. Each Source Balancing Authority and each source Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of Operating Reserves for any Operating Reserve transactions for which it is the Source Balancing Authority or source Reserve Sharing Group. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M4. Each Source Balancing Authority and each source Reserve Sharing Group will have dated documentation that demonstrates it maintained an amount of additional Operating Reserves identified in Requirement R1, greater than or equal to the amount and type of that identified in Requirement 4, for the entire period of the transaction.

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2 Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3 Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority and each Reserve Sharing Group shall keep evidence for Requirement R1 through R4 for three years plus calendar current.

1.4. Additional Compliance Information

1.4.1. This Standard shall apply to each Balancing Authority and each Reserve Sharing Group that has registered with WECC as provided in Part 1.4.2 of Section C.

Each Balancing Authority identified in the registration with WECC as provided in Part 1.4.2 of Section C shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

1.4.2. A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC: 1) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, 2) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and 3) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

1.4.3. If an agent properly designated in accordance with Part 1.4.2 of Section C identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance: 1) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, 2) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection 1) of this Part 1.4.3 of Section C, and 3) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection 1) of this Part 1.4.3 of Section C (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

1.4.4. If an agent properly designated in accordance with Part 1.4.2 of Section C fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

1.4.5. Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Part 1.4.2 of Section C shall be subject to this Standard on an individual basis.

Table of Compliance Elements

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.
R2	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 100% but greater than or equal to 90% of	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 90% but greater than or	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 80% but greater than or	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve Operating Reserve - Spinning is less than 70% of the required

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	equal to 80% of the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	equal to 70% of the required Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.	Operating Reserve–Spinning amount specified in Requirement R2, and both characteristics were met.
R3	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R3.
R4	Real-time Operations	High	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operating Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R4.	Operating Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R4.	Operating Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R4.	Operating Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R4.

D. Regional Variances
None.

E. Interpretations

Interpretation Requested

Arizona Public Service (APS) sought clarification that for purposes of BAL-002-WECC-2, Requirement R2, APS and other Balancing Authorities and/or Reserve Sharing Groups can include "technologies, such as batteries, both contemplated and not yet contemplated…as potential resources [to meet the Operating Reserve – Spinning requirement of BAL-002-WECC-2, Requirement R2] – so long as the…resource can meet the response characteristics described in the standard."

A standards interpretation team comprised of members of the original BAL drafting team concluded that APS' understanding was correct.

"[N]on-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" so long as they meet the technical and performance requirements in Requirement R2 (i.e., that the resources must be immediately and automatically responsive to frequency deviations through the action of a control system and capable of fully responding within ten minutes).[1]

[1] FERC Order 789, P47. July 18, 2013.

See also FERC Order 740, Section E, Demand-Side Management as a Resource, at P 50:
"The Commission clarified that the purpose of this directive was to ensure comparable treatment of demand-side management with conventional generation or any other technology and to allow demand-side management

In Order 789, Paragraph 48, the Federal Energy Regulatory Commission (Commission) responded to the California Independent System Operator that:

> **Commission Determination**
>
> 48. The Commission determines that non-traditional resources, including electric storage facilities, may qualify as "Operating Reserve – Spinning" provided those resources satisfy the technical and performance requirements in Requirement R2. Our determination is supported by the standard drafting team's response to a comment during the standard drafting process where the standard drafting team stated that "technologies, such as batteries, both contemplated and not yet contemplated are included in the standard as potential resources – so long as the undefined resource can meet the response characteristics described in the standard …The language does not preclude any specific technology; rather, the language delineates how that technology must [] respond."[2] We also note that non-traditional resources could contribute to contingency reserve under the regional Reliability Standard if they are resources, "other than generation or load, that can provide energy or reduce energy consumption."

to be considered as a resource for contingency reserves on this basis without requiring the use of any particular contingency reserve option."

[2] "Fn 44 Petition, Exhibit C at 20."

F. Associated Documents

None.

Attachment A

Attachment A is illustrative only; it is not a requirement. Requirement R1 calls for an amount of Contingency Reserve to be maintained, predicated on an amount of generation and load required in Requirement R1, Part 1.1., specifically:

> "**1.1** The greater of either:
>
> - The amount of Contingency Reserve equal to the loss of the most severe single contingency;
> - The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation."

Attachment A illustrates one possible way to account for and calculate the amount of generation upon which the Contingency Reserve amount is predicated.

Below is a practical illustration showing how the generation amount may be calculated under Requirement R1 for Balancing Authorities (BA) and Reserve Sharing Groups (RSG).

BA1 / RSG 1	**Generation**	**Part of Generator**
Generator 1	300 MWs online	Yes
Generator 2	200 MWs online	Yes
Generator 3 (Pseudo-Tied out to BA2)	100 MWs online	No
Generator 4 QF (has backup contract)	10 MWs online	No
Generator 5 QF in EMS	10 MWs online	Yes
Generator 6	0 MWs online	Yes

Dynamic Schedule to BA2 from BA1[3]	(50 MWs)	
Generation	620 MWs	(The sum of gen 1-6)
BA generation (EMS)	510 MWs	(The sum of gen 1, 2, and 5)
Generation to use Under BAL-002-WECC-1	460 MWs**	(The sum of gen 1, 2 and 5 minus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would maintain reserves based on 510 MWs Generation.

BA2 / RSG2	**Generation**	**Part of Generator**
Generator 11	100 MWs	Yes
Generator 12	100 MWs	Yes
Generator 3 (Pseudo-Tied in from BA1)	100 MWs	Yes

[3] Note: This Dynamic Schedule is not the same as the Generator 3 Pseudo-Tie.

<u>Dynamic Schedule from BA1 to BA2</u>	<u>50 MWs</u>	<u>Yes</u>

Generation	300 MWs	(The sum of gen 11, 12 and 3.)
BA generation (EMS)	300 MWs	(The sum of gen 11, 12 and 3)
Generation to use Under BAL-002-WECC-1	350 MWs**	(The sum of gen 11, 12 and 3 plus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would have to maintain reserves based on 510MWs Generation and BA2 would determine its generation to be 300 MWs.

Guideline and Technical Basis

A Guidance Document addressing implementation of this standard has been filed with this standard.

Version History

Version	Date	Action	Change Tracking
1	October 29, 2008	Adopted by NERC Board of Trustees	
1	October 21, 2010	Order issued remanding BAL-002-WECC-1	
2	November 7, 2012	Adopted by NERC Board of Trustees	
2	November 21, 2013	FERC Order issued approving BAL-002-WECC-2. (Order becomes effective 1/28/14.)	
2a	December 1, 2015	Approved by WECC Board of Directors	Clarified resources available for use in Requirement R2
2a	November 2, 2016	Approved by NERC Board of Trustees	
2a	January 24, 2017	FERC letter Order approving BAL-002-WECC-2a. Docket No. RD17-3-000	

EXHIBIT 3

ORIGINAL

BALANCING AUTHORITY AREA SERVICES AGREEMENT

BETWEEN

LOS ANGELES DEPARTMENT OF WATER AND POWER

AND

GLENDALE WATER AND POWER

BALANCING AUTHORITY AREA SERVICES AGREEMENT
BETWEEN
LOS ANGELES DEPARTMENT OF WATER AND POWER
AND
GLENDALE WATER AND POWER

This Balancing Authority Area Services Agreement ("Agreement"), dated as of November 18, 2015, is entered into by and between the City of Los Angeles on behalf of its Department of Water and Power ("LADWP") in its capacity as the operator of the LADWP Balancing Authority Area and City of Glendale, on behalf of its Water and Power Department ("GWP"). LADWP and GWP are sometimes referred to herein individually as a "Party" and collectively as the "Parties."

RECITALS

WHEREAS, GWP owns and operates a combination of transmission, generation and distribution components (collectively GWP's "System"), and serves its own retail customers using its System and GWP's transmission rights under its existing transmission contracts ("ETCs");

WHEREAS, GWP's System is currently located within the LADWP Balancing Authority Area;

WHEREAS, LADWP has an OATT under which it provides transmission service through its Balancing Authority Area;

WHEREAS, the Parties are also parties to certain transmission agreements which provide for points of interconnection, points of receipt, points of delivery and provide for coordinated operations between the Parties' Systems;

WHEREAS, pursuant to this Agreement, LADWP as the Balancing Authority will provide certain Balancing Authority Area Services to GWP under the terms and conditions set forth herein, as of the Implementation Date;

WHEREAS, GWP and LADWP hereby agree to enter into this Agreement to set forth the terms and conditions for the provision by LADWP of certain Balancing Authority Area Services to GWP, to establish the rates for such services, and the payment for such services as of the Effective Date;

WHEREAS, the Parties wish to establish in this Agreement measures to coordinate certain operation and maintenance of the Interconnection Facilities (as defined herein) and their respective Systems to effectuate the operation of the Balancing Authority Area and meet their respective obligations under the Applicable Reliability Standards as promulgated and enforced by the Federal Energy Regulatory Commission ("FERC" or the "Commission"), the North American Electric Reliability Corporation ("NERC") and the Western Electricity Coordinating Council ("WECC");

WHEREAS, the Parties will continue to operate the Interconnection Facilities and their respective Systems related to the operation of the Balancing Authority Area in accordance with Good Utility Practice; and

NOW THEREFORE, in consideration of the foregoing and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE I
DEFINITIONS

1.0 **Definitions**. As used in this Agreement, the following terms shall have the meanings stated below. Terms defined in other sections of this Agreement shall have the meanings stated in those sections. Any other initially capitalized term in this Agreement shall have the definition of that term as set forth in the NERC Glossary of Terms Used in Reliability Standards ("NERC Glossary") as may be amended from time to time, unless otherwise defined in this Agreement, and the NERC Glossary is hereby incorporated by reference into this Agreement.

1.1 "**Applicable Reliability Standard**" shall mean with respect to a Party, refers to those Reliability Standards that apply to that Party based upon its registered entity status or as otherwise may be determined by FERC, NERC or WECC, as they may be amended from time to time. Reliability Standards are as set forth in Section 215(a)(3) of the Federal Power Act, 16 U.S.C. §824*o*(a)(3), or any successor legislation imposing mandatory requirements to provide for the reliable operation of the Bulk Power System, as defined in 16 U.S.C. §824*o*(a)(1), and any regulations validly promulgated thereunder. Reliability Standards include national standards and regional reliability standards promulgated by FERC, NERC and WECC

1.2 "**Authorized Representative**" shall mean the representative of a Party designated in accordance with Article IV of this Agreement.

1.3 "**Balancing Authority**" ("BA") As this term is defined in the NERC Glossary of Terms to refer to the LADWP BA, unless another BA is specifically referenced herein.

1.4 "**Balancing Authority Area**" ("BAA") As this term is defined in the NERC Glossary of Terms to refer to the LADWP BAA, unless another BAA is specifically referenced herein.

1.5 "**Balancing Authority Area Services**" shall mean the services provided in Schedules 1 through 6 of this Agreement that are necessary to support GWP's delivery of its capacity and energy.

1.6 "**Commission**" or "**FERC**" shall mean the Federal Energy Regulatory Commission or its successor.

1.7 "**Confidential Information**" shall mean information that is furnished by one Party to the other Party after the date of execution of this Agreement, whether written or recorded/electronic, and regardless of the manner in which furnished, and which is marked "Confidential" or "Official Use Only - Subject to Non-Disclosure Agreement" or with a similar designation indicating limitations on disclosure. Confidential Information is subject to the requirements of Section 8.10 of this Agreement.

1.8 "**Contingency Recovery Period**" shall mean a period beginning at the time that GWP begins taking contingency reserve energy from any source, and extending to the time when GWP's CE returns to zero.

1.9 “**Control Error”** (“CE”) shall have the meaning as set forth in Schedule 4 of this Agreement.

1.10 “**Deviation Bank**” shall mean the continuously accumulating account of inadvertent interchange energy (on-peak and off-peak) between the Parties that is zeroed out at the end of each calendar month, as described in Schedules 4 through 6 of this Agreement.

1.11 “**Effective Date**” shall be the effective date set forth in the Settlement Agreement and Release of Claims between the Parties (DWP Agreement No. BP 15-020).

1.12 ”**Emergency**” shall mean any System condition that requires immediate automatic or manual action to prevent or limit the failure of the transmission facilities or generation supply that could adversely affect the reliability of (a) with respect to the Balancing Authority, the Bulk Electric System and/or the Balancing Authority Area’s electric system, or (b) with respect to GWP, the GWP’s System.

1.13 “**Energy Imbalance**” shall mean the Net Actual Interchange minus the Net Interchange Scheduled over the applicable period, as set forth in Schedule 4.

1.14 “**Energy Imbalance Service**” shall mean the services defined in Schedule 4 of this Agreement.

1.15 ”**FERC**” see “**Commission**”, as defined in Section 1.6.

1.16 “**Good Utility Practice**” shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

1.17 “**Implementation Date**” shall mean the date this Agreement shall first be implemented, which shall be the date commencing at 12:01 AM Pacific Prevailing Time on the first day of the first month after (1) the Effective Date and (2) the conditions set forth in Sections 2.5, 2.6, and 8.16.1 and Appendix F of this Agreement have been fulfilled.

1.18 “**Interconnection Facilities**” shall mean the transmission equipment listed in Appendix C that connects LADWP and GWP, and for purposes of calculating CE, Net Actual Interchange, Net Scheduled Interchange, and Energy Imbalance, and shall include the Western Substation.

1.19 “**LADWP Energy Rate**” shall be defined as the Intercontinental Exchange (ICE) Daily Price Indices at Palo Verde (PV) (On-peak or Off-peak) published in the ICE Day Ahead Power Price Report, or its successor.

1.20 “**LADWP Transmission System**” shall mean the transmission system of Balancing Authority.

1.21 "**NERC**" shall mean the North American Electric Reliability Corporation, the entity designated as the electric reliability organization certified by the Commission to establish and enforce the reliability standards of the Bulk Electric System, or its successor organization.

1.22 "**Net Actual Interchange**" shall mean the algebraic sum of all metered interchange across the Interconnection Facilities for a given period or instant in time.

1.23 "**Net Scheduled Interchange**" shall mean the algebraic sum of all interchange schedules across the Interconnection Facilities for a given period or instant in time.

1.24 "**Net Tie Deviation**" shall have the meaning set forth in Schedule 4 of this Agreement.

1.25 "**OASIS**" shall mean the Open Access Same Time Information System of LADWP.

1.26 "**OATT**" shall mean LADWP's Open Access Transmission Tariff, as it may be amended by LADWP from time to time.

1.27 "**Operating Reserve - Spinning Reserve Service**" shall mean the services defined in Schedule 5 of this Agreement.

1.28 "**Operating Reserve - Supplemental Reserve Service**" shall mean the services defined in Schedule 6 of this Agreement.

1.29 "**Outage**" shall mean a disconnection or separation, whether planned or forced, of one or more elements of an electric system.

1.30 "**Period Deviation**" shall have the meaning set forth in Schedule 4 of this Agreement.

1.31 "**Planned Outage**" shall mean outages that may affect the reliability of the respective Systems of the Parties that are coordinated with notice provided in accordance Section 3.7 of this Agreement.

1.32 "**Point of Interconnection**" shall mean Air Way Receiving Station.

1.33 "**Reactive Supply and Voltage Control from Generation or Other Sources Service**" shall mean the services defined in Schedule 2 of this Agreement.

1.34 "**Regulation and Frequency Response Service**" shall mean the services defined in Schedule 3 of this Agreement.

1.35 "**Scheduling, System Control and Dispatch Service**" shall mean the services defined in Schedule 1 of this Agreement.

1.36 "**Shut-down Energy**" shall have the meaning set forth in Appendix E.

1.37 "**Start-up Energy**" shall have the meaning set forth in Appendix E.

1.38 "**Tie Line Bias**" shall have the meaning set forth in Schedule 4 of this Agreement.

1.39 **"Uncontrollable Forces"** shall mean any act of God, act of the public enemy, terrorism, war, insurrection, riot, fire, storm, flood, earthquake, explosion, any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities or any other event beyond the reasonable control of the Balancing Authority or GWP, and which by exercise of Good Utility Practice, the Party could not avoid. The unavailability of funds or financing, economic or market forces, or the economic hardship of either Party shall not be considered an Uncontrollable Force.

1.40 "**WECC**" shall mean the Western Electricity Coordinating Council, or its successor organization.

ARTICLE II
SCOPE OF SERVICES

2.0 **Scope of Services**. LADWP shall offer to provide GWP the services listed in Schedules 1 through 6 of this Agreement, as requested by GWP. LADWP shall offer to provide full contingency reserve service to GWP, as set forth in Schedules 5 and 6 of this Agreement. GWP shall request the services listed in Schedules 1 through 6 pursuant to this Agreement and the provisions of relevant LADWP Business Practices.

2.1 **Term**. Services under this Agreement shall commence on the Implementation Date, and continue until: (i) this Agreement is terminated in accordance with Article VI, or (ii) the Parties otherwise mutually agree.

2.2 **No Implied Effect on Other Rights or Agreements**:

2.2.1 Except as specifically and explicitly set forth in this Agreement, nothing in this Agreement is intended to modify or otherwise affect any rights or obligations of either Party under any agreement existing as of the Effective Date (the "Existing Agreements"), including but not limited to the City-Glendale Interconnection Agreement, DWP No. 10131 ("Interconnection Agreement"), the City-Glendale Pacific Intertie D-C Transmission Facilities Agreement, DWP No. 10128 ("PDCI Agreement"), and the City-Glendale 1968 Interchange Agreement, DWP No. 10135 ("Interchange Agreement").

2.2.2 For the term of this Agreement, this Agreement shall satisfy GWP's obligations under the Existing Agreements to provide spinning reserves, supplemental reserves (sometimes referred to as "non-spinning reserves") or any other contingency reserves.

2.3 **GWP's Load and Schedules**. LADWP shall offer Balancing Authority Services under this Agreement to support GWP's retail obligations. GWP shall be responsible for timely submission of any necessary schedules and NERC e-Tags in accordance with Applicable Reliability Standards, and in accordance with the requirements set forth in Schedules 1 through 6 of this Agreement.

2.4 **Rates**. If GWP takes service under this Agreement, GWP shall pay the rates for Balancing Authority Area Services provided by LADWP in Schedules 1 through 6 hereto as set forth in the formula and examples in Appendices B, D and H. GWP shall pay for the services provided under this Agreement in accordance with the provisions of Article V. The formulas set forth in Appendices B, D and H shall only be adjusted with the mutual consent of both Parties. The inputs to the formulas are variables that may change from time-to-time, as defined in the Appendices and Schedules to this Agreement.

2.4.1 **One-time Revisions to Rates.** After the Implementation Date of this Agreement, upon the first revision of LADWP's August 14, 2014 OATT, if any of the rates specified in Schedules 1 through 6 of the OATT are reduced, LADWP shall provide a one-time credit as an offset to GWP's next months' bills that reflects the difference in rates for service taken under this Agreement, with interest calculated as set forth in Section 5.3, from the Implementation Date to the effective date of the new rates in Schedules 1 through 6 of the OATT.

2.5. **Development of Protocols, Business Practices or Procedures to Allow GWP to Self-Provide or Purchase Balancing Authority Area Services from Third-Parties.** Prior to the Implementation Date, LADWP shall develop and adopt protocols, business practices or procedures that specify the technical requirements necessary for GWP to purchase from third-parties or self-provide the Balancing Authority Area Services set forth in Schedules 1, 2, 3, 4, 5 and 6 of this Agreement. Such protocols, practices or procedures shall be consistent with industry standards and Good Utility Practice.

2.6 **Exchange of Emergency and Restoration Plans and Procedures**. GWP and LADWP will exchange emergency procedures, system restoration plans, voltage and MVAr plans, and capacity and energy emergency plans prior to the Implementation Date.

ARTICLE III
TECHNICAL REQUIREMENTS

3.0 **Metering**. GWP's interchange shall be measured at the Interconnection Facilities defined in Section 1.18 pursuant to the metering configuration identified in Appendix C. Metering equipment may be owned and maintained by the Parties and/or Burbank Water and Power ("BWP"). The Parties will exchange real-time data from their meters in accordance with LADWP's generally-applicable metering and communications requirements. All metering, communications, and data exchanges required to implement this Agreement shall be automated to the greatest extent reasonably practicable. The standards and specifications for metering and communications equipment as well as any related hardware and software required to implement this Agreement shall meet all Applicable Reliability Standards, and be consistent with industry standards and Good Utility Practice, if reasonably practicable, be compatible with the Parties' existing and planned facilities or software,

3.0.1 **Modifications to Meters**. In the event either Party intends to modify or replace meters at the Interconnection Facilities, that Party shall notify the other in writing not less than thirty (30) days prior to making any such modifications or replacements, except in the case of an Emergency, in which case the Party making the modification or replacement shall provide the other Party as much notice as reasonably practicable. The Parties shall have the right to monitor in-person any meter modifications or replacements or any meter testing conducted by any other Party at the Interconnection Facilities. Unless otherwise agreed to by the Parties, commencing on the Implementation Date, the Parties shall jointly test each of the interchange meters identified in Appendix C in the second and fourth calendar quarter (i.e., Q2 and Q4) of each year after the Implementation Date and each Party shall bear their own costs for such testing. The Parties shall have the right to request periodic meter testing of the other Party's meters upon thirty (30) days prior notice and the requesting Party shall bear the cost of such tests. If any tests show any meter to be inaccurate by more than one percent, or if any meter fails to register, a billing adjustment shall be made correcting all measurements made by such meter to the past meter check or up to three (3) months, whichever is shorter. The adjustment shall be equal to the amount of error as determined for the actual period of such erroneous meter registration.

3.0.2 **Interconnection Substations.** There are two "Interconnection Substations" that are relevant to this Agreement: (1) Air Way Receiving Station ("Air Way" or "Airway") and (2) Western Substation ("Western"). To the extent a Party is responsible for operating one or more of the aforementioned Interconnection Substations, the Party shall be responsible for meeting the metering requirements: as set forth in Sections 3.0, 3.0.1 and 3.0.2 of this Agreement for that Interconnection Substation; and that are consistent with their individual operations and maintenance requirements.

3.1 **Modifications to Either Party's System**. In the event either Party intends to modify its System in a manner which in the exercise of Good Utility Practice would materially impact the obligations of the other Party under this Agreement (*e.g.,* Balancing Authority's BAA obligations), the Party making the modifications shall provide notice, in accordance with Good Utility Practice, of its intended modification(s) as soon as reasonably practicable, but in no event later than sixty (60) days prior to making such modification(s) to its System. Within thirty (30) days of receiving such notice, the Party that is not modifying its System shall determine if the modification requires any amendments to the obligations set forth in this Agreement and shall notify the other Party of its proposed amendments. To the extent the Parties disagree on the proposed amendments the Parties will attempt to resolve the dispute using the dispute resolution provisions in Article VII of this Agreement.

3.2 [RESERVED].

3.3 [RESERVED].

3.4 Reliability Standards.

3.4.1 Each Party agrees to notify the other Party as far in advance as reasonably practicable of any FERC, NERC or WECC audit, investigation or spot-check of compliance with Applicable Reliability Standards pertaining to services under this Agreement. Each Party agrees to timely cooperate with the other Party in the event that a Party is subject to such an audit, investigation or spot-check by timely providing any supporting evidence in its possession that may requested by the other Party to demonstrate compliance to a reviewing authority. During an on-site audit or investigation, each Party shall provide the other Party with such supporting evidence to assist with responses to data requests no later than one (1) business day after it is requested, unless the Parties mutually agree to an alternative deadline.

3.4.2 Each Party shall use Good Utility Practice to cooperate with the other Party, through notifications, the exchange of data, coordination of plans, studies and schedules, and other actions that may be required to comply with Applicable Reliability Standards and related requirements.

3.4.3 It is the intent of the Parties for each Party to be responsible for compliance with Applicable Reliability Standards. If any new, revised or eliminated Reliability Standard changes the obligations of any Party during the term of this Agreement, the Parties shall cooperate using Good Utility Practice to ensure that each Party shall operate under the Applicable Reliability Standards as of the implementation date of such new or revised Reliability Standards.

3.4.4 Upon approval by FERC, the Parties agree to promptly meet to review any new, revised or eliminated Reliability Standard that changes the obligations of any Party during the term of this Agreement and to discuss any necessary modifications to this Agreement, including but not limited to adjustments to the calculation of charges and payment obligations as a result of changes in reserve obligations under this Agreement (e.g., a change in the Spinning Reserve obligations under Schedule 5). Parties may mutually agree that a meeting is not necessary.

3.4.4.1 Nothing in this Agreement shall require either Party to take any action under this Agreement contravening or violating any new or revised Applicable Reliability Standard.

3.4.5 If the BA's Applicable Reliability Standards are modified such that the BA's obligation to provide reserves of any type are modified or eliminated, GWP's obligation under this Agreement to pay for said reserves shall be deemed proportionately modified or eliminated as of the effective date of such modification and LADWP shall credit back or invoice to GWP any payments for said reserves after the modification's effective date.

3.5 **Operation and Maintenance**

3.5.1 Each Party shall, to the fullest extent practicable, cause all its transmission and generating equipment to be designed, constructed, maintained, and operated in accordance with Good Utility Practice.

3.5.2 Each Party shall operate its System in parallel with other Systems with which it shares interconnections and shall maintain and operate its System so as to minimize the likelihood and effect of disturbances or Outages on its System which might impair service to the customers of any other Party. Each Party shall be the sole judge of whether service to its own customers is being or would be impaired by operating conditions on the System of any other Party, and may request such other Party to take, or may itself take, appropriate corrective action.

3.5.3 Except as may be specifically provided for in arrangements between the Parties involved, or as may be arranged by mutual agreement in specific cases by both Parties at the request of a Party, no Party shall be entitled to or obligated to furnish or to receive unscheduled megawatts (MW) or megavars (MVAr) to or from another Party, unless in a System Emergency. During a System Emergency, all Parties shall meet all requirements of Applicable Reliability Standards and any other applicable standard to mitigate any capacity and energy Emergency and return to scheduled MW and MVAr flow between or among the Parties.

3.5.4 Each Party shall, at its own expense or as otherwise provided by separate written agreement between or among the Parties sharing the interconnection, maintain in good operating condition its portion of each interconnection; provided, however, that an interconnection may be removed from service or reduced in capacity in accordance with Section 3.7, and shall be restored to service as soon as practicable following any Outage.

3.6 Emergency Operations

3.6.1 In the event of an Emergency, each Party shall render all available Emergency assistance to the other Party as requested, if the requesting entity has implemented similar Emergency procedures, and if such assistance would not violate safety, equipment, or regulatory or statutory requirements. This Agreement does not address obligations for payment or other compensation that may or may not exist under other agreements that may exist or may be entered into by the Parties in connection with, or as a result of Emergency assistance.

3.6.2 No Party shall perform switching under Emergency conditions at or at Air Way Receiving Station without coordinating with the other Party at such location, unless such Emergency conditions require switching to avoid or mitigate unsafe conditions.

3.6.3 GWP shall immediately comply with Reliability Directives from LADWP in its functional role as the Transmission Operator and Balancing Authority, unless such actions would violate safety, equipment, regulatory or statutory requirements. GWP shall comply as follows:

3.6.3.1 Adjust generation output if conditions in the Balancing Authority Area require such adjustment for reliability purposes. The adjustment will be for the minimum quantity and duration necessary to resolve the reliability condition. Balancing Authority shall take or be taking the same or substantially similar actions when directing GWP to adjust their generation.

3.6.3.2 Take all necessary actions, up to and including, shedding of firm load, to alleviate a reliability issue in the Balancing Authority Area. LADWP shall take or be taking the same or substantially similar action to mitigate a reliability condition.

3.6.3.3 Immediately advise LADWP of the inability to perform the directive due to the above mentioned reasons so that LADWP can implement alternate remedial actions.

3.6.4 LADWP shall not charge GWP for complying with Reliability Directives.

3.6.5 Each Party will implement and maintain an automatic underfrequency load shedding program that meets the requirements of the WECC Off-Nominal Frequency Load Shedding Program.

3.7 Planned Outages and Coordination

3.7.1 The Parties shall plan and coordinate, with at least three (3) business days advance notice whenever possible, all Planned Outages on circuits or equipment and other maintenance activities affecting the reliability of the interconnection or delivery of energy affecting the Parties' electric Systems. Parties shall attempt to minimize the impact to the Parties of said Outages.

3.7.2 The Parties shall plan and coordinate with one another, at least three (3) business days in advance, any Planned Outages of System voltage regulating equipment, including but not limited to automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, and reactors.

3.7.3 The Parties shall plan and coordinate Planned Outages of telemetering and control equipment and associated communication channels between and among the affected areas at least three (3) business days in advance.

3.7.4 The Parties shall plan and coordinate Planned Outages of generation resources at least seven (7) business days in advance whenever possible. When time does not permit such notifications and coordination, or in the event of a Forced Outage of generation resources, the Parties shall notify each other at the earliest possible time.

3.8 Voltage and MVAr Control

3.8.1 Each Party shall operate its generators with the Automatic Voltage Regulator (AVR) in service and on voltage control. GWP will notify Balancing Authority as soon as practical but within 30 minutes whenever a generator is operating with the AVR off.

3.8.2 Each Party shall maintain its System voltage within the range specified by its internal voltage guidelines. Parties will coordinate and exchange operating voltage information to ensure voltage control and MVAr control equipment remains within operating limits.

3.8.3 GWP shall maintain the net total MVAr flow at Airway and Western within +/- 10-MVAr.

3.8.4 The individual voltage schedule shall have priority over MVAr flow limits set forth in Section 3.8.3.

3.8.5 Each Party shall immediately advise the other Party if it is unable to maintain voltage and/or reactive power within the prescribed limits set forth in Sections 3.8.2 and 3.8.3. Parties will assist each other to the maximum extent possible when notified of a voltage problem on the other System.

3.8.6 Each Party will take all necessary action up to and including shedding firm load if the Party cannot maintain its voltage or MVAr exchange within the limits set forth in Sections 3.8.2 and 3.8.3 after receiving all available assistance and it is burdening the other Party's System.

3.9 [RESERVED].

3.10 **Operational Reliability Information.**

3.10.1 The Parties shall provide one another with such information as may be necessary (where confidentiality agreements allow) in order to coordinate their current-day, next-day, and seasonal operations.

3.10.2 Each Party shall provide information as requested by the other Party to conduct operational reliability assessments and coordinate reliable operations.

3.10.3 In accordance with Good Utility Practice, GWP shall timely notify LADWP, within 30 minutes if reasonably practicable, of changes in generation capabilities and characteristics including but not limited to changes in real generation output capabilities.

3.10.4 GWP shall notify Balancing Authority as soon as practical, but within 30 minutes of a status or capability change on any generator, including the status of each power system stabilizer and the expected duration of the change in status or capability.

3.10.5 Each Party shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

3.11 Monitoring System Conditions

3.11.1 If GWP is supplying any reserves to LADWP, GWP shall: (i) inform LADWP of all generating resources available for use by LADWP as the BA; (ii) calculate all available operating reserves, and (iii) Telemeter this capability to LADWP in real time.

3.11.2 The Parties shall exchange real time operating data as required by any Party to meet its reliability obligations under the Applicable Reliability Standards.

3.11.3 To the extent the Parties are unable to meet the requirements of Sections 3.11.1-2, the Parties will work diligently to achieve this ability to exchange the aforementioned data.

3.12 Communication

3.12.1 The Parties' System Operators and load dispatchers shall communicate with each other using the applicable Operating Personnel Communications Protocols and procedures, including three-part communications, as set forth in the Applicable Reliability Standard when Reliability Directives or Operating Instructions are issued.

3.12.2 Reliability Directives from LADWP to GWP shall be clearly stated as a directive and will include what action is being requested, what quantity of change or action is required, and when that action is to be taken.

3.12.3 Following unusual events and Forced Outages the Parties shall exchange operating information.

3.12.4 Before beginning switching at the Point of Interconnection, the Parties shall communicate and agree as to what switching will take place and what the final condition will be.

3.12.5 The Parties shall provide each other, on a timely basis, all information necessary for the Parties to fulfill their obligations set forth in the Schedules.

3.13 Payment for Start-up and Shutdown. Energy transferred from GWP to LADWP during generator Start-up or Shutdown, as described in Appendix E, shall be purchased by LADWP at a price equal to 70 percent of the LADWP Energy Rate. LADWP agrees to purchase the Start-up and Shutdown energy during the Start-up and Shutdown periods for specified units having a Start-up or Shutdown period greater than 15 minutes per provisions of Appendix E.

ARTICLE IV
NOTICES

4.0 All notices under this Agreement shall be provided in accordance with Appendix F.

4.1 **Authorized Representatives**. Each Party shall designate an authorized representative who shall be authorized to act on its behalf with respect to those matters contained herein (each an "Authorized Representative"), which shall be the functions and responsibilities of such Authorized Representatives. Each Party may also designate an alternate who may act for the Authorized Representative. The identity of each Party's Authorized Representative, and alternate if designated, shall be listed in Appendix F. Each Party shall promptly notify the other Party of any subsequent changes in such designations in accordance with this Article IV. The Authorized Representatives shall have no authority to alter, modify, or delete any of the provisions of this Agreement.

4.2 **Modification of Contacts.** Modifications to Appendix F of this Agreement, including the designation of a new Authorized Representative under this Agreement, shall be accomplished by timely written notice to all Parties' then-current Authorized Representatives routed via U.S. Mail. Such notice shall, where applicable, include any changes in mailing address, telephone number, facsimile number, and electronic mail address.

4.3 **Informal Communications**. Informal communications of a routine nature are not required to meet the written notice requirement set forth in Appendix F; provided, however, that the Parties engaging in such informal communications are not authorized to use those informal communications to take formal actions under this Agreement, including but not limited to entering into amendments to the Agreement or its attachments.

ARTICLE V
BILLING

5.1 **Invoice.** Within a reasonable time after the first day of each month after the month that either Party provides service under this Agreement, the Party providing service shall submit an invoice for the prior month to the other Party for service under this Agreement.

5.2 **Payment**. The invoice shall be paid by the Party receiving it on the twentieth (20th) day of the invoicing month or the tenth (10th) day after receipt of the invoice, whichever occurs later ("Payment Due Date"). All payments shall be made in immediately available funds in U.S. dollars payable to the invoicing Party. In the event the Party receiving the invoice fails, for any reason other than a billing dispute described in Section 5.4, to make a payment to the invoicing Party by the Payment Due Date, and such failure of payment is not corrected within thirty (30) calendar days after the invoicing Party notifies the Party receiving the invoice to cure such failure, a default by the Party receiving the invoice shall be deemed to exist.

5.3 **Interest**. Interest on invoices under Section 5.1 of this Agreement unpaid after the Payment Due Date shall be payable with interest calculated daily, at a rate equal to 200 basis points above the per annum Prime Rate reported daily in the Wall Street Journal for the period beginning on the day after the due date and ending on the day of payment; provided that, such interest shall not exceed the amount permitted by law. Interest on delinquent amounts shall be calculated from the due date of the invoice to the date of payment. When payments are made by mail, invoices shall be considered as having been paid on the date postmarked.

5.4 **Billing Disputes.** In order to dispute an invoice in whole or in part, the Party receiving the invoice must provide written notice of the dispute to the invoicing Party. Such written notices shall specify the amount in dispute and state the basis for the dispute. In case any portion of any invoice is in dispute, the entire invoice shall be paid when due, unless the basis for the dispute is a clearly erroneous billing amount in which case the parties will make a good faith effort to promptly correct the error. Any excess amount of invoices which, through inadvertent errors or as a result of a dispute, may have been overpaid shall be returned by the invoicing Party upon determination of the correct amount, with interest calculated in the manner set forth in Section 5.3. Either Party shall only have the right to dispute the accuracy of any invoice or payment for a period of two (2) years from the date on which the invoice was initially delivered. If the invoicing Party's records reveal that a bill was not delivered, then the invoicing Party may deliver to the Party receiving the invoice an invoice within two (2) years from the date on which the invoice would have been delivered under this Agreement. The right to payment is waived with respect to any amounts not invoiced within such two (2) year period.

5.5 **Record-Keeping and Financial Audits.** Each Party, or any third party representative of a Party, shall keep complete and accurate records, and shall maintain such data as may be necessary for the purpose of ascertaining the accuracy of all relevant data, estimates, or statements of charges submitted hereunder for a period of two (2) years from the date the invoice was delivered under this Agreement. Within a two (2) year period from the date on which the invoice was initially delivered, any Party to the applicable transaction may request in writing copies of the records of the other Party for that transaction to the extent reasonably necessary to verify the accuracy of any statement or charge. The Party from which documents or data has been requested shall provide all reasonably requested documents and data within a reasonable time period. Any Party shall have the right at all times, and at its own expense, to audit and to examine any costs or payments resulting from any item set forth in this Agreement. Any Party may designate its own employee representative(s) or its contracted representatives with a certified accounting firm to conduct the audit. Any audits shall occur during normal business hours, and the Party being audited agrees to cooperate in such audit.

ARTICLE VI
DEFAULT AND TERMINATION

6.0 **Termination For Convenience by Party(ies)**. Either Party may seek to terminate this Agreement at any time with at least eighteen (18) months prior written notice to the non-terminating Party. Such written notice shall specify a Termination Date. Upon request, the Parties shall make reasonable efforts to extend the Termination Date for up to an additional eighteen (18) month period, or a longer period with the mutual agreement of the Parties, if necessary to implement the provisions of Section 6.4.

6.1 **Payment Default**. In the event the Party receiving the invoice fails, for any reason other than a billing dispute as described in Section 6.1.1, to make payment to the invoicing Party on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the invoicing Party notifies the Party receiving the invoice to cure such failure, a default by the Party receiving the invoice shall be deemed to exist.

6.1.1 In the event of a billing dispute between the invoicing Party and the Party receiving the invoice, the invoicing Party will continue to provide service under this Agreement as long as the Party receiving the invoice complies with Section 5.4.

6.2 **Termination for Payment Default**. Upon the occurrence of a default in accordance with Section 6.1, the invoicing Party may provide written notice to the Party receiving the invoice of the invoicing Party's intent to terminate this Agreement at least sixty (60) calendar days from the date of such notice. The Party receiving the invoice shall have seven (7) calendar days following the receipt of LADWP's notice of termination to submit a written request to the invoicing Party to commence the dispute resolution procedures of Section 7.0 of this Agreement. If the Party receiving the invoice does not provide such notice within seven (7) calendar days of receipt of the notice of termination, then the invoicing Party may terminate this Agreement to the Party receiving the invoice on the date specified in the notice of termination. If the Party receiving the invoice does submit a timely written request to commence dispute resolution procedures, then Article VII of this Agreement shall apply.

6.3 **Termination for Performance Default**. Either Party (the "Non-Defaulting Party") may terminate this Agreement if the other Party (the "Defaulting Party") materially breaches its obligations hereunder. Such termination shall be effected by written notice to the Defaulting Party that specifies a termination date at least ninety (90) days following receipt of the notice by the receiving Party, unless agreed otherwise by the Parties. The Defaulting Party shall have ninety (90) calendar days following the receipt of the Non-Defaulting Party's notice of termination to cure, or take reasonable steps to cure, its material breach of its obligations, and seven (7) calendar days following the receipt of the notice of termination to submit a written request to commence the dispute resolution procedures of Article VII of this Agreement. If the Defaulting Party does not cure, or take reasonable steps to cure, the material breach of its obligations within ninety (90) calendar days or provide notice within seven (7) calendar days to commence the dispute resolution procedures following its receipt of the notice of receipt of the notice of termination, the Non-Defaulting Party may terminate this Agreement on the date specified in the notice of termination. The remedy of termination shall not be exclusive of any other rights or remedies, at law or in equity, which may be available to the Non-Defaulting Party.

6.4 **Good Faith Efforts Following Notice of Termination**. The Parties will work in good faith, using reasonable efforts to effectuate any necessary subsequent agreements for balancing authority area services. Notwithstanding the foregoing, if there is a dispute over a Party's request to terminate this Agreement that dispute will be resolved pursuant to Article VII of this Agreement.

ARTICLE VII
DISPUTES

7.0 **Dispute Resolution.** If a dispute arises between the Parties under this Agreement the Parties shall meet within ten (10) days after either Party provides notice of the dispute, and the Parties shall endeavor in good faith to resolve it. If the dispute is not resolved, the Parties to such dispute may, but are not required to, submit the dispute to mediation or non-binding arbitration by mutual consent. If the Parties do not agree on resolving a dispute in mediation or non-binding arbitration, or, if the Parties' attempts to mediate or arbitrate the dispute do not resolve it, either Party may bring an action in a court of law or such other appropriate forum.

7.1. **Governing Law and Costs**. This Agreement was made and entered into by LADWP pursuant to the laws of the State of California and the City of Los Angeles. This Agreement shall be governed by, interpreted and enforced in accordance with the laws of the State of California without regard to conflict of law principles. Both Parties hereto agree that in any action to enforce the terms of this Agreement, each Party shall be responsible for its own attorneys' fees and costs.

ARTICLE VIII
MISCELLANEOUS

8.1 **Relationship of Parties**. The obligations and liabilities of the Parties under this Agreement are several and not joint or collective, and nothing herein contained shall be construed to create an association, joint venture, trust, or partnership, or to impose a trust or partnership obligation or liability on or with regard to the other Party. Each Party shall be individually liable for its own obligations and liabilities provided herein. Neither Party shall be under the control of the other Party or be deemed to be under the control of the other Party, and neither Party shall be the agent of or have the right or power to bind the other Party, without such other Party's express written consent.

8.2 **Non-Dedication of Facilities**. An undertaking by either Party to the other Party under this Agreement shall not constitute the dedication of the System, or any portion thereof, of that Party to the public or to the other Party, or affect the status of that Party as an independent System.

8.3 **Captions and Headings**. All captions and headings appearing in this Agreement are inserted to facilitate reference and shall not govern the interpretations of the provisions hereof, except where logically necessary.

8.4 **Entire Agreement**. This Agreement constitutes the entire agreement between the Parties pertaining to the subject matter hereof, and shall fully supersede any and all prior understandings, contemporaneous oral or written negotiations, representations, warranties, and agreements between the Parties, or any of one them, and may be modified only by written agreement signed by both Parties. All attachments and appendices to this Agreement, including Schedules 1 through 6, are incorporated into and made part of this Agreement. If there is a conflict between this Agreement and LADWP's business practices or protocols regarding the obligations set forth in this Agreement, this Agreement shall control.

8.5 **Execution in Counterparts**. This Agreement may be executed in any number of counterparts, each of which shall be an original, but all of which together shall constitute one instrument.

8.6 **Signature Clause**. The signatories hereto represent that they have been appropriately authorized to enter into this Agreement on behalf of the Party for which they sign.

8.7 **No Third-Party Beneficiary.** The provisions of this Agreement are for the benefit of the Parties and not for any other person or third-party beneficiary. The provisions of this Agreement shall not impart rights enforceable by any person, firm or organization other than a Party or a successor a Party to this Agreement.

8.8 **Assignment**. This Agreement may be assigned by either Party only with the prior written consent of the other Party. Any attempted assignment that violates this article is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations pursuant to this Agreement.

8.9 **Modifications.** This Agreement may not be amended or otherwise modified except by written agreement subscribed by all of the Parties to be charged with such modifications.

8.10 **Confidentiality.** Confidential Information shall be held as confidential by the receiving Party. Notwithstanding the foregoing, Confidential Information shall not include information which (i) is disclosed with the prior written consent of the originating Party, (ii) at the time of disclosure is within the public domain through no breach of this Agreement by either Party, (iii) has been known or independently developed by and is currently in the possession of either Party prior to disclosure hereunder, (iv) was or is acquired by either from a third-party who did not to the receiving Party's knowledge breach an obligation of confidentiality by disclosing it to either Party, (v) is disclosed to credit rating agencies or in official statements or other disclosure statements relating to the issuance of bonds, notes, commercial paper or other evidences of indebtedness under customary financial practices, or (vi) is required to be disclosed to comply with any applicable law, order, regulation or ruling or other legal requirement, including but not limited to, oral questions, discovery requests, subpoenas, civil investigations or similar processes. For disclosures made pursuant to subsection (vi) of this paragraph, if the originating Party fails to obtain a protective order or other legal remedy preventing or limiting disclosure, the receiving Party may disclose the Confidential Information without liability to the originating Party.

8.10.1 The Parties recognize and agree that for the purposes of complying with the Reliability Standards and responding to requests from the FERC, NERC or WECC, they will receive information from each other that has been marked as Confidential Information. Except as set forth herein, the Parties agree to keep in confidence and not to copy, disclose, or distribute any Confidential Information or any part thereof, without the prior written permission of the other Party.

8.10.2 Confidential Information that the Parties have given to each other, whether in electronic or hard copy form, which is intended for disclosure to the Compliance Monitor during the course of a compliance audit will be kept in a secure and restricted location.

8.10.3 If a Party is requested or required, pursuant to any applicable law, regulation, order, rule, ruling or other requirement of law, discovery request, subpoena, civil investigation or similar process to disclose any of the Confidential Information, such Party shall provide prompt written notice to the other Party of such request or requirement so that at such other Party's expense, such other Party can seek a protective order or other appropriate remedy concerning such disclosure.

8.10.4 The provisions of this Section 8.10 shall survive the termination of this Agreement for a period of 10 years provided, that the confidentiality obligations imposed by this Agreement as to any Confidential Information of a Party which may be deemed to be information classified as "critical infrastructure information" or "protected critical infrastructure information" or "protected system" shall survive until such Party has advised the other Party in writing that such information may be released.

8.11 **Consistency with State and Federal Laws and Regulations.** Nothing in this Agreement shall compel any Party to violate state and/or federal statutes, regulations or orders lawfully promulgated thereunder. If any provision in this Agreement is inconsistent with any obligation imposed on any Party by statute, regulation or order, it shall be inapplicable to that Party. No Party shall incur any liability by failing to comply with a provision of this Agreement, if the reason for doing so is such provision is inapplicable to that Party by reason of being inconsistent with state or federal statute, regulation or orders lawfully promulgated thereunder; provided, however, such Party shall comply with the provisions of this Agreement to the extent that applicable state or federal laws, regulation and orders promulgated thereunder permit it to do so.

8.12 **LADWP Disclaimer of FERC Jurisdiction.** No provision of this Agreement shall be construed as an acknowledgement or admission on the part of LADWP that: (i) FERC has jurisdiction over any of transactions involving LADWP and GWP that are addressed in this Agreement; (ii) FERC has jurisdiction over the consideration provided under this Agreement; (iii) any of the consideration provided under this Agreement constitutes a refund under the Federal Power Act; or (iv) either Party owes any refund or is subject to any other remedy under the Federal Power Act.

8.13 **Severability.** If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any Party, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise against public interest by any court or government agency of competent jurisdiction, then all other terms, covenants, and conditions of this Agreement and their application shall not be affected thereby, but shall remain in force and effect to the maximum extent permitted by law. The Parties shall comply with their obligations under this Agreement to the maximum extent possible, unless a court or government agency of competent jurisdiction holds that such obligations are separable from all other provisions of this Agreement.

8.14 **Uncontrollable Forces.**

8.14.1 Neither the LADWP nor GWP will be considered in default of any obligation under this Agreement if prevented from fulfilling that obligation due to the occurrence of an Uncontrollable Force; provided, however, that such Party is in compliance with Section 8.14.2.

8.14.2 In the event of the occurrence of an Uncontrollable Force, which prevents LADWP or GWP from performing any of its obligations under this Agreement, the affected entity shall (i) continue to comply with obligations under this Agreement to the extent possible, including responding to the applicable Reliability Directives; (ii) promptly notify the other Party, telephonically and followed up in writing as soon as possible, of the occurrence of such Uncontrollable Force, describe the extent of the impact from the event, and indicate the expected duration the event will cause the affected Party to be unable to perform its obligations; (iii) not be entitled to suspend performance of its obligations under this Agreement in any greater scope or for any longer duration than is required by the Uncontrollable Force, (iv) use its best efforts to mitigate, circumvent or otherwise overcome the effects of such Uncontrollable Force, remedy its inability to perform and resume full performance of its obligations hereunder, (v) keep the other Party apprised of such efforts on a continual basis and; (vi) describe the steps the affected Party will take to recover from the Force Majeure event; (vii) provide written notice of the resumption of its performance of its obligations hereunder.

8.15 **Third-Party Claims and Limitation on Liability.**

8.15.1 **Third-Party Claims**. The Parties will be subject to California Government Code Section 895.4 in resolution of any liabilities arising from third-party claims under this Agreement. Each Party shall only be liable for their proportionate share of damages based on their individual fault as determined by a court of competent jurisdiction.

8.15.2 **Limitation on Liability**. Neither Party shall be liable to the other Party under any provision of this Agreement for any losses, damages, penalties, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, claims of customers, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability.

8.16 **Municipal Tax Exempt Bonds**. Notwithstanding any other provision of this Agreement, LADWP shall not be required to provide GWP service under this Agreement if the provision of such service would result in "private business use" as defined in Section 141(b)(6) of the Internal Revenue Code and the Treasury Regulations promulgated thereunder, as such laws and regulations may be amended, updated, modified or replaced.

8.16.1 GWP has provided, and LADWP acknowledges the receipt of a Governmental Person Use Certificate attached hereto as Appendix A.

8.16.2 **Supplemental Procedures for Resale of Service**. GWP may only sell, lay-off, or otherwise transfer in any manner, any service in accordance with and pursuant to this Agreement, if the total term of such transaction including all renewal options, does not exceed three (3) years, unless in the exclusive determination of LADWP the entity to which such scheduling service is sold, laid-off or otherwise transferred has also satisfied the requirements in the form of the Governmental Person Use Certificate attached hereto as Appendix I. Any resale, assignment or transfer of service by GWP that fails to conform to the provisions of this Agreement, including Section 8.16 and all Appendices, by intent or otherwise, shall be void and unenforceable.

8.17 **Waivers.** No waiver of any provision of this Agreement shall be effective unless such waiver is in writing and signed by the waiving Party and any such waiver shall not be deemed a waiver of any other provision of this Agreement.

8.18 **Electronic Delivery Signatures**. Notwithstanding any other provision of this Agreement, this Agreement may be delivered electronically (e.g., by facsimile or PDF attached to email), in which case the Parties shall promptly exchange hard copies of the signature pages, but the electronically delivered signed copies shall be valid, binding and admissible as if originals in accordance with the California Evidence Code.

8.19 **Authorship/Contra Proferentem.** This Agreement shall not be interpreted against the interest of a Party merely because that Party proposed this Agreement or some provision in it or because that Party relies on a provision of this Agreement to protect itself.

8.20 **Representative Examples.** The representative examples set forth in the Appendices to this Agreement shall constitute specific instances in which the Parties have agreed to operationalize the respective provision in this Agreement; provided, however, that interpretation and operation of such provisions are not intended to be limited to such examples.

AUTHORIZED BY RES. 016 086

For LADWP

DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES BY BOARD OF WATER AND POWER COMMISSIONERS OF THE CITY OF LOS ANELES

By: Michael S. Webster for
MARCIE L. EDWARDS
General Manager

Date: 11-6-15

And: Barbara E. Moschos
BARBARA E. MOSCHOS
Board Secretary

For GWP

CITY OF GLENDALE

By: _______________ 11/19/15
Printed: Scott Ochoa
City Manager

APPROVED AS TO FORM
____
Principal Assistant City Attorney
Date November 18, 2015

APPROVED AS TO FORM AND LEGALITY
MICHAEL N. FEUER, CITY ATTORNEY

OCT 02 2015

BY _______________
SYNDI DRISCOLL
DEPUTY CITY ATTORNEY

SCHEDULE 1
SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into a Balancing Authority Area. This service can be provided only by the operator of the Balancing Authority Area in which the transmission and generation facilities used for ancillary service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Balancing Authority Area operator) or indirectly by the Transmission Provider making arrangements with the Balancing Authority Area operator that performs this service for the Transmission Provider's Transmission System.

The rates and charges for Scheduling, System Control and Dispatch Service are set forth in Appendix B. The Parties agree that Schedule 1 fees shall not apply except as required to supply services under Schedules 5 and 6 of this Agreement.

SCHEDULE 2
REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION OR OTHER SOURCES SERVICE

In order to maintain transmission voltages in the Balancing Authority Area within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the Balancing Authority are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction in the Balancing Authority Area. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to GWP's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Balancing Authority.

The Parties agree to operate their Systems collaboratively based on the operating parameters agreed upon by the Parties to maintain appropriate reactive power at the Interconnection Facilities reflected in Appendix C to this Agreement. Unless mutually agreed to by the Parties, the Balancing Authority shall not charge GWP for Reactive Supply and Voltage Control.

If either Party fails to consistently operate its System in accordance with the parameters set forth in Section 3.8 of this Agreement, the Authorized Representative for the other Party may request a meeting in accordance with Article VII to discuss amending this schedule to address the cost implications arising from such failure.

The rates and charges for Reactive Supply and Voltage Control from Generation or Other Sources Service are set forth in Appendix B. The Parties agree that Schedule 2 fees shall not apply except as required to supply services under Schedules 5 and 6 of this Agreement.

SCHEDULE 3
REGULATION AND FREQUENCY RESPONSE SERVICE

Regulation and Frequency Response ("RFR") Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). RFR Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of Automatic Generating Control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Balancing Authority Area. The Balancing Authority will offer this service to GWP when the load being served by GWP is within its Balancing Authority Area. GWP must either purchase this service from the Balancing Authority or make alternative comparable arrangements to satisfy its RFR Service obligation.

The formula to determine the amount of and charges for RFR Service are set forth below. RFR Service as provided under this Agreement is only applicable to those point(s) of delivery located within the Balancing Authority Area. The rates and charges for RFR Service, applying the formula set forth below, are provided in Appendices B and H.

1. Annual RFR Rate = $\frac{ARR_t \times PR_t}{(NEL_{LADWP} + NEL_{BWP} + NEL_{GWP})_t}$

Where:
Annual RFR Rate = Cost of RFR Service expressed in \$/MWh of load.
ARR = Annual Revenue Requirement for RFR Service
PR = Purchase Requirement stated as the "percent of the Transmission Customer's Reserved Capacity for Point-to-Point Transmission Service" (*e.g.*, 1.1 percent) in Schedule 3 of the LADWP OATT.
NEL_{LADWP} = LADWP Annual Net Energy for Load as filed by LADWP in FERC Form 714
NEL_{BWP} = BWP Annual Net Energy for Load as filed by LADWP in FERC Form 714
NEL_{GWP} = GWP Annual Net Energy for Load as filed by LADWP in FERC Form 714
t = LADWP Cost of Service Study Test Year used in the calculation of the LADWP OATT rates in effect for the year in which service is elected.

2. Billing Demand for Annual Service:

If GWP elects to purchase annual RFR Service from the Balancing Authority, LADWP shall supply and GWP shall purchase a base amount of regulation equal to +/- 8 MW, and the billing determinants for such Service charges shall be based on NEL_{GWP} as defined in Section 1 of this Schedule 3. LADWP shall invoice GWP on a monthly basis for one-twelfth of the annual cost of providing this service to GWP, which is annual RFR Rate times NEL_{GWP}.

If GWP elects not to purchase annual RFR Service from the Balancing Authority, GWP shall not be charged for services under this Schedule and the deviation bands in Schedule 4 will be adjusted to reflect the non-purchase of RFR Service.

3. Illustrative Example Applying Annual RFR Rate and Billing Demand for Annual RFR Service:

For the 8-MW purchased by GWP in the First Deviation Band reflected in Schedule 4, the following charges will result:

ARRt = $547,775,766

PR = 1.1%

NEL_{LADWP} = 27,160,120 MWh.

NEL_{BWP} = 1,185,006 MWh

NEL_{GWP} = 1,182,736 MWh

Annual RFR rate = $0.204/MWh

Annual Cost of RFR Service = 1,185,006 MWh x $0.204/MWh = $241,278

Monthly Cost of RFR Service = $241,278 / 12 = $20,107

4. RFR Service Allowance and Rate for Incremental Deviation Bandwidth:

GWP may elect to purchase additional RFR Service from LADWP on a monthly or annual basis. Such purchase will increase the Deviation Bands, as described in Section C of Schedule 4 for the period of time such RFR Service is purchased.

IRFRy = (Annual Cost of RFR Service /8) x MW

IRFRm = ((Monthly Cost of RFR Service /8) x MW

Where:

IRFRy = The rate per MWh for incremental MW of bandwidth for a year.

IRFRm = The rate per MWh for incremental MW of bandwidth for a month.

MW = The number of additional MW requested and provided for a year or month.

5. Illustrative Example Applying Rate for Incremental Deviation Bandwidth:

A. GWP requests 5 MW of additional deviation bandwidth for one year:

IRFRy = $241,278 / 8 = $30,159.75 x 5 MW = $150,798.75

B. GWP requests 5 MW of additional deviation bandwidth for one month:

IRFRm = $20,107 / 8 = $2,513.38 x 5 MW = $12,566.88

SCHEDULE 4
ENERGY IMBALANCE SERVICE AND PERIOD DEVIATION CHARGES

Energy Imbalance Service is provided when the Energy Imbalance does not equal zero. The Balancing Authority will offer this service to GWP. GWP may either purchase this service from the Balancing Authority or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. Imbalance energy from the Deviation Bank shall be returned in-kind at the points of delivery set forth in Appendix C to this Agreement.

A. Calculation of Control Error and In-kind Return of Energy Imbalances

1. **Control Error** shall mean a value in instantaneous MW calculated by utilizing either Tie Line Bias or Net Tie Deviation and calculated as follows:

   a. **Tie Line Bias ("TLB"):** When operating in this mode, the CE shall be equal to:

      Net Actual Interchange minus Net Scheduled Interchange
      minus 10(Frequency Bias_{GWP})(Frequency Deviation)

      Where:

      Frequency Bias_{GWP} = a value usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with GWP's metered subsystem that approximates GWP's metered subsystem's response to the Western Interconnection frequency error.

      If GWP elects to use TLB, Parties will agree on the proper Frequency Bias value to be used based on analysis of the WECC designated events and said value may change.

   b. **Net Tie Deviation ("NTD"):** When operating in this mode, the CE shall be equal to:

      Net Actual Interchange minus Net Scheduled Interchange

   c. **Notice:** GWP shall deliver notice to the Balancing Authority of it election to use Tie Line Bias or Net Tie Deviation at least 30 days prior to the month that such designation begins.

   d. **Period Deviation ("PD")** is the calculated average deviation for each performance period. There will be four clock 15-minute performance periods in each hour (minutes 1-15, 16-30, 31-45 and 46-60). PD is calculated by (i) sampling CE every one minute (with sampling from the top of each minute using the first valid data point within 10 seconds after the top of such minute), and (ii) taking the average of the algebraic sum of sample MW values to determine PD. The PD value will be the average of the available, valid data points and will be truncated to an integer value with no carryover to the next period.

2. **Deviation Bands** – PD performance will fall into three bands. **First Deviation Band** will be based on the Schedule 3 Regulation Service purchased, nominally zero to +/- 8 MW. **Second Deviation Band** will start above the upper limit of the First Deviation Band and extend 8 MW in the plus and minus direction, nominally +/- 9 to 16 MW. **Third Deviation Band** starts above the upper limit of Second Deviation Band and has no cap, nominally +/- 17 MW with no limit. The First, Second and Third Deviation Band magnitudes may be modified pursuant to Section C of this Schedule.

3. **Returning energy in-kind (on or off-peak as appropriate).** Energy Imbalance is calculated hourly in MWh and added to the applicable on-peak or off-peak Deviation Bank. All Energy Imbalance shall be added to the appropriate Deviation Bank, separate and apart from the Deviation Band calculated for the 15-minute period. At the conclusion of each calendar month, these Deviation Bank values are agreed upon and the running balances set to zero. The verified end of month values will be scheduled for return in either on-peak or off-peak periods between the Parties at a mutually agreeable time and rate (MW/hr). To the extent possible, the return will be scheduled by taking the verified amounts and dividing by the number of on-peak and off-peak (respectively) hours in the return period. The whole number value is scheduled for each hour, and the fractional portion is scheduled by scheduling one extra MW for a proportional number of the hours evenly spaced, unless otherwise mutually agreed by the Parties' schedulers.

4. Within each month, GWP will attempt to reduce to zero the balance in the applicable on-peak and off-peak Deviation Banks.

B. Period Deviation Charges

1. Charges are calculated for either positive or negative deviations in each 15 minute averaging period as set forth in Section B of this Schedule. The charge for each 15 minute period stands alone and does not vary regardless of the end-of-hour net MWh deviation. Certain 15 minute periods shall be exempted from charges as specified in Section D of this Schedule.

2. **The First Deviation Band:** If the value of PD falls within First Deviation Band, there is no monetary charge for that period.

3. **The Second Deviation Band:** If the value of PD falls within the Second Deviation Band, GWP will pay 10% of the LADWP Energy Rate times the number of MW outside the First Deviation Band.

4. **The Third Deviation Band:** If the value of PD falls within the Third Deviation Band, in addition to paying the charges under the Second Deviation Band, GWP will pay 25% of the LADWP Energy Rate for each MW falling within the Third Band.

C. GWP Option to Purchase Incremental First Deviation Band

1. GWP may in its sole discretion, request to expand its First Deviation Band beyond +/- 8 MW by purchasing additional RFR Service as described in

Schedule 3. If GWP makes such a purchase, each Deviation Band limit will then be recalculated as described in Section C.3 of this Schedule 4. Such purchase(s) shall not be reduced by either Party for the term of such purchase, unless mutually agreed otherwise.

2. In accordance with the notification provisions in Appendix F, the request to purchase such incremental MW of bandwidth shall be for a defined term, with a minimum of one (1) month duration and up to twelve (12) months duration, with notice of such request to be delivered no later than three (3) business days prior to the beginning of such period. Upon receipt of such request, Balancing Authority shall provide such incremental MW of bandwidth in monthly increments for a defined term, if available. Balancing Authority shall not unreasonably deny a request, withhold a response or condition the purchase.

3. If GWP purchases additional RFR Service as described in Schedule 3, the limits of the First Deviation Band will be expanded in the plus and minus directions 1-MW for each additional MW of RFR Service purchased. In such case, the upper and lower limits of the Second Deviation Band and lower limit of the Third Deviation Band will be expanded by 1 MW for each additional MW of RFR Service purchased. Such purchase(s) of additional bandwidth shall not be rescinded, reduced or recalled by either Party for the term of such purchase, unless mutually agreed otherwise.

4. If GWP elects not to purchase annual RFR Service from the Balancing Authority, GWP shall not be charged for services under this Schedule and there will be no First Deviation Band. The Second Deviation Band will be zero to +/- 8 MW. The Third Deviation Band will start above the upper limit of the Second Deviation Band and has no cap, nominally +/- 9 MW with no limit.

D. Deviations from Schedule That Are Excluded from Period Deviation Charges

The conditions, events or periods set forth below in subsections 1-9 shall be excluded from charges for deviations under this Schedule. When any of the events listed below in subsections 1-6 and 8-9 occur, GWP will, to the extent possible, provide documentation to LADWP Manager of Grid Operations of the event that initiates the exclusion period, within 7 business days of the event's occurrence.

1. **Reserve Recovery period:** The "Excluded 15-Minute Periods" begin with the 15-minute period during which the event occurs and reserves are activated and extending through and including the 15-minute period when GWP CE crosses zero. The Period Deviation Charges in this Schedule would resume during the first 15-minute period following the zero CE crossing.

2. **Directed Emergency Action (Reliability Directives):** The "Excluded 15-Minute Periods" begin with the period during which the directed Emergency action is initiated and extending through and including the period when the directed Emergency action is terminated. The Period Deviation Charges in this Schedule shall resume during the first 15-minute period following the termination of directed Emergency action.

3. **LADWP error causing GWP to operate off schedule:** The "Excluded 15-Minute Periods" include any 15-Minute period(s) in which GWP operated off schedule due to an error on the part of LADWP.

4. **GWP Loss of Load:** The "Excluded 15-Minute Periods" begins with the15-Minute period in which a loss of load greater than 8 MW occurs and extending through and including one additional 15-minute period.

5. **GWP Emergency Action:** The "Excluded 15-Minute Periods" are the periods containing an Emergency action plus one additional 15-minute period.

6. **Uncontrollable Force:** The "Excluded 15-Minute Periods" include the 15-minute period in which an event caused by an Uncontrollable Force occurs and extending through and including the 15-minute period when the GWP CE crosses zero. The Period Deviation Charges in this Schedule shall resume during the first 15-minute period following the zero CE crossing.

7. **Invalid or Missing Data:** The "Excluded 15-Minute Periods" are any 15-minute period(s) where 25% or more of the data samples are missing or contain invalid data.

8. **Frequency Response:** To the extent that excessive deviation is a result of GWP frequency response, applicable Second and Third Deviation Band charges or credits shall be waived for the period of the frequency excursion. The excluded deviation charges or credits will be calculated at 5 MW per 0.1 Hz, provided that the initial frequency disturbance is greater than +/- 0.06 Hz. If GWP chooses TLB, this Section 8 shall not apply, but this Section 8 will apply if GWP elects NTD.

9. **Generator Start-Ups and Shut-Downs:** For generators with a start-up or shut-down period of 15 minutes or less that have been identified by GWP, "Excluded 15-Minute Periods" shall begin with the 15-minute period in which the start-up or shut-down action occurs and extend through and including a maximum of one (1) additional 15-Minute Period; provided that GWP has given prior notice to LADWP or if started or shut down in an Emergency GWP has given notice as soon as possible. Units with start-up time or shut-down times greater than 15 minutes will be handled under Appendix E.

    a. If the unit start-up is initiated by a call for reserves under this Agreement, "Excluded 15-Minute Periods" shall begin with the 15-minute period in which the start-up or shut-down action occurs and extend through and including a maximum of three (3) additional 15-Minute Periods.

E. Nothing in this Schedule relieves GWP from responding to Reliability Directives from LADWP in its role as BA or Transmission Operator if an event(s) on the GWP System is burdening LADWP or the interconnection.

SCHEDULE 5
OPERATING RESERVE - SPINNING RESERVE SERVICE

1. Spinning Reserve service may be provided by generators that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service.

2. The BA shall be responsible for determining and providing information in real-time to GWP regarding the BAA's Most Severe Single Contingency, as defined in the WECC Reliability Criteria ("MSSC").

3. The BA assumes full obligation for BAA Spinning Reserves, which include Spinning Reserves owned, contracted for, or procured by the Balancing Authority and any Spinning Reserves made available to the BAA by GWP under this or similar agreements.

4. GWP will receive the full Spinning Reserve portion of the full contingency reserve service described in Section 2.0 of this Agreement if GWP purchases this service from the BA on an annual basis.

    a. The price GWP will pay for full Spinning Reserves service shall be calculated based on 40 MW as is reflected in Appendix D of this Agreement.

        1. Pursuant to Section 3.4.4 of this Agreement, the Parties agree to promptly meet to review any new, revised or eliminated Applicable Reliability Standard that changes the obligations of any Party during the term of this Agreement, including but not limited to adjustments to the calculation of charges and payment obligations as a result of the changes in reserve obligations under this Agreement (*e.g.,* a change in the Spinning Reserve obligations under this Schedule 5).

        2. If the BA's Applicable Reliability Standards are modified such that the BA's obligation to provide reserves of any type are modified or eliminated, GWP's obligation under this Agreement to pay for said reserves shall be deemed proportionately modified or eliminated as of the effective date of such modification and LADWP shall credit back or invoice to GWP any payments for said reserves after the modification's effective date.

    b. To reduce all or a portion of its payment for full Spinning Reserves, GWP may, at its option, self-supply and/or purchase from a third-party Spinning Reserves. Such Spinning Reserves may be comprised of any combination of reserves owned, contracted for, or purchased from a third-party and must be available to the BA in advance of the operating period for which the reserves are to be provided. Reserves purchased from a third-party must be deliverable using GWP's or a third-party's firm transmission rights, and e-Tagged with "LASYSTEM" as the point of delivery (POD) and sink.

    c. If GWP schedules more than 86 MW (at Nevada Oregon Border ("NOB")) on the PDCI sinking in the BAA, GWP shall self-supply or purchase additional Spinning Reserves from a third-party to support the schedules greater than 86 MW. For such schedules, GWP must notify LADWP no less than one hour prior to scheduling more than 86 MW on the Pacific HVDC Intertie.

d. No later than six months prior to each calendar year, the Parties will agree on the amount of Spinning Reserves that GWP will self-provide or purchase from third-parties as described below. Upon mutual written agreement, this six month notice period may be reduced.

e. No later than six months prior to each calendar year ("Planning Horizon"), the Balancing Authority may request that GWP provide Spinning Reserves during the calendar year. GWP, at its sole discretion, may provide the requested reserves, in which case LADWP's charges for these reserves will be proportionately reduced.

5. LADWP will be responsible for fully responding to all BAA contingencies utilizing any Spinning and Supplemental Reserves available to LADWP as the BAA operator. LADWP shall be authorized to call on any Spinning Reserves made available by GWP and such reserves must respond within 10 minutes of the request for activation from LADWP.

6. If Spinning Reserves made available by GWP fail to respond within 10 minutes of the time the reserves are requested by LADWP, GWP will pay to LADWP a fee equal to 3 x [Monthly OATT Rate] x [MW Short] per reserve activation. This charge will not apply if GWP is in a Contingency Recovery Period, however other Emergency provisions may apply as set forth in Section 12 of this Schedule 5.

7. GWP may sell Spinning Reserve service outside of the BAA subject to the following conditions:

a. If GWP makes such sales of Spinning Reserves it shall provide said Spinning Reserves from its resources or resources that it contracts for that are separate and distinct from the purchase of reserves from LADWP under this Agreement. Notwithstanding the foregoing, upon mutual agreement of the Parties, GWP may purchase and resell additional Spinning Reserves from LADWP over and above the reserves provided for under this Agreement.

b. Any GWP sale, transfer or conveyance of Spinning Reserves purchased from LADWP shall be subject to the terms and conditions of Section 8.16 of this Agreement.

c. GWP must provide firm transmission needed to support the Spinning Reserve sale.

d. LADWP must be advised of the details of a Spinning Reserve sale under this Section, no less than one hour prior to scheduling the Spinning Reserve sale.

e. GWP must ensure an appropriate capacity e-Tag is generated.

f. If GWP fails to have the Spinning Reserves available during the period of the Spinning Reserve sale, it will pay LADWP for each MW of shortage 3 x [Monthly

OATT Rate] x [MW Short] per calendar day until such Spinning Reserves are restored.

g. If the Spinning Reserves supporting the sale fail to respond when called upon, GWP will pay a capacity charge to LADWP of 3 x [Monthly OATT Rate] x [MW Short] for each occurrence plus an energy charge of 1.5 x [LADWP Energy Rate] x MWh for the energy delivered by LADWP on GWP's behalf from the time of the event until reserve energy service is terminated or for 60 minutes whichever occurs first. If the reserve energy draw continues past 60 minutes, they will pay to LADWP 3 x [LADWP Energy Rate] x MWh for the energy provided from 60 minutes after the time of the event until the reserve energy service is terminated

8. GWP may draw energy from the BAA following a contingency event causing a resource reduction for GWP up to 60 minutes from the time of the event.

9. GWP must be able to deliver energy associated with the Spinning Reserves it makes available to the BAA for a minimum of 60 minutes following receipt of notice of a contingency event.

10. Energy delivered in conjunction with Spinning Reserve capacity activation following a contingency event will (1) be added to the Deviation Bank and will be returned in kind (same provisions as other deviation return), and (2) will be paid for as follows :

a. If energy flows to GWP from LADWP, GWP will pay an additional charge to LADWP of 1.5 x [LADWP Energy Rate] x MWh for the energy received from the time of the event until either GWP's CE returns to zero or for 60 minutes whichever occurs first. If GWP fails to return CE to zero within 60 minutes, it will pay an additional charge to LADWP of 3 x [LADWP Energy Rate] x MWh for the energy received from 60 minutes after the time of the event until GWP's CE returns to zero. The energy subject to this charge will be calculated in MW/minutes converted to MWh by LADWP summing the one minute CE reads (with sampling from the top of each minute using the first valid data point within 10 seconds after the top of such minute) times the MW deviation at each minute divided by 60.

b. If energy flows from GWP to LADWP, GWP will receive an additional payment from LADWP of 1.5 x [LADWP Energy Rate] x MWh for the energy delivered from the time of the reserve activation until the request for energy associated with the reserves is terminated. The energy subject to this charge will be calculated in MW/minutes converted to MWh by LADWP summing the one minute CE reads (with sampling from the top of each minute using the first valid data point within 10 seconds after the top of such minute) times the MW deviation at each minute (not to exceed the amount of reserves requested) divided by 60. Any energy delivered to LADWP beyond the conclusion of the Spinning Reserve activation period will be excluded from any Schedule 4 Period Deviation Charges unless LADWP expressly terminates the Spinning Reserve activation but GWP continues to supply the energy. If LADWP does not expressly terminate the reserve activation and GWP continues to supply energy after the 60 minute period, LADWP shall pay GWP 3 x [LADWP Energy Rate] x

MWh for the energy received from 60 minutes after the time of the event until their CE returns to zero.

c. Following 10-minutes notice to terminate energy associated with Spinning Reserves to ramp to return CE to zero, LADWP shall cease payment for energy associated with Spinning Reserves.

11. GWP will annually provide a list of its current individual generator and transmission single largest contingencies (SLC) to the BA. At least six months prior to GWP acquiring a new generation or transmission resource that could be an individual SLC of GWP, or increase the BA MSSC, the Parties will meet and confer.

12. Emergency Conditions

a. If GWP is unable to provide the Spinning Reserves it has committed to the BAA in real time and GWP is not in a Contingency Recovery Period but the BAA has sufficient Spinning Reserves, GWP will pay to LADWP 3x [Daily OATT Rate] x [MW Short] per calendar day until such Spinning Reserves are restored.

b. If GWP is unable to provide the Spinning Reserves it has committed to the BAA in real time and GWP is not in a Contingency Recovery Period and the BAA has insufficient reserves the Parties will implement their Emergency plans. In the event that such Emergency plans require load shedding, GWP will shed load up to the quantity of GWP's real time deficiency. LADWP will shed any additional load required to meet the Applicable Reliability Standards for BAA reserves. Any load shed by any Party will only be for the quantity and duration necessary.

c. If the BAA is deficient in Spinning Reserves, and GWP is providing its committed Spinning Reserves, LADWP will shed load for the quantity and duration necessary to meet the Applicable Reliability Standards for BAA reserves.

d. Should any Party be energy deficient, the Emergency assistance provisions documented elsewhere will apply. The deficient Party may need to request an Energy Emergency Alert declaration from the Reliability Coordinator and shed load in order to maintain load/resource balance.

13. Other Conditions

a. If the BA (1) determines that the BAA is deficient of Spinning Reserves in a reserve recovery period or projects the BAA will be deficient of Spinning Reserves, and (2) the BA is unable to acquire additional Spinning Reserves or determines it would be beneficial to have GWP supply additional reserves, GWP may, at GWP's sole discretion, and upon the BA's request, either:

i. Make an energy sale to LADWP if such energy is available. This generation will be used to back down LADWP generation resources thereby increasing the BAA Spinning Reserves. LADWP will pay GWP 1.1 x [the GWP costs] for each MWh LADWP purchases, or

ii. Provide Spinning Reserves to the BA from resources available to the GWP System as GWP determines such reserves to be available. The BA will request that such Spinning Reserves be made available to the BAA on an hourly, daily, weekly or monthly basis and LADWP shall pay the applicable Hourly, Daily, Weekly, or Monthly LADWP OATT Rate in Schedule 5 x MW provided by GWP .

iii. GWP shall not unreasonably deny a request by the BA to purchase Spinning Reserve service under Section 13, provided however, that GWP has no obligation to sell reserves if to do so would (1) inhibit GWP's ability to meet its own Spinning Reserve commitments, or (2) subject GWP to any charges set forth in this Schedule.

SCHEDULE 6
OPERATING RESERVE - SUPPLEMENTAL RESERVE SERVICE

1. Supplemental Reserve Service is needed to serve load in the event of a System contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service.

2. The BA shall be responsible for determining and providing information in real-time to GWP regarding the BAA's MSSC.

3. The BA assumes full obligation for BAA Supplemental Reserves, which include Supplemental Reserves owned, contracted for, or procured by the Balancing Authority and any Supplemental Reserves made available to the BAA by GWP under this or similar agreements.

4. GWP will receive the full Supplemental Reserve portion of the full contingency reserve service described in Section 2.0 of this Agreement if GWP purchases this service from the BA on an annual basis.

    a. The price GWP will pay for full Supplemental Reserves service shall be calculated based on 40 MW as is reflected in Appendix D of this Agreement.

        1. Pursuant to Section 3.4.4 of this Agreement, the Parties agree to promptly meet to review any new, revised or eliminated Applicable Reliability Standard that changes the obligations of any Party during the term of this Agreement, including but not limited to adjustments to the calculation of charges and payment obligations as a result of the changes in reserve obligations under this Agreement (*e.g.,* a change in the Supplemental Reserve obligations under this Schedule 6).

        2. If the BA's Applicable Reliability Standards are modified such that the BA's obligation to provide reserves of any type are modified or eliminated, GWP's obligation under this Agreement to pay for said reserves shall be deemed proportionately modified or eliminated as of the effective date of such modification and LADWP shall credit back or invoice to GWP any payments for said reserves after the modification's effective date.

    b. To reduce all or a portion of its payment for full Supplemental Reserves, GWP may, at its option, self-supply and/or purchase from a third-party Supplemental Reserves. Such Supplemental Reserves may be comprised of any combination of reserves owned, contracted for, or purchased from a third-party and must be available to the BA in advance of the operating period for which the reserves are to be provided. Reserves purchased from a third-party must be deliverable using GWP's or the third-party's firm transmission rights, and e-Tagged with LASYSTEM as the point of delivery (POD) and sink.

c. If GWP schedules more than 86 MW (at Nevada Oregon Border ("NOB")) on the PDCI sinking in the BAA, GWP shall self-supply or purchase additional Supplemental Reserves from a third-party to support the greater than 86 MW. For such schedules, GWP must notify LADWP no less than one hour prior to scheduling more than 86 MW on the Pacific HVDC Intertie.

d. No later than six months prior to each calendar year, the Parties will agree on the amount of Supplemental Reserves that GWP will self-provide or purchase from third-parties as described below. Upon mutual written agreement, this six month notice period may be reduced.

e. No later than six months prior to each calendar year ("Planning Horizon"), the Balancing Authority may request that GWP provide Supplemental Reserves during the calendar year. GWP , at its sole discretion, may provide the requested reserves, in which case LADWP's charges for these reserves will be proportionately reduced.

5. LADWP will be responsible for fully responding to all BAA contingencies utilizing any Spinning and Supplemental Reserves available to LADWP as the BAA operator. LADWP shall be authorized to call on any Supplemental Reserves made available by GWP and such reserves must respond within 10 minutes of the request for activation from LADWP.

6. If Supplemental Reserves made available by GWP fail to respond within 10 minutes of the time the reserves are requested by LADWP, GWP will pay to LADWP a fee equal to 3 x [Monthly OATT Rate] x [MW Short] per reserve activation. This charge will not apply if GWP is in a Contingency Recovery Period, however other Emergency provisions may apply as set forth in Section 12.b of this Schedule 6.

7. GWP may sell Supplemental Reserve service outside of the BAA subject to the following conditions:

a. If GWP sells Supplemental Reserves it shall provide said Supplemental Reserves from its resources or resources that it contracts for that are separate and distinct from the purchase of reserves from LADWP under this Agreement. Notwithstanding the foregoing, upon mutual agreement of the Parties, GWP may purchase and resell additional Supplemental Reserves from LADWP over and above the reserves provided for under this Agreement.

b. Any GWP sale, transfer or conveyance of Supplemental Reserves purchased from LADWP shall be subject to the terms and conditions of Section 8.16 of this Agreement.

c. GWP must provide firm transmission needed to support the Supplemental Reserve sale.

d. LADWP must be advised of the details of a Supplemental Reserve sale under this Section, no less than one hour prior to scheduling the Supplemental Reserve sale.

e. GWP must ensure an appropriate capacity e-Tag is generated.

f. If GWP fails to have the Supplemental Reserves available during the period of the Supplemental Reserve sale, it will pay LADWP for each MW of shortage 3 x [Monthly OATT Rate] x [MW Short] per calendar day until such Supplemental Reserves are restored.

g. If the Supplemental Reserves supporting the sale fail to respond when called upon, GWP will pay a capacity charge to LADWP of 3 x [Monthly OATT Rate] x [MW Short] for each occurrence plus an energy charge of 1.5 x [LADWP Energy Rate] x MWh for the energy delivered by LADWP on GWP's behalf from the time of the event until reserve energy service is terminated or for 60 minutes whichever occurs first. If the reserve energy draw continues past 60 minutes, they will pay to LADWP 3 x [LADWP Energy Rate] x MWh for the energy provided from 60 minutes after the time of the event until the reserve energy service is terminated.

8. GWP may draw energy from the BAA following a contingency event causing a resource reduction for GWP up to 60 minutes from the time of the event.

9. GWP must be able to deliver energy associated with the Supplemental Reserves it makes available to the BAA for a minimum of 60 minutes following receipt of notice of a contingency event.

10. Energy delivered in conjunction with Supplemental Reserve capacity activation following a contingency event will (1) be added to the Deviation Bank and will be returned in kind (same provisions as other deviation return), and (2) will be paid for as follows :

a. If energy flows to GWP from LADWP, GWP will pay an additional charge to LADWP of 1.5 x [LADWP Energy Rate] x MWh for the energy received from the time of the event until either GWP's CE returns to zero or for 60 minutes whichever occurs first. If GWP fails to return CE to zero within 60 minutes, it will pay an additional charge to LADWP of 3 x [LADWP Energy Rate] x MWh for the energy received from 60 minutes after the time of the event until GWP's CE returns to zero. The energy subject to this charge will be calculated in MW/minutes converted to MWh by LADWP summing the one minute CE reads (with sampling from the top of each minute using the first valid data point within 10 seconds after the top of such minute) times the MW deviation at each minute divided by 60.

b. If energy flows from GWP to LADWP, GWP will receive an additional payment from LADWP of 1.5 x [LADWP Energy Rate] x MWh for the energy delivered from the time of the reserve activation until the request for energy associated with the reserves is terminated. The energy subject to this charge will be calculated in MW/minutes converted to MWh by LADWP summing the one minute CE reads (with sampling from the top of each minute using the first valid data point within 10 seconds after the top of such minute) times the MW deviation at each minute (not to exceed the amount of reserves requested) divided by 60. Any energy delivered to LADWP beyond the conclusion of the Supplemental Reserve activation period will be excluded from any Schedule 4

Period Deviation Charges unless LADWP expressly terminates the Supplemental Reserve activation but GWP continues to supply the energy. If LADWP does not expressly terminate the reserve activation and GWP continues to supply energy after the 60 minute period, LADWP shall pay GWP 3 x [LADWP Energy Rate] x MWh for the energy received from 60 minutes after the time of the event until their CE returns to zero.

c. Following 10-minutes notice to terminate energy associated with Supplemental Reserves to ramp to return CE to zero, LADWP shall cease payment for energy associated with Supplemental Reserves.

11. GWP will annually provide a list of its current individual generator and transmission single largest contingencies (SLC) to the BA. At least six months prior to GWP acquiring a new generation or transmission resource that could be an individual SLC of GWP, or increase the BA MSSC, the Parties will meet and confer.

12. Emergency Conditions

a. If GWP is unable to provide the Supplemental Reserves it has committed to the BAA in real time and GWP is not in a Contingency Recovery Period but the BAA has sufficient Supplemental Reserves, GWP will pay to LADWP 3x [Daily OATT Rate] x [MW Short] per calendar day until such Supplemental Reserves are restored.

b. If GWP is unable to provide the Supplemental Reserves it has committed to the BAA in real time and GWP is not in a Contingency Recovery Period and the BAA has insufficient reserves the Parties will implement their Emergency plans. In accordance with its Emergency plan, GWP shall request from the Reliability Coordinator an Energy Emergency Alert, in accordance with Applicable Reliability Standards, and designate an amount of load to be shed equal to its real-time deficiency. LADWP will designate sufficient additional load required to meet the Applicable Reliability Standards for BAA reserves. Any load designated by any Party will only be for the quantity and duration necessary.

c. If the BAA is deficient in Supplemental Reserves, and GWP is providing its committed Supplemental Reserves, LADWP will follow its Emergency plan and designate load for the quantity and duration necessary to meet the Applicable Reliability Standards for BAA reserves.

d. Should any Party be energy deficient, the Emergency assistance provisions in Section 3.6.1 of this Agreement shall apply. The deficient Party may need to request an Energy Emergency Alert declaration from the Reliability Coordinator and shed load in order to maintain load/resource balance.

13. Other Conditions

a. If the BA (1) determines that the BAA is deficient of Supplemental Reserves in a reserve recovery period or projects the BA will be deficient of Supplemental Reserves, and (2) the BA is unable to acquire additional Supplemental Reserves or determines it would be beneficial to have GWP supply additional reserves, GWP may, at GWP's sole discretion, and upon the BA's request, either:

i. Make an energy sale to LADWP if such energy is available. This generation will be used to back down LADWP generation resources thereby increasing the BAA Supplemental Reserves. LADWP will pay GWP 1.1 x [the GWP costs] for each MWh LADWP purchases, or

ii. Provide Supplemental Reserves to the BAA from resources available to the GWP System as GWP determines such reserves to be available. The BA will request that such Supplemental Reserves be made available to the BAA on an hourly, daily, weekly or monthly basis and LADWP shall pay the applicable Hourly, Daily, Weekly, or Monthly LADWP OATT Rate in Schedule 5 x MW provided by GWP .

iii. GWP shall not unreasonably deny a request by the BA to purchase Supplemental Reserve service under Section 13, provided however, that GWP has no obligation to sell reserves if to do so would (1) inhibit GWP's ability to meet its own Supplemental Reserve commitments, or (2) subject GWP to any charges set forth in this Schedule.

TABLE OF APPENDICES

APPENDIX A

GOVERNMENTAL PERSON USE CERTIFICATE (BAASA)

In connection with the execution of the Balancing Authority Area Services Agreement ("Agreement"), dated as of November 18, 2015, by and between the City of Los Angeles on behalf of its Department of Water and Power ("LADWP") in its capacity as the operator of the LADWP Balancing Authority Area ("Balancing Authority") and City of Glendale, on behalf of its Water and Power Department ("Certifying Entity")., DWP No. BP 15-26 (Agreement), relating to balancing area services as described therein, Certifying Entity certifies, represents and agrees as follows:

(a) Officer Signing. I am the duly appointed General Manager of Glendale Water and Power, a department of the Certifying Entity, authorized to sign this Certificate.

(b) Tax-Exempt Bonds. Certifying Entity understands that this Certificate relates to Facilities that were financed with tax-exempt bonds, Build America Bonds and/or Qualified Energy Conservation Bonds, issued by or on behalf of LADWP.

(c) Governmental Status. The Certifying Entity is a municipal utility that is owned by a state or local governmental unit or a political subdivision or instrumentality thereof, or is itself a state or local governmental unit or a political subdivision or instrumentality thereof (a "Governmental Person").

(d) Qualifying Use. Except as provided in (e) and (f) below, for the term of any scheduling service, including any renewal periods, the Certifying Entity will use the scheduling service for the Facilities only in connection with its retail electric system in providing electricity to its retail electric customers.

(e) Short-term Uses. Any sale, assignment, transfer or lay-off in any manner of any service provided to the Certifying Entity under this Agreement shall comply with the Agreement's procedures for resale, assignment or transfer of service and this Certificate.

(f) Governmental Person Uses Permitted. In the event there is to be a sale, lay-off, or other transfer in any manner, of any scheduling service pursuant to the Agreement, by the Certifying Entity, to another Governmental Person for a period of longer than 3 years, such may only be permitted if such other Governmental Person will not, in LADWP's exclusive determination, jeopardize the tax-exempt status of any municipal bond(s) used to finance the Facilities and executes a form of this Certificate.

(g) Reimbursement of Reasonable Costs and Expenses for LADWP Review. Certifying Entity agrees to pay or reimburse LADWP for reasonable costs and expenses (including fees and expenses of counsel) that may be incurred by LADWP for review of the individual Certifying Entity's Governmental Person Use Certificate.

(h) Additional information. Certifying Entity agrees to immediately inform, in writing, LADWP of any change regarding the foregoing certifications, representations and agreements and agrees that, if such change is reasonably likely, in the discretion of LADWP, to adversely affect the tax exempt status of the LADWP's bonds, LADWP may immediately terminate all scheduling services affected by such change under the Agreement.

SUBSCRIBED AND SWORN BEFORE A NOTARY PUBLIC

Dated:

By ______________________
Stephen M. Zurn
General Manager of Glendale Water and Power
City of Glendale

APPROVED AS TO FORM
____
Principal Assistant City Attorney
Date November 23, 2015

CALIFORNIA ALL PURPOSE ACKNOWLEDGMENT

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

STATE OF CALIFORNIA }

COUNTY OF Los Angeles }

On Nov. 24, 2015 before me, A. Mary Tchagaspanian Notary Public,

Date (here insert name and title of the officer)

personally appeared Stephen M. Zurn

who proved to me on the basis of satisfactory evidence to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

A. MARY TCHAGASPANIAN
Commission # 2076812
Notary Public - California
Los Angeles County
My Comm. Expires Aug 31, 2018

Signature: (Seal)

OPTIONAL

Description of Attached Document

Title or Type of Document: Governmental Person Use certificate (BAASA) DWP No. BP 15-26 Number of Pages: 2

Document Date: Other:

APPENDIX B

LADWP TRANSMISSION AND ANCILLARY SERVICE RATES DATED 9-1-14

LADWP's OATT Transmission and Ancillary Service Rates are provided at http://www.oasis.oati.com/LDWP/LDWPdocs/OATT_Rates.pdf

Or OATT Cost of Service Study Summary as posted on OASIS.

LADWP's OATT rates listed below are the rates put into effect on 9-1-14. For the calculations in Schedule 3, below, data for "Net Energy for Load" (NEL) will be taken from the FERC Form 714 filed by LADWP for the same test year used to calculate LADWP's OATT rates used herein.

SCHEDULE 1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

The charge for Scheduling, System Control Service is set forth below.

Annual Scheduling, System Control Service = $1,310/MW.

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Sources Service

The charge for Reactive Supply Service is set forth below.

Annual Reactive Supply = $4,990/MW.

SCHEDULE 3

Regulation and Frequency Response Service

Components of the formula to determine the amount of and charges for RFR Service are set forth below.

RFR Annual Revenue Requirement = $547,775,766

RFR Purchase Obligation = 1.1%

NEL_{LADWP} = 27,160,120 MWh.

NEL_{BWP} = 1,185,006 MWh

NEL_{GWP} = 1,182,736 MWh

Annual RFR rate = $0.204/MWh

Schedule 5- OPERATING RESERVE:
Spinning Reserve Service

The charge for Spinning Reserve Service is set forth below.

Annual Spinning Reserve Service = $47,040/MW.

Schedule 6- OPERATING RESERVE:
Supplemental Reserve Service

The charge for Supplemental Reserve Service is set forth below.

Annual Supplemental Reserve Service = $5,190/MW.

Schedule 7
Firm Point to Point Transmission Service

The charge for Firm Point to Point Transmission Service is set forth below.

Annual Firm Point to Point Transmission Service, as rate divisor has been adjusted for inclusion of BWP/GWP load = $39,257/MW.

REVISION OF THIS APPENDIX

The costs in this Appendix B may be changed from time-to-time to reflect LADWP's then current OATT rates.

Definitions of Annual Reserve Rate Variables Used in Formula

S_5: Spinning Reserve Rate associated with the 50% Purchase Requirement Yearly Rate under the OATT in $/MW-Yr.

S_6: Supplemental Reserve Rate associated with the 50% Purchase Requirement Yearly Rate under the OATT in $/MW-Yr.

D: Delivery of Reserve based on Transmission Rate under the OATT in $/MW-Yr.

R: Reactive Power Rate under the OATT in $/MW-Yr.

S: Scheduling, System Control and Dispatch Rate under the OATT in $/MW-Yr.

SS_5: Amount of GWP self-supply Spinning Reserve in MW.

SS_6: Amount of GWP self-supply Supplemental Reserve in MW.

Formula

Annual Reserve Cost = $((S_5 \times (40\text{ MW} - SS_5)) + (S_6 \times (40\text{ MW} - SS_6)) + (D + R + S) \times$

$((40\ MW + 40\ MW) - (SS_5 + SS_6))) \times ((100 - 43.32)/100)^*$

Monthly Reserve Cost = Annual Reserve Cost / 12

Illustrative Example Applying Formula

S_5: $47,040 [$/MW-Yr.]
S_6: $5,190 [$/MW-Yr.]
D: $39,257 [$/MW-Yr.]
R: $1,310 [$/MW-Yr.]
S: $4,990 [$/MW-Yr.]
SS_5: Amount of GWP self-supply Spinning Reserve in MW.
SS_6: Amount of GWP self-supply Supplemental Reserve in MW.

Full Operating Reserve Service Example:

SS_5: 0 MW
SS_6: 0 MW

Annual Reserve Cost = (($47,040 x (40 MW – 0 MW)) + ($5,190 x (40 MW – 0 MW)) + ($39,257 + $1,310 + $4,990) x ((40 MW + 40 MW) – (0 MW + 0 MW))) x ((100 – 43.32) /100)* = $3,249,895.17

Monthly Reserve Cost = $3,249,895.17 / 12 = $270,824.60

Partial Operating Reserve Service Example:

SS_5: 10 MW
SS_6: 15 MW

Annual Reserve Cost = (($47,040 x (40 MW – 10)) + ($5,190 x (40 MW – 15)) + ($39,257 + $1,310 + $4,990) x ((40 MW + 40 MW) – (10 + 15))) x ((100 – 43.32) /100)* = $2,293,604.38

Monthly Reserve Cost = $2,293,604.38 / 12 = $191,133.70

* This discount shall not be changed.

APPENDIX C
INTERCONNECTION FACILITIES

Energy Imbalance may be returned in-kind at the following points of delivery: Airway, and any other facilities mutually agreed to by the Parties.

The Interconnection Facilities include the interconnection between GWP and LADWP at Airway and the interconnection between BWP and GWP at Western substation.

LADWP-Burbank

The interconnection facilities between LADWP and Burbank shall include the following equipment at Toluca Receiving Station E (RS-E):

230-kV Bus 1 and Bus 2
Transformer Banks E and F
69-kV Bus 1 and Bus 2
69-kV Toluca-Capon Lines 1, 2 & 3
69-kV Burbank Toluca-Valley 1, 2 & 3
Switchgear associated with the above listed

The interconnection is metered at the high side bushings of Banks E & F.

LADWP operates and maintains all Interconnection Facilities at RS-E except for operation of the load tap changers on Banks E & F which are jointly controlled with primary responsibility resting with Burbank.

Burbank operates and maintains all 69-kV equipment outside the RS-E fence line.

In case of any conflict or inconsistency between this Appendix C and the City-Burbank Interconnection Agreement, the City-Burbank Interconnection Agreement shall control.

LADWP-Glendale

The interconnection facilities between LADWP and Glendale shall include the following equipment at Air Way Receiving Station (AWY-RS):

230-kV Bus 1 and Bus 2
230-kV Rinaldi-Air Way Lines 1 & 2
230-kV Atwater-Air Way Lines 1 & 2
Transformer Banks 1, 2 & 3
69-kV Air Way-Kellogg 1, 2 and 3
Switchgear associated with the above listed

The interconnection is metered at the high side bushings of Banks 1, 2 and 3.

LADWP operates and maintains all Interconnection Facilities at AWY-RS up to and including the 69-kV disconnects on the Air Way-Kellogg 1, 2 and 3 except for operation of the load tap changers on Banks 1, 2 and 3, which are jointly controlled with primary responsibility resting with Glendale.

Glendale operates and maintains all 69-kV equipment from the potheads on the 69-kV Air Way-Kellogg 1, 2 and 3 to the Glendale system.

In case of any conflict or inconsistency between this Appendix C and the Air Way Interconnection Agreement, the Air Way Interconnection Agreement shall control.

Burbank-Glendale

The interconnection facilities between Burbank and Glendale at Western shall include the following equipment:

69-kV East Bus
69-kV West Bus
Olive-Capon-Western Lines 1 and 2
Switchgear associated with the above listed

The interconnection is metered as follows: Meter No. 1 is located at the terminus of the Olive-Capon-Western No. 1 Line at the 69 KV East Bus of the Western Substation. Meter No. 2 is located at the terminus of the Olive-Capon-Western No. 2 Line at the 69 KV West Bus of the Western Substation.

APPENDIX D

FORMULA FOR CALCULATING THE RATE FOR GWP'S PURCHASE OF FULL OR PARTIAL CONTINGENCY RESERVES FROM LADWP

OPERATING RESERVES

(Schedule 5- Spinning Reserve Service and Schedule 6- Supplemental Reserve Service)

The formula to determine the amount of and charges for Operating Reserve Service are set forth below. Operating Reserve Service as provided under this Agreement is only applicable to those point(s) of delivery located within the Balancing Authority Area. The rates and charges for Operating Reserve Service, applying the formula set forth below.

Definitions of Annual Reserve Rate Variables Used in Formula

S_5: Spinning Reserve Rate associated with the 50% Purchase Requirement Yearly Rate under the OATT in $/MW-Yr.

S_6: Supplemental Reserve Rate associated with the 50% Purchase Requirement Yearly Rate under the OATT in $/MW-Yr.

D: Delivery of Reserve Service based on Transmission Rate under the OATT in $/MW-Yr.

R: Reactive Power Rate under the OATT in $/MW-Yr.

S: Scheduling, System Control and Dispatch Rate under the OATT in $/MW-Yr.

SS_5: Amount of GWP self-supply of Spinning Reserve Service in MW.

SS_6: Amount of GWP self-supply of Supplemental Reserve Service in MW.

Formula

Annual Reserve Cost = $((S_5 \times (40\text{ MW}^{**} - SS_5)) + (S_6 \times (40\text{ MW}^{**} - SS_6)) + (D + R + S) \times ((40\text{ MW}^{**} + 40\text{ MW}) - (SS_5 + SS_6))) \times ((100 - 43.32)/100)^{*}$

Monthly Reserve Cost = Annual Reserve Cost / 12

Illustrative Example Applying Formula

S_5: $47,040 [$/MW-Yr.]
S_6: $5,190 [$/MW-Yr.]
D: $39,257 [$/MW-Yr.]
R: $1,310 [$/MW-Yr.]
S: $4,990 [$/MW-Yr.]
SS_5: Amount of GWP self-supply of Spinning Reserve Service in MW.
SS_6: Amount of GWP self-supply of Supplemental Reserve Service in MW.

Full Operating Reserve Service Example:

SS_5: 0 MW
SS_6: 0 MW

Annual Reserve Cost = (($47,040 x (40 MW** – 0 MW)) + ($5,190 x (40 MW** – 0 MW)) + ($39,257 + $1,310 + $4,990) x ((40 MW** + 40 MW**) – (0 MW + 0 MW))) x ((100 – 43.32) /100)* = $3,249,895.17

Monthly Reserve Cost = $3,249,895.17 / 12 = $270,824.60

Partial Operating Reserve Service Example:

SS_5: 10 MW
SS_6: 15 MW

Annual Reserve Cost = (($47,040 x (40 MW** – 10)) + ($5,190 x (40 MW** – 15)) + ($39,257 + $1,310 + $4,990) x ((40 MW** + 40 MW**) – (10 + 15))) x ((100 – 43.32) /100)* = $2,293,604.38

Monthly Reserve Cost = $2,293,604.38 / 12 = $191,133.70.

REVISION OF THIS APPENDIX

The costs in this Appendix D may be changed from time-to-time to reflect LADWP's then current OATT rates.

* This discount shall not be changed.

** The references to the 40 MWs shall only be adjusted in accordance with the provisions of Section 3.4 of this Agreement.

APPENDIX E

START-UP AND SHUTDOWN ENERGY

In order to minimize CE and Energy Imbalance, Parties agree that LADWP will purchase the Start-up and Shutdown energy for units and unit combinations (combined cycle) with a Start-up time greater than 15 minutes per the terms of this Appendix E. Since Start-up/Shutdown energy is scheduled and delivered dynamically and therefore not a contributor to CE, the Out-of-Band Motivators will apply to all PD, subject to any exclusions, per Schedule 4.

A. **"Start-Up"** for the purposes of this Agreement shall be defined as the period starting when the generator synchronizes and concluding when both (i) the generator output is fully scheduled to the unit participant(s) and (ii) the energy being delivered to LADWP returns to zero. The Start-Up period shall not normally exceed six hours.

B. **"Shutdown"** for the purposes of this Agreement shall be defined as the period starting when the generator operator commences the (i) reduction of the unit participant(s) energy schedule to zero and (ii) transfer the corresponding energy schedule to LADWP, and concluding when the generator is off line and the energy schedule to LADWP returns to zero. The Shutdown period shall not normally exceed three hours.

C. **Start-up and Shut-down Comparable to "Test".** Parties recognize that energy provided during the periods defined above may vary and deviate from the Start-Up or Shutdown schedule provided by the generator operator.

D. **Units with a Dynamic Schedule to LADWP**: Units, while operating with a dynamic schedule to LADWP, will have self-correcting schedules that will not impact GWP's CE calculations.

E. **Coordination of Start-ups and Shutdowns**

1. Generator operator will supply a typical Start-up and Shutdown schedule showing time vs. MW for each generator subject to this Appendix.

2. Generator operator will notify LADWP of the schedule of planned Start-ups and Shutdowns with a minimum of two (2) business day notice (preferably three (3) days) for all planned unit Start-ups and Shutdowns. Parties will coordinate the timing of the proposed Start-ups and Shutdowns.

3. Generator operator will provide notice of unplanned Start-ups and Shutdowns to LADWP's generation dispatcher as soon as the need and timing is known. This includes restarts after a trip.

4. Generator operator and LADWP will work cooperatively to determine an optimal time for a Start-up or Shutdown to occur. Generator operator will provide outage plans to LADWP on a quarterly basis to ensure that LADWP can sufficiently integrate these events into their forward System planning. LADWP shall accept Start-up/Shutdown energy unless doing so would cause a reliability condition on the LADWP System (*i.e.* inability to control ACE need to curtail interchange

schedules, line flow problems, and/or voltage control problems). LADWP Balancing Authority (BA) will assess the System conditions and provide a "go, no-go" to the generator operator on a day-ahead basis. The LADWP on duty dispatchers will make the final determination based on prevailing system conditions.

F. Start-up Event

1. Generator operator will advise LADWP of when the Start-up will occur.

2. Prior to Start-up, Generator operator and LADWP will initiate a dynamic signal with an initial value of zero.

3. Generator operator will generate a dynamic e-Tag for the Start-up energy.

4. During the Start-up period, start-up energy will flow to and be purchased by LADWP until the energy is scheduled to the generator participant(s).

5. When the generator(s) reaches stable operating conditions and the generator operator is ready to schedule to the generator participant(s), the generator operator will advise the LADWP generation dispatcher and:

    a. For dynamically scheduled unit(s), the generator operator will commence ramping out the start-up dynamic schedule and the ramping in the participant dynamic schedules in equal and opposite directions until the LADWP dynamic reaches zero.

    b. For statically scheduled unit(s), the generator operator will identify a ramp time and duration for initiating schedules to the generator participants and ramp out the dynamic schedule to LADWP across the started ramp period. Generator operator will strive to commence scheduling to the unit participants at the lowest load level practical.

6. For each hour of the Start-up period, LADWP and the generator operator will agree to an integrated MWh value. The generator operator will input the after the-fact value in the dynamic e-Tag per scheduling practice.

G. Shutdown Event

1. Generator operator will advise LADWP when the Shutdown will occur.

2. Generator operator will notify LADWP at least 30-minutes prior to the time they are ready to ramp out the energy schedules for the unit participants and ramping in the schedule to LADWP.

3. Prior to ramping out the schedules to the participants and ramping in the schedule to LADWP, the generator operator and LADWP will initiate a dynamic schedule to LADWP with an initial value of zero.

4. Generator operator will generate a dynamic e-Tag for the Shutdown energy.

5. Generator operator will strive to reduce the participant schedules to the lowest value practical prior to initiating dynamic energy delivery to LADWP.

6. During the Shutdown period, all energy will flow to and be purchased by LADWP.

7. When the generator(s) reaches minimum loading and the generator operator is ready to zero the schedules to the generator participant(s), the generator operator will advise the LADWP generation dispatcher and:
   a. For dynamically scheduled unit(s), the generator operator will commence ramping in the dynamic schedule to LADWP and ramping out the participant dynamic schedules in equal and opposite directions until the participant dynamic reaches zero.
   b. For statically scheduled unit(s), the generator operator will identify a ramp time and duration for ramping out the generator participant schedules and will ramp in the dynamic schedule to LADWP across the started ramp period.

8. The generator operator will reduce the unit(s) output to the most practical minimum load prior to shutting down the unit. For each hour of the Shutdown period, LADWP and generator operator will agree to an integrated MWh value. The generator operator will input the after-the-fact value in the e-Tag per scheduling practices.

H. **Net Output of GWP's Generators.** The net output (MW and MWh) for the Start-ups and Shutdowns of dynamically scheduled and non-dynamically schedule generators covered under this Agreement will be provided to LADWP by the generator operator per the communication protocol set forth in this Appendix.

I. **Communication Protocol:** Proposed communication protocol and acceptance procedure will be comprised of the following:

1. All meter and status data will be supplied via an ICCP link.

2. A single status binary (0/1) point will be provided to LADWP "system" from the generator operator requesting acceptance of the energy for either period. A single status (0/1) point will be provided from LADWP "system" to the generator operator indicating acceptance of said energy. A single analog point providing generator(s) Net MW output will be provided to LADWP "System" exclusion from the generator operator's deviation calculations. The generator operator will create a dynamic e-Tag to be effective during the Start-up or Shutdown period. The e-Tag will contain the estimated MWh for each hour and will be adjusted after the hour to reflect the MWh output.

J. **<u>Alternate Scheduling Method</u>**. If dynamic scheduling is not available, a unit Start-up/Shutdown will be accomplished using one of the following options at LADWP's discretion:

a) If LADWP is receiving an output value from generator(s), LADWP will calculate a clock 15-minute average of the generator(s) output and an integrated hourly MWH.

i. Each clock 15-minute average will be subtracted from the corresponding Period Deviation. This adjusted Period Deviation shall be deemed to be the value for billing under Schedule 4.

ii. The calculated integrated MWH value will be used to adjust the Start-up/Shutdown e-Tag unless the generator operator provides an appropriate value.

b) If LADWP is not receiving an output value from generator(s), the calculated Schedule 4 Period Deviation will be exempted from Schedule 4 billing. The generator operator must be able to provide an integrated MWH value for each hour. Said value will be used to adjust the Start-up/Shutdown e-Tag.

Parties will make reasonable efforts to (re)establish systems and communications necessary to implement the dynamic schedule to LADWP prior to commencing a Start-up or Shutdown. However, lack of dynamic scheduling capability shall not be sufficient reason for LADWP to deny a Start-up or Shutdown.

APPENDIX F

NOTICES AND SYSTEM OPERATIONS PERSONNEL

All notices under this Agreement shall be provided in writing to the Authorized Representatives listed below. For convenience, notices may be routed via electronic mail or facsimile, provided, however, that such notice is also routed contemporaneously in written form via U.S. Mail to the Authorized Representative's address indicated below. The Authorized Representatives are permitted to delegate such Authorized Representative's responsibilities under this Agreement to another employee of the Party. Any Authorized Representative making such delegation will provide notice pursuant to Section 4.1 of this Agreement.

Notices to LADWP. Notices to LADWP under this Agreement shall be provided in writing to the following Authorized Representatives:

Los Angeles Department of Water and Power
Attn: Mark Lieberman, Manager of Long Term Transmission Mgmt
Address: 111 N Hope St, JFB Room: 1246, Los Angeles
Phone: (213) 367-2454
Email: Mark.Lieberman@ladwp.com

With Copy to:

Los Angeles Department of Water and Power
Attn: John R. Dennis, Director of Power System Planning & Development
Address: 111 N Hope St, JFB Room: 921, Los Angeles
Phone: (213) 367-0881
Email: John.Dennis@ladwp.com

Notices to GWP. Notices to GWP under this Agreement shall be provided in writing to the following Authorized Representatives:

General Manager, Glendale Water & Power
141 N. Glendale Avenue, Level 4
Glendale, CA 91206
Ph (818) 548-2107
Email: szurn@glendaleca.gov

With a copy to:

City Attorney's Office
Attn: GWP Counsel
613 E. Broadway, Suite 220
Glendale, CA 91206
(818) 548-2080
Email: cgodinez@glendaleca.gov

2. NOTICES OF AN OPERATING NATURE

Prior to the Implementation Date, the Parties shall exchange the names, titles, address, voice phone number and Fax number for routine operational activities associated with operation activities delineated under this Agreement. Such operational activities shall include, but are not limited to outage coordination, generation dispatch and system dispatch. Any notice, request or demand of an operating nature between the BA and GWP shall be made orally, via electronic communication, or in writing, by facsimile, by First Class mail or overnight delivery service.

*****************NON-PUBLIC INFORMATION BELOW*****************

*****************NOT FOR INCLUSION IN PUBLIC DOCUMENT****************

APPENDIX G

PRO-FORMA SAMPLE INVOICE

Department of Water and Power

Of the City of Los Angeles
Cost and Project Accounting, Room 450

P.O. Box 51212
Los Angeles, California 90051-5512

PRO FORMA INVOICE

Date	9/23/2015
Due Date	10/5/2015
Invoice #	GAXXXXXX
Customer ID	City of Glendale
Service Month	Aug-2015

BILLED TO
Accounts Payable
Glendale Water and Power
141 N. Glendale Avenue, Level 4
Glendale, CA 91206
(818) 548-6461
AGREEMENT NO. BAASA

INVOICE COLLECTIBLE NO. GAXXXXXX
Please Pay **AMOUNT DUE** $ 290,931.11

SEND PAYMENT TO
DEPARTMENT OF WATER & POWER
COST AND PROJECT ACCOUNTING, ROOM 450
P.O. BOX 51212, LOS ANGELES, CA 90051-5512

UNIT OF MEASURE	DESCRIPTION	QTY	UNIT PRICE	TOTAL AMOUNT
	Schedule 3 - Regulation and Frequency Response Services			-
MW	Annual RFR Service Contracted - 2015 +/-8 MW	1	20,106.51	20,106.51
MW	Incremental Deviation Bandwidth Contracted for August 2015 +/- 1 MW	0	2,513.31	-
	Schedule 4 - Period Deviation Charges (Net Tie Deviation)			
Instances * MW	Second Deviation Band (10% of energy rate)	0	varies	
Instances * MW	Third Deviation Band (25% of energy rate)	0	varies	
	Schedule 5 - Spinning Reserve Service			
MW	Reserves Purchased-- Deliv, Reactive Power, Sched/Syst Cntrl/Disp Rate		3,796.42	
MW	Amount of Self-Supply Spinning Reserve	0	3,920.00	
	Monthly Reserve Cost - Net After Self-Supply			174,946.60
	Schedule 6- Supplemental Reserve Service			
MW	Reserves Purchased-- Deliv, Reactive Power, Sched/Syst Cntrl/Disp Rate		3,796.42	
MW	Amount of Self-Supply Supplemental Reserve	0	432.50	
	Monthly Reserve Cost - Net After Self-Supply			95,878.00
	Motivators for Schedules 5 & 6			
MW	Failure for Capacity Perform [3 x [Monthly OATT Rate] x [MW Short] per occurence]			
MW	Energy Associated w/ Activation of Reserves [1.5 x [Energy Price] + Return in Kind]			
MW	Failure to Terminate Energy Draw after 60 min [3 x [Energy Price] + Return in Kind]			
MW	RT Failure to Supply Reserves [3 x [Monthly OATT Rate] x [MW Short] per occurence]			
MW	Energy Delivered to LADWP to Create Reserves [1.1 x [BWP/GWP Cost]]			
MW	Reserve Purchase (short-term) from BWP or GWP by LADWP [[Applicable OATT Rate] x [MW]]			-
				-
			Total	$ 290,931.11

TO ENSURE PROPER CREDIT TO YOUR ACCOUNT, PLEASE RETURN BOTTOM PORTION WITH PAYMENT.
Please do not combine payment of this invoice with utility bills.

APPROVED: MANAGER OF PROJECTS AND BILLINGS

REFERENCE NO. TEAR OFF HERE AND RETURN WITH PAYMENT - KEEP TOP FOR YOUR RECORDS

Credit Account	Work Order No.	Symbol Code	Amount
			$ 290,931.11

I.C. No. 1111111
I.C. Date 9/23/2015
Fund Power RBs
Amount Enclosed $

Accounts Payable
Glendale Water and Power
141 N. Glendale Avenue, Level 4
Glendale, CA 91206

Issuing Organization Copy

APPENDIX H

FORMULA FOR CALCULATING THE RATE FOR GWP'S PURCHASE OF REGULATION AND FREQUENCY RESPONSE SERVICE FROM LADWP

SCHEDULE 3
Regulation and Frequency Response Service

The formula to determine the amount of and charges for RFR Service are set forth below. RFR Service as provided under this Agreement is only applicable to those point(s) of delivery located within the Balancing Authority Area. The rates and charges for RFR Service, applying the formula set forth below.

1. **Annual RFR Rate** = $\frac{ARR_t \times PR_t}{(NEL_{LADWP} + NEL_{BWP} + NEL_{GWP})_t}$

Where:
Annual RFR Rate = Cost of RFR Service expressed in \$/MWh of load.
ARR = Annual Revenue Requirement for RFR Service
PR = Purchase Requirement stated as the "percent of the Transmission Customer's Reserved Capacity for Point-to-Point Transmission Service" (*e.g.,* 1.1 percent) in Schedule 3 of the LADWP OATT.
NEL_{LADWP} = LADWP Annual Net Energy for Load as filed by LADWP in FERC Form 714
NEL_{BWP} = BWP Annual Net Energy for Load as filed by LADWP in FERC Form 714
NEL_{GWP} = GWP Annual Net Energy for Load as filed by LADWP in FERC Form 714
t = LADWP Cost of Service Study Test Year used in the calculation of the LADWP OATT rates in effect for the year in which service is elected.

2. **Billing Demand for Annual Service:**

If GWP elects to purchase annual RFR Service from the Balancing Authority, LADWP shall supply and GWP shall purchase a base amount of regulation equal to +/- 8 MW, and the billing determinants for such Service charges shall be based on NEL_{GWP} as defined in Section 1 of this Schedule 3. LADWP shall invoice GWP on a monthly basis for one-twelfth of the annual cost of providing this service to GWP, which is annual RFR Rate times NEL_{GWP}.

If GWP elects not to purchase annual RFR Service from the Balancing Authority, the Deviation Bands will be adjusted as indicated in Schedule 4.

3. **Illustrative Example Applying Annual RFR Rate and Billing Demand for Annual RFR Service:**

For the 8-MW purchased by GWP in the First Deviation Band reflected in Schedule 4, the following charges will result:

ARRt = \$547,775,766

PR = 1.1%

NEL_{LADWP} = 27,160,120 MWh.

NEL_{BWP} = 1,185,006 MWh

NEL_{GWP} = 1,182,736 MWh

Annual RFR rate = $0.204/MWh

Annual Cost of RFR Service = 1,185,006 MWh x $0.204/MWh = $241,278

Monthly Cost of RFR Service = $241,278 / 12 = $20,107

4. Rate for Incremental Deviation Bandwidth:

GWP may elect to purchase additional RFR Service from LADWP on a monthly or annual basis. Such purchase will increase the Deviation Bands, as described in Section C of Schedule 4 for the period of time such RFR Service is purchased..

IRFRy = (Annual Cost of RFR Service /8) x MW

IRFRm = ((Monthly Cost of RFR Service /8) x MW

Where:
IRFRy = The rate per MWh for incremental MW of bandwidth for a year.
IRFRm = The rate per MWh for incremental MW of bandwidth for a month.
MW = The number of additional MW requested and provided for a year or month.

5. Illustrative Example Applying Rate for Incremental Deviation Bandwidth:

A. GWP requests 5 MW of additional deviation bandwidth for one year:

IRFRy = $241,278 / 8 = $30,159.75 x 5 MW = $150,798.75

B. GWP requests 5 MW of additional deviation bandwidth for one month:

IRFRm = $20,107 / 8 = $2,513.38 x 5 MW = $12,566.88

REVISION OF THIS APPENDIX

The costs in this Appendix H may be changed from time-to-time to reflect LADWP's then current OATT rates.

APPENDIX I

FORM OF

GOVERNMENTAL PERSON USE CERTIFICATE

In connection with the execution of the Balancing Authority Area Services Agreement ("Agreement"), dated as of September _____, 2015, is entered into by and between the City of Los Angeles on behalf of its Department of Water and Power ("LADWP") in its capacity as the operator of the LADWP Balancing Authority Area ("Balancing Authority") and City of Glendale, on behalf of its Water and Power Department ("GWP")., DWP No. ___ (Agreement), [NAME of GOVERNMENTAL ENTITY OR COUNTER PARTY] ("Certifying Entity") relating to balancing area services as described therein, Eligible Customer certifies, represents and agrees as follows::

(a) Officer Signing. I am the duly [elected/appointed] [Title] of Certifying Entity, authorized to sign this Certificate.

(b) Tax-Exempt Bonds. Certifying Entity understands that this Certificate relates to LADWP facilities that were financed with tax-exempt bonds, Build America Bonds and/or Qualified Energy Conservation Bonds, issued by or on behalf of LADWP ("Facilitites").

(c) Governmental Status. The Certifying Entity is a municipal utility that is owned by a state or local governmental unit or a political subdivision or instrumentality thereof, or is itself a state or local governmental unit or a political subdivision or instrumentality thereof (a "Governmental Person").

(d) Qualifying Use. Except as provided in (e) and (f) below, for the term of any services set forth in the Agreement, including any renewal periods, the Certifying Entity will use the service for the Facilities only in connection with its retail electric system in providing electricity to its retail electric customers.

(e) Short-term Uses. Any sale, assignment, transfer or lay-off in any manner of any service provided to the Certifying Entity under this Agreement shall comply with the Agreement's procedures for resale, assignment or transfer of service and this Certificate.

(f) Governmental Person Uses Permitted. In the event there is to be a sale, lay-off, or other transfer in any manner, of any scheduling service pursuant to the Agreement, by the Certifying Entity, to another Governmental Person for a period of longer than 3 years, such may only be permitted if such other Governmental Person will not, in LADWP's exclusive determination, jeopardize the tax-exempt status of any municipal bond(s) used to finance the Facilities and executes a form of this Certificate.

(g) Reimbursement of Reasonable Costs and Expenses for LADWP Review. Certifying Entity agrees to pay or reimburse LADWP for reasonable costs and expenses (including fees and expenses of counsel) that may be incurred by LADWP for review of the individual Certifying Entity's Governmental Person Use Certificate.

(h) Additional information. Certifying Entity agrees to immediately inform, in writing, LADWP of any change regarding the foregoing certifications, representations and agreements and agrees that, if such change is reasonably likely, in the discretion of LADWP, to adversely affect the tax exempt status of the LADWP's bonds, LADWP may immediately terminate all scheduling services affected by such change under the Agreement.

SUBSCRIBED AND SWORN BEFORE A NOTARY PUBLIC

Dated:

by________________________

[Name and title of senior management representative duly authorized to represent Certifying Entity]

EXHIBIT 4

MEMORANDUM

To: Evan Gillespie
From: James H. Caldwell, Jr.
Date: April 8, 2018
Re: Glendale Contingency Reserve Obligations

Per your request, I have reviewed Glendale Water and Power's (GWP) "Topical Responses" to the Draft EIR for the Grayson Repowering Project dated March 1, 2018. In particular, I reviewed "Topical Response No. 3 – Project Need" regarding transmission constraints and operating reserves obligations that GWP uses to establish "need" for a minimum of 234 MW of new capacity at the Grayson site.[1] It is my professional opinion that there are material misstatements of facts in GWP's responses that have significant impact on GWP's analysis of need for the Grayson Repowering Project.

The most obvious and consequential error in GWP's need analysis is the assertion that: "Glendale's Contingency Reserve obligations require it to carry reserves equal to the loss of its single largest contingency (N-1 contingency), and its next largest contingency (N-1-1 contingency).[2]" Yet, none of the reliability rules or regulations or contractual commitments cited by GWP have such a requirement. The Western Electricity Coordinating Council (WECC) Standard cited by GWP, WECC Standard BAL-002-WECC-2a- Contingency Reserves, applies at the Balancing Authority (LADWP) level, not at the Metered Sub-System (GWP) level.[3] The national North American Electric Reliability Council (NERC) standard that the WECC standard is derived from contains identical language as to the "Responsible Entity." In fact, "Metered Sub-System" is not a defined term in the Glossary of Terms for either NERC or WECC reliability standards. When citing to these standards, GWP itself quotes them to say that *"LADWP* is required"[4] to carry reserves sufficient to meet an "N-1" and an "N-1-1" contingency. At one point in history, as a "load serving entity" within a Balancing Authority, GWP did have certain reserve obligations under NERC

[1] Final Environmental Impact Report, Grayson Repowering Project, Response to Comments, Topical Response #3, p. 9.49. GWP calculates this N-1-1 "need" as 171 MW.
[2] op cit p. 9.46

[3] WECC Standard BAL-002-WECC-2a Section 4.1
[4] emphasis added, FEIR Response to Comments p.9.45

Reliability Standards. However, NERC proposed and FERC agreed to eliminate that requirement by clearly stating:

> We accept NERC's proposal to eliminate the load serving entity as a registered function subject to the Reliability Standards.[5]

GWP does retain some obligations under the NERC reliability umbrella such as a requirement to report load data and load forecasts as well as participate in emergency under-frequency load shedding protocols.[6]

While GWP has no independent need to carry reserves for its own 171 MW N-1 and N-1-1 contingencies[7] according to any NERC, FERC or WECC reliability rule, it is obligated by contract with LADWP to pay for 80 MW of LADWP's reserve obligation which is deemed to be GWP's "fair share" of the Balancing Authority obligation under WECC Standard BAL-002-WECC-2a.[8] LADWP is roughly 20 times the size of GWP and since it is carrying full reserves for its own N-1 and N-1-1 contingencies including GWP's load, it makes no sense to establish an independent reserve obligation for every small fraction of the Balancing Authority load. GWP states that "under its [existing] transmission agreements with LADWP, Glendale is required to meet its subsystem's reserve obligations.[9] However the Balancing Authority Area Services Agreement (BAASA) clearly states that "for the term of this Agreement, this Agreement shall satisfy GWP's obligations under the Existing Agreements to provide spinning reserves, supplemental reserves (sometimes referred to as "non-spinning reserves") or any other contingency reserves.[10]" The BAASA calculates the cost of the reserves purchased from LADWP as $40.6/kw-yr or some 20% of the cost of the Grayson Repowering Project.[11] Clearly, paying five times the unit

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[5] 153 FERC P61,024, Docket No. RR15-4-001 p.11

[6] id, Commission Determinations 19-23 pp. 9-10

[7] It is not clear how GWP calculated its "N-1" as loss of the Pacific DC Intertie (PDCI) at precisely 100 MW since the PDCI is not the most severe single contingency (MSSC) for LADWP and Glendale owns 119 MW of the PDCI. By definition LADWP carries operating reserves for a larger N-1 than loss of the PDCI.

[8] Balancing Authority Area Services Agreement Between Los Angeles Department of Water and Power and Glendale Water and Power, November 18, 2015.

[9] FEIR Responses to Comments p. 9.45

[10] BAASA Article 2.2.2 p. 6

[11] Id, APPENDIX D, p.47-48

market price for over twice the contractually required reserves does not constitute a legitimate "need" for the project.

However, the BAASA does also require GWP to pay for its share of the energy supplied on the rare occasion that LADWP actually uses its operating reserves. If the reserves or a portion of the reserves are "called" and GWP does not, within one hour, replace the energy associated with that reserve call, it is required to pay LADWP a premium over the then current market price of energy.[12] This premium operates as an incentive for GWP to reduce its peak load during an emergency, maximize the energy production from facilities that it controls, or purchase additional peak energy from a third party. Although this "Imbalance Energy" is indeed intentionally "pricey," the cost to GWP for this very rare event is only a very small fraction of the cost of constructing, maintaining and operating Grayson.

GWP's erroneously dismisses one very cost effective method of supplying this "Imbalance Energy" by stating that it cannot join the emerging Western Energy Imbalance Market (EIM) because it "is not a Balancing Authority.[13]" However, as GWP points out, LADWP in 2017 announced its intention to join the EIM and will offer "Energy Imbalance Services" to any metered subsystem in its Balancing Authority.[14] The EIM offers an automated, voluntary exchange for the purchase or sale of energy in real time from any of its participating members. Over 70% of utilities in the eleven state WECC region have either joined the EIM or announced an intention to join. At this point in time, the major non-participants are the two Federal Power Marketing Authorities, Bonneville Power Authority (BPA) and the Western Area Power Authority (WAPA). These entities are studying the possibility of joining the EIM but require modification to their Federal Charter to participate. The functionality of the EIM is slated to increase dramatically in 2019 when plans to offer a day ahead as well as real time market are implemented. This day ahead market will allow GWP to reserve in advance operating reserves and imbalance energy whenever it forecasts high peak loads and/or resource outages.

GWP erroneously dismisses a second very cost effective method of self-supplying a portion of its BAASA required operating reserves as well as

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[12] id, Schedule 5 p. 32-33 and Schedule 6 p 37-38
[13] FEIR Responses to Comments p. 9.48
[14] www.westerneim.com/Documents/Appendix B17_EIMEntityAgreement

an incremental source of imbalance energy by stating that the 12 MW of additional capacity from the Magnolia Plant's supplemental duct burners are "held in reserve for an emergency."[15] However, a need for operating reserves and/or imbalance energy is precisely that emergency.

GWP erroneously dismisses a third option for self-supplying all or a portion of its BAASA required operating reserves as well as an additional source of imbalance energy by stating that it "cannot interconnect to the California Independent System Operator Balancing Authority (CAISO), because it is not a member of the CAISO Balancing Authority.[16]" However, there is no requirement that GWP become a member of the CAISO to directly interconnect without going through the LADWP Balancing Authority. Once interconnected, it could make purchases or sales of energy or capacity, short term or long term with any member of CAISO or any other entity interconnected with the CAISO throughout the WECC utilizing the CAISO tariff instead of the LADWP tariff. Case in point is LADWP itself that has absolutely no intention of "joining the CAISO" but is robustly interconnected with the CAISO, has executed numerous "Interconnection Agreements" with the CAISO to upgrade those interconnections and share costs, and routinely makes purchases and sales with CAISO members and others interconnected with the CAISO. The IRP from 2015 contains a reference to an "interim screening report for new interconnection options, which estimated a $66Million cost to create an interconnection to the CAISO at Eagle Rock to access an additional 150 MW of CAISO transmission.[17] " The cost effectiveness of this option would require an economic study, and GWP would have to apply to the CAISO's annual Transmission Interconnection Process to make this investment. Detailed results of these studies are unknown at present, but we point out that $66M for 150 MW is less than one-quarter the unit cost of Grayson's $500M for 250 MW of capacity.

In summary, GWP's need analysis for the Grayson Repowering Project is fundamentally flawed principally because it significantly and arbitrarily inflates GWP required planning reserve margin and ignores several apparently less expensive options for supplying energy and capacity to GWP's system.

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[15] FEIR Responses to Comments p. 9.42 footnote 36.
[16] Op cit p. 9.43
[17] Op cit p. 9.36

EXHIBIT 5

Power Glendale with Renewable Energy

Most of the aging Grayson Power Plant will soon be retired. Instead of building a new costly, polluting gas plant, Glendale Water and Power (GWP) has the opportunity to power Glendale with cleaner energy.

Save Ratepayers $250 Million

Rooftop solar, energy storage and energy efficiency will cost half as much as the proposed $500 million gas plant.

Provide Reliable Energy

Building 50 MW of energy storage at the former gas plant will provide equally reliable electricity.

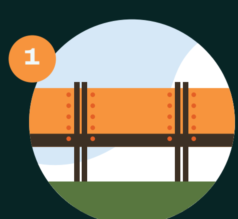
Cut Air Pollution

The current proposal promises to increase global warming pollution 690% while increasing deadly soot and smog pollution.

Invest in Our Community:

Clean energy alternatives like solar and efficiency will help schools, seniors, and businesses cut their energy use and save money.

How We Get There



Redirect methane currently used at Grayson Gas Plant from Scholl Canyon landfill to fuel cells at Grayson site.

Retire aging units 3,4 and 5 now. Their energy is not needed and would provide immediate clean air benefits. Initiate clean energy alternatives study.

Keep units 8 and 9 online for now. Implement plan to build 50 MW rooftop solar, 50 MW energy storage, and 85 MW of energy efficiency programs.

Tell GWP we want a cleaner, cost-efficient energy source! ***sc.org/StopGrayson*** | SIERRA CLUB

EXHIBIT 6

Glendale Water and Power Planning for a Low Cost, Low Carbon Reliable Future Electric System

James H Caldwell

April 2018

Disclaimer

This worked was conducted on behalf of and paid for by the Sierra Club and EarthJustice, but the analysis and conclusions are the author’s alone and do not necessarily represent the views of either organization

Statement of the Problem

- The existing Grayson Generating Station (except Unit 9) must be retired "soon."
- A significant investment in new resources to replace Grayson is needed to reliably serve GWP load.
- An alternative to burning the Scholl Canyon landfill gas in Grayson boilers must be found.
- The autonomy of the GWP system should be preserved.
- Reliability, sustainability and local economic benefit while maintaining stable electric rates are the key objectives.

The Grayson Repowering Proposal

Name	Type	Capacity, MW	Age	Disposition
Unit 3	ST	17	1941	Retire
Unit 4	ST	28	1959	Retire*
Unit 5	ST	38	1964	Retire
Unit 8 A,B,C**	CC	34 x 3/20 x 2	1977	Retire
Unit 9	CT	48	2004	Retain
New	CT	50 x 2	new	Construct
New	CC	75 x 2	new	Construct

Existing Capacity = 273 MW New Capacity = 298 MW Cost = $500M

* Currently burns Scholl Canyon methane

** Units 1,2 are the steam turbines for the combined cycle

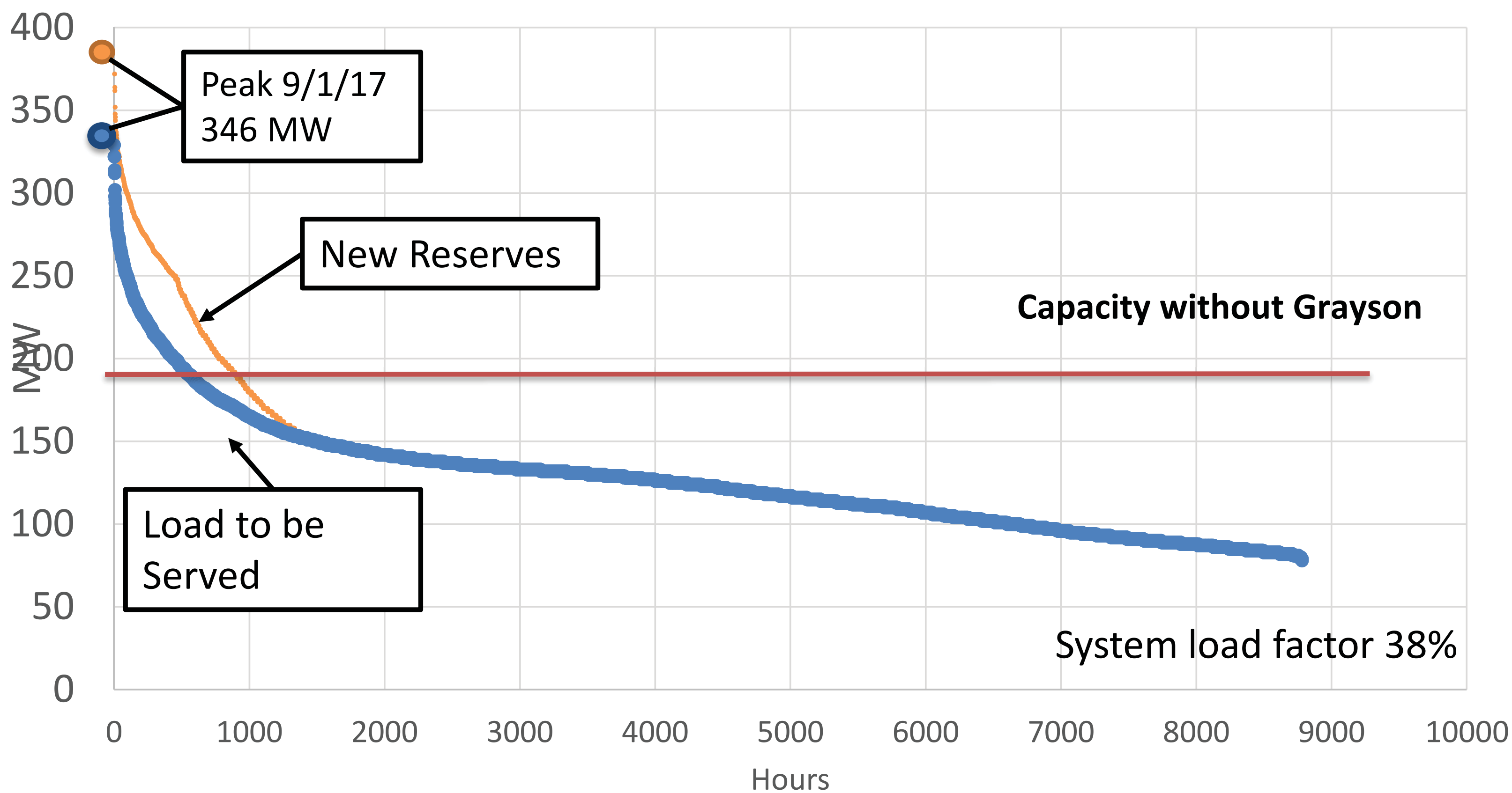
Findings on the Proposed Grayson Repowering Project (1)

- **The proposal to “repower” Grayson with 250 MW of new gas turbines at a cost of $500 M is expensive.**
  - Roughly 33% more expensive than the CA average cost of a new combined cycle plant.
  - Almost twice as expensive as Puente, the rejected natural gas plant in Oxnard.
  - Ten to twenty times more expensive than either Energy Efficiency (CEC estimate for SB 350) or Demand Response (LBNL estimate for CPUC).
  - Almost twice as expensive as four hour battery storage (Lazard late 2017 estimate).

Findings on the Proposed Grayson Repowering Project (2)

- **250 MW of new gas capacity is unsustainable given CA energy policy, and will lead to stranded assets.**
  - **250 MW new plus Unit 9 plus Magnolia equals gas capacity capable of meeting greater than 100% of “one in ten” peak load.**
  - **Glendale load is rarely high enough to require ANY new capacity of any kind after Grayson shutdown.**
    - Only roughly 500 Hrs/yr: 2015 = 530 hours; 2016 = 440 Hours; 2017 = 458 Hours through September.
    - System load factor is very low (>40%)
  - **Sale of “surplus” gas energy/capacity has no buyer.**
    - The state has roughly twice as much gas capacity as needed by 2030. The issue is orderly retirement of existing gas, not new construction.
    - Currently, roughly 2000 MW of < 10 year old gas capacity is in mothballs and another 4000-6000 MW is at risk of “early” retirement.
    - Aliso Canyon closure means that a significant fraction of this retirement should be in the Los Angeles Basin.

2016 Glendale Load



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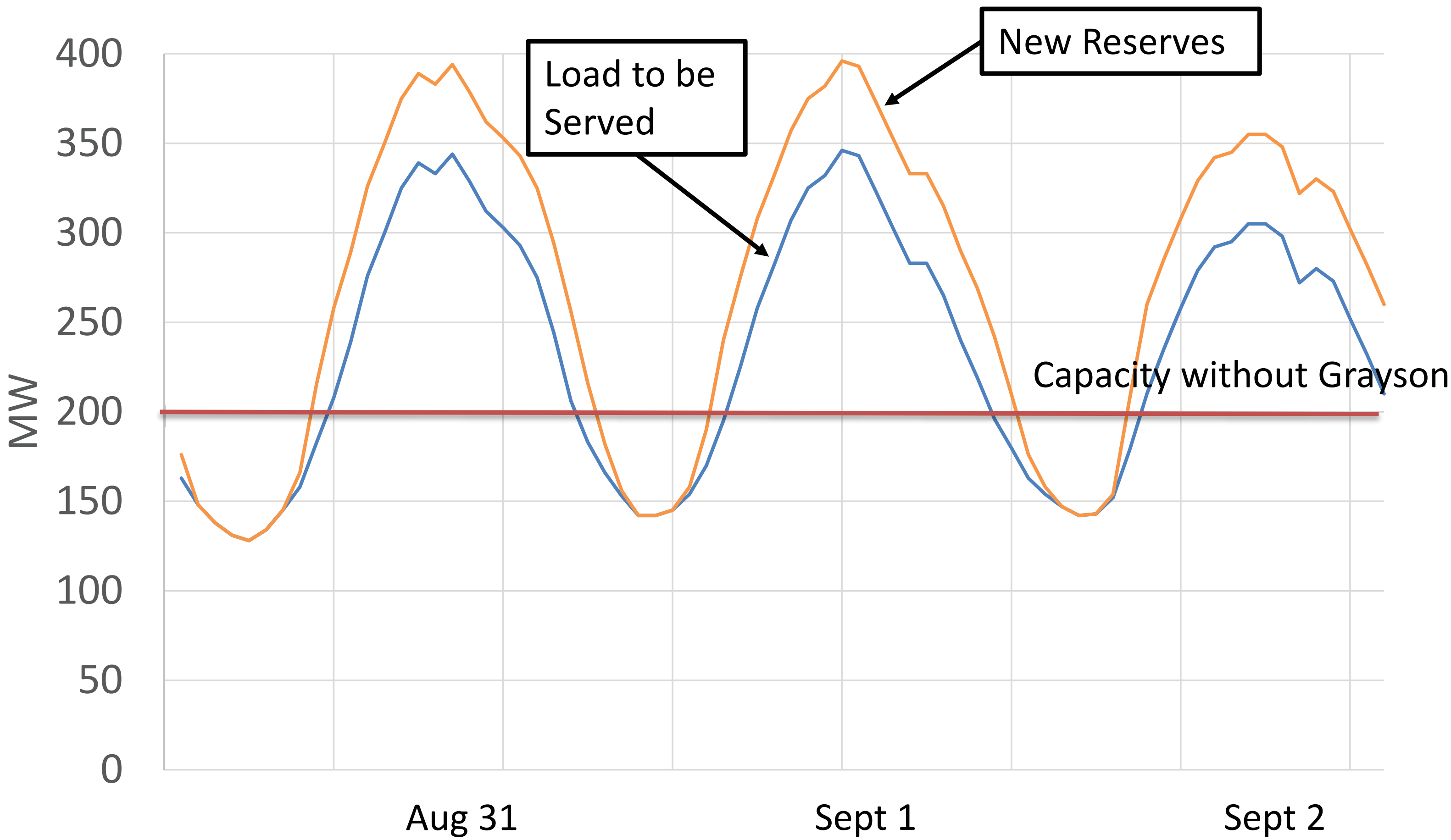
Findings on Proposed Grayson Repowering Project (3)

- **A planning reserve margin of 100 MW above 1 in 10 peak load (~28% planning reserve margin or "PRM") or 177 MW (~ 51% PRM) is arbitrary and inconsistent with planning reserve margin policies in neighboring systems.**
  - **Quantity of operating reserves is determined in real time by the Balancing Authority Area Services Agreement (BAASA) with LADWP, not "NERC Rules."**
    - This translates into 6% of load (21 MW at peak) or the load ratio share of the LADWP Maximum Single System Contingency ("MSSC") whichever is greater.
    - Load ratio share of MSSC for LADWP Balancing Authority is 80 MW.
  - **Operating reserves can be purchased from LADWP or self provided. This is an economic decision, not a reliability requirement.**
  - **Planning reserve margins are set to ensure that operating reserve requirements can be met under foreseeable future scenarios.**
    - Calling the "planning" MSSC as complete loss of the PDCI and setting a planning reserve margin at 177 MW is inconsistent with NERC/WECC/CA practice and treatment by LADWP, CAISO and BPA (affected Balancing Authorities).
    - 80 MW planning reserve margin (~23% PRM) is required by the BAASA.

Peak Day Load Profile
Sept 2017



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Findings on Proposed Grayson Repowering Project (4)

- **Purported need for "firming and shaping" is mischaracterized and exaggerated.**
- **More appropriately expressed as a system "flexibility" need.**
  - Resource portfolio needs the following characteristics:
    - Highly "flexible" > 20-25%
      - Hoover, PDCI, storage, some gas (not currently part of Grayson repowering plan).
    - "Semi-flexible" 50-75%
      - ~ 50/50 Mixture of wind and solar, most gas (e.g., proposed Grayson repowering plan), "system power" imports.
    - "Inflexible" < 25%
      - Nuclear, coal, geothermal, cogeneration
  - Important considerations to provide flexibility options (NOT tied to new resource mix decision)
    - Attack the needle peak with energy efficiency and demand response.
    - "Join" the voluntary CAISO energy imbalance market ("EIM") along with LADWP in 2019-2020.
    - Enhance grid operations software and operator training.

Findings on Proposed Grayson Repowering Project (5)

- **"Preferred Resource" potentials underestimated in the IRP leading to an "all gas" proposal.**
  - Numerous studies point to at least ~ 50MW of local solar potential at ~ one-half Grayson unit cost.
  - CEC SB 350 studies (requirement to double energy efficiency) plus Navigant study for GWP indicate ~ 50MW potential additional achievable energy efficiency "AAEE" at ~ one-tenth Grayson unit cost.
  - Lawrence Berkeley National Laboratory studies for CPUC indicate ~ 35 MW of demand response potential at ~one-twentieth Grayson unit cost.
  - 50 MW battery storage at Grayson site easily available at ~one-half Grayson unit cost.

Grayson Repowering Project Alternative Plan

- **Buy time by "immediate" retirement of Grayson boilers (Units 3,4,5). Largest emission reductions at lowest cost.**
  - Deal with Scholl Canyon methane.
    - Explore cleanup/sale or direct use options. Enclosed flare as temporary fallback option.
  - Retire Grayson boilers and renovate site.
- **Coordinate with relevant existing studies:**
  - LADWP in basin gas "Once Through Cooling" study. Draft results April 2018.
  - LADWP "100% Vision Study" [through 2019].
  - CAISO/LADWP "Increased Capabilities for Transfer of Low Carbon Electricity between the Pacific Northwest and California" Special study in CAISO TPP ~ Fall 2018.

Grayson Repowering Project Alternative Plan (con.)

- **Observe analogous 2018 "preferred resource LCR RFPs" in Ventura/Santa Barbara (SCE) and Oakland (PG&E).**

- **Conduct "preferred resource" peak capacity requirement study (~ six months).**
  - Confirm Airway and Western substation resiliency.
  - Set realistic PRM for planning purposes base on projected renewable procurement portfolio.
  - Develop plan for CAISO EIM.
  - Design PV, DR, EE programs/projects to set targets and capture technical potential.
- **Defer retirement of Grayson 8 A, B and C (inc. Units 1 & 2) until most of alternative plan is in place.**
- **Return with alternative plan for approval ~ March 2019**

Illustrative Result of Grayson Alternative Plan

- **250 MW new peak capacity consisting of:**
  - Up to 93 MW reserve quantity reduction (177 – 80).
  - 50 MW/200 mwh battery at Grayson site.
  - 50+ MW local solar by 2021.
  - 50+ MW AAEE by 2021.
  - 35+ MW demand response by 2021.

- **Conceptual budget = $250M**

Benefits of Alternative Plan

- Roughly one-half the cost. No risk of stranded investment.
- Same near term emissions reductions. Significantly greater long term reductions.
- Local economic benefits spread through local economy.
- Consistent with long term, low carbon vision. Avoids over dependence on natural gas.
- Facilitates Aliso Canyon phase out.
- No delay in construction. Retains options for new renewable imports.

EXHIBIT 7

S&P Global
Platts

US power grid can run well no matter what fuels it uses: reliability official

Washington (Platts)--29 Mar 2018 431 pm EDT/2031 GMT

With the right policies and infrastructure, the US could get most of its electricity from renewable resources without hurting the performance of the power grid, according to an official who helps develop and oversee compliance with reliability standards.

"Variable resources can be reliably integrated, but they need to be cautiously planned and operated," John Moura, director of reliability assessment and system analysis at the North American Electric Reliability Corp., said Wednesday at an event hosted by the US Energy Association in Washington. "You can have 30%, 40%, 80% renewable resources, you just have to plan and operate the system correctly."

Moura's comments fit into a broader debate that erupted in September after Energy Secretary Rick Perry directed the Federal Energy Regulatory Commission to ensure nuclear and coal-fired power plants receive more financial support for the reliability benefits Perry said they provide. FERC in January rejected the proposed rule, which critics skewered as a bailout of industries the Trump administration favors.

"We're reliability extremists," said Moura, whose group became FERC's designated electric reliability organization in 2006 after functioning largely as an industry group that created voluntary reliability standards, "but a lot of the challenges that we see aren't insurmountable, and I think that that's a key message. ... We can transition to a grid that has whatever fuel you really want to power the system by, but policy changes are needed, structural changes are needed."

Article continues below...

"No matter what the resource mix, you've got to have a threshold of bulk power system reliability standards to keep the pace," Moura added. "If we create these standards in a technology-neutral, fuel-neutral way, that really creates the criteria for maintaining a reliable grid."

Moura said regulations like the one FERC adopted in July 2016 requiring that small power generators that interconnect with the grid are able to "ride through abnormal frequency and voltage events" have helped ensure renewables do not hurt system reliability.

He also said the US could from Germany's experience trying to overhaul that country's energy system. "I talked to the Germans and they said if they could do one thing [differently] they would have started building ... transmission expansions earlier, because that's really what their pinch point is," Moura said.

Building new transmission lines, which can aid renewable-energy development by balancing intermittent resources across regions and moving power from remote areas to population centers, is notoriously difficult in the US. After the Department of Energy ended a partnership with the developer of a 700-mile transmission line into the southeastern part of the country, Stefani Millie Grant, senior manager for external affairs and sustainability at Unilever Corp., said companies outside of the energy sector that are pursuing renewable energy targets "need to engage in the transmission-planning process."

Bloomberg New Energy Finance, a research firm, said Wednesday that falling costs and improved efficiency are making wind, solar and battery technologies viable alternatives to fossil fuel plants for bulk power generation, dispatchable power and flexibility.

"From a reliability perspective, what I can say is [energy storage] tears down that whole concept of having to simultaneously match demand and supply," Moura said. "And so if you take away that assumption, now you've got a lot more flexibility in your system." --Michael Copley, S&P Global Market Intelligence

--Edited by Valarie Jackson, newsdesk@spglobal.com

EXHIBIT 8

M I N U T E S
GLENDALE CITY COUNCIL
NOVEMBER 8, 2016

ROLL CALL – Absent: Friedman

1. **CLOSED SESSION** – 4:28 p.m.
   a. **Public Employment – Attorneys.**
   b. **Conference with Labor Negotiators. The City-Designated Negotiators Attending the Closed Session are: Scott Ochoa, Yasmin Beers, Mike Garcia, Gillian van Muyden, Matt Doyle, Robert Elliot, Robert Castro, and Michele Flynn. The Name of the Employee Organization is: Glendale Management Association.**

   City Attorney Michael J. Garcia indicated that action is anticipated. Council recessed to Closed Session at 4:28 p.m.

2. **REGULAR BUSINESS AGENDA –** 6:05 p.m.
   Roll Call – All Present
   a. **Flag Salute: Council Member Sinanyan**
   b. **Invocation: Ardy Kassakhian, City Clerk**
   c. **Report of City Clerk, re: Posting of Agenda. The Agenda for the November 8, 2016 Regular Meeting of the Glendale City Council was Posted on Friday, November 4, 2016, on the Bulletin Board Outside City Hall.**

3. **PRESENTATIONS AND APPOINTMENTS**
   a. **Agenda Preview for the Meetings of Tuesday, November 15, 2016**
   Asst. City Manager Yasmin Beers provided the preview.

4. **CONSENT ITEMS** (Including Minutes)
   The following are Routine and May be Acted Upon by One Motion. Any Member of Council or the Audience Requesting Separate Consideration May do so by Making Such Request Before Motion is Proposed.

   Item 4b pulled for separate discussion.

   a. **Minutes of the Special City Council and the Regular City Council Meetings of November 1, 2016**
   Moved: Sinanyan Seconded: Gharpetian
   Vote as Follows

Ayes:	Friedman, Gharpetian, Najarian, Sinanyan, Devine
Noes:	None
Absent:	None
Abstain:	None

b. **Chief Information Officer, re: Purchase of Information Technology, Equipment, and Subscription and Maintenance Services to Support the Replacement of the Primary Internet Boundary Firewalls**

Staff Comment:
Brian Ganley, CIO

1. Motion Authorizing the Purchasing Manager to Issue a Purchase Order with CDW Government, LLC using Competitively Bid Volume Discounted Pricing

Moved: Najarian Seconded: Gharpetian
Vote as Follows

Ayes:	Friedman, Gharpetian, Najarian, Sinanyan, Devine
Noes:	None
Absent:	None
Abstain:	None

c. **Chief of Police, re: Amended and Restated Memorandum of Understanding (MOU) Between City of Burbank and City of Glendale for the Operation of the Joint Law Enforcement Air Support Unit**

1. Motion Authorizing the City Manager and Chief of Police to Execute the Amended and Restated MOU and Authorizing the City Manager to Execute Any Future Amendments Relative to Building Maintenance Procedures

Moved: Sinanyan Seconded: Gharpetian
Vote as Follows

Ayes:	Friedman, Gharpetian, Najarian, Sinanyan, Devine
Noes:	None
Absent:	None
Abstain:	None

d. **Director of Community Services and Parks, re: Award of Contract for Catering Services for the Elderly Nutrition Program**

1. Motion Awarding a Contract for Catering Services to Morrison Management Specialists, Inc. for a Term of Four Years in the Amount Not-to-Exceed $204,000 Annually, and Authorizing the City Manager or His Designee to Execute a Four Year Contract with Morrison Management Specialist, Inc.

Moved: Sinanyan Seconded: Gharpetian
Vote as Follows

Ayes:	Friedman, Gharpetian, Najarian, Sinanyan, Devine
Noes:	None
Absent:	None
Abstain:	None

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2. Resolution 16-193 Appropriating Additional Grant Funds in the Amount of $8,611 From the Los Angeles County Department of Community and Senior Services for the Elderly Nutrition Program

Moved: Sinanyan Seconded: Gharpetian

Vote as Follows

Ayes:	Friedman, Gharpetian, Najarian, Sinanyan, Devine
Noes:	None
Absent:	None
Abstain:	None

5. CITY COUNCIL/STAFF COMMENTS

Council Member Friedman attended the Homeowners Association Annual Event at Verdugo Woodlands.

Council Member Sinanyan announced there will be a Community Meeting in January 2017, which he will provide a report on the Eco Rapid Transit Meeting held in Japan last month.

Council Member Gharpetian attended the following Events: Homeowners Association Annual Event at Verdugo Woodlands, Glendale Health Festival, and the Wilson Middle School Community Meeting regarding soccer fields. On another note, he has done some research on some homes in Glendale built between the 1900-1960s. He asked staff to look into issues in the community for homes with historic values. Finally, he asked staff to put some sod or grass on the Veterans Memorial in Montrose.

Mayor Devine addressed bulky-item pick-up with a presentation.

6. COMMUNITY EVENT ANNOUNCEMENTS (3-Minutes)

Lisa Raggio and Don Biggs
Relinda Beesemyer
V. Valentine

7. ADOPTION OF ORDINANCES

Item 7d moved for discussion on November 15, 2016, Regular Council Meeting.

a. Ordinance 5890 Amending Section 10.40.120 and Repealing Section 10.40.130 of the Glendale Municipal Code, 1995, Relating to the Establishment of Parking Meter Zones and Parking Meter Space Exclusions (Gharpetian, 11/1/2016)

Moved: Gharpetian Seconded: Najarian

Vote as Follows

Ayes:	Friedman, Gharpetian, Najarian, Sinanyan, Devine
Noes:	None
Absent:	None
Abstain:	None

Staff Comments:
Scott Ochoa, City Manager
Roubik Golanian, Director of Public Works

b. **Ordinance 5891 Amending Sections 30.33.120 and 30.33.220, of title 30 of the Glendale Municipal Code, 1995, Relating Accessory Wall Signs in the Downtown Specific Plan/Gateway and Broadway Center Districts (Case No. PZC1622217) (Gharpetian, 10/18/2016)**

Moved: Gharpetian   Seconded: Najarian

Vote as Follows

Ayes:	Friedman, Gharpetian, Najarian, Sinanyan
Noes:	Devine
Absent:	None
Abstain:	None

Staff Comments:
Scott Ochoa, City Manager
Mike Garcia, City Attorney

Presenting:
Phil Lanzafame, Director of Community Development

c. **Ordinance Amending Sections 30.11.070 of Title 30 of the Glendale Municipal Code, 1995, Relating to Circular Driveways in the ROS, R1R, and R1 Zones (Case No. PZC1622217) (Gharpetian, 11/1/2016)**

Gharpetian rescinded his motion and item is taken off calendar.

Staff Comment:
Mike Garcia, City Attorney

Public Comment:
Grant Michals

d. **Ordinance Adopting the 2016 California Building Code as Volume ia, the 2016 California Residential Code as Volume ib, the 2016 California Existing Building Code as Volume ic, the 2016 California Plumbing Code as Volume II, the 2016 California Mechanical Code as Volume III, the 2016 California Electrical Code as Volume IV, the 1997 Uniform Housing Code as Volume V, the 2016 California Fire Code as Volume VI, the Glendale Security Code as Volume VII and the Glendale Commercial, Industrial Property Maintenance Code as Volume VIII and the 2016 California Green Building Standards Code as Volume IX All of Which Comprise the Building and Safety Code of the City of Glendale, 2017**

1. Resolution Adopting Legislative Findings Supporting Amendments and Changes to the California State Building Standards Code as Contained In the Glendale Building and Safety Code, 2017
2. Amending the Adopted Fiscal Year 2016-17 Citywide Fee Schedule with Respect To Administrative Citations, by Updating Building and Safety Code Section References to be Consistent with the Building and Safety Code of the City Of Glendale, 2017

8. Action Items

Item 8c moved for discussion on December 6, 2016, Regular Council Meeting.

a. City Attorney and Director of Finance, re: Amendments to the Tax Administrator's (Director of Finance) Authority to Enforce the Transient Occupancy Tax

Staff Comments:
Scott Ochoa, City Manager
Mike Garcia, City Attorney

1. Ordinance for Introduction

Ordinance introduced by: Gharpetian

b. Attorney, re: Cancellation of City Council Meetings

Staff Comments:
Mike Garcia, City Attorney
Scott Ochoa, City Manager

1. Motion Directing Staff to Modify the Schedule of Cancelled City Council Meetings per City Council Direction and to Provide all Required Noticing
2. Motion Directing Staff to Retain the Existing Schedule of Cancelled City Council Meetings as is

c. City Manager, re: Proposed Code Amendments to Section 4.12 of the Glendale Municipal Code, 1997 Pertaining to City Contracts

1. Ordinance for Introduction

d. General Manager of GWP, re: Award Contract for the Sale of Power Island Equipment and Services for the Proposed Repowering of the Grayson Power Plant and Issuance of a Limited Notice to Proceed to Siemens Energy, Inc.

Mayor Devine and Council Member Najarian left the chambers at 7:29 p.m. due to a possible conflict of interest. Mayor Devine passed the gavel to Mayor Pro Tem Sinanyan. Devine entered the chambers at 8:00 p.m. and resumed her duties as chair of the meeting.

Presenting:
Steve Zurn, General Manager of GWP

1. Resolution 16-194 Authorizing the City Manager or His Designee to Execute a Contract with Siemens Energy, Inc., for the Sale of Power Island Equipment and Services for the Proposed Repowering of the Grayson Power Plant and Authorizing the Issuance of a Limited Notice to Proceed in the Amount of $3,804,000 to Provide Design and Engineering Deliverables Necessary for Permitting, Development of Specification, and Analysis Under the California Environmental Quality Act (CEQA)

Moved: Gharpetian Seconded: Friedman
Vote as Follows

Ayes: Friedman, Gharpetian, Sinanyan
Noes: None
Absent: Najarian (recused), Devine (recused)
Abstain: None

2. Resolution 16-195 of Appropriating the Sum of $3,804,000 from the Electric Fund Net Position Account No. 27900-552 to Project Account No. 43110-553-921-13748-UP100

Moved: Gharpetian Seconded: Friedman
Vote as Follows

Ayes: Friedman, Gharpetian, Sinanyan
Noes: None
Absent: Najarian (recused), Devine (recused)
Abstain: None

9. HEARINGS

10. REPORTS – INFORMATION

11. WRITTEN COMMUNICATIONS

12. ORAL COMMUNICATIONS (5-Minutes)

Discussion is Limited to Items NOT a Part of this Agenda. Each Speaker is Allowed 5 Minutes. Council May Question or Respond to The Speaker But There Will be no Debate or Decision. The City Manager May Refer the Matter to the Appropriate Department for Investigation and Report.

13. NEW BUSINESS

a. Motion to Enter into a Retainer Agreement with the Bill H. Seki of Seki Nishimura & Watase LLP, to Assist the City Attorney on a Legal Matter.

Moved: Gharpetian Seconded: Sinanyan
Vote as Follows

Ayes: Gharpetian, Sinanyan, Devine
Noes: None
Absent: Najarian
Abstain: Friedman

14. ADJOURNMENT– 8:02 p.m.

Moved: Friedman Seconded: Sinanyan

____
Mayor of the City of Glendale

____
City Clerk of the City of Glendale

EXHIBIT 9

Decision 13-02-015 February 13, 2013

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014 (Filed March 22, 2012)

DECISION AUTHORIZING LONG-TERM PROCUREMENT FOR LOCAL CAPACITY REQUIREMENTS

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(cont.)

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DECISION AUTHORIZING LONG-TERM PROCUREMENT FOR LOCAL CAPACITY REQUIREMENTS

1. Summary

In this decision, we authorize Southern California Edison Company (SCE) to procure between 1400 and 1800 Megawatts (MW) of electrical capacity in the West Los Angeles sub-area of the Los Angeles (LA) basin local reliability area to meet long-term local capacity requirements (LCRs) by 2021. SCE is also authorized to procure between 215 and 290 MW of the Moorpark sub-area of the Big Creek/Ventura local reliability area. The LCRs require resources be located in a specific transmission-constrained area in order to ensure adequate available electrical capacity to meet peak demand, and ensure the safety and reliability of the local electrical grid.

For the defined portion of the LA basin local area, at least 1000 MW, but no more than 1200 MW of this capacity must be procured from conventional gas-fired resources. At least 50 MW must be procured from energy storage resources. At least 150 MW of capacity must be procured through preferred resources consistent with the Loading Order in the Energy Action Plan, or energy storage resources. SCE is also authorized to procure up to an additional 600 MW of capacity from preferred resources and/or energy storage resources. In addition, SCE will continue to obtain resources which can be used in these local reliability areas through processes defined in energy efficiency, demand response, renewables portfolio standard, energy storage and other relevant dockets.

The long-term LCRs are expected to result from the retirement of thousands of MW from current once-through cooling generators due to compliance with State Water Quality Control Board regulations. We anticipate that much of the additional LCR need currently forecast by the California Independent System Operator can be filled by preferred resources, either through procurement of capacity or reduction in demand. Preferred resources include energy efficiency, demand response, and distributed generation including combined heat and power. Energy storage resources may also be available.

In the next long-term procurement proceeding, expected to commence in 2014, we will evaluate whether there are additional LCR needs for local reliability areas in California.

SCE is directed to begin a solicitation process to procure authorized LCR resources. The first step is a plan to issue one or more Request for Offers and/or to enter into cost-of-service contracts per Assembly Bill 1576 (Stats 2005, ch. 374). SCE should also actively pursue locally-targeted and cost-effective preferred resources. SCE's procurement plan shall be consistent to the extent possible with the multi-agency Energy Action Plan, which places cost-effective energy efficiency and demand response resources first in the Loading Order, followed by renewable resources and then fossil-fuel resources. Energy storage resources should be considered along with preferred resources. SCE's procurement plan should take into account the technical reliability requirements of the California Independent System Operator. Energy Division will review SCE's adherence to these and other requirements before SCE commences its public solicitation process.

We consider today's decision a measured first step in a longer process. If as much or more of the preferred resources we expect do materialize, there will be no need for further LCR procurement based on current assumptions. If circumstances change, there may be a need for further LCR procurement in the next long-term procurement proceeding. We are confident that today's decision is the appropriate and considered step at this time.

SCE is directed to file an Application for each local reliability area seeking approval of contracts arising from the procurement process we authorize today. The Applications are expected in late 2013 or early 2014. Separately and earlier, SCE may also file applications for gas-fired generation in order to expedite review of such contracts. This decision establishes criteria for review of SCE's forthcoming Applications. A significant aspect of that review will be to ensure consistency with the Loading Order.

2. Background

This proceeding is the successor proceeding to rulemakings dating back to 2001 intended to ensure that California's major investor-owned utilities (IOUs) can maintain electric supply procurement responsibilities on behalf of their customers. The most recent predecessor to this proceeding was Rulemaking (R.) 10-05-006. As stated in the order originating this rulemaking in Ordering Paragraph 3, the record developed in R.10-05-006 is "fully available for consideration in this proceeding" and is therefore incorporated into the record of this proceeding.

In the Scoping Memo for this proceeding, issued on May 17, 2012, the general issues for the 2012 procurement planning cycle were divided into three topics[1]:

1. Identify Commission-jurisdictional needs for new resources to meet local or system resource adequacy (RA), renewable integration, or other requirements and to

[1] Scoping Ruling at 5.

consider authorization of investor-owned utility (IOU) procurement to meet that need. This includes issues related to long-term renewable planning and need for replacement generation infrastructure to eliminate reliance on power plants using once-through cooling technology (OTC);

2. Update, and review individual IOU bundled procurement plans consistent with Public Utilities Code § 454.5;[2] and
3. Develop or refine procurement rules that were not resolved in R.10-06-005, and consider other emerging procurement policy topics.

The Scoping Memo divided the proceeding into three Tracks:

1. Track 1: Local Reliability
2. Track 2: System Reliability
3. Track 3: Procurement Rules and Bundled Procurement Plans

This is the decision for Track 1 of this proceeding. In recent years the California Independent System Operator (ISO or CAISO) has performed an annual Local Capacity Requirements (LCR) study, which is filed in the Commission's RA proceeding. This study is used to adopt local RA procurement requirements for the next year; for example, requirements for 2013 were adopted in Decision (D.) 12-06-025, in the 2012 RA proceeding (R.11-10-023).

In RA decisions, the Commission has focused on LCR for local reliability for one forward year. In the Local Reliability track of this proceeding, we consider authorizing long-term procurement of new infrastructure for local

[2] All statutory references are to the Public Utilities Code, unless otherwise noted.

reliability purposes for the years 2021 and beyond.[3] As the Scoping Memo stated, the end result of this track of the proceeding should be that the IOUs and/or other load-serving entities (LSEs) will be authorized or required to contract for local reliability needs over the next several years, to the extent that the Commission finds there is such a need.

The main driver of local capacity requirements is that around 4900 megawatts (MW) of OTC plants in the local transmission-constrained areas of the Los Angeles (LA) basin local area may retire in the next several years, as well as other OTC plants in the Big Creek/Ventura and San Diego local areas because of State Water Resources Control Board (SWRCB) regulations.[4][5] By 2021, approximately 7000 MW of OTC capacity is expected to retire in the LA basin local area and the Big Creek/Ventura local area.

"Once-through cooling" is a method to dispose of waste heat produced by a power plant (heat not converted into electricity) in which cold ocean or river water is pumped one time through the plant, absorbing and carrying out the plant's waste heat back into the ocean or river. Because the water pumped through the plant and back into the ocean or river can cause considerable stress on the local aquatic ecosystems, the result is considered as water pollution under Section 316(b) of the Federal Clean Water Act. In California, the SWRCB is the

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[3] A local capacity area is a geographic area that does not have sufficient transmission import capability to serve the customer demand in the area without the operation of generation located within that area.

[4] *See* State Water Resources Control Board Resolution No. 2010-0020, adopted on May 4, 2010, effective 9/28/2010; Attachment 1, Milestone No. 26 at 14.

[5] Issues related to infrastructure needs for the San Diego local area are being considered in Application (A.) 11-05-023 and will not be in the scope of this proceeding, except to the extent that any decisions in that proceeding inform the record.

state agency that enforces the Federal Clean Water Act. As part of such regulation, the SWRCB now requires that most of these aging coastal fossil-fuel plants become compliant with their policy by the end of the year 2020, with some exceptions with different dates. Compliance can occur either through changing cooling intake to no longer use once-through cooling, or by reducing entrainment by 93%. Most generators in their plans filed with the SWRCB have indicated that they are pursuing the first option, which implies retirement or repowering of the facility.

Table 1 shows the plants, locations and expected compliance dates for OTC plants in the LA basin and Big Creek Ventura local areas.[6]

[6] The San Onofre Nuclear Generating Stations (SONGS) plants are OTC plants, but are not included in this analysis.

TABLE 1

Once-Through Cooling Plants Compliance Schedule Per State Water Resources Control Board

Los Angeles Basin Local Reliability Area

Unit Name	Owner	NQC	Compliance date
		175	12/31/20
		175	12/31/20
		332	12/31/20
		336	12/31/20
		498	12/31/20
		495	12/31/20
El Segundo Unit 3	NRG	335	12/31/15
El Segundo Unit 4	NRG	335	12/31/15
Huntington Beach Unit 1	Edison Mission Energy	226	12/31/20
Huntington Beach Unit 2	Edison Mission Energy	226	12/31/20
Huntington Beach Unit 3	Edison Mission Energy	225	12/31/12
Huntington Beach Unit 4	Edison Mission Energy	227	12/31/12
Redondo Beach Unit 5	AES	179	12/31/20
Redondo Beach Unit 6	AES	175	12/31/20
Redondo Beach Unit 7	AES	493	12/31/20
Redondo Beach Unit 8	AES	496	12/31/20

Big Creek - Ventura Local Reliability Area

Unit Name	Owner	NQC	Compliance date
Mandalay Unit 1	GenOn	215	12/31/20
Mandalay Unit 2	GenOn	215	12/31/20
Ormond Beach Unit 1	GenOn	741	12/31/20
Ormond Beach Unit 2	GenOn	775	12/31/20

Units and compliance dates from:
http://www.waterboards.ca.gov/publications_forms/publications/factsheets/docs/oncethroughcooling0811.pdf

As noted, Table 1 excludes
SONGS

* Net Qualified Capacity (NQC) from:
http://www.cpuc.ca.gov/NR/rdonlyres/C6BE7182-D647-4C70-B1AC-5D3A1CE207C3/0/CPUCNQCLocalAreaData_ComplianceYear2012.xls

In a settlement agreement approved by the Commission in D.12-04-046 in the previous long-term procurement plan Rulemaking,[7] parties to the agreement found that in the first quarter of 2012 the ISO would present a study of integration of renewable resources into local transmission-constrained areas, along with a study of the effect of potential OTC plant retirements. The adopted settlement included a recommendation that the Commission issue a decision by the end of 2012 on the need for sufficient resources to integrate the number of renewable resources coming online to meet a 33% renewable portfolio standard by 2020 and the retirement of OTC plants.

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[7] This settlement was entitled: "Motion For Expedited Suspension Of Track 1 Schedule, And For Approval Of Settlement Agreement Between And Among Pacific Gas And Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, The Division Of Ratepayer Advocates, The Utility Reform Network, Green

Footnote continued on next page

Section 454.5(b)(9)(C) states that utilities must first meet their "unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible." Consistent with this code section, the Commission has held that all utility procurement must be consistent with the Commission's established Loading Order, or prioritization. The Loading Order, first set forth in the Commission's 2003 Energy Action Plan, was presented in the Energy Action Plan II adopted by this Commission and the California Energy Commission (CEC) in October 2005. The Loading Order, which has been reiterated in multiple forums (including D.12-01-033 in the predecessor to this docket), requires the utilities to procure resources in a specific order:

"The 'Loading Order' established that the state, in meeting its energy needs, would invest first in energy efficiency and demand-side resources, followed by renewable resources, and only then in clean conventional electricity supply." (Energy Action Plan 2008 Update at 1.)

In the 2008 Energy Action Plan Update at 20, the Commission further interpreted this directive to mean that the IOUs are obligated to follow the loading order on an ongoing basis. Once procurement targets are achieved for preferred resources, the IOUs are not relieved of their duty to follow the Loading

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Power Institute, California Large Energy Consumers Association, The California Independent System Operator, The California Wind Energy Association, The California Cogeneration Council, The Sierra Club, Communities For A Better Environment, Pacific Environment, Cogeneration Association Of California, Energy Producers And Users Coalition, Calpine Corporation, Jack Ellis, Genon California North LLC, The Center For Energy Efficiency And Renewable Technologies, The Natural Resource Defense Council, NRG Energy, Inc., The Vote Solar Initiative, And The Western Power Trading Forum."

Order. In D.07-12-052 at 12, the Commission stated that once demand response and energy efficiency targets are reached, "the utility is to procure renewable generation to the fullest extent possible." The obligation to procure resources according to the Loading Order is ongoing. (D.12-01-033 at 19.) In D.12-01-033 at 21, the Commission recognized that procuring additional preferred resources is more difficult than "just signing up for more conventional fossil fuel generation," but consistency with the Loading Order and advancing California's policy of fossil fuel reduction demand strict compliance with the loading order.

This clarified Loading Order is a departure from the Commission's previous position of procuring energy efficiency and demand response, then renewable energy, and then allowing "additional clean, fossil-fuel, central-station generation," because "preferred resources require both sufficient investment and adequate time to 'get to scale.'" (D.04-06-011, footnote 22 at 31). Instead of procuring a fixed amount of preferred resources and then procuring fossil-fuel resources, the IOUs are required to continue to procure the preferred resources "to the extent that they are feasibly available and cost effective." (D.12-01-033 at 21.) While procuring a fixed amount of preferred resources provides flexibility and a clearer idea of how to approach the procurement process, the ongoing Loading Order approach is more consistent with Commission policy. (*Id.*)

A prehearing conference (PHC) was held on April 18, 2012. At the PHC, the ISO stated that it had completed a study of LCRs through 2016 in its Transmission Planning Process. The ISO also completed a study of local capacity needs related to expected or potential retirements of OTC plants through 2021. These studies are consistent with the studies anticipated in the settlement agreement adopted in D.12-04-046. In its comments on the scope of this proceeding and at the PHC, the ISO maintained that it cannot evaluate any additional renewable portfolio scenarios beyond those already in the record of R.10-05-006 in time for a decision by the Commission by the end of 2012.

In this proceeding, parties were given the opportunity to present evidence that the ISO's studies should be modified, or that the Commission should consider additional factors beyond the ISO's studies, for the purposes of determining local reliability needs. The Scoping Memo presented a list of specific issues for this phase of the proceeding.

The ISO served its testimony on May 23, 2012. Parties served testimony in response to the ISO and on issues from the Scoping Memo on June 25, 2012. The assigned Commissioner issued a Ruling on July 13, 2012 seeking clarification on certain issues raised in opening testimony. Parties (including the ISO) served reply testimony (including issues from the assigned Commissioner's Ruling) on July 23, 2012.[8] Evidentiary hearings were held August 7-10 and August 13-17, 2012. Briefs were filed on September 24, 2012 and Reply Briefs were filed on October 7, 2012. Per a Ruling issued September 14, 2012, comments were filed on October 9, 2012 regarding certain implementation issues arising from a workshop on September 7, 2012. This track of the proceeding was submitted on October 9, 2012.

The parties which served testimony in Track 1 of this proceeding are[9]: AES Southland (AES); Alliance for Retail Energy Markets, Direct Access

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[8] Certain parties served supplemental and other versions of testimony on other dates with permission of the Administrative Law Judge (ALJ).

[9] Parties serving testimony that was subsequently stricken from the record are not included in this list.

Customer Coalition and Marin Energy Authority (collectively, AReM); California Cogeneration Council (CCC); California Energy Storage Alliance (CESA); California Environmental Justice Alliance (CEJA); CAISO or ISO; California Large Energy Consumer's Association (CLECA); Calpine Corporation (Calpine); Center for Energy Efficiency and Renewable Technologies (CEERT); Cogeneration Association of California (CAC); Division of Ratepayer Advocates (DRA); EnerNOC, Inc. (EnerNOC); GenOn Energy, Inc. (GenOn); Independent Energy Producers Association (IEP); Natural Resources Defense Council (NRDC); Pacific Gas and Electric Company (PG&E); San Diego Gas and Electric Company (SDG&E); Southern California Edison Company (SCE); South San Joaquin Irrigation District (SSJID); The Utility Reform Network (TURN); The Vote Solar Initiative (Vote Solar); and Women's Energy Matters (WEM). Testimony from each of these parties was received into evidence at the evidentiary hearing.

Each of these parties also filed comments and/or briefs. In addition, comments and/or briefs were filed by Alliance for Nuclear Responsibility (ANR); Beacon Power, LLC; City and County of San Francisco; Clean Coalition; Community Environmental Council; Distributed Energy Consumer Advocates; Ormat Technologies; and Sierra Club California (Sierra Club).

3. Long-Term Local Capacity Requirements for the LA Basin Local Area – Party Positions

3.1. ISO

Overall, the ISO recommends the long-term procurement of approximately 2400 MW in the LA basin local area to meet LCR needs in 2021, if the generation is selected from the most effective sites. This amount includes a specific identified need for 225 MW in the Ellis sub-area of the LA basin local area.[10] The ISO recommends that the Commission authorize this procurement by the end of 2012 and that SCE begins a contracting process in 2013. The ISO found that potential retirement of OTC generation in the PG&E service territory is not expected to create local capacity deficiencies.[11]

The ISO performed local capacity technical studies to determine the minimum amount of resources within a local capacity area needed to address reliability concerns following the occurrence of various contingencies on the electric system.[12] The ISO used power flow modeling as the basis for its recommendations. The ISO's recommendations for the amount of local capacity required to ensure that there is sufficient capacity to keep the lights on at all times are based on load circumstances that are projected by the CEC to occur once in 10 years,[13] and the assumption that the two largest generation or transmission failures occur nearly simultaneously in a local area.

In the previous Rulemaking (R.10-05-006), Commission staff provided the ISO with four scenarios consistent with the 33% renewables portfolio standard[14] (RPS).[15] These scenarios provided information for models tested by the ISO in

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[10] Exhibit ISO-1 (Sparks) at 17.

[11] Exhibit ISO-1 (Sparks) at 3.

[12] Exhibit ISO-1 (Sparks) at 3.

[13] Exhibit ISO-1 (Sparks) at 16.

[14] *See* Pub. Util. Code §§ 399.11-399.31.

[15] The four scenarios are: 1) Trajectory, or the current procurement path; 2) Environmentally-constrained, which focused on reducing land-use impacts; 3) the ISO Base Case, which was a modified version of the CPUC's cost-constrained case wherein cost was the primary consideration; and 4) the time-constrained case, which focused on attaining 33% renewables as quickly as possible.

that proceeding, based on analysis developed in the Commission's RPS proceeding. Due to the settlement adopted in D.12-04-046, such models were not used as the basis for a Commission decision, but these models remain available for use in this proceeding.

In opening testimony, ISO witnesses Rothleder and Sparks describe how in this proceeding they again modeled a number of possible outcomes for the ISO based on the same RPS portfolios. An important part of the modeling was the use of demand forecasts provided by the CEC in its 2010 Integrated Energy Policy Report (IEPR), which used 2009 demand forecast data. Rothleder describes certain modeling changes that led to different results from those produced in R.10-05-006.[16]

The ISO performed a local capacity technical study that "determined the minimum amount of resources within a local capacity area needed to address reliability concerns following the occurrence of various contingencies on the electric system."[17] While the ISO has performed annual short-term (one year out) local capacity studies for a number of years that are used in the Commission's RA proceedings, here the ISO performed a local capacity study that looked at a 10-year planning horizon.[18] This is the first time the ISO has performed this 10-year study.[19]

The ISO performed its studies assuming that generation to meet LCR needs stemming from the assumed retirement of OTC plants would be met via

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[16] Exhibit ISO-4 (Rothleder) at 5-6.

[17] Exhibit ISO-1 (Sparks) at 3.

[18] Exhibit ISO-1 (Sparks) at 5.

[19] Reporter's Transcript (RT) 117.

repowering or replacement in the same locations as the OTC plants.[20] The ISO provided a range of forecasts for each RPS portfolio. The lower end of the range for the four RPS scenarios corresponds to the amount of generation needed if it were located at existing OTC sites that are the most effective at mitigating the identified transmission constraint. The higher end of the range corresponds to the amount of generation needed if it were located at existing OTC sites that are the least effective at mitigating the identified transmission constraint.[21] In the various studies, the ISO found an LCR need of at least 1870 MW for the most effective sites, and up to 3896 MW for less effective sites in the LA basin local area served by SCE. Specifically, the LCR need would be in the Western LA portion of the LA basin local area (a transmission-constrained sub-area of the LA basin).

Several parties challenged the ISO's methodology, as discussed herein. The ISO maintains that no party presented a valid alternative to the ISO's methodology, which it describes as "a deterministic approach based on Northern American Electric Reliability Council/Western Electricity Coordinating Council planning criteria and ISO tariff requirements."[22]

No capacity from demand response[23] was included in any ISO analysis because the ISO "does not believe that demand response can be relied upon to address local capacity needs, unless the demand response can provide equivalent

[20] Exhibit ISO-1 (Sparks) at 2.

[21] Exhibit ISO-1 (Sparks) at 6.

[22] ISO Opening Brief at 2.

[23] There appears to be price-responsive demand response built into the CEC demand forecast, but not other demand response programs.

characteristics and response to that of a dispatchable generator." The ISO claims "demand response does not have these characteristics at this time."[24]

Nor does the ISO include any demand reduction for uncommitted energy efficiency or uncommitted combined heat and power (CHP) in its forecasts.[25] Uncommitted energy efficiency and uncommitted CHP are potentially viable energy efficiency programs or CHP installations not already included in the 2009 CEC demand forecast, regardless of actions taken after that forecast. The ISO contends that it has "no basis for expecting that uncommitted energy efficiency and uncommitted CHP generation can be counted upon for meeting local reliability needs beyond the committed programs that were included in the CEC's officially adopted demand forecast."[26]

Table 2 shows the various outcomes of the ISO studies.

[24] Exhibit CEJA x ISO-1 at 3.

[25] These resources are termed either "incremental" or "uncommitted." Either term refers to resources beyond the amounts embedded in the CEC's demand forecast.

[26] Exhibit ISO-1 (Sparks) at 15.

TABLE 2

Summary of ISO Studies by RPS Portfolio

<table>
<tr><th rowspan="2">Local Area</th><th colspan="4">Local Area Requirements (MW)</th><th colspan="4">Replacement OTC Generation Need (MW)</th></tr>
<tr><th>Trajectory</th><th>Environmentally Constrained</th><th>ISO Base Case</th><th>Time Constrained</th><th>Trajectory</th><th>Environmentally Constrained</th><th>ISO Base Case</th><th>Time Constrained</th></tr>
<tr><td>LA Basin (this area includes sub-area below)</td><td>10,743</td><td>11,246</td><td>11,010</td><td>12,165</td><td rowspan="2">2,370 – 3,741</td><td rowspan="2">1,870 – 2,884</td><td rowspan="2">2,424 – 3,834</td><td rowspan="2">2,460 – 3,896</td></tr>
<tr><td>Western LA Basin (sub-Area of the larger LA Basin)</td><td>7,797</td><td>7,564</td><td>7,517</td><td>7,397</td></tr>
<tr><td rowspan="2">Big Creek/Ventura (BC/V) Area</td><td rowspan="2">2,371</td><td rowspan="2">2,604</td><td rowspan="2">2,438</td><td rowspan="2">2,653</td><td colspan="4">(Need is for Moorpark only, a sub-area of the Big Creek/Ventura Local area)</td></tr>
<tr><td>430</td><td>430</td><td>430</td><td>430</td></tr>
</table>

In each of the four RPS scenarios, the ISO model included assumptions of distributed generation MW, and non-distributed generation MW for 2021; all scenarios assumed the same demand forecasts from the CEC. Tables 3 - 6 show the ISO's distributed generation and non-distributed generation assumptions for each scenario.[27]

[27] Exhibit ISO-1 (Sparks) at 7-9.

TABLE 3

Portfolios	Area	Local Area Reqm't Non-D.G. (MW)	D.G. (MW)	Total (MW)	Replacement OTC Units Needed?	Constraint	Contingency
Trajectory	Overall LA Basin	12,961	339	13,300	Yes	Mira Loma West 500/230 Bank #1 (24-Hr rating)	Chino-Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV Bank #2
		10,404	339	10,743	Yes	Eagle Rock-Sylmar S 230 kV line	Sylmar S-Gould 230 kV line + Lugo-Victorville 500 kV line
	Western	7,529	268	7,797	Yes	Serrano-Villa PK #1	Serrano-Lewis #1 / Serrano-Villa PK #2
	Ellis	225	59	284	Yes	Voltage Collapse	Barre-Ellis 230 kV line + SONGS - Santiago #1 and #2 230 kV lines
	El Nido	614	5	619	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

TABLE 4

Portfolios	Area	Local Area Reqm't Non-D.G. (MW)	D.G. (MW)	Total (MW)	Replacement OTC Units Needed?	Constraint	Contingency
Environmentally Constrained	Overall LA Basin	11,048	1,519	12,567	Yes	Mira Loma West 500/230 bank #1 (24-Hr rating)	Chino-Mira Loma East #3 23 0kV line + Mira Loma West 500/230 kV bank #2
		9,727	1,519	11,246	Yes	Eagle Rock-Sylmar S 230 kV line	Sylmar S - Gould 230 kV line + Lugo - Victorville 500 kV line
	Western	6,695	869	7,584	Yes	Serrano- Villa PK #1	Serrano-Lewis #1 / Serrano-Villa PK #2
	Ellis	225	124	349	Yes	Voltage Collapse	Barre-Ellis 230kV Line + SONGS - Santiago #1 and #2 230 kV lines
	El Nido	494	91	585	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

TABLE 5

Portfolios	Area	Local Area Reqm't Non-D.G. (MW)	D.G. (MW)	Total (MW)	Replacement OTC Units Needed?	Constraint	Contingency
Base	Overall LA Basin	12,659	271	12,930	Yes	Mira Loma West 500/230 Bank #1 (24-Hr rating)	Chino-Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV bank #2
		10,739	271	11,010	Yes	Eagle Rock-Sylmar S 230 kV line	Sylmar S-Gould 230kV line + Lugo-Victorville 500 kV line
	Western	7,325	192	7,517	Yes	Serrano-Villa PK #1	Serrano - Lewis #1 / Serrano - Villa PK #2
	Ellis	225	39	264	Yes	Voltage Collapse	Barre-Ellis 230kV Line + SONGS-Santiago #1 and #2 230 kV lines
	El Nido	544	94	568	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

TABLE 6

Portfolios	Area	Local Area Reqm't Non-D.G. (MW)	D.G. (MW)	Total (MW)	Replacement OTC Units Needed?	Constraint	Contingency
Time-Constrained	Overall LA Basin	12,677	687	13,364	Yes	Mira Loma West 500/230 bank #1 (24-Hr rating)	Chino - Mira Loma East #3 230 kV line + Mira Loma West 500/230 kV bank #2
		11,478	687	12,165	Yes	Eagle Rock-Sylmar S 230 kV Line	Sylmar S-Gould 230 kV line + Lugo-Victorville 500kV line
	Western	6,954	443	7,397	Yes	Serrano-Villa PK #1	Serrano-Lewis #1 / Serrano-Villa PK #2
	Ellis	225	61	286	Yes	Voltage Collapse	Barre - Ellis 230 kV line + SONGS-Santiago #1 and #2 230 kV lines
	El Nido	589	31	620	No	La Fresa-Hinson 230 kV line	La Fresa-Redondo #1 and #2 230 kV lines

The ISO recommendation is based on the Trajectory scenario because "the Trajectory scenario studied in the OTC studies is the scenario most aligned with commercial interest."[28] The ISO also believes this scenario best reflects future

[28] Exhibit ISO-1 (Sparks) at 17.

load growth and renewable generation development.[29] The Trajectory scenario forecasts a need for 2370 MW in the LA basin local area, which Sparks rounds up to 2400 MW.[30] This forecast includes a specific need for 225 MW in the Ellis sub-area.

In supplemental testimony, Sparks describes a sensitivity analysis performed at the request of this Commission, the CEC and the California Air Resources Board (CARB), to study a variation on the Environmentally Constrained portfolio. As part of the sensitivity analysis, demand reduction from 1950 MW of uncommitted energy efficiency and 201 MW of additional CHP was included in the model,[31] as provided by the three state agencies and adjusted for the LA basin local area (as part of 2461 MW of uncommitted energy efficiency and 209 MW of uncommitted CHP for the entire SCE territory).[32] For the Western LA basin sub-area, 1121 MW of uncommitted energy efficiency was included in this analysis, and 180 MW of CHP.[33]

According to this testimony, the results of this sensitivity analysis show a need of 1042 MW needed in the Western LA section of the LA basin local area for 2021 for effective sites, with the range reflecting the same effectiveness considerations as described above.[34] This compares to 1870 MW for effectives sites for 2021 in the Environmentally Constrained scenario in Table 2 herein. The

[29] ISO Opening Brief at 3.

[30] RT 197-198.

[31] Exhibit ISO-9 at (Table 3.4-1).

[32] Exhibit ISO-2 (Sparks) at 2-3.

[33] RT 137-143; Exhibit CEJA x ISO-1 at 2-3.

[34] Exhibit ISO-2 (Sparks) at Table 2.

sensitivity analysis also models the Del Amo-Ellis 230 kilovolt line loop-in project in service, based on updated information in the ISO's supplemental testimony that the ISO Board has now approved this project for 2012. This project eliminates the need for local generation in the Ellis sub-area in this scenario.[35]

The ISO does not recommend relying upon its sensitivity analysis to make a determination as to local area needs in this proceeding. Sparks testified that the ISO does not believe it is prudent to rely on uncommitted resources (such as uncommitted energy efficiency and CHP) for assessing future local needs. Further, Sparks testified that "deliberately conservative forecasts must be employed in the assessment of reliability requirements for capacity in constrained areas since the consequences of being marginally short versus marginally long are asymmetric. A marginal shortage means the loss of firm load, which puts public safety and the economy in jeopardy, whereas a marginal surplus has only a marginal cost implication."[36] Further, Sparks testified that there is "uncertainty" concerning both uncommitted energy efficiency and incremental CHP which makes it imprudent to include these potential resources in the ISO forecasts.[37]

Sparks testified that it is necessary to begin the procurement process for 2021 local capacity needs in 2013 "to ensure we don't forgo the best options, and also to make sure that the options that are available are actually feasible."[38]

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[35] Exhibit ISO-2 (Sparks) at 2-3.

[36] Exhibit ISO-2 (Sparks) at 3-4.

[37] Exhibit ISO-2 (Sparks) at 5-6.

[38] RT 199.

3.2. SCE Position

SCE generally agrees with the ISO's analysis identifying a 2021 need for up to 2370 MW of existing LCR generation in the LA basin local area to remain in service or be replaced with similarly located generation (also known as, or up to 3741 MW if new generation cannot be placed at the most effective sites in the local area.[39] SCE seeks authority to start a process in 2013 to enter into contracts for between zero MW and 3741 MW in the LA basin local area.

SCE seeks flexibility in conducting any LCR procurement that is needed. In general, SCE would prefer not to procure resources to meet system needs and to make long-term commitments that would subsequently be rendered less valuable by changed circumstances.[40] SCE "prefers procurement of new LCR generation through a new multi-year forward procurement auction, such as a capacity market or a new generation auction administered by the CAISO" but acknowledges that such a mechanism is not currently available.[41]

Due to uncertainty in forecasts, SCE describes input assumptions in the ISO models that may change based on new information, and which could lead to a higher or lower need for LCR resources than the ISO identified. These include changes to the reliability planning standards, demand forecast, resource scenarios, LCR generation sites, and transmission options.[42] SCE witness Minick testified that another variable in determining long-term LCR needs is accurate

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[39] Exhibit SCE-1 (Cushnie/Silsbee/Minick) at 1, 3-5. SCE uses a slightly different definition of "effective" and "less effective" sites than the ISO.

[40] Exhibit SCE-1 (Cushnie) at 2.

[41] Exhibit SCE-1 (Cushnie) at 1.

[42] Exhibit SCE-1 (Minick/Cabbell) at 5-9.

identification of when the OTC plants are expected to close. He points to the potential for extensions of SWRCB deadlines and other changes surrounding OTC regulations as uncertainties in determining need.[43]

Minick also testified that the ISO did not recognize the potential for increased distributed generation, assumptions for uncommitted energy efficiency or increased localized generation, all of which would lower the load on the transmission system.[44] In reply testimony, SCE cites concerns raised by many parties about the ISO's assumptions regarding the availability and use of preferred resources, agreeing with claims by parties that higher levels of preferred resources than forecasted by the ISO will reduce or eliminate the need for new LCR generation in SCE territory.[45]

Despite these uncertainties, SCE witness Silsbee testified that at least some new generation procurement needs to occur to meet LCRs in the LA basin local area. He points to difficulties in constructing new generation in the LA Basin local area, which mean that it might take 7 to 9 years to develop new replacement generation. While there are uncertainties about the dates when OTC plants will cease to operate, there are also uncertainties around the lead time for generation permitting and construction. Therefore, Silsbee testified that there is a need to start initial procurement processes soon; for example, with a Purchased Power Agreement (PPA) entered into and approved by the Commission in 2013, it would potentially take until 2020 or longer for the plant to become operational.[46]

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[43] Exhibit SCE-1 (Minick) at 10.

[44] Exhibit SCE-1 (Minick) at 7.

[45] Exhibit SCE-2 (Silsbee) at 4.

[46] Exhibit SCE-1 (Silsbee) at 16-17.

3.3. DRA Position

DRA recommends the Commission defer a decision on SCE's LCR procurement, in order to allow the Commission to take into account final adopted planning standards in Track 2 of this proceeding that relate to distributed generation standards. DRA also recommends a transmission study to determine if there is further potential to increase imports into constrained areas, and ways to upgrade current transmission facilities. If the Commission authorizes SCE to procure LCR resources, DRA recommends authorization of no more than 169 MW for the LA basin local area for 2021 and no more than 278 MW for this area for 2022.[47]

DRA witness Fagan testified that "the risk of not procuring now is minimal if not zero," and that there is not a technical reliability risk in waiting another two years to make the LCR determination.[48] DRA's concern is that the Commission could authorize procurement of fossil-fuel plants now, when preferred resources may materialize soon which would obviate the need for some fossil fuel resources. Alternatively, DRA recommends that there be an opportunity to revise the LCR need determinations after 2012 planning assumptions are finalized.[49]

DRA has significant concerns about the ISO models for LCR needs. Fagan testified:

> …the CAISO's modeling analyses overestimate the range of deficiency of resources needed to meet 2021 local capacity

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[47] Exhibit DRA-6 (Fagan) at 4.

[48] RT 924.

[49] Exhibit DRA-3 (Spencer) at 12.

> requirements in the LA basin…primarily by either excluding or minimizing the effect that preferred demand side resources, including uncommitted energy efficiency and demand response, can have on projected peak load in these areas by 2021."[50]

Fagan calculates that LCR needs are lowered by more than 40% from the ISO's estimates of 1870 to 2664 MW in the Environmentally Constrained scenario (*see* Table 2) to only 828 to 1207 MW when the additional resources are included in the Environmentally Constrained scenario sensitivity analysis (*see* Table 3).[51]

Fagan testified that the ISO's primary modeling estimates are too high primarily because they exclude all uncommitted energy efficiency and all demand response resources. He believes these resources will be available and should be considered when planning for future year procurement needs.[52] Fagan recommends reducing the ISO forecast by 957 MW of uncommitted energy efficiency and 1550 MW of demand response.[53] Fagan acknowledges that these figures are part of a load and resources table, which is a simpler tool than the ISO's power flow model, and does not consider sub-areas; nevertheless, he contends that DRA's method is appropriate for a procurement proceeding.

DRA witness Spencer testified that the ISO has not properly accounted for the amount of preferred resources (including demand response, energy efficiency and renewable resources) expected to be available to reduce load or

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[50] Exhibit DRA-1 (Fagan) at 2-3.

[51] Exhibit DRA-1 (Fagan) at 2-3, 12-20. There are some methodological differences which cause a variation between DRA's figures and the ISO's figures.

[52] Exhibit DRA-1 (Fagan) at 17.

[53] Exhibit DRA-1 (Fagan) at 18, Table RF-2.

meet electricity demand. He maintains that "failure to adequately account for such resources increases the risk of over-procurement,"[54] including underutilized assets and "crowding out" of preferred resources. Further, over-procurement poses the risk of additional expenses for ratepayers.[55] In other words, ratepayers would pay to reduce load and increase supply, but would then (under the ISO recommendation) also be required to pay for additional supply as if the first set of funded initiatives did not exist.

Spencer also contends State policy goals should be given weight when considering the ISO 2021 local capacity needs recommendations. Specifically, California Governor Brown recently called for the development of 12,000 MW of distributed generation by 2020.[56] While the ISO recommendation of the Trajectory scenario includes 339 MW of distributed generation for the LA basin local area, it also modeled (but did not recommend) the Environmentally Constrained scenario with 1519 MW of distributed generation. DRA supports using the Environmentally Constrained scenario because DRA contends it is in line with California's commitment to distributed generation goals.[57]

3.4. TURN Position

TURN recommends that the Commission authorize procurement sufficient to satisfy 2/3 of the LCR needs sought by the ISO, due to problems with the ISO forecasts. Specifically TURN witness Woodruff contends that the ISO forecasts are "moving targets" that can vary significantly with each new iteration of the

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[54] Exhibit DRA-3 (Spencer) at 1.

[55] Exhibit DRA-3 (Spencer) at 3.

[56] Governor Jerry Brown, Clean Energy Jobs Plan at 3; June 2010.

[57] Exhibit DRA-3 (Spencer) at 8-9.

study.[58] TURN contends that both over-procurement and under-procurement would be costly, but that the ISO ignores the potential costs to ratepayers and focuses only on the "extremely low risk of criteria violations that could potentially result from significant shortage under extraordinarily stressed system conditions."[59]

TURN recommends that the Commission task SCE with procurement of any new local resources authorized in this docket, as the only practical option. TURN recommends that the Commission adopt one or more mechanisms to mitigate potential market power issues and other LCR procurement challenges. Possible mitigations measures include:

- Holding RFPs to seek the most competitive replacements for OTC resources, even in sub-areas in which there are currently no known alternatives to an OTC unit. Such RFPs should solicit both conventional generation and non-fossil alternatives.
- Providing minimum and maximum procurement targets to ensure truly needed amounts are procured but prevent procurement of capacity that will not necessarily be needed.
- Implementing some type of "circuit breaker" mechanism to allow procurement of lower amounts of capacity should prices of one or more bids greatly exceed a reasonable cost.
- Providing procurement in the most logistically challenging areas first, such as the Ellis and Moorpark sub-areas.[60]

[58] Exhibit TURN-1 (Woodruff) at 7-9.

[59] TURN Opening Brief at 6.

[60] Exhibit TURN-1 (Woodruff) at 2-3.

3.5. Environmental Parties' Positions

CEJA, NRDC, Sierra Club and WEM all contend that the ISO local capacity methodology should not have excluded significant amounts of uncommitted energy efficiency, CHP, demand response and energy storage. CEJA claims that "CAISO's results are inherently conservative and call for greater MW than will actually be needed."[61] NRDC claims "the amount of efficiency included in the CAISO's assessment of local capacity needs is unreasonably low because it excludes all savings from future energy efficiency policies, as well as some that were recently adopted."[62] Sierra Club contends that the ISO "uses worst case, unrealistic assumptions," such as modeling for outages which have not occurred in the last 10 years.[63] WEM argues that omitting certain categories of uncommitted energy efficiency "will lead to major forecast errors."[64]

Vote Solar recommends the Commission make a finding of LCR need for the total of the LA basin local area and the Big Creek/Ventura local area of between 800 MW and 1700 MW, depending on location.[65] However, Vote Solar recommends authorizing SCE to procure some of the identified LCR needs via gas-fired plants (preferably in the most efficient locations), but to wait a few years to see how much uncommitted energy efficiency, demand response and

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[61] Exhibit CEJA-1 (Powers) at 4.

[62] Exhibit NRDC-1 (Martinez) at 1.

[63] Sierra Club Opening Brief at 5-6.

[64] Exhibit WEM-1 (George) at 10.

[65] Vote Solar Opening Brief at 2, 4-5.

distributed photovoltaic installations will be available for delivery to reduce LCR needs by 2020.[66]

CEJA's analysis foresees additional resources, including additional transmission fixes, which can lower the LCR need in the LA basin local area for 2021. CEJA contends that these added resources tend to be available when most needed and are distributed geographically. CEJA claims that the ISO's failure to consider or include uncommitted energy efficiency, demand response, incremental CHP and all available distributed generation is unreasonable. CEJA concludes that, after including these additional resources, the actual LCR need under each of the four RPS scenarios is "likely zero."[67] Sierra Club also recommends a finding of zero LCR need for the LA basin local area.[68]

CEERT contends that the ISO assumed higher customer loads than adopted as State policy, inconsistent with the Loading Order. While CEERT is concerned that the ISO's forecasts are based upon relatively rare contingencies, CEERT does recommend finding procurement of no more than 1800 MW for LCR needs in this proceeding.[69] However, CEERT wants the Commission to identify eligibility requirements and performance metrics for preferred resources that can meet LCR needs, before authorizing LCR procurement.[70] CEERT would

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[66] Exhibit Vote Solar-1 (Gimon) at 4-5.

[67] Exhibit CEJA-3 (May) at 2-3.

[68] Sierra Club Opening Brief at 19.

[69] CEERT Opening Brief at 30.

[70] CEERT Opening Brief at 4-5.

allow non-traditional resources (those other than gas-fired resources) to submit bids in any solicitation to fill this need, consistent with the Loading Order.[71]

3.6. Other Party Positions

PG&E recommends that the LCR need determination should be based on the ISO study, because the ISO uses a conservative approach without modification for uncertain resource availability. PG&E also recommends that the Commission not establish any preferred resources set-asides in this proceeding.[72] SDG&E recommends that the ISO's LCR determinations should be accorded considerable weight by the Commission. SDG&E endorses SCE's position that SCE be authorized to procure up to the LCR amounts recommended by the ISO, with review by the Commission of SCE proposed contracts.[73]

CLECA contends that new generation can be operational in less than 7 to 9 years in some circumstances, such as by getting plants to the point of construction but only paying for an option to build if necessary. CLECA suggests the Commission could authorize development contracts that include permitting and site development but do not include construction, effectively creating an option for expedited development of new generation if and when it is needed.[74] CLECA also contends that the ISO, due to its obligations with respect to grid reliability, recommends over-procurement compared to what are required under NERC/WECC standards, leading to excessive ratepayer costs.[75]

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[71] Exhibit CEERT-1 (Caldwell) at II-3 - II-4.

[72] PG&E Opening Brief at 4-9.

[73] SDG&E Opening Brief at 3-11.

[74] CLECA Opening Brief, p. 28.

[75] CLECA Opening Brief, pp. 12-19.

IEP contends there is a need for some form of replacement capacity for the potential retirement of at least some OTC units, and that IOUs should procure LCR resources through competitive solicitations, or cost-of-service contracts.[76] IEP recommends a "somewhat more conservative approach" to determining LCR needs in order to ensure that firm load curtailments do not occur.[77] IEP proposes an "Incremental Need" calculation to set procurement targets; the Commission would authorize IOUs to procure resources at the level recommended by the ISO, but acknowledge that other resources might become committed in the future.[78]

EnerNOC criticizes the ISO for leaving various preferred resources out of its forecasts, focusing on the exclusion of demand response resources.[79] EnerNOC recommends the Commission find an LCR need for the LA basin local area of 2400 MW minus a MW amount reflective of expected growth of preferred resources in the local area, as an interim target. EnerNOC recommends the Commission reconsider the level of LCR need in the next long-term procurement proceeding, expected in 2014.[80]

Calpine recommends that any procurement authorized in this proceeding to satisfy LCR needs not be granted until system needs have also been determined in Phase 2 of this proceeding. Calpine contends that such an approach will put the IOUs in a better position to identify the least cost/best fit

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[76] Exhibit IEP-1 (Monsen) at 5-11.

[77] Exhibit IEP-1 (Monsen) at 20-21.

[78] Exhibit IEP-1 (Monsen) at 5-11.

[79] EnerNOC Opening Brief at 4-15.

[80] EnerNOC Opening Brief at 15.

mix of resource options to satisfy both local and system needs.[81] Calpine also recommends adopting procurement rules to ensure all viable technologies, resources and solutions are considered by the IOUs to satisfy local and system reliability needs. This would include gas-fired plants, preferred resources and transmission alternatives and upgrades.[82]

AES calculates a need for approximately 2300 MW at certain OTC locations in the LA Basin local area. Therefore, AES finds the ISO recommendation for approximately 2400 MW at effective locations to be consistent with its own analysis.[83]

CCC disagrees with the ISO that uncommitted energy efficiency and CHP should be excluded from LCR forecast models. CCC argues that the ISO's reliance on the CEC's IEPR misses more recent developments with regard to CHP. Specifically, CCC points to Commission approval of the "QF/CHP Settlement Agreement" in D.10-12-035 which has led to IOUs conducting their initial Request for Offers (RFOs) to procure 2000 MW of CHP capacity.[84] CCC also cites to more recent CEC efforts to update its projections for future CHP development in California.[85]

ANR endorses the ISO's Trajectory scenario estimate for the LA basin local area, but has strong reservations about the future availability of SONGS and a 600 MW transmission transfer. ANR contends the risk of over-capacity is smaller

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[81] Exhibit Calpine-1 (Barmack) at 1, 4.

[82] Exhibit Calpine-1 (Barmack) at 5.

[83] Exhibit AES-1 (Ballouz) at 1-2.

[84] Exhibit CCC-1 (Beach) at 6-7.

[85] Exhibit CCC-1 (Beach) at 7-8.

than the risk of under-capacity.[86] ANR recommends that Track 1 of this proceeding be continued after the Commission decision issues for the purpose of adjusting the determined LCR need, in order to take into account new information contained in the upcoming ISO 2012-2013 Transmission Plan.[87]

4. Long-Term Local Capacity Requirements for LA Basin Local Area – Discussion

4.1. Statutory Guidance

The Legislature has stated its policy goals relating to reliability, reasonableness of rates, and a commitment to a clean environment in the "Reliable Electric Service Investments Act," codified as § 399(b). This statute protects these divergent interests by ensuring investments in the integrity of the grid, in a sizeable and well trained utility workforce, in cost-effective energy efficiency improvements, in a sustainable supply of renewable energy, and in research and development that will advance the public interest.

The Commission is also bound by the RA Requirements in § 380. Section 380(c) states:

> Each load-serving entity shall maintain physical generating capacity adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves. The generating capacity shall be deliverable to locations and at times as may be necessary to provide reliable electric service.

The implementation of RA serves to ensure system reliability as well as siting and construction of new resources. Section 380 requires LSEs to maintain 100% of forecast load available as well as a 15% reserve. LSEs are also required

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86 ANR Opening Brief at 21.

87 ANR Opening Brief at 22.

to demonstrate to the Commission that sufficient Local RA resources have been procured in order to meet the needs of transmission constrained Local Areas.

A primary responsibility of this Commission is to ensure reliability in the electrical system. It would neither be prudent nor responsible to allow the system to fail and the lights to go out when we reasonably could have avoided such deleterious outcomes. Similarly, the primary mission of the ISO is to ensure reliability in the California electrical grid. Section 345 states:

> The Independent System Operator shall ensure efficient use and reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the North American Electric Reliability Council.

A significant difference between the ISO's reliability mission and the Commission's reliability emphasis is that the Commission must balance its reliability mandate with other statutory and policy considerations. Primarily, these considerations are reasonableness of rates and a commitment to a clean environment. These considerations stem from both statute and Commission policy consistent with statute.

Regarding reasonableness of rates, § 451 states in pertinent part:

> All charges demanded or received by any public utility… shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful.

Further, § 454 states:

> Except as provided in Section 455, no public utility shall change any rate or so alter any classification, contract, practice, or rule as to result in any new rate, except upon a showing before the commission and a finding by the commission that the new rate is justified.

There are a number of statutes which require the Commission to implement procurement-related policies to protect the environment. As a primary example, the Commission's RPS program is established in §§ 399.11-399.31. As discussed in Section 2, the Loading Order was established both in the Energy Action Plan and in statute.

In this decision, we strike a balance among the Commission's three primary statutory directives for ensuring reliability, reasonable rates and a clean environment. We cannot, and will not, sacrifice or ignore any of these imperatives. Nor need we do so; the record in this case supports outcomes which enable us to accomplish all our goals, meet statutory requirements and direct utilities to procure sufficient levels of diverse resources in a timely manner at a reasonable cost so as to ensure reliability. We now turn to the specific details.

4.2. Assumptions

ISO witness Sparks acknowledged that forecasting one year ahead is easier than 10 years out, with the 10-year forecast entailing more uncertainty on many factors.[88] Referring to the sensitivity analysis of the Environmentally Constrained scenario (which includes assumptions of more distributed generation, more uncommitted energy efficiency and more demand response than the Trajectory scenario), Sparks testified that the ISO study methodology "would need to be revisited if we were to actually see these types of changes to the resource supply in the area."[89] Because of the difficulty in assessing forecasts 10 years into the future done for the first time, it is necessary to carefully assess

[88] RT 79.

[89] RT 81.

the assumptions in such forecasts and to build in a method to revisit the forecasts when more information is available.

Sparks further testified:

> The ISO has no basis for expecting that uncommitted energy efficiency and uncommitted combined heat and power generation can be counted on for meeting local reliability needs beyond the committed programs that were included in the CEC's officially adopted demand forecast."[90]

However, we do have a basis for considering an estimate of such resources in our analysis. We discuss such estimates below.

Sparks claims that "the consequences of being marginally short versus marginally long are asymmetrical" because "a marginal shortage means a loss of firm load, which puts public safety and the economy in jeopardy, whereas a marginal surplus has only a marginal cost implication."[91] DRA disagrees. DRA witness Spencer cites costs reaching over one billion dollars (plus annual maintenance costs) as being very significant and not simply marginal.[92] In addition, there are significant environmental detriments to building and running more fossil-fuel power plants than necessary.

ISO witness Millar agrees that if reliability needs are met through natural gas generation, but more distributed generation occurs than the ISO forecasts, this would increase ratepayer costs (although he contends "that is a consequence

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90 Exhibit ISO-1 (Sparks) at 15.

91 Exhibit ISO-2 (Sparks/Millar) at 4; Exhibit DRA-3 (Spencer) at 16, citing Rebuttal Testimony of Robert Sparks on Behalf of the California Independent System Operator Corporation, A.11-05-023, June 4, 2012 at 3.

92 Exhibit DRA-3 (Spencer) at 16, citing PG&E's pending Oakley power plant Application (A.12-03-026).

of having to move forward in the face of uncertainty.")[93] Presumably, increased ratepayer costs would also occur if more energy efficiency or other resources than in the ISO models came to fruition. On the other hand, as already noted herein, the ISO contends that delaying procurement can result in lost opportunities due to a potential seven to nine year lead time for certain plants to go from proposal to operational.

We agree with the ISO that under-procurement entails significant risks. We also agree with DRA and others that over-procurement entails significant risks. We do not agree with the ISO that one error is necessarily more problematic than the other; neither error is desirable if avoidable. Nor can the consequences of either outcome be easily quantified; neither the ISO nor anyone else has quantified these consequences.[94]

Our intent is to neither authorize over-procurement nor under-procurement. However, the procurement process is of necessity imperfect because it relies on future forecasts. One benefit of a long planning horizon is the opportunity to adjust to the inevitable changes in circumstances. We will balance the potential for lost or limited opportunities to procure certain resources with long lead times against the opportunities to reconsider circumstances in the future.

The ISO used power flow modeling to develop its scenarios to forecast LCR needs. SCE agrees with this approach because it takes into consideration transmission constraints and limitations in specific local areas.[95] DRA proposes

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[93] RT 474.

[94] RT 499-503.

[95] Exhibit SCE-2 (Cabbell) at 16.

using a load and resources table. While DRA's approach has its benefits, there is general agreement that the ISO's modeling is more sophisticated and precise. We find the use of the ISO's power flow modeling to be reasonable for these purposes.

Sparks agreed that the precision of the ISO's power flow simulation is "completely dependent" upon the accuracy of the input assumptions, and that if the input assumptions vary, then the results would vary.[96] Therefore, it is important to consider whether any major assumptions used by the ISO should be revisited.

4.2.1. One-in-Ten Year Load, with Two Major Contingencies

The first question is whether the ISO's general methodology is reasonable. In our RA proceedings, we use ISO forecasts with a one-in-10-year load forecast, with two major contingency outages, to assess LCR needs one year in advance. In this proceeding, the ISO for the first time extended this methodology out to 10 years in advance.

A number of parties question whether the ISO's approach is appropriate. CEERT and others raise the issue of whether we should authorize procurement of up to several thousand MW of capacity based on a rare set of circumstances – essentially (as CEJA puts it) a "scenario that two import pathways to SCE's territory are unavailable on the hottest day in 10 years."[97] ISO witness Sparks testified that this situation in the LA basin local area has never

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[96] RT 167.

[97] CEJA Opening Brief at vii, 6-8.

occurred in the last 10 years.[98] The ISO did not analyze any scenario with only one contingency.

We recognize that the ISO models use assumptions of rare and unusual circumstances, which may never occur. However, this methodology is well-tested in our RA proceedings as a means of procurement of resources for local reliability purposes. As PG&E points out, the Commission must ensure the system will be reliable under a variety of possible future states, including a high load stress condition.[99] While the circumstances underlying the methodology are (hopefully) rare, the consequences of not having sufficient resources in such a rare situation would be extremely serious. We generally will use the ISO methodology for consideration of LCR needs, with the caveats concerning inputs discussed herein.

4.2.2. OTC Plant Compliance Schedule

The next question to consider is whether the OTC plants are likely to retire according to the compliance schedule presented in Table 1 herein. The schedule determined by the SWRCB is beyond our jurisdiction. However, we can consider relevant factors in the record that might influence whether the schedule will hold.

ISO witness Sparks testified that the ISO participates in a SWRCB committee called the Statewide Advisory Committee on Cooling Water Intake Structure (SACCWIS). In that committee, Sparks stated that the ISO "would seek to adjust the [OTC retirement] schedule" if it determines that reliability cannot be

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[98] RT 120.

[99] PG&E Opening Brief at 6.

met within the schedule.[100] If the retirement schedule is delayed for one or more plants past 2020, there could be a reduction in the local reliability need for the LA basin local area. In addition, Sparks testified that the continued operation of OTC plants was one possible way to meet local needs.

ISO witness Millar testified that there are a range of mitigation options in lieu of the addition of generation by SCE, if reliability cannot be met. He continued that these options may "fall within our current framework and our current authorities as well as should we be seeking additional authorities in order to advance the necessary reinforcements." For example, continuation of procurement already under ISO contract and consideration of load-shedding are other options. However, he also stated that while "[t]here is no framework to simply delay compliance with once-through cooling" retirement deadlines, working with the SWRCB to consider changing deadlines would be an option (but not "a given").[101]

If the Commission authorizes procurement based on the current OTC plant closure schedule, there could be over-procurement to the detriment of ratepayers and the environment if the plants do not close as scheduled. DRA contends that several OTC plants in the LA basin local area have asked for partial deadline extensions of up to six years.[102] DRA claims that the SACCWIS in March 2012 recommended considering extension deadlines on a unit-by-unit basis.[103] CEJA contends that SWRCB OTC policy does not require any coastal OTC plants to

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[100] RT 193 - 194.

[101] RT 447-456.

[102] Exhibit DRA-2 (Siao) at 5.

[103] Exhibit DRA-9.

actually retire, but allows these plants to remain operating should they comply with one of two tracks in the OTC policy (new cooling technologies or unit-by-unit measures to reduce marine impacts). CEJA claims many OTC units will not retire but will comply with one of the two tracks.[104] CLECA points out that delaying implementation of the OTC policy is an option for some limited period of time if it takes a little longer to implement full mitigation of the LCR consequences of this policy or to resolve some of the uncertainties that are currently driving the expected cost of LCR mitigation.[105]

We are aware of some efforts by specific OTC plant owners to comply with one of the SWRCB tracks to avoid retirement. However, there is at this time insufficient evidence that any change to the OTC deadlines in Table 1 will occur. As CLECA suggests, it may be that the ISO will request a delay in the OTC closure schedule in order to ensure ongoing reliability. While we do not anticipate such a delay, if any extensions to OTC closure deadlines do occur, this can be taken into account in future procurement proceedings or in review of a procurement application by SCE. At this time, it is reasonable to accept as a fact that, based on information available today, OTC plants will close as per the SWRCB schedule in Table 1.

4.2.3. Transmission

DRA contends that there are transmission fixes that may be able to offset some of the local capacity needs identified by the ISO. However, DRA acknowledges that it remains unclear whether additional cost-effective

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[104] Exhibit CEJA-1 (Powers) at 27-30.

[105] CLECA Opening Brief, p. 25.

transmission solutions are available that can reduce LCR need, and recommends further study.[106]

SCE agrees with DRA that the ISO did not consider certain transmission mitigation that could reduce LCR need,[107] but contends that the ISO's transmission infrastructure assumptions are reasonable.[108] SCE witness Cabbell testified that every year SCE evaluates the transmission grid and (with the ISO) looks for feasible and cost-effective transmission fixes.[109] However, she also asserts that there are challenges to reducing the local capacity need through transmission fixes, including the viability of construction of new transmission lines in the LA basin local area, increased need for voltage support for upgraded transmission, and a 7-to-10 year lead time to put in new transmission lines.[110] ISO witness Millar testified that "we have identified the…low-hanging fruit where transmission reinforcement was a viable way to reduce local capacity requirements" and these reinforcements were included in the ISO forecasts.[111]

CEJA contends that the ISO should have assumed in its models a 600 MW transmission load transfer to resolve the most critical contingency for the overall LA basin involving the Mira Loma West transmission line. According to CEJA, this transfer would significantly lower levels of LCR in the LA basin, if

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106 Exhibit DRA-1 (Fagan) at 4-5. Also *see* RT 907-910 and DRA Opening Brief at 24.

107 Exhibit SCE-1 (Cabbell) at 8-9.

108 Exhibit SCE-2 (Cabbell) at 16.

109 RT 778.

110 Exhibit SCE-2 (Cabbell) at 17-18; RT 798.

111 RT 421.

feasible.[112] The ISO states that "it is a reasonable assumption to base the 2021 local area generation on the proposed [600 MW] mitigation." The ISO also states that it has had preliminary discussions with SCE on this matter, but needs to obtain a cost and schedule for such an upgrade from SCE.[113] SCE witness Cabbell testified that SCE has not performed any technical analysis or power flow modeling on this proposal, which would require further investigation with the ISO. However, she understands that this mitigation measure could be useful for reducing the LA basin local area LCR but not necessarily the Western LA basin sub-area LCR.[114]

We find there is no conclusive evidence that any assumptions used by the ISO with regard to transmission capacity and contingencies are not appropriate. It is possible or even likely that there are certain mitigation options for transmission constraints or certain transmission upgrades which were not fully considered by the ISO and which may become feasible. It is also possible that certain transmission fixes may become feasible and cost-effective, including the use of synchronous condensers, static var compensators and shunt capacitors, all of which SCE considers annually.[115] In future procurement proceedings and in SCE's procurement application, we may be able to incorporate new information about transmission upgrades and new transmission capacity.

We find the ISO's transmission assumptions to be reasonable for use in this proceeding in determining LCR procurement authorizations.

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[112] Exhibit CEJA-3 (May) at 4-7.

[113] Exhibit CEJA-3 (May) at 6 (from ISO response to CEJA request No. 8).

[114] RT 782; 828.

[115] RT 173; 780-781.

4.2.4. Demand Assumptions

The ISO used the 2009 mid-energy demand case of the Final California Energy Demand Forecast of the CEC for 2010 - 2020, prepared as part of the CEC's 2010 IEPR, as the basis for its demand assumptions in its power flow models.[116] In and of itself, no party disputed that this forecast was reasonable. We agree. However, this is not the end of the analysis. We now consider whether there are elements of demand that should be considered in addition to or as supplements to that forecast.

4.2.4.1. Energy Efficiency

The ISO included in its modeling the amount of energy efficiency included in the CEC 2009 demand forecast (mid-energy forecast). This amount includes a significant amount of energy efficiency stemming from programs approved by the Commission through the IOUs (such as lighting programs and appliance efficiency programs)[117] and statewide programs approved by the CEC (such as building standards). This amount does not include any uncommitted energy efficiency. Several parties recommend adding in some forecast of uncommitted energy efficiency, which would decrease demand and, if located effectively, decrease local capacity needs.

As SCE witness Cushnie notes: "Energy efficiency can't address all of the needs of the electric system."[118] This includes meeting all technical requirements to directly reduce LCR needs. However, energy efficiency does directly reduce

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[116] This forecast was posted on May 30, 2012 on the CEC website.

[117] *See* D.12-11-015 for the most recent Commission-approved energy efficiency programs for IOUs.

[118] RT 688.

electrical demand, which indirectly reduces local capacity requirements. The question before us is whether some amount of uncommitted energy efficiency is certain enough to reduce demand through 2021.

IOU energy efficiency programs are funded on a three-year cycle basis (with occasional one-year extensions.) After the three-year cycle concludes, these resources are not considered committed in the CEC demand forecast analysis used by the ISO. As DRA witness Fagan points out, this does not mean the resources are not available. He testified that, due to the State policy of placing energy efficiency first in the Loading Order, "it is a relatively safe bet that funding will continue and that those resources will show up."[119]

NRDC contends that uncommitted energy efficiency levels in the CEC's 2009 Incremental Impacts Report[120] is what the CEC stated should be subtracted from the its base forecast. The CEC uncommitted energy efficiency forecast from 2009 included all anticipated energy efficiency programs from 2013-2020, all building code improvements between 2006 and 2020 and all appliance standards improvements between 2005 and 2020.[121] NRDC and CEJA list a number of energy efficiency programs which have already been adopted and are already saving energy, but which were excluded from the ISO forecasts because they were categorized as uncommitted.

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119 RT 904-906.

120 *Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast, CEC, May 2010. See* excerpts in Exhibit CEJA-2 at 75-77.

121 Exhibit NRDC-1 (Martinez) at 3-4.

CEJA contends that the CEC's 2009 Incremental Impacts forecast for uncommitted energy efficiency is actually conservative, as it includes a low realization rate for "Big Bold Energy Efficiency Strategies" (BBEES) adopted as goals by this Commission in D.07-10-032 and in our 2008 Energy Efficiency Strategic Plan.[122] One of the BBEES is that all new commercial construction will be zero net energy by 2030.[123] As evidence that the BBEES are becoming more likely to be realized, CEJA points to Governor Brown's Executive Order B-18-12 which calls for 50% of California state government commercial buildings to reach zero net energy by 2025.[124]

ISO witness Millar agreed that the CEC demand forecast from the 2009 IEPR used by the ISO did not include BBEES or other uncommitted energy efficiency programs.[125] Examples of such programs already adopted or already in place include:[126]

- California's 2008 Title 24 Building Code;
- California's 2010 Title 20 Lighting Standard;
- California's 2010 Television Efficiency Standard;
- California's 2012 Title 20 Battery Charge Standard;
- California's 2013 Title 24 Building Code; and

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122 Exhibit CEJA-1 (Powers) at 5.

123 The other BBEES are: a) All new residential construction in California will be zero net energy by 2020; b) Heating ventilation and air conditioning will be transformed to ensure that its energy performance is optimal for California's climate; and c) all eligible low-income customers will be given the opportunity to participate in the low income energy efficiency program by 2020.

124 Exhibit CEJA-1 (Powers) at 3.

125 RT 445-447.

126 Exhibit NRDC-1 (Martinez) at 4-5.

- Several Federal standards on appliances such as water heaters and clothes washers.

Energy efficiency is first in the Loading Order set forth in the Energy Action Plan. Our commitment to cost-effective energy efficiency has been consistent, and the resources we have approved for IOU energy efficiency programs have grown considerably over the last several years. In D.09-09-047, we approved approximately $3.2 billion in energy efficiency funding for 2010 through 2012. As required by statute, we fully expect to continue to fund all cost-effective energy efficiency into the foreseeable future. Recently, in D.12-05-014, we adopted 2013-2014 IOU energy efficiency portfolios, with estimates of 576 MW of energy savings statewide and 293 MW in SCE territory specifically.[127] Thus there is good reason to expect that California's commitment to energy efficiency will continue, if not strengthen. The likelihood that stretch energy efficiency goals will be achieved was enhanced by the November 6, 2012 passage of California Proposition 39, which (among other things) provides for $500 million per year in additional energy efficiency funds.

SCE's practice for many years has been to include certain components of uncommitted energy efficiency in doing its own internal load forecasts.[128] The ISO agrees that, to the extent uncommitted resources ultimately develop, they can be helpful in reducing overall net demand.[129] It is entirely consistent to assume that our ongoing energy efficiency efforts will result in continuation of successful programs and development of improved programs. We have no

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[127] D.12-05-015, section 4.5.8. Savings here are from programs, not including standards.

[128] RT 1032.

[129] Exhibit ISO-2 (Sparks/Millar) at 4.

doubt that the California Public Utilities Commission, CEC and federal programs and standards incorporated into uncommitted energy efficiency amounts will occur, as these are already in place.

We find that amounts of uncommitted energy efficiency in programs and standards already approved by this Commission and other agencies, but not yet in the demand forecast used by the ISO, should result in adjustments to demand forecasts for the purpose of authorizing LCR procurement levels.[130] There is a significant amount of uncommitted energy efficiency in such programs and standards that is certain to exist in the future. Many approved actions were included in the 2009 CEC uncommitted energy efficiency forecasts. Not all uncommitted energy efficiency is as certain to occur. For example, the Commission's BBEES are goals that may well materialize – and we intend to actively pursue these goals -- but achievement of these laudable goals is still somewhat speculative at this time. The CEC 2009 forecast of uncommitted energy efficiency properly evaluates the potential savings from uncommitted energy efficiency.

We now turn to the question of how much demand in the LA basin local area should be reduced by uncommitted energy efficiency. NRDC recommends a minimum amount of 2461 MW of uncommitted energy efficiency for the SCE territory.[131] This figure is derived from the Scoping Memo in R.10-05-006[132] (the

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[130] The CEC may wish to consider eliminating the distinction between forecasted energy efficiency and forecasted uncommitted energy efficiency in the future in favor of a single forecast of anticipated levels.

[131] Exhibit NRDC-1 (Martinez) at 6-7.

predecessor to this proceeding and part of the record in this proceeding), and is based on the CEC's analysis of the total amount of energy efficiency that is incremental to its 2009 demand forecast. However, this amount is for all of the SCE territory, not just the LA basin local area. DRA uses the same information as the ISO uses in the Environmentally Constrained Scenario sensitivity analysis, and recommends assuming 2305 MW of uncommitted energy efficiency in the LA basin local area by 2021. CEJA estimates 1934 MW of uncommitted energy efficiency in the LA basin local area by 2021.[133]

There is a difference between using uncommitted energy efficiency levels for projecting future demand levels and using uncommitted energy efficiency levels for forecasting local capacity requirements. Lower demand levels do not reduce LCRs on a one-to-one basis, but must be modeled. In addition, uncommitted energy efficiency may not occur uniformly across the state. Amounts must be allocated or assigned to specific areas to model outcomes. A sophisticated power flow model can show the impacts of different demand levels with accuracy and detail. This is exactly what the ISO did in the Environmentally Constrained scenario sensitivity analysis. For the LA basin local area, the ISO determined that the LCR need for 2021 is 1042 MW in that scenario sensitivity analysis for effective sites, after including the CEC's uncommitted energy efficiency forecasts.

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[132] Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling, R.10-05-006 (December 3, 2010), Attachment 1; and Corrections to December 3, 2010 Long-Term Procurement Plans (LTPP) Scoping Memo (February 10, 2011).

[133] Exhibit CEJA-3 (May) at 2.

The ISO determination of 1042 MW in the sensitivity analysis is 828 MW below its determination for the Environmentally Constrained scenario (*See* Table 2). The only difference between these scenarios is modeling of uncommitted energy efficiency and CHP resources. We can impute that a similar 828 MW reduction in LCR needs would occur in other scenarios.

We find that the ISO's Environmentally Constrained scenario sensitivity analysis includes a reasonable level of uncommitted energy efficiency for the LA basin local area. We will consider this level as part of our authorization of what level of LCR need SCE is authorized to seek.

4.2.4.2. Demand Response

The ISO did not include any demand response in its forecast beyond the amount embedded in the CEC IEPR forecast.[134] As with energy efficiency, there are various demand response programs that already exist, but were not included in the ISO models. There are also a number of demand response programs under development. Demand response is equal with energy efficiency at the top of the Loading Order in the Energy Action Plan.

CEJA contends the ISO should have included more demand response in its analysis estimating that up to 2224 MW of demand response resources may be available in the LA basin.[135] CEJA cites D.12-04-045 stating "demand response will be an increasingly valuable resource as we pursue future policy challenges."[136] CEJA lists a number of recent developments at the Commission

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[134] SCE witness Silsbee testified that price-responsive demand may be embedded in the CEC demand forecast. RT 1040.

[135] Exhibit CEJA-1 (Powers) at 6 – 14; Exhibit CEJA-3 (May) at 2.

[136] D.12-04-045 at 77.

and the ISO to facilitate integration of demand resources into ISO electricity markets. In its Opening Brief, CEJA estimates that 1064 MW of demand response should be considered in the LCR calculation.[137]

EnerNOC claims that SCE has identified an opportunity to nearly double its existing demand response portfolio by 2017 as a result of such technologies as SCE's Smart Grid Deployment Plan by adding an additional 1500 MW of demand response potential, to approximately 3000 MW. EnerNOC contends that at least some of this should be assumed to be in the LA Basin and have capability of reducing that area's LCR need.[138]

DRA presented evidence that SCE's most recent load impact report predicts 942 MW of demand response for 2020 for the Western LA Basin.[139] This forecast does not identify a level of locally dispatchable demand response resources nor does it evaluate the effectiveness of demand response resources in reducing LCR needs. SCE witness Silsbee testified that at least 549 MW of demand response is currently available in the Western LA Basin, with 102 MW in the most effective locations.[140] It is unclear how much of these resources are locally dispatchable.

EnerNOC objects to the ISO's LCR need assessment for its "failure to include or adequately consider demand response resources in (its) need assessment, either in terms of meeting or reducing its need."[141] EnerNOC

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137 CEJA Opening Brief, p. 35.

138 Exhibit EnerNOC-1 (Tierney-Lloyd) at II-8.

139 Exhibit DRA-6 (Fagan), p. 8 (Table RF-1)

140 RT 1079, referencing Exhibit CEJA x SCE 03.

141 EnerNOC Opening Brief at 16.

witness Tierney-Lloyd testified with regard to demand resources that "the filter for evaluating preferred resources must not only be what is feasible and reliable by today's standards; but, what is likely to be available during the planning window."[142]

We agree that demand response programs are important resources in the California electricity system. However, there are differences between demand response and energy efficiency. The ISO contends that demand response programs should not be counted for local reliability purposes because there are limitations on the use of these programs, customers are not required to shed load when called upon, demand response programs generally do not have the necessary characteristics (such as voltage support) of supply-side resources,[143] and the effects of demand response programs may not materialize at the times and in the locations needed.[144]

ISO witness Sparks allows that demand response "could be used to reduce the replacement OTC needs if the demand response is in electrically equivalent locations and if they materialize and are determined to be feasible for mitigation."[145] ISO witness Millar also testified that it may be possible to develop specific demand response programs which would be able to count for reliability purposes, possibly including programs targeted to specific local areas,[146] or to

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142 Exhibit EnerNOC-3 (Tierney-Lloyd) at III-2.

143 Exhibit ISO-4 (Rothleder) at 9; RT 287.

144 RT 350 - 352.

145 Exhibit ISO-1 (Sparks) at 15; RT 204-205.

146 RT 352-355.

shave peak load (which would reduce the load forecast).[147] However, there are no demand response programs at this time which the ISO believes meet reliability criteria.

In D.11-10-003 in the RA proceeding, we adopted protocols for counting demand response resources for reliability purposes. In that decision, we required that, effective in 2013, demand response resources must be dispatchable locally to count as RA resources. Millar contends that, even with this requirement, there is "no basis yet to have…sufficient comfort that (demand response resources) will actually reduce our local capacity needs" because it is unclear that there will be any locally dispatchable demand response programs.[148]

In other proceedings, we are moving forward to promote cost-effective demand response and to integrate demand response programs as reliability resources. SCE acknowledges the potential of demand response resources to address the transmission contingencies in the ISO's analysis.[149] SCE witness Silsbee testified that he sees "no reason" why a small amount of demand response which now counts for local RA requirements cannot be counted toward meeting LCR needs (although there may be limits to the ability of demand response to meet LCR needs).[150] However, SCE recommends additional work regarding the economics and viability of demand response programs for reliability purposes, and for meeting the needs of the grid and fitting in with the

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[147] RT 423-425.

[148] RT 433-434.

[149] Exhibit SCE-2 (Silsbee) at 12-13.

[150] RT 1044-1045.

transmission system. Therefore, SCE recommends more study to see if such programs can reduce the LCR need.[151]

We fully expect that innovative demand response programs will continue to develop, including those that possess characteristics that are consistent with ISO local reliability criteria. In R.10-05-006, the predecessor to the proceeding, the Scoping Memo (Appendix 1 at 60) estimated 2842 MW of demand response resources would be available in the SCE territory in 2020. In D.12-04-045, our recent demand response decision, we stated:

> The California Clean Energy Future plan expressly acknowledges that in addition to its historic role as an emergency and peak demand management tool, DR will be able to provide a range of services that can support grid integration of large quantities of intermittent and variable renewable resources. The plan also articulates our collective commitment to integrating DR into the CAISO's wholesale energy markets.

We reiterate our commitment to a strong demand response program consistent with D.12-04-045. We agree with parties who contend that demand response resources are likely to be able to provide capabilities which should reduce LCR needs recommended by the ISO. While the ISO did not study a scenario with additional demand response resources, it is reasonable to assume that some amount of demand response resources will be located in the LA Basin, be locally dispatchable, and available to meet LCR needs by 2020. Estimates of 2000 to 3000 MW of demand response are clearly overly optimistic for local reliability purposes, as these estimates are not specific to the LA Basin, may not be locally dispatchable and may not effectively reduce LCR needs.

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[151] RT 607; 646.

In order to determine a reasonable level of demand response likely to be available by 2020 to reduce LCR needs, we take a conservative approach. We will assume a nominal level of 200 MW of dispatchable demand response resources that will be available in the LA Basin to reduce LCR needs by 2020. Since there appears to be at least 100 MW of demand response in the most effective locations now in the LA Basin (and 549 MW of total demand response resources now in that area), by 2020 it is likely that the actual amount available to reduce LCR needs in the LA Basin will be significantly higher – perhaps closer to DRA and CEJA's estimates of around 1000 MW. As the Commission, the ISO and the industry work together over time to clarify the technical characteristics for the circumstances in which demand response resources should count for meeting local capacity requirements (such as local dispatchability), our confidence in the viability of these resources for such purposes should grow. In the future, it is likely that there will be more consensus about how to include demand response resources in LCR forecasts.

4.2.4.3. Distributed Generation

Under Governor Brown's June 2010 Clean Energy Jobs Plan, approximately 6500 MW of new CHP would be added to the grid over the next 20 years with a plan to add 12,000 MW of distributed generation statewide by 2020. The Assembly Bill (AB) 32 Scoping Plan sets a goal of 4000 MW of new CHP by 2020.

The Commission's commitment to expanded distributed generation is supported by a multitude of programs, including the California Solar Initiative, Net Energy Metering, Self-Generation Incentive Program (SGIP), the Renewable Auction Mechanism (RAM), Renewable Market Adjusting Tariff (Re-MAT), Combined Heat and Power tariffs, and the Utility Photovoltaic and

Fuel Cell Programs. In 2013 the Commission will implement Senate Bill (SB) 1122 expanding offerings to bioenergy distributed generation projects. These programs commit IOU customers to substantial investment in distributed generation and promise to deliver thousands of megawatts.

The ISO scenarios assume between 271 MW and 1519 MW of distributed generation actually will be developed in the LA basin local area over the next 10 years, based on the standardized planning assumptions developed in R.10-05-006.[152] Most of this appears to be rooftop solar and other small solar installations. ISO witness Millar testified that if distributed generation increased beyond what the ISO is forecasting, that generally would lower the local capacity need. However, the ISO does not recommend relying on the 1519 MW distributed generation forecast in the Environmentally Constrained scenario, but on a range from 271 MW to 687 MW embedded within the other three scenarios. This is because the ISO claims the distributed generation level in the Environmentally Constrained scenario may be an "admirable goal" but "it is not a capacity amount that can be depended on for ensuring reliability of the bulk power system."[153]

The ISO does not consider it reasonable or prudent to rely on incremental CHP programs beyond what has been considered in the 2009 CEC forecast due to uncertainty that exists with regard to future increases in CHP development. However, Millar also contends that CHP should not be excluded from meeting reliability needs if such facilities can meet ISO technical characteristics. Further,

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152 DRA similarly estimates between 347 MW and 2468 MW of new CHP in SCE's region by 2020.

153 Exhibit ISO-2 (Sparks/Millar) at 6-7.

Millar testified, in the context of state policy objectives supporting CHP: "We want to support [CHP] if there's some work we can do to help those programs or those resources meet these [reliability] needs providing they have the like characteristics."

As ISO witness Millar states, with regard to including energy efficiency in a demand forecast, "we would turn largely to the judgment of the CEC in developing their forecast."[154] We agree, and find that similar consideration should be given with regard to distributed generation forecasts by state agencies. We do not agree with the ISO's decision to unilaterally dismiss the CEC forecast of 1519 MW of distributed generation under the Environmentally Constrained scenario. This forecast has the same validity as CEC forecasts in the other three scenarios and should be considered as part of our analysis. However, we will adopt the ISO's recommendation to use the 339 MW projection of distributed generation, except for uncommitted CHP.

SCE witness Cushnie testified: "CHP has some of the same characteristics that conventional gas-fired resources would have, but they are not going to be as effective as (gas-fired resources) in meeting the need."[155] CEJA contends the ISO should have considered more CHP in its analysis, citing to the Governor's goals and a CARB 2008 Scoping Plan adopting a CHP goal of an additional 4000 MW of installed CHP capacity by 2020. Specifically, CEJA recommends inclusion of at least 285 MW of incremental CHP should be included in the ISO forecast for the LA basin local area, which is a proportion of 360 MW of incremental CHP for SCE's total territory (this amount is taken from the Scoping Memo in

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[154] RT 492.

[155] RT 731.

R.10-05-006.) CCC presents a report showing a medium projection of 621 MW of additional CHP by 2020.

We find that there is the potential for additional CHP to be realized over the ISO's Trajectory scenario. The exact amount that can be assumed is not clear from the record; however, it is reasonable to assume that some amount of uncommitted CHP will come to fruition in the LA basin local area before 2021. Thus, we find there will be more distributed generation than was included in the ISO Trajectory scenario. SCE's point that CHP may not be as effective as gas-fired generation in meeting LCR needs is important; it is necessary to model the impacts of increased CHP. This is what the ISO has done in the four scenarios it studied; Table 3 – 6 herein show that the ISO assumed between 271 MW (Base scenario) and 1519 MW (Environmentally Constrained scenario) of distributed generation. The ISO's recommended Trajectory scenario includes 339 MW of distributed generation.

As with uncommitted energy efficiency, we are convinced that the ISO should have included some projection of uncommitted CHP into its models. As with energy efficiency, a significant amount of what the CEC categorized in 2009 as uncommitted CHP is now more certain to exist. As discussed in Section 4.2.4.1 herein, we find that the ISO's Environmentally Constrained scenario sensitivity analysis includes a reasonable maximum level of uncommitted energy efficiency for the LA basin local area. This same forecast also includes the full amount of uncommitted CHP in the CEC forecast. The combination of uncommitted energy efficiency and uncommitted CHP led to a reduction in LCR needs of 828 MW in the one ISO scenario which modeled this modification. We will consider this level as part of our authorization of what level of LCR need SCE is authorized to seek.

4.2.4.4. Energy Storage

Under California Governor Brown's June 2010 Clean Energy Jobs Plan, approximately 3000 MW of energy storage would be added to the grid to meet peak demand and support renewable energy generation.

CESA recommends that the Commission closely coordinate this proceeding with the Energy Storage Rulemaking, R.10-12-007. CESA calls for the full integration of storage into long-term procurement planning as "a powerful and resource adequacy-improving asset class."[156] CESA contends that energy storage can meet LCR needs and, like generation, is dispatchable.[157]

CEJA contends it is not reasonable that the ISO did not consider any energy storage in its analysis.[158] CEJA claims that energy storage has been found to be more effective than conventional peaking generation, and that both SCE and the ISO recognize the value of storage and the increasing viability of storage technology.

ISO witness Millar testified that, at this time, there are no energy storage facilities on the net qualifying capacity (NQC) list for local capacity[159] (i.e., eligible to be counted for RA purposes) and that the ISO has not identified any energy storage projects in its transmission planning process.[160] However, he stated that there is a process by which any energy storage facilities which emerge could be placed on the NQC list and be eligible to provide local reliability for RA

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[156] Exhibit CESA-1 (Lin) at 8.

[157] Exhibit CESA-2 (Lin) at 2.

[158] Exhibit CEJA-1 (Powers) at 14-19.

[159] RT 347.

[160] RT 404.

purposes.[161] Similar to demand response resources, Millar testified that if energy storage technologies met certain performance requirements, they could count for reliability purposes.[162] However, he testified that "we don't know" if energy storage can meet ISO technical characteristics in the next ten years.[163]

SCE witness Minick testified that there are "only a few test programs for energy storage on our system, and they are not specifically located in areas that would be of any benefit for LCR analysis." He continued: "We have looked at 20 to 30 different energy storage technologies, and we have presented that information to the Commission, and I don't think we have found many, if any, cost-effective."[164]

We are examining the feasibility of energy storage technologies in R.10-12-007. In that proceeding we are considering multiple energy storage options to determine the cost-effectiveness of these potential resources. At this time we do not have sufficient information to determine how many viable energy storage facilities will emerge between now and 2021 that can be used for local reliability purposes in the LA basin local area (or elsewhere). We will not consider a modification to the ISO local reliability need forecast for energy storage for the LA basin local area at this time.

However, we intend to promote the inclusion of energy storage technologies in SCE's upcoming procurement process. CEJA details a number of SCE energy storage initiative and projects underway that will increase energy

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[161] RT 348-349.

[162] RT 355.

[163] RT 461.

[164] RT 948.

storage capacity in its territory (although largely outside of the LA Basin).[165] As a result, CEJA recommends a minimum procurement level of 48 MW of energy storage resources, based upon a storage assumption of 100 MW for the LA Basin, with the Western LA Basin as approximately 48% of the LA Basin.[166] As explained below, we will require that SCE procure at least 50 MW of energy storage resources for LCR purposes in the LA basin local area. We view this as a reasonable and modest level of targeted procurement of an emerging resources, and as an opportunity to assess the cost and performance of energy storage resources.

5. Minimum and Maximum Procurement Authorizations

As noted above, SCE recommends that we authorize a range of procurement from zero to 3871 MW. While SCE and many parties have significant concerns about the LCR procurement levels recommended by the ISO, SCE proposes the widest possible range of procurement flexibility. Other parties find fault in SCE's expansive proposal. CEJA, for example, recommends that SCE's proposal be rejected as "a bad idea to take an economically risky (and environmentally harmful) scenario, and simply shift the burden of this risk to ratepayers."[167]

To address this concern, TURN recommends both a minimum and maximum procurement authorization level, partially to "provide purchaser flexibility when negotiating with bidders."[168] SCE contends that a minimum

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165 CEJA Opening Brief, pp. 55-56.

166 CEJA Reply Brief, p. 2.

167 Exhibit CEJA-5 (May) at 2.

168 Exhibit TURN-1 (Woodruff) at 22.

LCR procurement target is not useful as the specific proposals and options available to meet the LCR need are not known at this time; instead SCE would have the Commission finalize appropriate LCR levels in SCE's future application for approval of proposed LCR projects.[169]

We agree with SCE that not all information is known. We can and will further refine LCR authorization requirements in future long-term procurement planning proceedings. However, we take seriously the ISO's concern (seconded by SCE and others) that there are some procurement opportunities associated with gas-fired power plants which may be lost if there is a delay in moving forward, due to a likely seven to nine year lead time. We do not agree with DRA that "there is zero reliability risk of waiting to procure additional fossil resources" for 2021.[170] Gas-fired resources are appropriate resources to procure for their technical reliability characteristics and for cost considerations; however, we discuss below that procurement should be consistent with the Loading Order to the extent possible.

We will set a minimum LCR procurement level. There is some uncertainty about what how much uncommitted energy efficiency will be available to reduce demand by 2021, and how much uncommitted CHP will be available to fill LCR needs. However the forecast of zero for these resources included in the ISO Trajectory scenario is not reasonable. Therefore, the LCR need is less than the ISO forecasts in its Trajectory scenario. At the same time, the record establishes that there is a significant need for LCR resources to replace retiring OTC plants

[169] Exhibit SCE-2 (Cushnie) at 7.

[170] RT 912.

by 2021 under every ISO scenario and sensitivity analysis. It is reasonable to require a minimum procurement level to ensure reliability.

TURN recommends a "circuit breaker" mechanism if the Commission allows procurement of a lower amount of capacity than the ISO recommends (which is the maximum level SCE recommends.) The "circuit breaker" would occur "if the prices of one or more bids greatly exceed a reasonable cost."[171] SCE argues this proposal is not needed if the Commission does not adopt a minimum LCR procurement target.[172] However, we do adopt a minimum LCR procurement level. While we are cognizant of the potential for bids with excessive cost, already existing mechanisms such as cost-of-service contracts and reliance upon requests for offers provide some ratepayer protection. Further, the Commission-established Procurement Review Groups, Independent Evaluators and Energy Division staff review also provide important and substantive ratepayer protections.

Adjustments to the ISO forecasts to include the maximum reasonable level of uncommitted energy efficiency and CHP, lead to the ISO's Environmentally Constrained scenario sensitivity analysis. As shown in Table 2, this analysis leads to a forecast of 1042 MW of LCR need for effective sites. However, this scenario is a derivative of the Environmentally Constrained scenario. The difference between the Trajectory scenario and the Environmentally Constrained scenario is that the latter included 1519 MW of supply-side distributed generation,[173] as compared to 339 MW in the Trajectory scenario. There is no

[171] Exhibit TURN-1 (Woodruff) at 22.

[172] Exhibit SCE-2 (Cushnie) at 9-10.

[173] Some distributed generation is embedded in the CEC's demand forecast.

credible evidence in the record that there will be 1519 MW of supply-side distributed generation in the LA Basin by 2020.

We agree with the ISO, SCE and others that the Trajectory scenario is appropriate for determining LCR needs. However, we have determined herein that it is appropriate to reduce the ISO forecasts to account for the likelihood that 828 MW of uncommitted energy efficiency and CHP will exist, and that at least 200 MW of locally-dispatchable demand response will exist.

The ISO did not provide a sensitivity analysis for the Trajectory scenario. It is possible to roughly calculate the impact of including more energy efficiency, CHP and demand response resources into the Trajectory scenario. The sole difference between the ISO Environmentally Constrained scenario and the sensitivity study for this scenario is the inclusion of uncommitted energy efficiency and CHP. The ISO shows that these resources would decrease LCR needs by 828 MW. It is reasonable to assume that modeling uncommitted energy efficiency and CHP into the Trajectory scenario would result in at least this much reduction in LCR needs (given that the Trajectory scenario starts with a higher LCR need). We will assume that inclusion of 100% of uncommitted energy efficiency and 100% of uncommitted CHP will reduce the LCR need in the Trajectory scenario by 800 MW (with rounding). In addition, we have determined that we will assume a conservative projection of 200 MW of locally dispatchable demand response resources.

In sum, the Trajectory scenario LCR forecast should be reduced by a maximum of 1000 MW to account for undercounted resource availability. We therefore adopt a minimum LCR need of 1400 MW for the West LA sub-area of the LA basin local area.

We have stated herein that potential demand response and energy storage resources are likely to be able to reduce LCR needs in the future. A way of looking at this is that even if some uncommitted energy efficiency and/or CHP resources included in the ISO forecast do not ultimately appear, there is a reasonable likelihood that other resources including locally-dispatchable demand response (beyond our conservative forecast of 200 MW) and/or energy storage resources will appear which can similarly fill or reduce LCR needs. Alternatively, there may also be transmission-related improvements which can decrease LCR needs. These additional potential resources strengthen our determination that far lower levels of new generation procurement are needed to satisfy LCR needs in the LA basin local area than recommended by the ISO in the Trajectory scenario.

We will also set a maximum procurement level. SCE's proposal for a maximum procurement level is based on the highest ISO forecast level, given less efficient locations.[174] Our analysis of the demand forecast used by the ISO convinces us that the ISO's recommendations for procurement of LCR needs in the LA basin local area are too high. Further, we are convinced that inevitably changing circumstances over the next several years must be taken into consideration. By adopting a lower maximum procurement level than the ISO recommends, the maximum levels are unlikely to turn out to be too high. If our adopted maximum procurement level is too low, there will be timely

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[174] SCE's method for recommending maximum LCR levels appears to be slightly different than the ISO's method for calculating the upper bound for LCR needs in each scenario. The ISO considered the least effective OTC sites in each local area, while SCE used less effective locations in each local area.

opportunities to obtain additional resources in future long-term procurement planning proceedings.

For determining the maximum procurement level, we reiterate that this projection should include a reasonable amount of uncommitted energy efficiency and uncommitted CHP. Again, this projection should also include information regarding potential demand response and energy storage resources which can meet LCR needs. In addition, the location of energy efficiency and CHP installations in the LA Basin local area (unknown at this time) may not be as effective in reducing LCR needs than other resources, such as gas-fired generation located at current OTC sites.

As with our determination of a minimum procurement level, we will assume subtraction of 1000 MW of uncommitted energy efficiency, uncommitted CHP and demand response resources from the Trajectory scenario forecast. For the maximum procurement level, we will add back 400 MW to reflect possible effectiveness factors. Therefore, we adopt a maximum LCR need of 1800 MW for the West LA sub-area of the LA basin local area.

The ISO forecasts provide a range of LCR needs depending upon location of new capacity. The low end of the ISO forecasts assume the new capacity is located at the most effective current OTC sites, and the high end assumes less effective OTC sites. Our determination of the minimum procurement level implicitly assumes that new capacity will be sited at the most effective sites. However, this may not be the case. SCE shall use the most up-to-date effectiveness ratings in its solicitation process.

As discussed further below, we will revisit LCR needs in the next long-term procurement proceeding, expected to commence in 2014. It is possible that in the next long-term procurement proceeding there will be shown to be a need for more LCR procurement than the maximum procurement levels we establish today. We consider today's decision a measured first step in a longer process. If as much or more of the preferred resources we expect do materialize, there may be no need for further LCR procurement in this time period. If circumstances change, there may be a need for further procurement. We are confident that today's decision is the appropriate and considered step at this time.

6. Long-Term Local Capacity Requirements for Big Creek/Ventura Local Area

In the Big Creek/Ventura local area, the Ormond Beach and Mandalay power plants are OTC plants with four units that are scheduled to shut down per SWRCB regulations before 2021. In total, these units currently have approximately 2000 MW of capacity.

The ISO recommends LCR procurement of 430 MW in the Moorpark sub-area of the Big Creek/Ventura local area under all RPS scenarios, without a range for effectiveness of sites. This results from a need to mitigate reliability issues in the Moorpark sub-area of the Big Creek/Ventura local area, caused by a contingency of voltage collapse from a potential loss of area transmission lines.[175] The ISO analysis for the Big Creek/Ventura local area is consistent with the methodologies discussed above for studying long-term local capacity needs for the LA Basin local area.

SCE recommends deferring authorization for procuring additional local capacity in the Big Creek/Ventura local area until the next LTPP cycle (expected to commence in 2014). SCE contends that barriers to construction of new

[175] Exhibit ISO-1 (Sparks) at 13-14.

LCR generation is not as difficult in the Big Creek/Ventura local area as in the LA basin local area, because "this area does not have as many, or as stringent, siting restrictions as the LA basin."[176] SCE further argues that newer technology of various sizes is more likely to be the replacement generation in the Moorpark sub-area, which may be able to be built in 5 to 7 years.[177]

DRA contends that there is no immediate need for LCR generation in the Big Creek/Ventura local area and that ongoing review of LCR needs is required. DRA acknowledges that there would be a loss of 1946 MW in the area due to OTC retirements by 2020.[178] However, based on a load and resources table, DRA contends that there is a surplus of resources (up to 1820 MW) in the Big Creek/Ventura local area when considering the effect of demand side resources.[179] DRA believes that it would not take as long to go through the process to start running a new fossil-fueled power plant in the Big Creek/Ventura local area as in the LA basin local area, due to fewer concerns about siting.[180] DRA maintains that this timeframe would allow the Commission to revisit whether alternative preferred resources materialize in the area. Therefore, DRA contends the risk of not procuring now is minimal if not zero. CEERT agrees with SCE and DRA that no LCR procurement is required to be considered until the expected 2014 long-term procurement proceeding.[181]

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176 Exhibit SCE-1 (Minick) at 10-11.

177 Exhibit SCE-2 (Cabell) at 20.

178 Exhibit DRA-1 (Fagan) at 19.

179 Exhibit DRA-1 (Fagan) at 17-22 and Table RF-3.

180 RT 920-922.

181 CEERT Opening Brief at 31.

Calpine agrees with DRA that further analysis of the Moorpark sub-area is needed before LCR authorization in the Big Creek/Ventura local area is granted. Calpine sponsored an analysis that "suggests that there are potential transmission upgrades that may reduce or eliminate the need for OTC replacement generation in the Big Creek/Ventura local area."[182] Specifically, Calpine argues that one of several transmission alternatives was identified by the ISO that can reduce the LCR need to 100 MW, while other transmission alternatives suggested by Calpine can reduce the LCR need to from zero to 230 MW.[183]

GenOn contends that Calpine's examples of transmission projects are not feasible or desirable solutions for addressing local reliability needs.[184] GenOn contends it is necessary to adopt an LCR need determination for the Big Creek/Ventura local area by the end of 2012 because of plant closures expected in 2020.[185] GenOn contends that it will take seven years or more until commercial operation of new gas-fired plants can commence. GenOn does not agree with SCE that it is not as challenging to develop new LCR generation in the Big Creek/Ventura local area.[186] GenOn also discusses implementation plans it submitted to the SWRCB for several OTC plants, including the Mandalay and Ormond Beach Generating Stations in the Big Creek/Ventura local area. While GenOn originally intended to keep the plants open via a compliance track

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[182] Exhibit Calpine-2 (Calvert) at 2, details in at 2-11.

[183] Calpine Opening Brief at 7.

[184] GenOn Opening Brief at 8.

[185] Exhibit GenOn-2 (Beatty) at 2.

[186] Exhibit GenOn-2 (Beatty) at 7-9.

acceptable to the SWRCB, it now intends to retire (and potentially replace) the plants by the SWRCB compliance deadline.[187]

6.1. Discussion

As with the LA basin local area, there are questions about the ISO forecasts for the Big Creek/Ventura local area. Here, the ISO also did not include any values for uncommitted energy efficiency and uncommitted CHP. As with the LA basin local area, it is likely that the ISO models overstate the LCR need for the Big Creek/Ventura local area for this reason. Similarly, it is more likely that at least some amount of demand response and/or energy storage will emerge in the Big Creek/Ventura area which can be used to meet LCR needs in the next decade, then that there will be zero amount of these resources.

Calpine has shown that there are several transmission possibilities which might reduce LCR needs in the Big Creek/Ventura local area. It is not clear that all of Calpine's suggestions are feasible. However, the ISO did identify a non-generation (transmission) alternative similar as feasible to be completed.[188] This transmission option would result in a total OTC need of 100 MW, instead of 430 MW as proposed by the ISO.[189] The ISO disagrees with Calpine about whether this option is a superior mitigation solution in the Moorpark area, contending that either way there would still be a need for replacement generation.

While it may be mathematically possible to show that some combination of preferred resources and transmission solutions could reduce the LCR need to

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[187] Exhibit GenOn-1 (Beatty) at 3-5.

[188] Exhibit ISO-23 (Sparks) at 2.

[189] Exhibit ISO-23 (Sparks) at 3.

zero (or near zero), there are technical issues and operational benefits from having specific types of in-area generation with the characteristics of the current OTC plants for the Moorpark area. We find that the ISO has shown that there is a need for this type of in-area generation in the Moorpark area, in order to avoid adverse impacts on transmission voltages and loadings under some operation conditions.

The ISO contends that there is a need for 430 MW of total in-area generation in the Moorpark area, even with a viable transmission alternative (or any preferred resources which do not have similar operating characteristics to OTC plants.) The ISO recommendation appears to be conservative on this point, as the ISO has not shown that 430 MW is the minimum amount of LCR need necessary to maintain vital operational characteristics. While some in-area generation similar to existing plants appears to be necessary, some combination of transmission alternatives and preferred resources will necessarily reduce the LCR need below the ISO's projections.

We cannot agree with DRA, SCE and others that it is reasonable to wait to authorize procurement in the Big Creek/Ventura local area. Depending on assumptions, the ISO forecasts a need for the Moorpark sub-area of the Big Creek/Ventura local area, at least some of which must be filled by generation with similar characteristics to the current OTC plants. The most likely locations for new OTC-like generation are the sites of the current OTC plants. The record shows that it may take seven years or more until operations commence in these locations.

The combination of likely preferred resource options and at least one viable transmission solution lead to the conclusion that less than 430 MW is needed for the Moorpark sub-area. It is reasonable to provide SCE with a range of procurement levels to allow SCE to take advantage of different technologies and combinations of potential solutions. TURN's recommendation to allow SCE to procure up to 2/3 of the ISO's recommendation leads to a total of approximately 290 MW. Two of the retiring Mandalay OTC plants have an NQC of 215 MW.[190] It is reasonable to assume that there is a need for approximately the same size replacement generation. Therefore the minimum procurement level for the Moorpark sub-area will be 215 MW. A reasonable maximum level is the 290 MW level per the TURN recommendation. We will authorize SCE to start the process to procure between 215 and 290 MW in the Moorpark sub-area of the Big Creek/Ventura local area, consistent with the process described herein.

7. Procurement Process

7.1. Technical requirements for local capacity

In this decision, we have determined that SCE should be authorized to start a process in 2013 to enter into contracts for between 1400 MW and 1800 MW in the LA basin local area, and 215 to 290 MW in the Big Creek/Ventura local area. Our determination accounts for a reduced demand level due to more energy efficiency and demand response resources than assumed by the ISO, and additional CHP resources. Here we discuss the process for procurement of resources to meet these needs.

One significant issue is what technologies and resources SCE should be authorized to procure. The ISO does not assume any particular technology

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[190] As shown in Table 1, the Ormond Beach plants have a much higher NQC than the 435 MW recommendation from the ISO. Therefore, it is not reasonable to expect plants of this larger size to be replaced.

would be required to fill the local capacity needs, according to ISO witness Sparks: "As long as the resources are in the location where they are needed in these local areas, and they have characteristics of gas-fired generation, I don't believe the ISO has a preference on exactly what type of resources."[191] Regarding distributed generation, the ISO studied a scenario with a high level of renewable distributed generation (the Environmentally Constrained scenario). Referring to distributed generation, Sparks suggested that further study would be needed "to the extent that some of these nonflexible resources are very large, and these large magnitudes are meeting local needs…we would probably need to study all seasons and all load levels to ensure the system can continue…to reliably operate."[192]

SCE witness Cushnie testified that SCE is technology neutral in terms of the resources that it would acquire.[193] In general, SCE would procure resources that will meet ISO criteria for local reliability. However, as ISO witness Millar testified, there is no specific written protocol or tariff that can be referenced to determine the ISO's performance criteria for local reliability.[194] The ISO finds that gas-fired generation meets its criteria, as well as any other resources (or combination of resources) which have the same performance criteria as gas-fired generation. Demand response resources and CHP may meet the ISO's criteria, but not at this time. It is possible that other resources will pass the ISO test as

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[191] RT 201.

[192] RT 208–209.

[193] RT 604.

[194] RT 355-356.

well in the future. Of course, acquisition of more energy efficiency and demand side resources would reduce the LCR need.

Our concern is, without knowing upfront exactly what the ISO would find acceptable, that SCE could procure resources that would not past ISO muster. In that case, the ISO -- consistent with its reliability mandate -- could seek Commission action authorizing additional resources (thus lowering the value to ratepayers of already-procured resources) or could use its own authority (or seek new authority) to contract with resources to meet local needs (also increasing total costs). Either of these approaches is sub-optimal, both in cost terms and in environmental terms.

SCE proposes to use existing RA program rules to assess the effectiveness of proposed generation solutions for meeting LCR need. SCE proposes to identify its assumptions on the effectiveness of any resource for which the RA program does not provide clear guidance.[195] We will adopt SCE's proposal.

The ISO states that it will work with SCE and the Commission to develop the requirements needed for resources to compete in the procurement process.[196] We will require SCE to consult with the ISO regarding ISO performance characteristics (such as ramp-up time) for local reliability. In its application to procure specific resources to meet local reliability needs (discussed herein), SCE shall provide documentation of such efforts and how SCE meets ISO performance requirements.

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195 Exhibit SCE-2 (Silsbee) at 5.

196 ISO Opening Brief at 3.

7.2. Consistency with the Loading Order

SCE proposes to demonstrate that any proposed contract is consistent with the Loading Order by identifying each preferred resource and then assessing the availability, economics, viability and effectiveness of that supply in meeting the LCR need.[197] Per SCE witness Cushnie, SCE would also perform a cost/benefit analysis of the various procurement options.[198] This study would be performed in parallel with any RFO and/or bilateral negotiations for supply.[199]

Several parties have raised concerns that SCE's procurement process might not be consistent with the Loading Order in the Energy Action Plan. Vote Solar contends that preferred resources are endowed with advantages that are difficult to monetize or otherwise capture in an all-source RFO; for example, modularity (ability to be deployed in smaller MW), less environmental impact, smaller sites, and avoidance of outages and losses.[200] CEJA contends that implementation of the ISO recommendations for how to meet LCR needs will lead to excessive and unnecessary natural gas-fired capacity.[201] Similarly, Sierra Club contends that the ISO's models "turn the Loading Order upside down by creating a framework that favors conventional generation over preferred resources."[202]

CAC claims there are about 60 MW of existing CHP capacity in the Western LA basin sub-area, and 70 MW of existing CHP in the

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[197] Exhibit SCE-2 (Silsbee) at 4; RT 612-613; RT 627 (Cushnie).

[198] RT 626-627.

[199] RT 650.

[200] Exhibit Vote Solar-2 (Gimon) at 2–3.

[201] Exhibit CEJA-1 (Powers) at 31-32.

[202] Sierra Club Opening Brief at 13.

Big Creek/Ventura local area, which were not included in ISO studies. In order to be consistent with the Loading Order and obtain this capacity to meet LCR needs, CAC recommends that the Commission establish a rebuttable presumption that existing resource offers (presumably CHP) priced no greater than the cost of new conventional fossil generation be deemed reasonable in the IOU procurement process.[203]

CEERT recommends a process for SCE to procure preferred resources as part of its solicitation. This process includes consultation with the ISO and prospective bidders to establish metrics and protocols for dispatchability and performance of preferred resources. Next, SCE would issue a Request for Qualification to establish the likely quantity and price range of available qualified preferred resources. Then, a cost-effective level of transmission and load-shedding which could meet LCR need would be established by the Commission based on existing and new studies. Through this process, CEERT contends there will be sufficient data available to conduct a "directed procurement" of LCR need.[204]

IEP recommends an all-source RFO in which all resources can compete on an equal basis.[205] IEP proposes that any uncommitted energy efficiency and similar resources which are unable to qualify to compete in an all-source RFO would remain outside of the procurement mechanism until they materialize. At that point, these resources would be considered as committed, and reduce the

[203] Exhibit CAC-1 (Ross) at 3, 8-9.

[204] Exhibit CEERT-2 (Caldwell) at 3-4.

[205] Exhibit IEP-1 (Monsen) at 15.

amount of demand and amount of procurement needed in future procurement proceedings.[206]

7.3. Discussion

We have already determined herein the need to modify the ISO's recommendations for LCR needs in the LA basin local area to take into account reasonably-expected levels of energy efficiency, demand response resources and CHP (and the potential for more demand response resources as well as energy storage resources to become available which can meet LCR requirements). By assuming higher levels for these resources than the ISO, we are promoting the policies of the Loading Order, and reducing the anticipated LCR need.

Because the range of LCR need we establish herein includes between 50% and 100% of uncommitted energy efficiency and uncommitted CHP resources as well as a conservative forecast of demand response resources, SCE will need to ensure that these resources do exist in the future in order to ensure local reliability. As part of our review of SCE's procurement plan, and when considering SCE's procurement application, we will require SCE to show that it has done everything it could to obtain cost-effective demand-side resources which can reduce the LCR need, and cost-effective preferred resources and energy storage resources to meet LCR needs. This task includes efforts already underway and approved in other Commission proceedings, with an eye to focusing such efforts in the specific local geographic areas where LCR needs exist. In other words, for the purposes of meeting LCR needs, it will do no good

[206] IEP Opening Brief at 5-6.

to procure preferred resources such as energy efficiency outside of specific portions of the LA basin or Big Creek/Ventura local areas.

With respect specifically to SCE's procurement of RPS-eligible resources to meet some or all of the LCR needs identified in this decision, this decision does not set up any new RPS procurement processes. SCE should follow existing RPS program procurement authorizations, rules, and processes in its procurement of resources to meet these LCR needs. In SCE's procurement plan discussed below, we require SCE to detail the RPS procurement authorizations and processes that support its plans to acquire RPS-eligible resources to meet these LCR needs.[207]

We recognize that requirements regarding preferred resources must be reconciled with the additional requirement to consult with the ISO on performance criteria. We are confident that the dual objectives of reliability and adherence to the policy objectives of the Energy Action Plan can both be met.

In addition to meeting reliability criteria and consistency with the Loading Order, LCR procurement by SCE must be at least cost to ratepayers. SCE witness Cushnie testified that SCE "has every interest to do this in the least possible cost to the customers (because) there's no upside to the utility in doing this

[207] In its 2012 RPS procurement plan, SCE proposed that it would not hold a solicitation for RPS-eligible resources in the period covered by the 2012 RPS procurement plan. In D.12-11-016, the Commission allowed SCE not to hold a solicitation for RPS-eligible resources and put in place a parallel restriction on SCE's ability to enter into bilateral contracts for RPS-eligible resources during the same period. In D.12-11-016 at 57, the Commission stated that "should SCE determine it has an unmet RPS need during the 2012 solicitation cycle, we will revisit SCE's request to not hold a solicitation and the corresponding restriction adopted today on bilateral contracts." SCE should indicate in its procurement plan whether it intends to seek Commission reconsideration of the solicitation and bilateral contracting determinations in its 2012 RPS procurement plan.

procurement."[208] We will review SCE's efforts at cost minimization in SCE's forthcoming Application. However, balancing the three criteria of ensuring reliability, consistency with the Loading Order and cost-minimization is a challenge.

SCE explains that it intends to capture all cost-effective energy efficiency that can meet LCR needs.[209] Overall, SCE further explains its intention for load reduction resources:

> For preferred resources, SCE will assess the cost-effectiveness of such resources relative to supply-side options. If load reduction in the local area appears to be cost-effective, SCE will engage the CAISO to conduct transmission modeling load flow analysis to determine the operational effectiveness of load reduction programs and technology. SCE will reduce its procurement of supply-side resources to accommodate the future procurement and/or development of load reduction programs and technologies to the extent that they are determined to be cost-effective and operationally effective in reducing the identified LCR need.[210]

SCE's process for balancing objectives with regard to demand reduction resources is reasonable. We will also require SCE to apply a similar balancing to all preferred resources; we agree with SCE's recommended approach to pursue the most competitively-priced CHP and renewable resources, consistent with meeting LCR locational needs and technical characteristics. The remainder of SCE's LCR need will need to be met by supply-side resources and cost-effective transmission upgrades.

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[208] RT 760-761.

[209] RT 609-610.

[210] SCE Opening Brief at 5-6.

The record shows that there may be a significant amount of energy storage capacity and/or demand reduction from demand response resources in the next several years which are not included in any ISO model. We have determined that a significant amount of these resources may be available to meet or reduce LCR needs by 2021, even beyond the projections in the ISO models. We recognize there may be barriers to integration of these resources, including technical issues regarding whether such resources can meet ISO LCR criteria. At the same time, the prospect of additional resources to meet or reduce LCR needs provides an opportunity to further our Energy Action Plan through additional procurement of resources other than conventional gas-fired generation.

Because there is a strong likelihood that additional preferred and energy storage resources not included in our maximum procurement authorization (and potential changes to the transmission system) will be available to effectively meet or reduce LCR needs by 2021, we will require that SCE procure no more than 1200 MW from conventional gas-fired resources in the LA basin local area. The record shows that the most certain technology which can meet LCR needs (from the ISO's perspective) is gas-fired generation. In order to ensure a base level of procurement certain to ensure reliability under the most stringent criteria, we will require that at least 1000 MW in the LA basin local area be from gas-fired generation. In addition, because we intend to promote promising technologies with a strong potential to effectively meet LCR needs, we will require that SCE procure at least 50 MW of energy storage resources as part of its procurement plan for the LA basin local area.

Several parties, in their comments on the Proposed Decision, recommend that we include a requirement that some specified amount of preferred resources be required to be procured. One rationale is that if we have a minimum procurement level for gas-fired and energy storage resources, we should also do so for preferred resources consistent with the Loading Order. Because the Proposed Decision has been modified to increase the minimum procurement level, there is an opportunity to specify further how the minimum procurement level will be achieved. We will require that at least 150 MW of the minimum procurement level be procured through preferred resources.

To summarize: SCE shall procure at least 1400 MW to meet 2021 LCR needs in the west LA sub-area of the LA basin, using the process delineated herein. Included in that 1400 MW shall be 1000 - 1200 MW of conventional gas-fired generation,[211] at least 50 MW of energy storage capacity, and at least 150 MW of capacity from preferred resources. All additional resources beyond the minimum requirement must also be from preferred resources, or from energy storage resources. SCE is not authorized to procure more than 1800 MW of capacity to meet 2021 LCR needs in this part of the LA basin. All resource procurement is expected to follow the principles of least cost/best fit within these constraints. For example, if more than 50 MW of energy storage resources bids into the solicitation process, the most cost-effective and best-located projects should be used to fill the 50 MW requirement.

In addition to authorizing SCE to procure new generation resources, SCE continues to be authorized or required to obtain other resources, as detailed in decisions in the Commission's energy efficiency demand response, RPS and other proceedings. Nothing in this decision is intended to supersede or limit any authority or requirement stemming from any other commission proceeding.

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[211] Conventional gas-fired generation includes CHP resources that are electrically equivalent to conventional generation.

SCE's efforts to obtain these resources are critical to ensuring that the assumptions embedded in this decision will become reality and the reliability needs in SCE's territory will be met.

7.3.1. RFOs and Bilateral Negotiations

One way for SCE to procure the LCR resources we authorize in this order will be to issue one or more RFOs.[212] For example, an RFO to fill LCR needs could specify the amounts needed, the location needed, and technical requirements.

SCE agrees with TURN that an RFO can be very effective in determining the most competitive options for meeting LCR needs. However, SCE requests the flexibility to determine whether it should hold an RFO or not in local capacity areas with limited or no alternatives, because in such a case an RFO may not yield competitive or cost-effective results. SCE contends that such problematic results could occur because the existing generation location has numerous inherent advantages that it can seek to increase costs in a solicitation process.[213]

TURN agrees that some cost-of-service contracts may be needed for OTC unit owners in certain sub-areas where market power exists, in order to ensure reasonable costs to ratepayers.[214] Vote Solar contends that an all-source RFO could give rise to market power mitigation issues to address potentially unreasonable costs, irreversible outcomes, and a cumbersome process to take

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[212] SCE witness Cushnie testified that SCE conducts numerous RFO solicitations for procurement, including all-source solicitations, RPS solicitations and CHP solicitations. RT 686.

[213] Exhibit SCE-3 (Cushnie) at 8.

[214] Exhibit TURN-2 (Woodruff) at 3.

into account unique characteristics of preferred resources. CEJA proposes a phased RFO process, starting with a solicitation aimed at energy efficiency, then one for demand response, and on through the Loading Order.[215]

IEP recommends annual all-source solicitations after setting clearly defined performance requirements and obligations for various resource types, but cautions that there might be concerns about whether energy efficiency and demand response resources can be relied upon for firm capacity and deliverability.[216] IEP supports cost-of-service contracts if there is an IOU showing and a Commission finding of local market power.[217] GenOn also supports use of cost-of-service contracts in the situation where a solicitation does not yield robust results.[218]

AB 1576[219] (codified as § 454.6) authorizes the use of cost-of-service contracts to facilitate investment in the replacement or repowering of older, less-efficient thermal generation facilities when the ISO certified that the project is needed for local reliability. Section 454.6 states:

> (a) A contract entered into pursuant to Section 454.5 by an electrical corporation for the electricity generated by a replacement or repowering project that meets the criteria specified in subdivision (b) shall be recoverable in rates, taking into account any collateral requirements and debt equivalence associated with the contract, in a manner

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215 CEJA Opening Brief at 43.

216 Exhibit IEP-1 (Monsen) at 12-17, 21.

217 Exhibit IEP-1 (Monsen) at 8-11.

218 Exhibit GenOn-2 (Beatty) at 12.

219 Stats. 2005, ch. 374.

determined by the commission to provide the best value to ratepayers.

(b) To be eligible for rate treatment in accordance with subdivision (a), a contract shall be for a project which meets all of the following criteria:

1. The project is a replacement or repowering of an existing generation unit of a thermal powerplant.
2. The project complies with all applicable requirements of federal, state, and local laws.
3. The project will not require significant additional rights-of-way for electrical or fuel-related transmission facilities.
4. The project will result in significant and substantial increases in the efficiency of the production of electricity.
5. The Independent System Operator or local system operator certifies that the project is needed for local area reliability.
6. The project provides electricity to consumers of this state at the cost of generating that electricity, including a reasonable return on the investment and the costs of financing the project.

In situations where an RFO may not result in a reasonably priced contract, SCE proposes a targeted bilateral negotiation that may result in a cost-effective cost-of-service PPA option.[220] SCE contends that § 454.6 provides the option of using cost-of-service contracts to replace or repower existing generation. SCE witness Cushnie describes the relationship between an RFO solicitation and bilateral negotiations:

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220 Exhibit SCE-3 (Cushnie) at 8.

> If Edison was to negotiate separately through bilateral negotiations, the potential for a cost of service contract consistent with the legislation…the counterparty will not necessarily know what Edison's options are with respect to pursuing preferred resources with respect to transmission solutions. So it gives Edison more leverage in those negotiations that if we can't negotiate a contract that is reasonable, that we can then move to these other forms of procurement. But if we conduct the solicitation first and conclude that the solicitation was not competitive, we now have reduced any sort of leverage we might have in a subsequent bilateral negotiation because that will have informed the counterparty that there were no competitive options and now Edison just wants to negotiate on price. So it's a judgment call at the end of the day as to what makes the most sense.[221]

It is reasonable to authorize SCE to use either or both RFOs and cost-of-service contracts in its LCR procurement process. Both methods are intended to fill the LCR needs identified in this order, and to do so consistent with the Loading Order and cost minimization. We agree with SCE and other parties that cost-of-service contracts (also called bilateral contracts) are allowed under § 454.6 under specified circumstances which are likely to result in a procurement process as a result of this decision. Therefore, § 454.6 cost-of-service contracts are an option that SCE will be able to use in situations where there is significant market power that would be detrimental to ratepayers.

SCE opposes requiring all resources to bid into a single all-source RFO. SCE witness Cushnie contends: "Certain preferred resources just aren't going to be viable in (an all-source) solicitation," and that he is not aware of a preferred

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[221] RT 641.

resource ever prevailing against a conventional resource in an all-source RFO.[222] Instead, SCE recommends studying ways to assess the effectiveness and potential use of preferred resources separate from an RFO.[223] SCE maintains that these studies are necessary because such programs cannot be reasonably expected to be developed and bid into a utility solicitation to meet a need that begins in 2020 and extends for ten years or more.

We agree that load reduction programs may not fit well into a typical RFO. SCE witness Cushnie testified that "to the extent we can get comfort that the economics and the viability are there, we can do studies to see if that can reduce the LCR need to meet with supply side resources."[224] It is not clear exactly what SCE intends through this study process. However, we have already assumed a significant amount of preferred resources in determining the minimum and maximum LCR levels for the LA basin local area. SCE should continue to assess and implement all ways to include cost-effective and viable preferred resources to reduce LCR needs. As more preferred demand side resources are available to meet these needs, SCE's LCR needs will be reduced toward the minimum authorized procurement level.

In various other dockets, we have established programs to promote the development of cost-effective energy efficiency and demand response resources. In order to ensure these resources will best be available to meet LCR needs, DRA recommends that SCE should be directed to work with the ISO to determine a

[222] RT 628-629.

[223] RT 628.

[224] RT 612.

priority-ordered listing of the most electrically beneficial locations for preferred resources deployment.[225] We agree and will require SCE to do so.

Cushnie testified that before SCE undertakes any procurement method, it would take into account updated load forecasts and all available current information.[226] Thus, he recommends not locking down all the assumptions to use for LCR procurement at this time.[227] We agree with this approach. We have set minimum and maximum LCR procurement levels herein. Within this range, SCE will need to consider a variety of issues. These issues include (but are not necessarily limited to) effectiveness of siting, changes in load forecasts, potential cost-effective transmission upgrades, availability of SONGS and other existing resources, and potential market power of bidders. Within the parameters we set today, we will allow SCE managerial discretion to seek the best mix of resources. However, as set forth below, Energy Division will review SCE's procurement in advance, and SCE will need to file an application for approval of its procurement contracts.

One specific consideration is that the requirement to procure at least 50 MW of energy storage resources may provide energy storage providers with market power, to the detriment of ratepayers. TURN recommends allowing SCE to "invoke a price circuit-breaker for storage procurement if storage providers cannot provide resources that help meet local reliability at a reasonable price."[228] We agree. While we see considerable value in pursuing the experiment to

[225] DRA Opening Brief at 30.

[226] RT 757-758.

[227] RT 760.

[228] TURN Opening Comments on Proposed Decision, p. 4.

procure energy storage resources, we do not intend that SCE be required to sign contracts from energy storage suppliers at all costs. In its application to implement this decision, SCE shall present the required contracts for energy storage resources to the Commission for approval, or have the burden to show that it should procure less than 50 MW because the bids it received were unreasonable.

CEJA and DRA urge the Commission to consider OTC plants that comply with SWRCB Track 2 policy (90+% reduction in water usage) without retiring as potential resources to meet SCE's local procurement needs.[229] Such plants may provide SCE with additional capacity options and potentially lower costs to ratepayers. We find that it is reasonable for SCE to consider retrofits to existing OTC plants, assumed retired in the ISO studies, in its procurement process. SCE may negotiate with existing OTC plant owners, either through an RFO or consistent with § 454.6, to finance retrofits that will reduce these plants' environmental harm sufficiently to be in compliance with SWRCB policy. Any proposed retrofit of an OTC facility shall compete with other least cost/best fit options.

7.3.2. Energy Division Review of SCE Procurement Plan

SCE seeks flexibility to choose the exact circumstances and timing under which it would utilize an RFO process or a bilateral contract negotiation in its LCR solicitation process, including parallel use of both methods. We agree with SCE that it is difficult in advance to know which method would be most advantageous to ratepayers, and that SCE is in the best position to administer

[229] CEJA Opening Comments on Proposed Decision, p. 7. DRA Reply Comments on Proposed Decision, p. 2.

this process. We will allow SCE the flexibility it seeks, subject to review of its procurement plan by Energy Division and a subsequent Commission application.[230]

SCE shall provide its procurement plan for all required and authorized resources in the LA Basin and Big Creek/Ventura local areas to Energy Division no later than 150 days after the effective date of this decision. SCE may provide parts of its procurement plan to Energy Division earlier than 150 days. Specifically, we encourage SCE to present its plan for procurement of up to 1200 MW of gas-fired generation in the LA Basin and up to 290 MW of gas-fired generation in the Big Creek/Ventura local area earlier than 150 days. Due to the long lead time for these particular resources, it is imperative that SCE begin the procurement process (including Energy Division review) as soon as possible.

The procurement plan(s) shall include all of the following:

- A list of all applicable rules and statutes impacting the plan;
- A detailed description of how it intends to procure resources, specifying the structure of any RFO or alternative procurement process and related timelines;
- A methodology for determining least cost/ best fit that includes evaluating and quantifying performance characteristics that vary among resource type (e.g. time to start, output at various times, variable cost, effectiveness in meeting contingencies, etc.);
- What type of price benchmark will be used in determining cost-effectiveness for resources;

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[230] Nothing in this decision exempts SCE from previously adopted Commission rules on RFOs in D.07-12-052 and elsewhere.

- An explanation for each resource type indicating whether modifications will be made to existing programs or if a new approach will be utilized;
- A methodology for determining peak capacity for resources for which there is not a currently approved methodology for determining Net Qualifying Capacity; and
- A methodology for determining other reliability capabilities (e.g. voltage support) for resources for which there is not a currently approved methodology for determining these capabilities

We have reviewed the comments of parties filed in response to the September 7, 2012 energy storage/long-term procurement workshop. Based on those comments and the overall record in this proceeding, any RFO should include the following elements:

a) The resource must meet the identified reliability constraint identified by the California ISO;

b) The resource must be demonstrably incremental to the assumptions used in the California ISO studies, to ensure that a given resource is not double counted;

c) The consideration of costs and benefits must be adjusted by their relative effectiveness factor at meeting the California ISO identified constraint;

d) A requirement that resources offer the performance characteristics needed to be eligible to count as local RA capacity;

e) No provisions specifically or implicitly excluding any resource from the bidding process due to resource type (except as authorized through this decision);

f) No provision limiting bids to any specific contract length;

g) Provisions designed to be consistent with the Loading Order approved by the Commission in the Energy Action Plan and to pursue all cost-effective preferred resources in meeting local capacity needs;

h) Provisions designed to minimize costs to ratepayers by procuring the most cost-effective resources;

i) A reasonable method designed to procure local capacity requirement amounts at or within the levels authorized or required in this decision, not counting amounts procured through cost-of-service contracts;

j) An assessment of projected greenhouse gas emissions as part of the cost/benefit analysis;

k) A method to consider flexibility of resources without a requirement that only flexible resources be considered; and

l) Use of the most up-to-date effectiveness ratings.

SCE shall not begin its public solicitation process until Energy Division determines in writing that SCE has complied with the provisions of this Decision. Separate Energy Division approvals are needed for the procurement plan and any request for offers. Because the process for soliciting gas-fired capacity may be simpler than for other capacity, Energy Division may provide that the gas-fired capacity portion of SCE's procurement plan can go forward first. The determination of the Energy Division shall be final.

7.3.3. SCE Application

SCE estimates that it would take anywhere from one to two years after today's decision before SCE can submit an application to the Commission with final LCR procurement contracts for Commission approval, after procurement solicitations, bilateral negotiations and studies for preferred resources.[231] At that

[231] RT 719-720; 733-735.

time, SCE witness Cushnie foresees that "parties may choose to challenge the resources we're proposing to utilize to meet the LCR need."[232] In addition, he agrees that SCE would not object if a party wanted to assert that there were other preferred Loading Order resources that were available to SCE on a cost-effective basis that SCE failed to incorporate.

All contracts stemming from the LCR procurement authorization we establish today shall be brought to the Commission for approval in a single application for the LA basin local area and a single application for the Big Creek/Ventura local area (these applications may be combined if SCE chooses). Under SCE's schedule, the applications will be forthcoming sometime in late 2014. However, it is not self-evident why this process should take this amount of time. We expect that SCE's applications could be filed earlier than late 2014. Given the likely 7 to 9 year procurement process for gas-fired resources, we implore SCE to file its applications as soon as practical.

In its applications, SCE shall show:

- Cost-effectiveness;
- Consistency with the Loading Order, including a demonstration that it has identified each preferred resource and assessed the availability, economics, viability and effectiveness of that supply in meeting the LCR need;
- Procurement of between 215 and 290 MW to meet local capacity requirements in the Big Creek/Ventura local reliability area;
- Procurement of between 1400 and 1800 MW to meet local capacity requirements in the Los Angeles local reliability

[232] RT 758.

area (including specific provisions for conventional gas-fired and energy storage resources);

- For bilateral contracts negotiated under § 454.6, that the project will provide electricity at the cost of generation, including a reasonable return on the investment and the costs of financing the project; and
- A demonstration of technological neutrality, so that no resource was arbitrarily or unfairly prevented from bidding "or winning" in SCE's solicitation process, except as authorized through this decision. To the extent that the availability, viability and effectiveness of resources higher in the Loading Order are comparable to fossil-fueled resources, SCE shall show that it has contracted with these preferred resources first.

8. Flexible Capacity

The ISO recommends that any capacity to fill LCR needs "should have flexibility characteristics similar to the OTC generation" that needs to be replaced.[233] ISO witness Rothleder testified that flexible resources should:

> [p]rovide dispatch flexibility between minimum and maximum operating level[s]…can be used to respond to quick changes in load and variations of generation from renewable resources…can provide ancillary services…have inertia or governor control to respond to changes in frequency and a faster start, to respond more quickly when needed.[234]

Rothleder further testified that LCR resources would also need to meet other attributes of flexible conventional generation including "voltage support, flexibility, frequency response, sustained energy supply, reliable responsiveness,

[233] Exhibit ISO-1 (Sparks) at 17.

[234] Exhibit ISO-4 (Rothleder) at 8-9.

no significant use limitations and the ability to provide energy regulation, operating reserves and load following."[235]

SCE believes that all resources that have high NQC ratings -- as determined through the Commission's RA proceedings -- have the potential to meet local area needs (although some are more effective than others). SCE witness Minick testified: "In reality, an LCR resource doesn't need to have flexibility. They could be a baseload resource at a certain location and meet LCR requirements. But, it would be very nice from an operational perspective to have flexibility."[236] SCE witness Cushnie testified that "you might not want to have very stringent standards [for flexibility] in your solicitations" and SCE "can then look at various permutations of resource mixes including preferred resources."[237]

IEP recommends that the Commission wait for the completion of studies by the ISO necessary to determine the need for, and the preferred characteristics of, flexible resources before authorizing specific procurement of flexible resources.[238] EnerNOC believes that the Commission must define flexible attributes before requiring such attributes to be procured for LCR purposes.[239] EnerNOC contends that there are demand resources that provide several operational characteristics that the ISO considers in its description of flexibility.[240]

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[235] Exhibit ISO-4 (Rothleder) at 8-9.

[236] RT 972-973.

[237] RT 696-697.

[238] IEP Opening Brief at 10-11.

[239] EnerNOC Opening Brief at 22.

[240] Exhibit EnerNOC-2 (Huffman) at II-1 – II-6.

TURN does not believe that it is important to explicitly incorporate flexible capacity attributes into the LCR procurement process, because it is a serious challenge to establish specific values for different dimensions of flexibility. Further, TURN contends that new combined cycle plants and combustion turbines likely to bid into RFOs will possess tremendous flexibility, thus likely leading to procurement of flexible resources even without any explicit requirement.[241]

CEJA recommends that the Commission not limit potential procurement to resources that meet the ISO's flexibility definition, as LCR procurement in RA proceedings has never been equated with flexible capacity. CEJA points out that the ISO's modeling in R.10-05-006 (which is in the record of this proceeding) showed no flexibility need for 2020.[242]

WEM recommends that the Commission consider that various preferred resources (including demand side resources) should be able to provide certain flexibility characteristics. WEM recommends that the Commission establish final flexibility needs after completion of the ISO's flexibility analysis in Track 2.[243]

8.1. Discussion

SCE will be starting a procurement process as a result of this decision. In procuring resources, SCE will be able to determine what flexibility components various resources contain. At this time there is considerable uncertainty in both the types and quantities of flexible resources that may be needed to balance future resource needs. Preliminary ISO studies indicated a need with all OTC

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241 TURN Opening Brief at 19-20.

242 CEJA Opening Brief at 51.

243 WEM Opening Brief at 6.

resources compliant of 0 MW in the mid load scenarios, but a need of 4600 MW in the high load trajectory scenario.[244] The combined cycle gas turbine resources added from the local areas to a subsequent run of the renewable integration modeling had high capacity factors, over 75%, while combustion turbines had capacity factors close to 13%.[245] These results indicate that while flexibility is an important consideration, it is unclear what exact attributes and blend of flexible versus baseload resources are needed.

The issue of flexibility and determination of flexible attributes for LCR needs is also currently being considered in the RA proceeding, R.11-10-023. A decision in the RA proceeding is expected in the first half of 2013. There is no need to make a determination on flexibility issues in this track of this proceeding. There is also an insufficient record at this time. We cannot currently define flexibility for LCR procurement purposes with any specificity or determine what flexible attributes should or should not be procured by SCE.

Therefore, we will not require SCE to take into account any particular flexible attributes in its procurement process, and will not make acquisition of any flexible attributes a condition of approval of SCE's forthcoming LCR procurement application. However, SCE should identify any known flexible attributes or characteristics of resources bid into its RFO or considered in bilateral negotiations. To the extent that SCE can obtain flexibility in LCR contracts consistent with other requirements, it should do so.

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[244] Exhibit ISO-4 (Rothleder) at 2, 11-19.

[245] Exhibit ISO-4 (Rothleder) at 5, 7-20.

9. Cost Allocation Methodology (CAM)

9.1. CAM Overview

In D.04-12-048, the Commission adopted the IOUs' 2004 long-term procurement plans. As part of its efforts to ensure a long-term, reliable energy supply for California customers, the Commission authorized the IOUs to recover stranded costs associated with new PPAs and utility-owned generation (UOG) from all customers, with the goal of providing "the need for reasonable certainty of rate recovery."[246] By doing so, the Commission sought to address utilities' concern that they could end up over-procuring resources and incurring the associated stranded costs given the potential for a significant portion of their load to take service from a different electric service provider (ESP).

D.04-12-048 did not specify the actual implementation mechanism for recovering these costs. D.06-07-029 in the 2006 long-term procurement proceeding decision adopted the CAM, which allows the costs and benefits of new generation to be shared by all benefiting customers in an IOU's service territory. The Commission designated IOUs to procure the new generation through long-term PPAs, and the rights to the capacity were allocated among all LSEs in the IOU's service territory. The allocated capacity rights can be applied toward each LSE's RA requirements. In exchange for those benefits, the LSEs' customers – termed "benefitting customers" – pay for the net cost of the capacity.[247]

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[246] D.04-12-048, Conclusion of Law 14.

[247] The energy and capacity components of the newly acquired generation are disaggregated. The net capacity cost is calculated as the net of the total cost of the contract minus the energy revenues associated with the dispatch of the contract. The

Footnote continued on next page

The basic framework for the CAM was set forth in D.06-07-029 as follows: The IOU would contract with an Independent Evaluator to oversee an RFO for new resource contracts. At the conclusion of the RFO, the IOU would sign a long-term contract with the generator of a new resource. The IOU would seek contract approval from the Commission, and at that time, select whether or not it intends for the CAM to apply to the contract. The Commission's decision on the IOU's application determines the applicable CAM based on allocating the appropriate net capacity costs to all benefiting customers in the IOU service area.[248] The IOU would then request Commission approval to conduct periodic auctions with an Independent Evaluator for the energy rights of the resource, essentially selling the tolling right – the energy component – and retaining the RA benefit, which it then shares with all customers paying for the capacity.[249] D.06-07-029 at 26 explained that "benefiting customers" referred to all bundled service, direct access (DA), Community Choice Aggregator (CCA) customers and "other customers who are located within a utility distribution service territory but take service from a local publicly-owned utility subsequent to the date the new generation goes into service." D.06-07-029 at 26 (footnote 21) specified that current customers of publicly-owned utilities were exempt from the CAM.

Subsequent decisions clarified and amended the CAM. D.07-09-044 presented in greater depth the procedures for the energy auctions. The procedures established a backstop for the auctions. Should an auction fail to

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non-bypassable change levied is for the net capacity cost only, and the non-IOU LSEs maintain the ability to manage their energy purchases.

[248] D.06-07-029 at 52-53.

[249] D.06-07-029 at 31-32.

produce a successful bid for the energy products, the capacity costs would be calculated via a specified alternative mechanism.[250] D.08-09-012 set forth that customer generation departing load was exempt from the CAM. That decision clarified that only large municipalizations were subject to the CAM, while exempting other classes of municipal departing load.

Senate Bill 695, signed into law in 2009, requires that the net capacity costs of new generation resources deemed "needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's distribution service territory" must be passed on to bundled service customers, DA and CCA customers.[251] In order to align the CAM with the requirements of SB 695, D.11-05-005 did the following:

(1) Removed the right for the utility to elect or not elect CAM treatment for a resource that meets the conditions of the statues;

(2) Widened the scope of the CAM to apply to utility-owned generation resources, and

(3) Extended the duration of CAM treatment to match the duration of the underlying contract, eliminating the 10-year cap.[252]

SB 790 in 2011 codified the Commission requirement that the costs to ratepayers for CAM procurement are allocated to ratepayers in a "fair and equitable" manner.[253]

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[250] *See* D.07-09-044, Appendix A for specifics relating to the Joint Parties' Proposal, the alternative to the auction mechanism.

[251] Stats. 2009, ch. 337.

[252] D.11-05-005 reaffirmed that SB 695 does not require any revisions to the determinations made in D.08-09-012 regarding non-bypassable charges and the CAM process.

The Scoping Memo posed three questions related to the CAM:

(1) How should the costs of any additional local reliability needs be allocated among LSEs in light of the CAM?

(2) Should the CAM be modified at this time? and

(3) Should LSEs be able to opt-out of the CAM, and if so, what should the requirements be to permit such an opt-out?

In addition to the questions posed by the Commission, SSJID raised specific questions regarding its classification as a large municipalization and the CAM's application in its particular case. SSJID also questioned whether the CAM applies to municipal departing load in general.

9.2. Allocating Costs of Local Reliability Needs Among LSEs in Light of the CAM

The three IOUs, TURN and DRA all assert that the CAM should apply to all generation authorized in Track 1,[254] and net capacity costs should be allocated to all benefitting customers, including bundled service, DA, and CCA customers.[255] DRA explains that "since LCR resources would provide reliability benefits to all customers, the net capacity costs should similarly be allocated to all customers."[256]

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[253] Stats. 2011, ch. 599.

[254] Nothing in this decision is intended to imply or state that the CAM applies to bundled procurement.

[255] *See* Exhibit SDG&E-2 (Anderson) at 9; Exhibit SCE -2 (Cabbell/Cushnie/Minick/Silsbee) at 20-23; Exhibit TURN-2 (Woodruff) at 16; Exhibit DRA-5 (Ciupagea) at 1.

[256] Exhibit DRA-5 (Ciupagea) at 1.

AReM asserts that the Commission's goal should be to minimize CAM procurement.[257] AReM testified that it is only fair to allocate CAM costs when the need creating the costs can be attributed to all customers, and not solely to IOU bundled load. To that end, AReM maintains that the Commission must evaluate the characteristics of the load served by the IOUs versus the characteristics of the load served by the other LSEs in the IOU service area to determine the different rates at which they grow. If this analysis finds that bundled customer load is driving the peak or decreasing the system load factor, then AReM contends bundled customers should pay for the resources necessary to meet that need.

Further, AReM states that per its obligation under § 454.5, the Commission should ensure that CAM procurement is needed to meet a specified reliability need as defined by § 365.1(c)(2)(B). AReM contends that this means that the reliability need must be incremental to the needs associated with LSEs. For example, AReM argues that if a generation plant that "primarily" served bundled load retired or shut down and the IOU filed for approval for CAM procurement to replace the unit, the Commission should reject this application. According to AReM, while "incidental reliability benefits [from the replacement unit] would likely accrue to '*all*' customers, bundled customers would benefit disproportionately more, because the customers of other LSEs would subsidize their '*unmet needs*.'[258] Therefore, AReM reasons, CAM procurement should not be authorized.

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[257] Exhibit AReM-1 (Mara) at 5, 20.

[258] Exhibit AReM-1 (Mara) at 28.

AReM sets forth a two-step proposal for the Commission to determine whether a particular CAM project should be approved: (1) calculate the MWs of unmet need, and identify what portion of the unmet need is driven by the bundled load, and (2) if MWs of unmet need exist and are attributable to all benefiting customers in the service area, then AReM propose six criteria to ascertain whether the CAM should be applied in the particular case.[259] The proposed criteria are:

1. The IOU's Application requests, as required by § 365.1(c)(2)(A), the following: (i) approval for a specific contract with a third party to procure generation resources; or (ii) an order to procure a specific UOG resource.
2. The Commission has previously determined that the MWs in the Application may be subject to CAM procurement.
3. The Commission determines that the project identified in the Application fulfill an unmet need that is not attributable to any individual LSE.
4. The Commission determines that the project identified in the Application is required by the ISO to meet a specific System or Local RA need that cannot be reasonably met by other existing resources, demand response, energy efficiency or other alternatives and is required to be operational as of the timeline proposed in the IOU's Application to avoid degrading grid reliability.
5. The Commission determines that the project identified in the Application benefits all customers within the IOU's

[259] AReM proposes this criteria as a less restrictive alternative to a "benefits test" as a means of determining when to authorize CAM procurement per § 365.1(c)(2)(A). SDG&E and DRA both recommend that the Commission explore creating a defined "benefits test" for CAM procurement. *See* Exhibit SDG&E-1 (Anderson) at 10-11 and Exhibit DRA-5 (Ciupagea) at 4. SDG&E suggests that "the Commission should find that benefitting parties are those parties that have load in the reliability area." Exhibit SDG&E-1 (Anderson) at 11.

service territory, including DA and CCA customers, by the way in which it meets the reliability needs specified by the ISO, as required by § 365.1(c)(2)(B).

6. Local RA projects in an IOU's Local RA Area provide comparable reliability benefits, as specified by the ISO, to all customers located in the entire IOU's service area, as required by §§ 365.1(c)(2)(A), 365.1(c)(2)(B), and 366.2 (g). Projects that provide the specified reliability benefits primarily to customers located within the Local RA Area where the project will be developed must be rejected as inconsistent with the statutes noted.[260]

The three IOUs and DRA oppose AReM's cost causation principle, stating that LCR resources would provide reliability benefits to all customers, and thus, the net capacity costs should similarly be allocated to all customers.[261]

SDG&E proposes that the Commission explicitly adopt a rebuttable presumption that the net capacity costs of generation resources authorized to meet system and local reliability requirements should be allocated via the CAM to all customers within the IOU's service territory.[262] SDG&E acknowledges that while CAM procurement must receive careful consideration, minimizing CAM should not be the overriding consideration. As long as state policies and interests are served through utility procurements that provide benefits beyond the IOU's bundled customers, the Commission should allocate the costs via the

[260] Exhibit AReM-1 (Mara) at 30-31.

[261] Id. at 8-9; Exhibit SCE-2 (Cushnie) at 27-28; Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 8 (PG&E asserts that if AReM's cost causation proposal is accepted, then DA and CCA providers should be willing to agree to submit procurement plans to the Commission alongside IOUs); Exhibit DRA-5 (Ciupagea) at 1-2.

[262] Exhibit SDG&E-2 (Anderson) at 6.

CAM to all benefitting customers.[263] SDG&E also takes issue with what it perceives as AReM presupposing that utility bundled load drives growth in peak demand and decrease in system load factors, when these assumptions are debatable. SDG&E states that AReM fails to address the complicated reality that there is no "objective formula that can be devised for quantifying and allocating reliability benefits among different customer groups."[264]

SCE states that the costs of any SCE procurement to meet system reliability needs must be "fully recoverable and allocated appropriately" to DA and CCA customers via the CAM.[265] SCE asserts that it would prefer not to procure beyond its bundled customers for system reliability,[266] and maintains that it will not procure system reliability resources unless "all benefitting customers pay their fair share."[267]

PG&E recommends allocating the costs of LCR procurement in Track 1 to "all customers in the service area where LCR resources are added, whether bundled, DA, or CCA customers."[268] PG&E believes that LCR procurement in the LA basin should be allocated to all benefiting customers in SCE's service territory, but not to any customers in PG&E's service territory.[269]

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[263] Exhibit SDG&E-2 (Anderson) at 1-3.

[264] Exhibit SDG&E-2 (Anderson) at 8.

[265] Exhibit SCE-1 (Cushnie) at 25.

[266] Exhibit SCE-1 (Cushnie) at 21-22.

[267] Exhibit SCE-1 (Cushnie) at 21.

[268] Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 6.

[269] Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 4.

TURN asserts that "the most reliable means of getting any needed new capacity built is for Edison take on the responsibility of contracting for such capacity and allocate the costs to all benefit[ting] customers via the CAM."[270] TURN states that AReM's suggestions for CAM implementation would result in DA and CCA customers paying for less than a proportionate share of the reliability costs, and should thus, be rejected.[271]

9.3. Discussion

Section 365.1(c)(2)(A)-(B) holds that in instances when the Commission determines that new generation is needed to meet local or system area reliability needs for the benefit of all customers in the IOU's service area, the net capacity costs for the new capacity shall be allocated in a fair and equitable manner to all benefiting customers, including DA, CCA and bundled load. Simply put, each customer must pay their fair share for the benefits that flow to them from the new generation for the full life of the asset.[272]

AReM's driving peak/decreasing load proposal fails to recognize the interrelated nature of the electric system and the reality that some individual customers of ESPs, CCAs and IOUs have static load profiles, while others are driving the need for new resources. In addition, the retirement of existing resources creates the need for new resources to serve customers that may not be driving increases. Therefore, we continue the current Commission policy of allocating CAM costs and benefits at the IOU service area level.

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[270] Exhibit TURN-1 (Woodruff) at; Exhibit TURN-2 (Woodruff) at 16.

[271] Exhibit TURN-2 (Woodruff) at 4.

[272] We note that SB 695 relieves the IOUs of limiting CAM treatment to 10-year contracts.

In addition, we do not adopt AReM's two-step/six criteria framework. AReM's approach imposes additional requirements designed to limit CAM allocation, and appears to create a precise determination of "benefitting customers." However, precision is not the same as fairness. The Commission's previously adopted criteria fairly apportion costs to customers as envisioned by past Commission and the legislature actions. While creating more complexity, nothing in AReM's proposal improves on the fairness of the current allocation. Thus, the costs of local reliability needs shall continue to be allocated in accordance with previous Commission decisions.

9.4. Should the CAM be Modified at This Time?

AReM proposes several further modifications to the CAM, including changes to energy auction terms and the adopted program's proxy calculation. AReM suggests that the Commission make the current five-year maximum ceiling on energy auctions products to a five-year minimum floor. AReM contends that longer term tolling would more accurately reflect "the incremental hedging value of the PPA."[273]

AReM also opines that the net capacity cost calculation from the adopted program should be changed to better reflect the increased ancillary service value and value of "other products and services" provided by the new PPAs or UOG plants beyond non-spinning reserves.[274] In addition, AReM proposes that the Commission modify the adopted program in order to account for the options value associated with a long-term tolling contract. By failing to incorporate this

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[273] Exhibit AReM-1 (Fulmer) at 39.

[274] Exhibit AReM-1 (Fulmer) at 39-41.

value, AReM contends, the current CAM framework "ignores one of the primary driver of PPA cost: the opportunity value of purchasing energy with agreed-upon terms in a market characterized by energy price volatility.[275]

AReM also supports a levelized annual revenue requirement for UOG plants in order to account for the reality the imputed capacity costs of a UOG generating plant changes over time as the plant is depreciated.[276] Finally, AReM asserts that the CAM should be capped, as a "backstop to ensure reasonable results."[277] AReM recommends that the Commission convenes workshops to discuss the details of implementing some of their suggested design modifications.

SDG&E believes that the current auction mechanism is administratively unwieldy and not necessarily conducive to efficient capacity costs.[278] SDG&E supports the use of the adopted program[279] as an alternative to the use of an energy auction to determine the net capacity costs for CAM resources. SDG&E suggests that the Commission eliminate the IOUs' obligation to auction the right to the energy, unless the Commission directs otherwise; toward that end, SDG&E opines that the Commission should convene workshops to construct a permanent alternative to energy auctions.[280] In addition, SDG&E specifically

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275 Exhibit AReM-1 (Fulmer) at 42-43.

276 Exhibit AReM-1 (Fulmer) at 44.

277 Exhibit AReM-1 (Fulmer) at 48.

278 Exhibit SDG&E-1 (Anderson) at 10-11. TURN, on the other hand, expressed its support for CAM's current energy auction approach. Exhibit TURN-2 (Woodruff) at 3.

279 The adopted program refers to the current CAM program, adopted in D.06-07-029, and amended in subsequent decisions as previously laid out in this decision.

280 Exhibit SDG&E-2 (Anderson) at 10.

rejects AReM's proposal to amend the adopted program to include all major ancillary service products currently available in the ISO market, levelize the annual revenue requirement for utility-owned generation, and cap the CAM.[281]

DRA supports SDG&E's proposal to change the energy auctions. DRA encourages the Commission to convene workshops to explore possible modifications to the net capacity cost allocation, the valuation for energy and ancillary services and pursue the reduction of capacity costs for all parties.[282]

The three IOUs and TURN oppose AReM's proposal to incorporate ancillary services in calculating energy dispatch value.[283] SCE and PG&E align with SDG&E in objecting a levelized annual revenue requirement,[284] while all three IOUs and TURN expressly object to AReM's proposal to cap the CAM.[285]

We reject the proposed cap on CAM. We find that AReM's proposal to levelize the annual revenue requirement obviates the plain language of § 365.1(c)(2)(C), which states that the net capacity costs shall be determined by "subtracting the energy and ancillary services value of the resource from the total costs paid by the electrical corporation pursuant to a contract with a third party or the annual revenue requirement for the resource if the electrical corporation

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[281] SDG&E-2 (Anderson) at 6-12.

[282] Exhibit DRA-5 (Ciupagea) at 4.

[283] SDG&E-2 (Anderson) at 6-12; Exhibit SCE-2 (Cushnie) at Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 9-10, Exhibit TURN-2 (Woodruff) at 9.

[284] Exhibit SCE-2 (Cushnie) at 37; Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 10.

[285] Exhibit SCE-2 (Cushnie) at 32, 37-38; Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 11; Exhibit TURN-2 (Woodruff) at 8-9 (TURN contends that imposes a cap on CAM without simultaneously imposing a floor would be discriminatory).

directly owns the resource." (emphasis added.) Once the CAM contract has lapsed, bundled customers would overpay for the depreciated value of the generating asset capacity, while non-IOU customers would have paid less than their fair share of the full value of the asset's capacity value. Further, the proposal to cap the CAM contradicts its central purpose: apportioning system and local reliability costs to all benefiting customers in an IOU service area so that each benefitting customer pays their fair share.

We have stated an openness to revisit the energy auction mechanism adopted in D.07-09-044.[286] Toward that end, we appreciate the suggestions from parties in the current proceeding to consider improvements toward the current auction mechanism structure, including valuing net capacity costs. The record, however, fails to provide an adequate basis upon which to comprehensively consider and adopt any potential changes to the auction mechanism. We may consider taking a more focused look at these issues in the future.

9.5. CAM Opt-Out

In D.06-07-029, the Commission found the concept of a CAM opt-out mechanism for LSEs appealing, upon the demonstration that an LSE is fully resourced with new generation for ten years forward. However, D.06-07-029 stated "the reality is that we have no viable enforcement program or mechanism for doing so," such as a "multi-year RA program where an LSE could demonstrate it is fully resourced for the next four or 10 years."

AReM strongly supports an LSE opt-out, asserting that it is essential to maintaining market choice. AReM's opt-out would function as follows. Once

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[286] For example, *see* D.11-05-005.

the Commission determines unmet need subject to the CAM, an ESP or CCA would have the option to request an opt-out from the CAM. The LSE has until the IOUs submit any proposed CAM projects to request an opt-out. In order to qualify for an opt-out, an LSE would make a showing to the Commission that it has procured adequate generation resources for a five-year period.

AReM proposes three types of out-out: (1) Load Ratio Share Opt-Out; (2) Load-Based Opt-Out; and (3) Customer-Based Opt-Out, which are described in detail in its testimony.[287] The three IOUs, TURN and DRA all categorically reject AReM's opt-out proposals.[288] Each asserts that AReM's proposed five-year forward contract term showing is insufficient time to procure and finance new generation resources given the reality of long lead time for building new generation.[289] SDG&E contends that a CAM opt-out would encourage LSE free riding at the expense of utility ratepayers.[290] SCE asserts that a CAM opt out stands in direct contrast to the Legislature's intent to pass along costs to all benefiting customers in a fair and equitable manner.[291] PG&E points out that keeping track of all the potential LSEs who choose to opt out of the CAM via one of the three ways proposed by AReM will result in high administrative costs.[292]

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[287] *See* Exhibit AReM-1 (Mara), starting at 57.

[288] Exhibit SDG&E-2 (Anderson) at 13-14; Exhibit SCE-2 (Cushnie) at 38; Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 12; Exhibit TURN-2 (Woodruff) at 6-7; Exhibit DRA-5 (Ciupagea) at 5.

[289] Exhibit DRA-5 (Ciupagea) at 5.

[290] Exhibit SDG&E-2 (Anderson) at 12.

[291] Exhibit SCE-2 (Cushnie) at 39-40, which excerpts § 365.1(c)(2)(A)-(B).

[292] Exhibit PG&E-1 (Frazier-Hampton/Martyn/Williams) at 12.

TURN asserts that AReM's proposal would result in DA and CCA customers paying for less than a proportionate share of the costs of local reliability needs, with virtually no responsibility for new capacity needed to meet load reliably.[293] DRA argues that it is unclear how AReM's proposal would be enforceable to "ensure that 'there will be no free riders' vis-à-vis the cost of capacity of new generation,"[294] and disagrees with AReM that only non-IOU LSEs should be allowed to opt out of the CAM.[295]

9.6. Discussion

The issue of a CAM opt-out is complex. AReM has properly raised legitimate questions regarding equity of the current CAM structure. However, while AReM's detailed proposal of a potential opt-out structure is helpful, it is unclear how its five-year contract term/project life requirement would adequately ensure investment in new resources. Further, it is not at all clear that a CAM opt-out could be implemented without undue administrative burden. After considering comments from parties, we find the record insufficient to resolve these questions, and therefore do not adopt an opt-out at this time.

We will not rule out consideration of a CAM opt-out at a future date. However, we have considered parties' positions on more than one occasion, and declined to adopt a CAM opt-out. Therefore, we are disinclined to relitigate this issue in the future unless all or nearly all impacted parties can agree on a specific, detailed and implementable proposal, or there are significant changed circumstances.

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293 Exhibit TURN-2 (Woodruff) at 7.

294 Exhibit DRA-5 (Ciupagea) at 5, quoting Exhibit AReM-1 (Mara) at 19.

295 Exhibit DRA-5 (Ciupagea) at 5.

9.7. SSJID Proposal

SSJID asserts that it should be exempt from the CAM. Specifically, SSJID recommends the Commission should "exempt all existing and future [publicly-owned utility departing load], including large municipalizations, from CAM responsibility."[296]

PG&E argues that SSJID should be subject to the CAM. PG&E asserts that the Commission has already decided in D.08-09-012 at 27-30 that the CAM applies to all large municipalization departing loads, and that SSJID fits into the Commission's stipulated definition of a large municipalization.[297]

SSJID's argument against CAM application is that: (1) SSJID's Municipal Departing Load (MDL) should not be classified as a large municipalization as defined by the Commission in D.08-09-012; (2) California law does not require that Public-Owned Utilities (POUs) or MDL of any size (including large) be included as "benefiting customers" for the purposes of the CAM; (3) POUs do not present the same capacity procurement risks as DA or CCA loads; (4) POU customers may not be able to RA credits allocated under CAM; and (5) the Commission's alternative methodology for allocating RA costs and benefits to large municipalizations is an approximation and is impractical.[298]

Most of the matters raised by SSJID were addressed in D.08-09-012 and will not be relitigated here. Regarding the definition of "large municipalization," D.08-09-012 at 26-27 stated:

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296 Exhibit SSJID-1 (Shields) at 4.

297 Exhibit PG&E-2 (Rubin) at 2.

298 Exhibit SSJID-1 (Shields) at 3-4.

> While there is no precise measure of what constitutes a "large municipalization," in the context of this decision, we are defining "large municipalization" as any portion of an IOU's service territory that has been taken control of or annexed by a POU where the amount of load departing the IOUs' service territories due to the municipalization is of such a large magnitude that it cannot reasonably be assumed to have been reflected as part of the historical MDL trends used in developing the adopted LTPP load forecasts."

As indicated, D.08-09-012 did not specify the exact parameters for "large municipalization." It is not within the scope of this proceeding to determine whether SSJID is a large municipalization. SSJID has not convinced us that other issues it raised require any further action at this time.

10. Cost of Capital (COC)

SCE witness Hunt testified that SCE seeks Commission authorization to file a separate application to adjust its capital structure to take into account debt equivalence issues arising from additional PPAs.[299] Debt equivalence occurs when rating agencies determine that the capacity costs of PPAs are equivalent to debt for the IOUs because the payments cannot be avoided without defaulting on the PPA.

Hunt contends PPAs arising from this decision will create significant debt equivalents or debt equivalence on SCE's balance sheet that may need to be mitigated to preserve SCE's creditworthiness. Hunt estimates that SCE's 2013 debt equivalence will be about $2.5 billion, while LCR procurement contracts could increase that amount by $900 million to $2.9 billion.[300]

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299 RT 834.

300 Exhibit SCE-1 (Hunt) at 27.

DRA opposes SCE's request. DRA recommends that SCE should wait to have the Commission consider any changes in SCE's debt equivalence resulting from LCR procurement until the next COC proceeding. DRA asserts that since debt equivalence is only one of many credit risk drivers impacting SCE's credit rating, debt equivalence should be considered together with those other credit risk drivers.[301] TURN points out that the Commission has addressed this issue in several previous procurement-related proceedings and declined to approve the relief requested by the utility. TURN cites D.09-06-018 at 58, stating that "we will take action to address negative impacts on any utility's balance sheet or credit profile when warranted and necessary, and will do so in a manner consistent with the urgency of the matter."

SCE's capital structure is typically determined in its COC proceeding. On April 20, 2012, SCE filed its most recent COC application. SCE's next COC proceeding is expected in early 2015. SCE witness Hunt testified that the point at which SCE's procurement PPAs stemming from this order would be included in rating agencies' rating as debt equivalence is generally when energy deliveries begin under a contract.[302] Mr. Hunt also testified that to the extent that the contract will simply replace an expiring contract, Standard and Poor's rating agency will impute debt as though the future contract is a continuation of the existing contract.

SCE itself expects the process from today's decision to Commission-approved contracts to take about two years, or until late 2014. Any potential impact on SCE's COC will not commence until at least the time of the

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[301] Exhibit DRA-8 (Lasko) at 3.

[302] RT 839.

Commission's decision on SCE's LCR procurement application, if not for several years afterwards.

We will not change our policy from D.09-06-018 and previous decisions. SCE should use its next COC application, or other venue for consideration of COC, to seek any changes it considers appropriate due to debt equivalence for the contracts foreseen from today's decision.

11. Motion of Megawatt Storage Farms (MSF)

On October 5, 2012 MSF filed a motion asking the Commission to rule that energy storage should be ranked first in the Loading Order. MSF argues that this proceeding is evaluating and deciding on quantities of resources to be procured, and that energy storage must be considered here. MSF notes that energy storage is not mentioned explicitly by name in the current Loading Order, and that it is impossible for the LTPP Proceeding to analyze or decide on procurements unless a decision is made on energy storage's ranking within the Loading Order.

MSF articulates several reasons why it contends energy storage should be first in the Loading Order. First, MSF contends that energy storage reduces natural gas needs for renewables integration. Second, MSF claims energy storage reduces natural gas needs for frequency regulation. Third, MSF argues that energy storage promotes energy efficiency by time shifting. Finally, because energy storage does not fit into other specified categories (these categories are entitled "new generation" and "fossil fuel, central station generation"), MSF contends energy storage is properly placed in the first category.

Several parties filed in opposition to MSF's motion. Opposing parties argue that the MSF motion is untimely, that energy storage issues are being considered in another proceeding, and that the Loading Order should not be modified in this proceeding.

The MSF motion is denied. In this decision, we establish a solicitation process for SCE to procure for long-term LCR needs. In this process, there will be opportunities for potential energy storage facilities to participate; we specifically require SCE's solicitation process to be technologically-neutral. Further, we require SCE to procure at least 50 MW of energy storage.

However, it is premature to consider where energy storage should be placed in the Loading Order. As MSF acknowledges and as discussed herein, we are considering issues related to energy storage in R.10-12-007. In that proceeding, it is possible (though not guaranteed) that the Commission will establish procurement targets for energy storage or otherwise provide a method to facilitate the development of energy storage technologies. At this time, no decisions have been made concerning the viability, cost-effectiveness or public interest nature of energy storage technologies in that docket. If and when such action is taken, the role of energy storage technologies in the procurement process can be considered.

We also note that, as discussed herein, the Loading Order was developed in a multi-agency process and is, in part, established in statute. We do not intend to unilaterally reconsider the multi-agency Energy Action Plan in this decision; certainly, we cannot alter a statute here.

12. Categorization, Need for Hearings and Assignment

The assigned Commissioner is Michel Peter Florio and the assigned Administrative Law Judge (ALJ) is David M. Gamson. ALJ Gamson is the Presiding Officer.

13. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on January 14, 2013, and reply comments were filed on January 22, 2013.

Based on comments, the PD has been modified as follows:

- The minimum procurement level for the LA Basin has been increased from 1050 MW to 1400 MW;
- The maximum procurement level for the LA Basin has been increased from 1500 MW to 1800 MW;
- For the LA Basin, SCE is now required to procure at least 150 MW of preferred resources (as opposed to no requirement in the PD);
- For the LA Basin, SCE may procure up to 600 MW of preferred resources (as opposed to an authorization of 250 -450 MW in the PD), subject to the overall 1800 MW cap;
- As with the PD, SCE is required to present contracts for at least 50 MW of energy storage resources in the LA Basin to the Commission for approval, or (in the revised PD) to have the burden of proof to show that it should procure less than 50 MW because the bids it received were unreasonable;
- The PD's authorization for SCE to procure up to 1519 MW of distributed generation (less amount already expected to be procured) in the LA Basin is deleted;
- The ISO Trajectory scenario is used as a starting point for forecasting LCR needs for the LA Basin (instead of the ISO Environmentally Constrained scenario sensitivity analysis in the PD). The ISO Trajectory scenario is adjusted to account for 100% of uncommitted energy efficiency and CHP forecasts by the CEC, and to account for a conservative forecast of 200 MW of demand response resources;
- SCE is now required to consider retrofits of a power plant cooling system undertaken to comply with State Water

Resources Control Board Statewide OTC Policy as a new resource in considering resources to meet its LCR needs;

- A footnote in the PD is modified to allow certain CHP resources to qualify as part of the 1000 to 1200 MW requirement for conventional gas-fired resources in the LA Basin;
- Clarification of the relationship between procurement requirements in this proceeding and Commission procurement decisions in the RPS docket;
- Clarifications to requirements for SCE's Procurement Plan (reviewed by Energy Division) and subsequent procurement Applications;
- Other minor changes and clarifications to the PD are made as appropriate;
- Various Findings of Fact, Conclusions of Law and Ordering Paragraphs are modified to effectuate the changes to the PD listed above.

Findings of Fact

1. It is reasonable for the Commission only to consider LCR forecasts by the ISO using renewable portfolio scenarios already in the record of R.10-05-006.

2. It is reasonable to use local capacity studies and power flow modeling from the ISO for LCR forecasting.

3. The ISO used demand forecasts provided by the CEC in its 2009 IEPR, which used 2009 demand forecast data. It is reasonable to use this data for LCR forecasting in this proceeding.

4. In the LA basin local area, the Alamitos, El Segundo, Huntington Beach, Redondo Beach power plants use OTC technology. Sixteen OTC units are required to comply with SCRWB regulations to substantially reduce water use before 2021. In total, these units currently have more than 4900 MW of capacity.

5. In the Big Creek/Ventura local area, the Ormond Beach and Mandalay power plants are OTC plants with four units which are required to comply with SWRCB regulations to substantially reduce water use before 2021. In total, these units currently have more than 2000 MW of capacity.

6. The ISO forecasted LCR needs 10 years into the future for the first time; these forecasts (like other forecasts) are subject to error due to input assumptions and significant changes in circumstances in the future.

7. Both under-procurement and over-procurement entail significant risks. Under-procurement entails risks of reliability problems and the impacts of mitigating such problems in a short timeframe. Over-procurement entails risks of excessive costs and unnecessary environmental degradation. It is not possible to quantify whether the risks of over- or under-procurement are greater.

8. It is reasonable to use the CEC's one-in-10-year load forecast, combined with the contingencies identified by the ISO, for the purpose of LCR forecasting in this proceeding.

9. It is reasonable to use the ISO's analysis of transmission for the purpose of LCR forecasting in this proceeding.

10. It is reasonable to assume that the OTC plants in the SCE territory required to comply with SWRCB regulations will comply through retirement or repowering consistent with the SWRCB schedule, for the purpose of LCR forecasting in this proceeding. However, no finding on this point is intended to apply to SONGS.

11. Each of the four RPS scenarios analyzed by the ISO contain a reasonable minimum level of energy efficiency from CEC forecasts which can be used for the purposes of determining LCR needs for the LA basin local reliability area.

12. The four RPS scenarios analyzed by the ISO do not include any uncommitted energy efficiency or uncommitted CHP resources analyzed by the CEC.

13. To the extent uncommitted energy efficiency and uncommitted CHP resources ultimately develop, they can be helpful in reducing overall net demand. However, these resources are not likely to be as effective in reducing LCR needs as repowered gas-fired resources at existing OTC locations. Reducing overall net demand reduces LCR needs.

14. A significant amount of what is categorized by the CEC as uncommitted energy efficiency is certain to occur because it is based on standards already adopted by the CPUC, the CEC and federal agencies.

15. In the ISO's Environmentally Constrained scenario sensitivity analysis, the impacts of uncommitted energy efficiency and uncommitted CHP significantly reduced LCR needs for the LA basin local reliability area compared to other ISO scenarios.

16. There will be more uncommitted energy efficiency available in the LA basin local reliability area than was included in the ISO Trajectory scenario. The ISO Environmentally Constrained scenario sensitivity analysis includes a reasonable level of uncommitted energy efficiency for the LA basin local reliability area.

17. There is at least 100 MW of demand response in the most effective locations now in the LA Basin (and 549 MW of total demand response resources now).

18. By 2020 it is likely that the actual amount of demand response resources available to reduce LCR needs in the LA Basin will be considerably more than 100 MW, and possibly closer to DRA and CEJA's estimates of around 1000 MW.

19. There will be more uncommitted CHP available in the LA basin local reliability area than was included in the ISO Trajectory scenario.

20. The ISO's Trajectory scenario includes a reasonable minimum level of distributed generation for the LA basin local reliability area for the purposes of determining the LCR need in this proceeding, except that it does not include a sufficient estimate for uncommitted CHP.

21. The ISO's Environmentally Constrained scenario sensitivity analysis includes a reasonable maximum level of uncommitted CHP for the LA basin local reliability area for the purposes of determining the LCR need in this proceeding.

22. In R.10-12-007, the Commission is considering multiple energy storage options to determine the cost-effectiveness of these potential resources. At this time there is not sufficient information to determine how much viable energy storage facilities will emerge between now and 2021 that can be used for local reliability purposes.

23. It is premature to consider a modification to the ISO local reliability need forecast for energy storage for the LA basin local area at this time.

24. It is reasonable to expect that some unidentified amount of energy storage resources will be available in the future, and it is likely that some amount of energy storage resources will be available to meet future LCR needs. It is unclear whether the costs of energy storage resources will be reasonable.

25. It is likely that some LCR procurement opportunities would be lost if there is a delay in approving a procurement process for the LA basin local reliability area and the Big Creek/Ventura local reliability area, due to a seven to nine year lead time for conventional gas-fired resources.

26. Gas-fired resources at the current OTC sites are certain to meet the ISO's criteria for meeting LCR needs. Other resources can also meet or reduce LCR needs, but may not be effective in doing so.

27. There is a significant need for LCR resources to replace retiring OTC plants in the LA basin local area by 2021 under every ISO scenario, as well as under the Environmentally Constrained scenario sensitivity analysis.

28. Even if some uncommitted energy efficiency and/or uncommitted CHP resources included in the ISO Environmentally Constrained scenario sensitivity analysis do not ultimately appear, there is a reasonable likelihood that some demand response and/or energy storage resources and/or other distributed generation resources will be viable and able to similarly meet or reduce LCR needs.

29. The ISO's Environmentally Constrained scenario sensitivity analysis includes the highest reasonable levels of uncommitted energy efficiency and uncommitted CHP. This forecast shows an LCR need of 1042 MW for the LA basin local area for effective sites, which is 828 MW below the LCR need in the Environmentally Constrained scenario (everything else being equal).

30. It is necessary that a significant amount of this procurement level be met through conventional gas-fired resources in order to ensure LCR needs will be met.

31. In order to determine a minimum LCR procurement level for the LA basin local area with 100% of the CEC's forecast of uncommitted energy efficiency and uncommitted CHP, and 200 MW of demand response resources, it is reasonable to subtract the effects of these resources from the ISO's Trajectory scenario. Thus (with rounding), the ISO's projected need of 2400 MW in the Trajectory scenario would be reduced by 800 MW to account for 100% of

uncommitted energy efficiency and CHP, and by 200 MW to account for a conservative estimate of demand response resources. This leads to a minimum procurement level of 1400 MW.

32. A maximum LCR procurement level will protect ratepayers from excessive costs resulting from potential over-procurement.

33. In order to determine a maximum LCR procurement level for the LA basin local area it is reasonable to include an additional 400 MW authorization to reflect potential reduced effectiveness.

34. If SCE procures more than the minimum MW amount for the LA basin local area, it will be consistent with the Loading Order to require some additional capacity to come from non-fossil-fueled sources.

35. The ISO did not include any values for uncommitted energy efficiency and uncommitted CHP for the Big Creek/Ventura local area.

36. The ISO did not include any values for demand response or energy storage resources in the Big Creek/Ventura local area.

37. The ISO evaluated and found feasible a transmission alternative for the Moorpark sub-area of the Big Creek/Ventura local area.

38. The ISO has shown that there is a need for in-area generation with operational characteristics similar to retiring OTC plants in the Moorpark sub-area of the Big Creek/Ventura local area.

39. The most likely locations for to meet LCR needs in the Moorpark sub-area are the sites of the current OTC plants. The record shows that it may take seven years or more until operations commence in these locations.

40. The most likely size for at least one replacement plant in the Moorpark sub-area of the Big Creek/Ventura local area is 215 MW, as this is the size of two existing OTC units in that area.

41. There may be a need to procure up to 290 MW in the Moorpark sub-area, after accounting for the likelihood of preferred resources and/or transmission upgrades which are likely to exist in that area and be able to reduce or meet LCR needs.

42. There is an immediate need to begin a procurement process to meet LCR needs of between 215 and 290 MW in the Moorpark sub-area.

43. SCE will need to undertake technical studies to integrate certain preferred resources (including energy storage resources) so that they meet local reliability needs, and to work with the ISO to assess the impacts of such resources to meet or reduce LCR needs.

44. A requirement to procure a modest level of energy storage resources, such as 50 MW provides an opportunity to assess the cost and performance of energy storage resources.

45. A requirement to procure at least a minimum level of energy storage resources may provide energy storage providers with market power, to the detriment of ratepayers.

46. OTC plants that comply with SWRCB Track 2 policy (90+% reduction in water usage) without retiring are potential resources to meet SCE's local procurement needs. Such plants may provide SCE with additional capacity options and potentially lower costs to ratepayers.

47. It may take one year or more after today's decision before SCE can submit an application to the Commission with final LCR procurement contracts for Commission approval, after procurement solicitations, bilateral negotiations and studies for preferred resources.

48. Purchased power agreements arising from this decision may create significant debt equivalents on SCE's balance sheet that may need to be mitigated

to preserve SCE's creditworthiness. Such additional debt equivalence will not come into effect until the start of commercial operations of the plant, unless the contract is considered by a rating agency as a continuation of a current contract.

49. The cost allocation mechanism in effect today was established in D.06-07-029 and refined in D.07-09-04, D.08-09-012 and D.11-05-005.

50. AReM's driving peak/decreasing load CAM proposal is inconsistent with the principle that each customer must pay their fair share for the benefits that flow to them from the new generation.

51. AReM's two-step/six criteria framework for CAM allocation imposes additional requirements designed to limit CAM allocation, but does not improve on the fairness of the current allocation.

52. AReM's proposal to levelize the annual revenue requirement would result in bundled customers overpaying for the depreciated value of the generating asset capacity, while non-IOU customers would have paid less than their fair share of the full value of the asset's capacity value.

53. The record does not provide an adequate and persuasive basis upon which to comprehensively consider and adopt any potential changes to the auction mechanism.

54. In AReM's CAM opt-out proposal, it is unclear how AReM's five-year contract term/project life requirement would adequately ensure investment in new resources.

55. It is not clear that a CAM opt-out could be implemented without undue administrative burden.

Conclusions of Law

1. A significant difference between the ISO's reliability mission under § 345 and the Commission's reliability emphasis under § 380(c) is that the Commission

must balance its reliability mandate with other statutory and policy considerations. Primarily, these considerations are reasonableness of rates under § 451 and § 454 and a commitment to a clean environment under Pub. Util. Code sections including § 399.11 (Renewables Portfolio Standard) and § 454.5(b)(9)(C) (Loading Order).

2. Consistent with § 454.5(b)(9)(C), which states that utilities must first meet their "unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible," and the Commission's Loading Order established in the Energy Action Plan, utility LCR procurement must take into account the availability of preferred resources before procuring non-preferred resources.

3. The record in this proceeding supports outcomes which enable the Commission to meet statutory requirements and policy goals with regard to reliability, ratepayer costs and environmental protection, as well as to require the procurement of sufficient levels of diverse resources in a timely manner.

4. SCE's procurement process should have no provisions specifically or implicitly excluding any resource from the bidding process due to technology, except for specific requirements in this decision for the LA basin local area. Except as otherwise required by this decision, SCE's procurement process must have provisions designed to be consistent with the Loading Order approved by the Commission in the Energy Action Plan and § 454.5(b)(9)(C).

5. The ISO models overstate the LCR need for the LA basin local area and the Big Creek/Ventura local area.

6. It is reasonable to assume that 100% of the CEC's forecast of uncommitted energy efficiency and CHP levels will exist in order to determine minimum and maximum LCR procurement level for the LA basin local area.

7. It is reasonable, as a conservative approach, to assume a nominal level of 200 MW of locally-dispatchable demand response resource will be available in the LA Basin to reduce LCR needs by 2020.

8. Adoption of an LCR need range which takes into account the potential differences in the effectiveness of different resources, 100% of uncommitted energy efficiency and uncommitted distributed generation resources, and allows for the potential of demand response resources and energy storage resources which may meet ISO technical criteria for meeting LCR needs, is consistent with the applicable statutory and regulatory requirements for procurement of preferred resources, including the Loading Order.

9. SCE should be required to procure a minimum of 1400 MW and a maximum of 1800 MW in the West LA sub-area of the LA basin local reliability area. No more than 1200 MW should be from conventional gas-fired sources. At least 150 MW should be from preferred resources. Up to 600 MW of capacity may be from preferred resources or energy storage resources (in addition to resources already authorized or required to be obtained via Commission decisions in energy efficiency, demand response, RPS, energy storage and other relevant dockets), subject to the maximum procurement level.

10. SCE should be required to procure at least 50 MW of energy storage resources in the LA basin local area to meet LCR needs, subject to a showing that the costs of some or all of such procurement would not be reasonable.

11. SCE should be required to procure a minimum of 215 MW and a maximum of 290 MW in the Moorpark sub-area of the Big Creek/Ventura local reliability area.

12. SCE should be required to provide a procurement plan to Energy Division for compliance review of the requirements of this decision.

13. SCE should be required to file one or more Applications for approval of contracts to procure LCR resources consistent with this decision.

14. If there is additional information about the viability of preferred resources and/or transmission alternatives in the Moorpark sub-area of the Big Creek/Ventura local reliability area and West LA sub-area of the LA basin local reliability area when SCE files its Application for approval of contracts, that information should be considered at that time.

15. SCE should be required to determine the availability and cost-effectiveness of preferred resources, and energy storage resources, that can offer the necessary characteristics to meet or reduce LCR needs. SCE should then be required to work with the ISO to re-run its transmission modeling load-flow analysis to determine the impacts of such resources. To the extent such resources meet or reduce LCR needs, SCE should reduce procurement of non-preferred resources.

16. Cost-of-service contracts (also called bilateral contracts) allowed under § 454.6 are an option that SCE should be able to use in situations where there is significant market power that would be detrimental to ratepayers.

17. It is reasonable to authorize SCE to use either or both RFOs and cost-of-service contracts in its LCR procurement solicitation process.

18. It is reasonable for SCE to consider retrofits to existing OTC plants, assumed retired in the ISO studies, in its procurement process.

19. All contracts stemming from the LCR procurement authorization we establish today should be brought to the Commission for approval by application for each local reliability area, anticipated sometime in 2014. It is reasonable to allow an earlier application for gas-fired procurement due to the long lead time for such resources.

20. If any extensions to the OTC closure deadlines occur, this can be taken into account in future procurement proceedings or in a review of a procurement application by SCE.

21. The cost allocation mechanism established in D.06-07-029 and refined in D.07-09-04, D.08-09-012 and D.11-05-005 remains reasonable for application in this proceeding without modification, and is fair and equitable as required by Section 365.1(c)(2)(A)-(B).

22. The appropriate procedural venue for SCE to seek any changes it considers appropriate due to debt equivalence related to contracts foreseen from today's decision is its next COC application.

23. The record is insufficient to resolve outstanding questions about a CAM opt-out at this time.

24. It is not within the scope of this proceeding to determine whether SSJID is a large municipalization for the purposes of the CAM.

25. The Motion of MSF should be denied because it seeks to modify a policy adopted by the Commission along with other state agencies, and may conflict with statute.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company shall procure between 1400 and 1800 Megawatts (MW) of electrical capacity in the West Los Angeles sub-area of the Los Angeles basin local reliability area to meet long-term local capacity requirements by 2021. Procurement must abide by the following guidelines:

a. At least 1000 MW, but no more than 1200 MW, of this capacity must be from conventional gas-fired resources, including combined heat and power resources;

b. At least 50 MW of capacity must be procured from energy storage resources;

c. At least 150 MW of capacity must be procured from preferred resources consistent with the Loading Order of the Energy Action Plan;

d. Subject to the overall cap of 1800 MW, up to 600 MW of capacity, beyond the amounts specified required to be procured pursuant to subparagraphs (a), (b) and (c) above, may be procured through preferred resources consistent with the Loading Order of the Energy Action Plan (in addition to resources already required to be procured or obtain by the Commission through decisions in other relevant proceedings) and/or energy storage resources.

2. Southern California Edison Company shall procure between 215 and 290 Megawatts of electric capacity to meet local capacity requirements in the Moorpark sub-area of the Big Creek/Ventura local reliability area by 2021.

3. Southern California Edison Company (SCE) shall use existing Resource Adequacy (RA) program rules (as developed in Rulemaking 11-10-023 and successor proceedings) to assess the effectiveness of proposed generation solutions for meeting the local capacity requirements need established in this Order. SCE shall identify its assumptions on the effectiveness of any resource for which the RA program does not provide clear guidance.

4. Any Requests for Offers (RFO) issued by Southern California Edison Company pursuant to this Order shall include the following elements, in addition to any RFO requirements not delineated herein but specified by previous Commission procurement decisions (including Decision 07-12-052) and the authorization and requirements of this decision:

a. The resource must meet the identified reliability constraint identified by the California Independent System Operator (ISO);

b. The resource must be demonstrably incremental to the assumptions used in the California ISO studies, to ensure that a given resource is not double counted;

c. The consideration of costs and benefits must be adjusted by their relative effectiveness factor at meeting the California ISO identified constraint;

d. A requirement that resources offer the performance characteristics needed to be eligible to count as local Resource Adequacy capacity;

e. No provisions specifically or implicitly excluding any resource from the bidding process due to resource type (except as authorized in this Order);

f. No provision limiting bids to any specific contract length;

g. Provisions designed to be consistent with the Loading Order approved by the Commission in the Energy Action Plan and to pursue all cost-effective preferred resources in meeting local capacity needs;

h. Provisions designed to minimize costs to ratepayers by procuring the most cost-effective resources consistent with a least cost/best fit analysis;

i. A reasonable method designed to procure local capacity requirement amounts at or within the levels authorized or required in this decision, not counting amounts procured through cost-of-service contracts;

j. An assessment of projected greenhouse gas emissions as part of the cost/benefit analysis;

k. A method to consider flexibility of resources without a requirement that only flexibility of resources be considered; and

l. Use of the most up-to-date effectiveness ratings.

5. Southern California Edison Company (SCE) shall provide a procurement plan for all required and authorized resources in the Los Angeles Basin and Big Creek/Ventura local areas to Energy Division no later than 150 days after the effective date of this decision. SCE shall show that its proposed procurement plan is consistent with Ordering Paragraph 4. SCE shall not go forward with any public procurement process until Energy Division approves the process in writing, except that SCE may proceed with parts of its procurement plan if so authorized. SCE also shall adhere to previous Commission decisions regarding this proposed procurement process, including consultation with the Procurement Review Group and Independent Evaluators.

6. In its proposed procurement plan to be reviewed by Energy Division, Southern California Edison Company shall show that it has a specific plan to undertake integration of energy efficiency, demand response, energy storage and distributed generation resources in order to meet or reduce local capacity requirement needs through 2021.

7. In its proposed procurement plan to be reviewed by Energy Division, Southern California Edison Company shall include all of the following:

- A list of all applicable rules and statutes impacting the plan;
- A detailed description of how it intends to procure resources, specifying the structure of any RFO or alternative procurement process and related timelines;
- A statement as to whether or not SCE intends to seek Commission reconsideration of the solicitation and bilateral contracting determinations in its 2012 RPS procurement plan;
- A detailed list of the RPS procurement authorizations and processes that support SCE's plans to acquire RPS-eligible resources to meet LCR needs;

- A methodology for determining least cost/ best fit that includes evaluating and quantifying performance characteristics that vary among resource type (e.g. time to start, output at various times, variable cost, effectiveness in meeting contingencies, etc.);
- What type of price benchmark will be used in determining cost-effectiveness for resources;
- An explanation for each resource type indicating whether modifications will be made to existing programs or if a new approach will be utilized;
- A methodology for determining peak capacity for resources for which there is not a currently approved methodology for determining Net Qualifying Capacity; and
- A methodology for determining other reliability capabilities (e.g. voltage support) for resources for which there is not a currently approved methodology for determining these capabilities.

8. Southern California Edison Company may provide the conventional gas-fired resources portion of the procurement plan for review ahead of its full procurement plan. If Energy Division approves this portion of the plan Southern California Edison Company may go forward with that procurement.

9. Southern California Edison Company is authorized to procure bilateral cost-of-service contracts to meet authorize local capacity requirements as specified in this Order, including bilateral contracts consistent with the provisions of Public Utilities Code § 454.6.

10. Southern California Edison Company shall work with the California Independent System Operator to determine a priority-ordered listing of the most electrically beneficial locations for preferred resources deployment.

11. Southern California Edison Company (SCE) shall file one Application for approval of any and all contracts entered into as a result of the procurement process authorized by this decision for the Los Angeles basin local reliability area, and one Application for these purposes for the Big Creek/Ventura local reliability area. An exception to the requirement of this paragraph is if SCE's procurement plan, as approved by Energy Division, provides for one separate and earlier Application to procure gas-fired generation for both local reliability areas. SCE shall not receive recovery in rates for the costs related to any such contract before Commission review and approval of these Applications. In addition to currently applicable rules, the Applications shall specify how the totality of the contracts meet the following criteria:

a. Cost-effectiveness;
b. Consistency with the Loading Order, including a demonstration that it has identified each preferred resource and assessed the availability, economics, viability and effectiveness of that supply in meeting the LCR need;
c. Compliance with Ordering Paragraphs 1 and 2;
d. For applicable bilateral contracts, compliance with Public Utilities Code Section 454.6; and
e. A demonstration of technological neutrality, so that no resource was arbitrarily or unfairly prevented from bidding in SCE's solicitation process. To the extent that the availability, viability and effectiveness of resources higher in the Loading Order are comparable to fossil-fueled resources, SCE shall show that it has contracted with these preferred resources first.

12. In its application regarding the Los Angeles Basin local reliability area to implement this decision pursuant to Ordering Paragraph 11, Southern California Edison Company shall present contracts for at least 50 MW of energy storage resources (pursuant to Ordering Paragraph 1) to the Commission for approval,

or have the burden to show that it should procure less than 50 MW because the bids it received were unreasonable.

13. Southern California Edison Company shall treat the retrofitting of a power plant cooling system, which is undertaken to comply with State Water Resources Control Board Statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling and has a compliance deadline before December 31, 2022, as a new resource in considering resources to meet the needs in Ordering Paragraphs 1 and 2.

14. Southern California Edison Company (SCE) shall provide documentation in its Applications required by Ordering Paragraph 11 of efforts to consult with the California Independent System Operator to develop performance characteristics for local reliability, and how SCE meets any such performance characteristics.

15. Southern California Edison Company shall allocate costs incurred as a result of procurement authorized in this decision and approved by the Commission consistent with the cost allocation mechanism approved in Decisions (D.) 06-07-029, D.07-09-044, D.08-09-012 and D.11-05-005.

16. The October 5, 2012 Motion of Megawatt Storage Farms, Inc. is denied.
17. Rulemaking 12-03-014 shall remain open.

This order is effective today.

Dated February 13, 2013, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
CARLA J. PETERMAN
Commissioners

Exhibit 10

DOCKETED

Docket Number:	15-AFC-01
Project Title:	Puente Power Project
TN #:	221401
Document Title:	Committee Statement re PMPD Status
Description:	N/A
Filer:	Paul Kramer
Organization:	Energy Commission Hearing Office
Submitter Role:	Committee
Submission Date:	10/5/2017 5:33:09 PM
Docketed Date:	10/6/2017

Before the Energy Resources Conservation and Development Commission of the State of California
1516 Ninth Street, Sacramento, CA 95814
1-800-822-6228 – www.energy.ca.gov

APPLICATION FOR CERTIFICATION FOR THE: ***PUENTE POWER PROJECT***	**Docket No. 15-AFC-01**

COMMITTEE STATEMENT REGARDING THE STATE OF THE PRESIDING MEMBER'S PROPOSED DECISION

The Energy Commission Committee[1] (Committee) assigned to the Puente Power Project (Project) proceeding continues to work diligently in preparing a Presiding Member's Proposed Decision (PMPD) for the Project. As we do so, we find it appropriate to provide notice to the parties and interested members of the public of the current status of our deliberations.

Although the PMPD is not yet in final form, it is clear to us that the Project will be inconsistent with several Laws, Ordinances, Regulations or Standards (LORS) and will create significant unmitigable environmental effects. This, in turn, requires us to consider feasible alternatives that avoid or reduce those impacts and inconsistencies. The September 29, 2017 letter from the California Independent System Operator[2] (California ISO) addresses feasibility and informs us that preferred resource alternatives to the Project are technologically feasible. The California ISO also states that economic feasibility can only be ascertained through a new Request for Offer (RFO) process, and stresses that any such RFO would need to be expedited in order to ensure that the Mandalay facilities retire in accord with the State Water Resources Control Board's Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling.

While we have no current information about whether an expedited RFO is forthcoming, the timing constraints identified by the California ISO lead us to conclude that it is prudent to communicate the Committee's position before we complete the PMPD. We cannot recommend approval of a project that creates significant unmitigable impacts or is inconsistent with LORS unless we make the override findings required by law. That decision is entirely discretionary and allows the Energy Commission to consider the

[1] The Committee consists of Commissioner Janea A. Scott, Presiding Member, and Commissioner Karen Douglas, Associate Member.
[2] TN 221345.

balance of any project benefits against the impacts the project will cause. On the record currently before us, we are unwilling to override the significant impacts or LORS inconsistencies.

For this reason, we hereby notify the parties and interested members of the public that we intend to issue a PMPD that recommends denial of the Project on the grounds that it creates inconsistencies with LORS and significant environmental impacts that cannot be mitigated. The PMPD will contain a full discussion of all issues required by applicable statutes and regulations and will identify the facts and the analytical process underlying the conclusions reached therein.

We acknowledge that this statement is unusual, but observe that it in no way impairs the rights of the applicant or any other party. All procedural requirements will continue to be honored. After the PMPD is issued, the Committee will hold a PMPD conference to receive comments and determine whether any revisions are required. The Committee will then forward the PMPD (or a revised PMPD if one is issued) to the full Commission for consideration at a public hearing. The full Commission will have the opportunity to accept, reject, or modify the PMPD's conclusions. Indeed, the decision to issue this statement underscores our commitment to producing thorough and thoughtful decisions in a transparent public process that entails rigorous adherence to applicable legal requirements.

Una traducción al español de esta declaración será fichada a principios de la próxima semana. (A Spanish translation of this statement will be filed by early next week.)

Dated: October 5, 2017, at Sacramento, California

JANEA A. SCOTT	KAREN DOUGLAS
Commissioner and Presiding Member	Commissioner and Associate Member
Puente Power Project AFC Committee	Puente Power Project AFC Committee

EXHIBIT 11

EXCERPT FROM PUENTE POWER PLANT FINAL STAFF ASSESSMENT, PART 1 OF 2

HTTP://DOCKETPUBLIC.ENERGY.CA.GOV/PUBLICDOCUMENTS/15-AFC-01/TN214712_20161208T162906_PUENTE_POWER_PROJECT_FSA_PART_1.PDF

ENVIRONMENTAL JUSTICE

Lisa Worrall and Shawn Pittard[1]

SUMMARY OF CONCLUSIONS

Energy Commission staff concludes that construction and operation of the Puente Power Project (Puente or project) would not cause significant direct, indirect, or cumulative environmental justice impacts with the inclusion of proposed conditions of certification (see technical sections). Staff also concludes that project impacts would not disproportionately affect the environmental justice population.

INTRODUCTION

Staff's environmental justice impact analysis evaluates the project's direct, indirect, and cumulative impacts on the environmental justice population living within a six-mile radius of the project site, and whether any impacts would disproportionately affect the environmental justice (EJ) population. Staff uses a six-mile radius around the proposed site, based on the parameters for dispersion modeling used in staff's air quality analysis, to obtain data to gain a better understanding of the demographic makeup of the communities potentially impacted by the project.

WHAT IS ENVIRONMENTAL JUSTICE?

The U.S. Environmental Protection Agency (EPA) defines environmental justice as, "the fair treatment and meaningful involvement of all people regardless of race, color, national origin or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies (US EPA 2015, pg. 4)."

The "Project Outreach" subsection discusses the Energy Commission's outreach program specifically as it relates to the proposed project. The "Environmental Justice Screening" subsection describes the methodology used to identify an EJ population. The "Project-Specific Demographic Screening" subsection presents the demographic data for those people living in a six-mile radius of the project site and determination on presence or absence of an EJ population. When an EJ population is identified, staff in 12 technical disciplines [2] considers the project's impacts on this population and whether any impacts would disproportionately affect the EJ population.

ENVIRONMENTAL JUSTICE IN THE ENERGY COMMISSION SITING PROCESS

Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," focuses federal attention on the

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[1] Refer to the end of this section for a list of staff who contributed to the Environmental Justice analysis.

[2] The 12 technical disciplines are Air Quality, Cultural Resources, Hazardous Materials Management, Land Use, Noise and Vibration, Public Health, Socioeconomics, Soil and Water Resources, Traffic and Transportation, Transmission Line Safety and Nuisance, Visual Resources, and Waste Management. Cultural Resources staff considers impacts to Native American populations.

environment and human health conditions of minority communities and calls on federal agencies to achieve environmental justice as part of their mission. The order requires the U.S. EPA and all other federal agencies (as well as state agencies receiving federal funds) to develop strategies to address this issue. The agencies are required to identify and address any disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority and/or low-income populations.

The California Natural Resources Agency recognizes that EJ communities are commonly identified as those where residents are predominantly minorities or live below the poverty level; where residents have been excluded from the environmental policy setting or decision-making process; where they are subject to a disproportionate impact from one or more environmental hazards; and where residents experience disparate implementation of environmental regulations, requirements, practices, and activities in their communities. Environmental justice efforts attempt to address the inequities of environmental protection in these communities.

An EJ analysis is composed of the following:

- Identification of areas potentially affected by various emissions or impacts from a proposed project;
- Providing notice in appropriate languages (when possible) of the proposed project and opportunities for participation in public workshops to EJ communities;
- A determination of whether there is a significant population of minority persons, or persons below the poverty level, living in an area potentially affected by the proposed project; and
- A determination of whether there may be a significant adverse impact on a population of minority persons or persons below the poverty level caused by the proposed project alone, or in combination with other existing and/or planned projects in the area.

California law defines EJ as “the fair treatment of people of all races, cultures and income with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies” (Gov. Code, §65040.12; Pub. Resources Code, §§ 71110-71118). All departments, boards, commissions, conservancies and special programs of the Resources Agency must consider EJ in their decision-making process if their actions have an impact on the environment, environmental laws, or policies. Such actions that require EJ consideration may include:

- adopting regulations;
- enforcing environmental laws or regulations;
- making discretionary decisions or taking actions that affect the environment;
- providing funding for activities affecting the environment; and
- interacting with the public on environmental issues.

SCREENING STEPS

Demographic Data - Identifying an EJ population

Staff uses demographic data to identify presence or absence of an EJ population within a six mile radius of project. Staff's demographic screening is based on information contained in two documents: *Environmental Justice: Guidance Under the National Environmental Policy Act* (CEQ 1997) and *Final Guidance for Incorporating Environmental Justice Concerns in EPA's Compliance Analyses* (US EPA 1998). The intention is to identify minority and below-poverty-level populations potentially affected by the proposed project. Due to the changes in the data collection methods used by the US Census Bureau, Energy Commission staff's screening process relies on 2010 decennial US Census data to determine the number of minority populations and the most current data from the American Community Survey (ACS) to evaluate the presence of individuals living below the federal poverty level.

Minority Populations

According to *Environmental Justice: Guidance Under the National Environmental Policy Act*, minority individuals are defined as members of the following groups:

- American Indian or Alaskan Native
- Asian or Pacific Islander
- Black, not of Hispanic origin
- Hispanic

Staff identifies an EJ population when one or more U.S. Census blocks in the six-mile radius have a minority population greater than or equal to 50 percent.

Below-Poverty-Level Populations

The official poverty thresholds do not vary by geography (e.g. state, county, etc.), but are updated annually to allow for changes in the cost of living. The population for whom poverty status is determined does not include institutionalized people, people in military quarters, people in college dormitories, and unrelated individuals under 15 years old. The Council on Environmental Quality (CEQ) and U.S. EPA guidance documents identify a 50-percent threshold to determine whether minority populations are considered EJ populations, but do not provide a similar threshold for below-poverty-level populations. In the absence of thresholds, staff looks at the below-poverty-level populations in the six-mile radius and compares them to other appropriate reference geographies, such as Census County Divisions (CCDs), the county, or the state, to determine whether the below-poverty-level populations are less than, more than, or about the same as the populations in the comparison geographies. U.S. EPA guidance notes that a demographic comparison to the next larger geographic area or political jurisdiction should be presented to place population characteristics in context (US EPA

1998, pg. 12). This is consistent with staff's approach to identify below-poverty-level populations that constitute an EJ population.

Demographic Data Background - Using the US Census Bureau's Decennial Census and American Community Survey in Staff Assessments

After the 2000 decennial Census, the detailed social, economic, and housing information previously collected on the decennial census long form became the American Community Survey (ACS) (US Census 2013a). The U.S. Census Bureau's ACS is a nationwide, continuous survey that will continue to collect long-form-type information throughout the decade. Decennial census data is a 100 percent count collected once every ten years and represents information from a single reference point (April 1st). The main function of the decennial census is to provide counts of people for the purpose of congressional apportionment and legislative redistricting.

ACS collects data from a sample of the population based on information compiled continually and aggregated into one- and five-year estimates ("period estimates") released every year. The primary purpose of the ACS is to measure the changing social and economic characteristics of the U.S. population. As a result, the ACS does not provide official population counts in between censuses.

ACS collects data at every geography level from the largest level (nation) to the smallest level available (block group (BG)).[3] Census Bureau staff recommends the use of data no smaller than the census tract level.[4,5] ACS one-year estimates cannot reliably capture data from smaller geographical areas, as the population size does not allow for an adequate sample size. The aggregated five-year estimates provide sufficient sample size to yield reliable data in smaller geographies (e.g. less populated cities). Thus, Energy Commission staff uses data from the five-year estimates in the analysis to better represent a wider range of populated areas. A certain level of variability is associated with the estimates because they come from a sample population. This variability is expressed as a margin of error (MOE) which is used to calculate the coefficient of variation (CV). CVs are a standardized indicator of the

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[3] Census Block Group - A statistical subdivision of a census tract. A BG consists of all tabulation blocks whose numbers begin with the same digit in a census tract; for example, for Census 2000, BG 3 within a census tract includes all blocks numbered between 3000 and 3999. The block group is the lowest-level geographic entity for which the Census Bureau tabulates sample data from the decennial census. **Source:** http://www.census.gov/dmd/www/glossary.html.

[4] Census Tract - A small, relatively permanent statistical subdivision of a county or statistically equivalent entity, delineated for data presentation purposes by a local group of census data users or the geographic staff of a regional census center in accordance with Census Bureau guidelines. Census tracts are designed to be relatively homogeneous units with respect to population characteristics, economic status, and living conditions at the time they are established. Census tracts generally contain between 1,000 and 8,000 people, with an optimum size of 4,000 people. Census tract boundaries are delineated with the intention of being stable over many decades, so they generally follow relatively permanent visible features. **Source:** http://www.census.gov/dmd/www/glossary.html.

[5] Census Workshop: Using the American Community Survey (ACS) and The New American Factfinder (AFF) hosted by Sacramento Area Council of Governments on May 11 & 12, 2011. Workshop presented by Barbara Ferry, U.S. Census Partnership Data Services Specialist.

reliability of an estimate. While not a set rule, the US Census Bureau considers the use of estimates with a CV more than 15 percent a cause for caution when interpreting patterns in the data (US Census 2009). When CVs for estimates are high, the reliability of an estimate improves by using estimates for a larger geographic area (e.g. city or community versus census tract) or combining estimates across geographic areas.

CalEnviroScreen - More information about an EJ Population

California Communities Environmental Health Screening Tool: CalEnviroScreen Version 2.0 (CalEnviroScreen) is a science-based mapping tool used by the California EPA to identify disadvantaged communities[6] pursuant to Senate Bill 535. As required by SB 535, disadvantaged communities are identified based on geographic, socioeconomic, public health and environmental hazard criteria. CalEnviroScreen assesses communities at the census tract level in California to identify the communities most burdened by pollution from multiple sources and most vulnerable to its effects, taking into account socioeconomic characteristics and underlying health status (CalEPA 2014b, pg. 1).

The CalEnviroScreen score derived for a given tract is relative to other tracts in the state (CalEPA 2014a, pg. 5). Values for the various indicators are shown as percentiles, which rank the percent of all census tracts with a lower score. A higher percentile indicates a higher potential relative burden. CalEnviroScreen scores are calculated by multiplying the pollution burden and population characteristics categories together into a single unified score (Pollution Burden X Population Characteristics = CalEnviroScreen Score) (CalEPA 2014a). Each group has a maximum score of 10, thus the maximum CalEnviroScreen score is 100. **Environmental Justice Table 1** lists the indicators that go into the pollution burden score and the population characteristics score to form the unified CalEnviroScreen score. These indicators are used to measure factors that affect the potential for pollution impacts in communities.

[6] The California Environmental Protection Agency (CalEPA), for purposes of its Cap-and-Trade Program, has designated “disadvantaged communities” as census tracts having a CalEnviroScreen score at or above the 75th percentile (CalEPA 2014a).

Environmental Justice Table 1
Components that form the CalEnviroScreen 2.0 Score

Pollution Burden	
Exposure Indicator	Environmental Effects Indicators
Ozone concentrations	Cleanup sites
Particulate Matter (PM) 2.5 concentrations	Groundwater threats
Diesel PM emissions	Hazardous waste
Pesticide Use	Impaired water bodies
Drinking water contaminants	Solid waste sites and facilities
Toxic releases from facilities	
Traffic density	
Population Characteristics	
Sensitive Populations Indicators	Socioeconomic Factors Indicators
Children (under age 10) and elderly (over age 65)	Educational attainment
Low birth-weight births	Linguistic isolation
Asthma emergency department visits	Poverty
	Unemployment

There are several limitations with CalEnviroScreen that are important to note (CalEPA 2014). Some limitations of CalEnviroScreen include the following:

- The score is not an expression of health risk.
- The score does not provide quantitative information on increase of cumulative impacts for specific sites or projects.
- The score provides a relative ranking of communities based on a select set of available datasets through a summary score, but does not provide a basis for determining when differences between scores are significant in relation to public health or the environment.
- The score is not intended to be used as a health or ecological risk assessment for a specific area or site.
- The score cannot be used in lieu of performing analysis of the potentially significant impacts, including the cumulative impacts, of a specific project.
- There are no new programs, regulatory requirements, or legal obligations created by the publication of CalEnviroScreen and no mandates to use the tool or the underlying data.
- The score provides a broad environmental snapshot of a given region.

Based on CalEnviroScreen data and other data specific to the project area, staff considers where project impacts would potentially occur and the extent to which that area of potential project impact is currently burdened. With this combined information, staff then assesses the extent of the project's impact on the EJ population. Because a CalEnviroScreen score evaluates multiple pollutants and factors collectively, staff examined individual contributions of indicators that are relevant to their technical area.

Not all of the technical areas that consider project impacts to an EJ population have relevant CalEnviroScreen indicators to their technical area.

Part of staff's assessment of how, or if, the project would impact an EJ population includes a review of CalEnviroScreen data for the project area. Staff uses CalEnviroScreen to better understand the characteristics of the areas where the impact would occur and ensure that disadvantaged communities in the vicinity of the proposed project have not been missed when screened by race/ ethnicity and poverty.

PROJECT OUTREACH

As a part of the U.S. EPA's definition of environmental justice, meaningful involvement is an important part of the siting process. Meaningful involvement occurs when:

- those whose environment and/or health would be potentially affected by the decision on the proposed activity have an appropriate opportunity to participate in the decision;
- the population's contribution can influence the decision;
- the concerns of all participants involved would be considered in the decision-making process; and,
- involvement of the population potentially affected by the decision on proposed activity is sought. (US EPA 2016)

The Energy Commission's outreach program is primarily facilitated by the Public Adviser's Office (PAO). This is an ongoing process that to date has involved the following efforts related to the project.

LIBRARIES

On June 20, 2016, Energy Commission staff sent the Puente Power Project Preliminary Staff Assessment (PSA) to local libraries in Oxnard, and to the state libraries in Eureka, Sacramento, Fresno, San Francisco, Los Angeles and San Diego. The FSA will be sent to the same libraries.

INITIAL OUTREACH EFFORTS

Energy Commission staff and the PAO coordinated closely on public outreach early in the review process. A Notice of Receipt of the Puente Application for Certification (AFC) and Notice of Public Participation were docketed and mailed to the project mail list on April 27, 2015. Public notices for the project in both English and Spanish were published in local newspapers on May 24, 2015 and May 28, 2015. The PAO made a presentation to the Oxnard City Council on July 14, 2015, outlining the Energy Commission's review process and avenues for public participation.

The PAO contacted local elected officials, Native American tribal groups, and community groups, including Central Coast United for a Sustainable Economy (CAUSE), Mixteco Indigena Community Organizing Project (MICOP), and the United Farm Workers. PAO also published notices in English and Spanish in the local newspapers prior to the August 27, 2015 Site Visit, Informational Hearing and Environmental Scoping Meeting. Spanish-language interpreters facilitated public comment at the hearing.

Energy Commission regulations require staff to notice, at a minimum, property owners within 1,000 feet of a project and 500 feet of a linear facility (such as transmission lines, gas lines, and water lines). This was done for the project, and the property owners list has been augmented to include the surrounding political jurisdictions, school districts, state and federal agencies, and interest groups.

Energy Commission staff held a public workshop for the PSA in the city of Oxnard on Thursday July 21, 2016 at the Oxnard Performing Arts Center. Headsets with simultaneous Spanish translation were available for the workshop. The **Executive Summary** section of the PSA was translated into Spanish. The **Executive Summary** section of the FSA will also be translated in Spanish.

The Energy Commission Committee assigned to conduct proceedings on the AFC held a Status Conference in Oxnard on Tuesday September 27, 2016 at the Oxnard Performing Arts Center. The committee provided feedback on the PSA, discussed case progress and schedule, and heard public comments. Headsets with simultaneous Spanish translation were available for the Status Conference.

PROJECT-SPECIFIC DEMOGRAPHIC SCREENING

Puente is located in the city of Oxnard, Ventura County, within the boundaries of the existing Mandalay Generation Station (MGS) industrial site (393 North Harbor Boulevard).

Environmental Justice Figure 1 (using a one-, three-, and six-mile radius) shows that the population in these census blocks represents an EJ population based on race and ethnicity as defined by *Environmental Justice: Guidance Under the National Environmental Policy Act*. The population in the six-mile radius lives primarily within the cities of Oxnard, Port Hueneme, and San Buenaventura (Ventura) and portions of Ventura County.

In an effort to update population data since the 2010 decennial U.S. Census, staff has included **Environmental Justice Table 2** to provide the reader a comparison of decennial and ACS data for minority populations. As shown in the table below, the percent of minority populations in the cities of Oxnard and San Buenaventura have remained consistent since 2010, while there has been about a five percent increase in minority populations in Port Hueneme.

Environmental Justice Table 2
Minority Population Data Within the Project Area

Cities in the six-mile radius		Total Population	Not Hispanic or Latino: White alone	Minority	Percent Minority (%)
Oxnard	April 1, 2010 Census [1]	197,899	29,410	168,489	85.14
	2010-2014 Estimate [2]	201,744 ±157	28,493 ±1,301	173,25 ±1,310	85.88 ±0.65
Port Hueneme	April 1, 2010 Census	21,723	7,291	14,432	66.44
	2010-2014 Estimate	21,949 ±63	6,263 ±631	15,686 ±634	71.47 ±2.88
San Buenaventura (Ventura)	April 1, 2010 Census	106,433	63,879	42,554	39.98
	2010-2014 Estimate	108,449 ±55	64,312 ±1,295	44,137 ±1,296	40.70 ±1.20
Notes: Staff's analysis of the 2010 – 2014 estimates returned CV values less than 15, indicating the data is reliable. **Sources:** [1] US Census 2010a and [2] US Census 2015a.					

Low Income Populations

Staff identified the below-poverty-level population in the project area using place level data (city) from the ACS Five-Year Estimates[7] (US Census 2015b). **Environmental Justice Table 3** shows poverty data for the cities of Oxnard, San Buenaventura (Ventura), and Port Hueneme, and for Ventura County. The cities are situated in the six-mile radius of the project site, while Ventura County is the reference geography.

7 Staff determined that data at the place (city) level is the lowest level available that retains reasonable accuracy. The data represents a period estimate, meaning the numbers represent an area's characteristics for the specified time period.

Environmental Justice Table 3
Poverty Data within the Project Area

Cities in the six-mile radius	Total	Income in the past 12 months below poverty level	Percent below poverty level (%)
	Estimate*	Estimate	Estimate
Oxnard	200,076 ±394	31,956 ±2,320	16.00 ±1.2
Port Hueneme	21,020 ±310	3,848 ±838	18.30 ±4
San Buenaventura (Ventura)	106,870 ±262	11,532 ±1,399	10.80 ±1.3
Reference geography			
Ventura County	824,329 ±959	91,912 ±3,350	11.10 ±0.4
Notes: * Population for whom poverty status is determined. Staff's analysis of the 2010 – 2014 estimates returned CV values less than 15, indicating the data is reliable. **Source:** US Census 2015b.			

The cities of Oxnard and Port Hueneme have a higher percent of people living below the federal poverty level (approximately five and seven percent higher, respectively) when compared with Ventura County. Staff concludes that the below-poverty-level population in the cities of Oxnard and Port Hueneme constitutes an EJ population based on poverty as defined by *Environmental Justice: Guidance Under the National Environmental Policy Act*.

PROJECT-SPECIFIC CALENVIROSCREEN RESULTS

Environmental Justice Figure 1 presents the minority data at the census block geographic level and marks the census tract boundaries of the tracts identified in CalEnviroScreen 2.0 as disadvantaged communities. CalEPA identifies disadvantaged communities as the 25 percent (75 to 100 percentile) highest-scoring census tracts in California (CalEPA 2014b).

By layering the minority data at the census block level with the census tract boundaries identified as disadvantaged communities, the minority block level data shows the census blocks where people live. Areas within the census tract boundaries without any shading are areas without residences. The size of the census block correlates with the number of residences in the block; the same is true of census tracts. For example, the smaller the census block or tract, the more densely populated that block or tract is. Likewise, the larger the block or tract, the less densely populated that block or tract is. The census block is the smallest census geographic entity.

When the staff from the 12 technical areas identified impacts from the project that could affect an EJ population, staff reviewed **Environmental Justice Figure 1** and considered the associated data in their project impact analysis for the EJ population.

A review of **Environmental Justice Figure 1** shows that the closest residences to the project site within a disadvantaged census tract are at the southeast corner of the intersection of Pacific Coast Highway and West Fifth Street, approximately 4.5 miles due east from the project site.

Environmental Justice Table 4 presents the CalEnviroScreen data for the disadvantaged community census tracts in a six-mile radius of the Puente site. Where percentiles for CalEnviroScreen indicators are 90 and above, the percentile is shown in bold. These relatively higher percentiles could be seen as drivers for the census tract's identification as a disadvantaged community. Two of the census tracts in the project's six-mile radius have percentiles above 90 percent for population characteristics.
All of the disadvantaged census tracts have percentiles above 90 for pesticides. All but two disadvantaged census tracts have indicators in both the pollution burdens and population characteristics groups of indicators with percentiles above 90.

Environmental Justice Table 4
CalEnviroScreen Scores for Disadvantaged Communities

Disadvantaged Communities by Census tract in the Project's Six-Mile Radius[1]						
Census Tract Number		6111004902	6111009100	6111004715	6111003900	6111004503
Total Population		5,091	5,279	5,020	7,533	4,387
CES 2.0 Percentile Range[2]		96-100	91-95	91-95	81-85	76-80
Ozone	PERCENTILES	0.10	0	0	0	0
PM 2.5		36.54	36.33	39.30	36.95	37.89
Diesel PM		53.95	43.86	28.91	40.74	49.82
Drinking Water		38.41	38.91	54.48	38.91	38.91
Pesticides		**99.83**	**98.54**	**99.67**	**96.88**	**97.84**
Toxic Release		61.30	69.08	88.61	77.24	**96.51**
Traffic		71.92	36.57	24.65	47.57	53.09
Cleanup Sites		0	64.78	**92.91**	42.59	42.64
Groundwater Threats		85.12	**92.68**	88.36	85.01	0
Hazardous Waste		86.51	75.34	69.91	50.42	25.63
Impaired Water Bodies		**97.27**	0	80.63	0	0
Solid Waste		86.34	23.19	**95.83**	0	0
POLLUTION BURDEN		88.21	68.33	89.71	61.39	56.50
Age		85.80	57.47	49.23	54.93	33.04
Asthma		81.30	81.13	58.19	60.16	58.18
Low Birth Weight		74.09	75.39	81.90	44.55	78.53
Education		**99.10**	**98.81**	84.61	**92.96**	89.99
Linguistic Isolation		**91.43**	**93.49**	77.38	**97.41**	82.25
Poverty		89.90	**94.16**	67.75	89.38	81.23
Unemployment		26.96	82.51	58.54	66.14	78.08
POPULATION CHARACTERISTICS		93.65	97.57	80.65	86.68	85.73

Notes: [1]Disadvantaged Communities census tracts that intersect or are within a six-mile radius of the project site. Indicators with percentiles that are shown as **bold** text are in the 90 percentile or higher. [2]Overall CalEnviroScreen Score Percentile Range.
Source: CalEPA 2014a

PROJECT IMPACTS TO THE ENVIRONMENTAL JUSTICE POPULATION

The following is a summary of the conclusions on project impacts to the EJ population from each of the 12 technical areas. For more information refer to the subject technical area section of the Final Staff Assessment. The technical areas of cultural resources, hazardous materials management, land use, noise and vibration, socioeconomics, transmission line safety and nuisance, and visual resources would not have the type of impacts that would combine with any of the indicators that make up the CalEnviroScreen score.

AIR QUALITY

Staff concludes that the proposed project's air quality impacts would be mitigated to be less than significant, including ozone precursor and PM2.5 impacts. Both ozone and PM2.5 impacts are regional, not local, and require both time and space for these pollutants to form. As a result, mitigation measures are regional, not local. To evaluate the impacts on nearby EJ communities, staff reviewed **Environmental Justice Figure 1** and **Environmental Justice Table 3** and information found in CalEnviroScreen. With the proposed mitigation measures, EJ communities would not be exposed to increases in ozone or PM2.5 concentrations. Therefore, the project would not individually or cumulatively contribute to disproportionate impacts to the EJ population. Staff concludes that air quality impacts from the project on the EJ population would be less than significant.

CULTURAL RESOURCES

Environmental Justice Figure 1, which shows population based on race and ethnicity, and **Environmental Justice Table 3**, which displays population based on poverty, indicate that an environmental justice population does exist within a six-mile radius of the proposed project area. Staff also reviewed the ethnographic and historical literature to determine whether any Native American populations use or reside in the project area. Staff concluded that because there are no known currently used hunting and gathering areas that could be impacted by the proposed project, Native Americans are not considered members of the environmental justice population for this project. Therefore, staff concludes there would be no impacts to Native American populations and likewise, no disproportionate impact.

HAZARDOUS MATERIALS MANAGEMENT

Staff concludes that while the transportation, storage, and use of hazardous materials at the project could potentially pose a risk of impact to the Environmental Justice (EJ) population represented in **Environmental Justice Population Figure 1** and **Table 3**, such an occurrence would be very unlikely and would not be expected during the lifetime of the proposed project.

Two plausible yet very unlikely incidents include (1) a worst-case release of the entire contents of the aqueous ammonia storage tank and (2) an accident involving an aqueous ammonia delivery truck severe enough to release its contents. Staff's analysis shows that both of these incidents are highly unlikely. With the adoption of staff's proposed Conditions of Certification **HAZ-4, -5**, and **-6**, the use, storage, and transportation of hazardous materials at the project would not present a significant risk of impact to the surrounding EJ population. Similarly, the risk of a potential hazardous materials management impact would not disproportionately affect the EJ population.

LAND USE

Potential land use impacts for a project on an EJ population would be predominantly driven by physical land use incompatibilities or the division of an established community. Staff concluded that the construction, demolition, and operation of Puente would not result in physical land use incompatibilities or division of an established community. The project's land use impact area includes the proposed site and immediately adjacent and nearby land uses. There is not an EJ population residing within one mile of the project's land use impact area. Thus, the project's impacts would not have an effect on any population, including the EJ population during construction, decommissioning, and demolition. No impacts would occur during operations.

Staff concluded that the project's land use impacts would not disproportionately affect the EJ population, as the project impacts would not affect any population living in the impact area. The land use impacts from the project on the EJ population would be less than significant.

NOISE AND VIBRATION

Staff reviewed **Environmental Justice Figure 1** and **Table 3** in the **Environmental Justice** section to examine whether the construction and operation of Puente would have significant, unmitigated impacts or disproportionate impacts on an EJ population.

Staff has prepared Conditions of Certification **NOISE-1** through **NOISE-7** to ensure noise impacts are reduced to less than significant for all the area's population, including the EJ population.

The nearest EJ population is located approximately four miles east of the proposed project site, but noise impacts may occur within only one mile from the project site. The nearest residential receptors (future Beach Walk Subdivision) would be approximately 0.5 mile from the project, but would not be an EJ population. Farm workers are present within approximately 800 feet of the project fence line but restrictions on construction and demolition activities described in Conditions of Certification **NOISE-6** and **NOISE-7** would reduce the noise impact. In addition, these workers would be protected through their employer's OSHA requirements for hearing protection and Condition of Certification **NOISE-1** requiring the project owner to notify the farm workers' employer of the start of construction. Due to the distance between the project and where the nearest EJ population resides, noise impacts would not be disproportionate. Therefore, noise produced by project construction and operation would not cause significant, unmitigated impacts to noise-sensitive receptors and would not contribute to disproportionate impacts to the EJ population, individually or cumulatively.

PUBLIC HEALTH

Staff concludes that the proposed project would not cause impacts to public health, and health risks associated with construction, demolition and operation of the project would be less than significant. Therefore, no one (including the public, off-site nonresidential workers, recreational users, and EJ populations) would experience any acute or chronic cancer or non-cancer effects of health significance due to construction and operation of the proposed Puente facility and the demolition of MGS units 1 and 2. To evaluate the risks and impacts on nearby EJ communities, staff reviewed **Environmental Justice Figure 1** and **Table 3**, and the information generated by CalEnviroScreen 2.0. Upon further analysis on the CalEnviroScreen indicators related to public health, staff concluded that the Puente Power Project would not affect the EJ disadvantaged communities which are already burdened by some public health-related indicators. Also, public health impacts are usually not significant unless the emitting sources are extremely close to each other, within a few blocks, not miles. Therefore, staff concluded that Puente Power Project would not affect the EJ disadvantaged communities identifed by CalEnviroScreen and staff EJ evaluations.

SOCIOECONOMICS

Staff concludes that construction and operation of Puente would not cause significant adverse direct, indirect, or cumulative socioeconomic impacts on the project area's housing, law enforcement services, or parks. Staff also concludes the project would not induce a substantial population growth or displacement of population, or induce substantial increases in demand for housing, parks, or law enforcement services.

Impacts to housing supply could disproportionately affect minorities and low income populations. In the case of Puente's impacts, the few construction workers seeking lodging during project construction and demolition would result in a negligible reduction of the housing supply that would not disproportionately impact the EJ population living in the study area.

None of the socioeconomic impacts from Puente would disproportionately affect the EJ population.

Staff concludes that the project's socioeconomic impacts would be less than significant on the EJ population represented in **Environmental Justice Figure 1** and **Table 3**. In addition, these effects would not disproportionately impact the EJ population living in the study area.

SOIL AND WATER RESOURCES

Staff concludes that the proposed project would not cause impacts to groundwater quality or potable water supplies, and impacts on surface water quality would be mitigated to less than significant. Staff's evaluation of flood risks concludes that present-day flood risks are low and future flood risks could be between low and moderate. To evaluate the risks and impacts on nearby EJ communities, staff reviewed **Environmental Justice Figure 1** and **Table 3**, and the information found in CalEnviroScreen. Upon further analysis, staff concluded that Puente's wastewater would be managed to meet minimum water quality standards that would not affect potable water supplies. Impacts would not increase existing impairments to water resources and, therefore, would not individually or cumulatively contribute to disproportionate impacts to the EJ population. Soil and water resources impacts from the project on the EJ population would be less than significant.

TRAFFIC AND TRANSPORTATION

Staff identified one traffic impact that could potentially affect the EJ populations represented in **Environmental Justice Figure 1** and **Table 3**. With staff's proposed condition of certification (**TRANS-2**) implementing a Traffic Control Plan (TCP) and (**TRANS-3**) restoring all public roads, easements, and rights-of-way, the impact would be less than significant on any population, including the EJ population. **TRANS-2** would reduce the potential for accidents caused by construction traffic exiting the project site to travel northbound on Harbor Boulevard. **TRANS-3** would require the project owner to restore all public roads, easements, rights-of-way, and any other transportation infrastructure damaged due to project-related construction and demolition activities and traffic.

Staff reviewed **Environmental Justice Figure 1** and using the best reasonable estimate of where the less-than-significant project impacts would occur, compared the location of these impacts to the census tracts in the figure that are identified as disadvantaged communities by CalEPA. There are no disadvantaged communities in the vicinity of the project site and extending north on Harbor Boulevard and Victoria Avenue to Highway 101, where the less than significant project impacts are expected to occur.

Staff concluded that the project's traffic and transportation impacts would not disproportionately affect the EJ population, as these types of impacts would affect the EJ population just as they would affect any population living in the impact area. The traffic and transportation impacts from the project on the EJ population would be less than significant with staff's proposed condition of certification.

TRANSMISSION LINE SAFETY AND NUISANCE

Staff concludes that since the proposed transmission lines would be short in length with no nearby residences, there would be no potential for residential electric and magnetic field exposures, which have been of some health concern for previous projects. Short-term exposures have negligible health concerns. In addition, with the four proposed conditions of certification, any safety and nuisance impacts from construction and operation of the proposed lines would be less than significant. Any off-site workers, such as farm workers, would usually be in the vicinity of potential **TLSN** impacts only for a short period of time.

VISUAL RESOURCES

Staff's proposed mitigation would reduce visual resource impacts to less than significant for the population in general, including the EJ population represented in **Environmental Justice Figure 1** and **Table 3**. The project would occupy a very small portion of the field of view from EJ populations because of the distance to the project site. Overall, changes to the visual resource environment would not disproportionally affect individuals in EJ populations because of the low degree of visual change.

Staff concluded that the project's visual resource impacts would not disproportionately affect the EJ population, as these types of impacts would affect the EJ population just as they would affect the population living in the study area. The visual resource impacts from the project on the EJ population would be less than significant with staff's proposed conditions of certification.

WASTE MANAGEMENT

To evaluate the risks and impacts of the Puente project on nearby communities, staff reviewed **Environmental Justice Figure 1** and **Table 3**, and the information found in CalEnviroScreen. Although multiple factors increase the vulnerability of EJ communities to sites that require cleanup, increase exposure to hazardous waste sites, and increase exposure to illegal dump sites, the proposed Puente project would not exacerbate these conditions or cause disproportionate exposure to the EJ community from the perspective of waste management.

Staff believes that Puente would not result in any additional environmental impacts related to waste management that would disproportionately affect an EJ community. Staff has added conditions of certification that would reduce the risk associated with contaminated soils, and disposal of non-hazardous or hazardous waste, to a less than significant level. Staff concludes that there would be no significant impact from demolition, construction, or operation of the power plant on EJ populations.

STAFF CONTRIBUTORS TO THE ENVIRONMENTAL JUSTICE ANALYSIS

The following staff are responsible for specific topics and technical analyses in the **Environmental Justice** section of this staff assessment. Staff names are listed with their area of technical expertise.

Topic	Staff
Demographics	Lisa Worrall
Public Outreach	Shawn Pittard
Technical Area	**Staff**
Air Quality	Jacquelyn Record
Cultural Resources	Matt Braun
Hazardous Materials Management	Brett Fooks, P.E.
Land Use	Steven Kerr Ashley Gutierrez
Noise and Vibration	Shahab Khoshmashrab, P.E. Ed Brady, P.E.
Public Health	Huei-An (Ann) Chu, Ph.D.
Socioeconomics	Lisa Worrall
Soil and Water Resources	Marylou Taylor, P.E.
Traffic and Transportation	Andrea Koch-Eckhardt Jonathan Fong
Transmission Line Safety and Nuisance	Huei-An (Ann) Chu, Ph.D.
Visual Resources	Eric Knight
Waste Management	Ellie Townsend-Hough Paul Marshall

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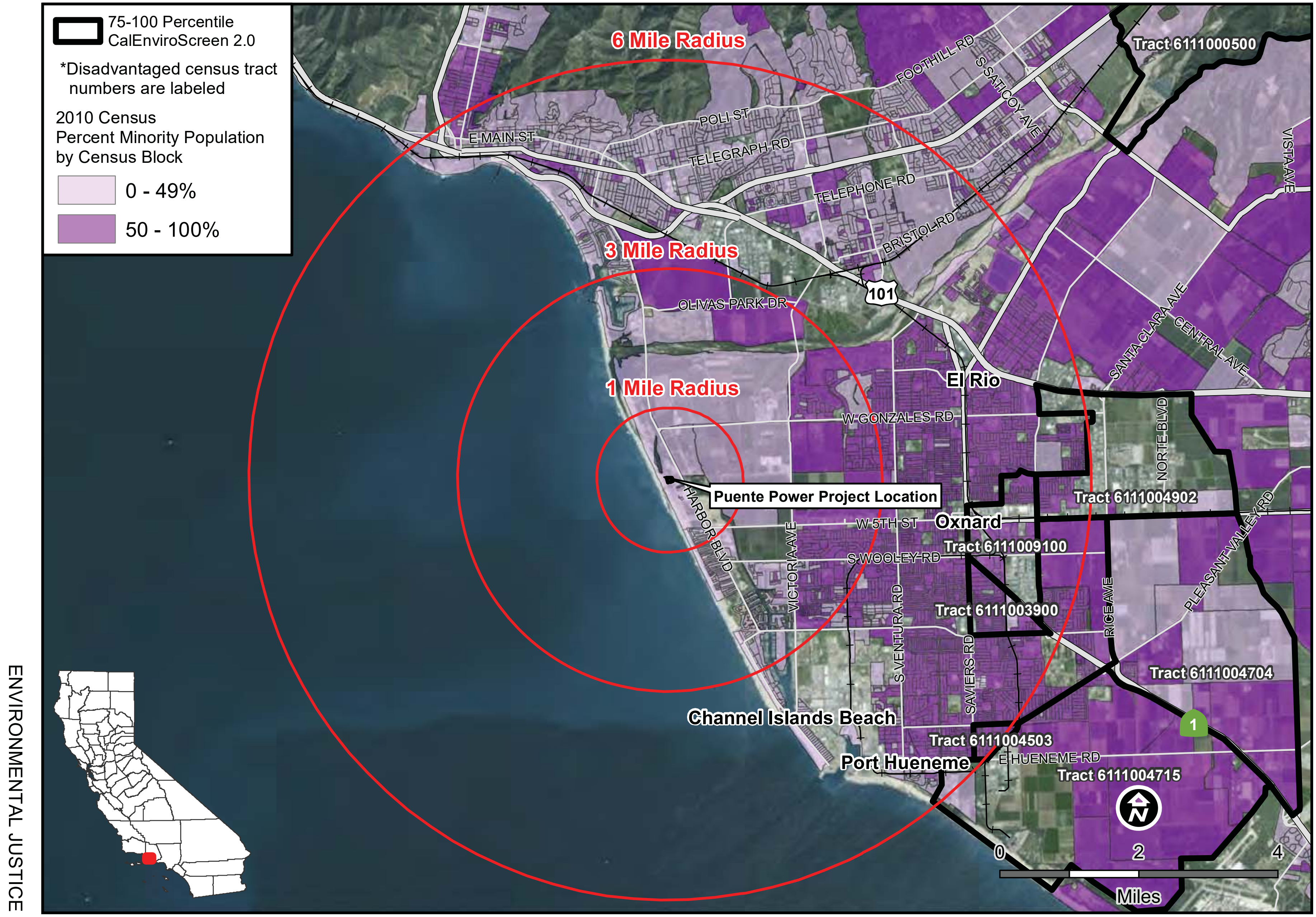
ENVIRONMENTAL JUSTICE - FIGURE 1

Puente Power Project (P3) - Census 2010 Minority Population by Census Block with CalEnviroScreen Disadvantaged Communities by CensusTracts



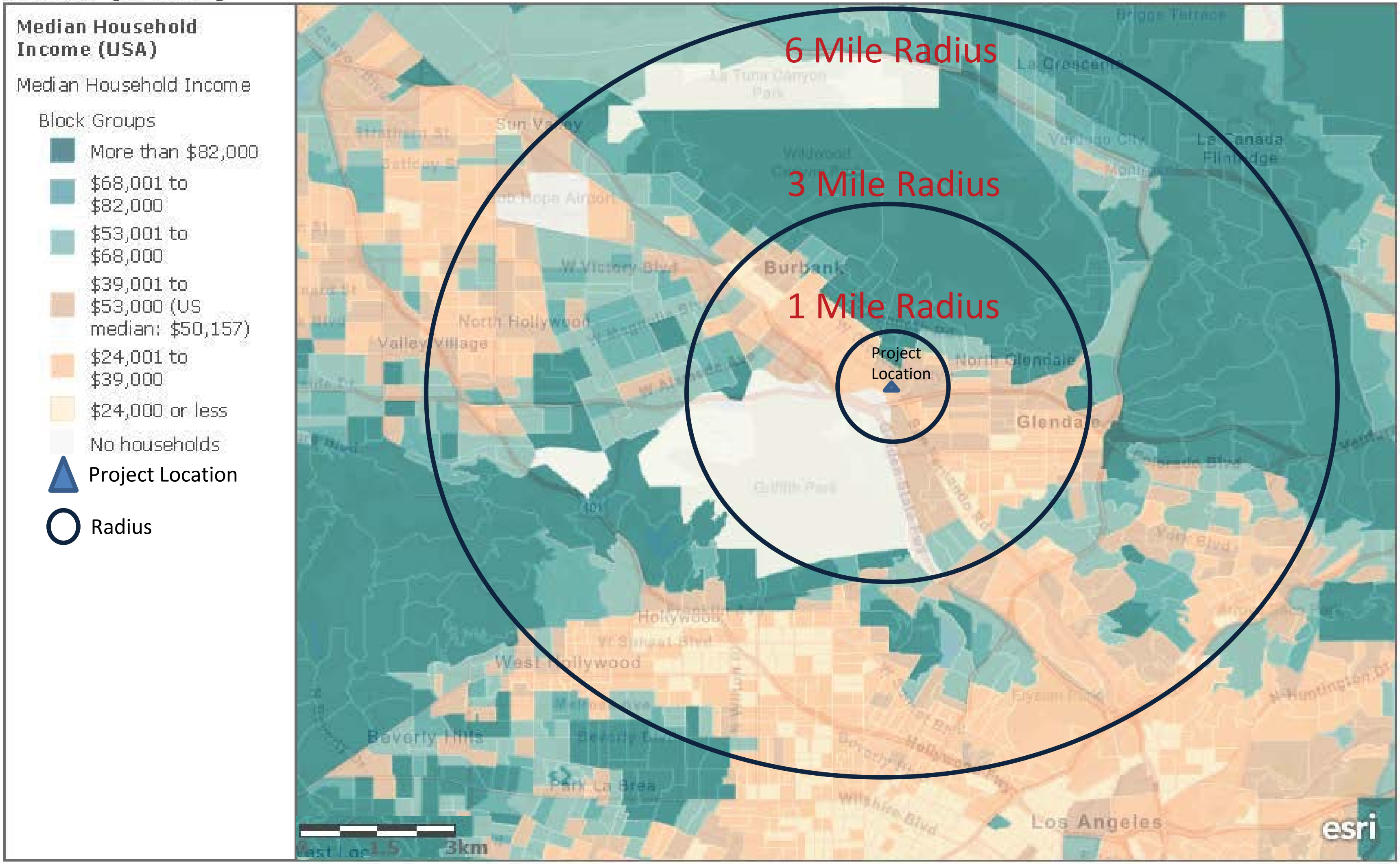
ENVIRONMENTAL JUSTICE

CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCES: Census 2010 PL 94-171 Data and CalEnviroScreen 2.0 CalEPA 2014

EXHIBIT 12

Streets (WGS84)



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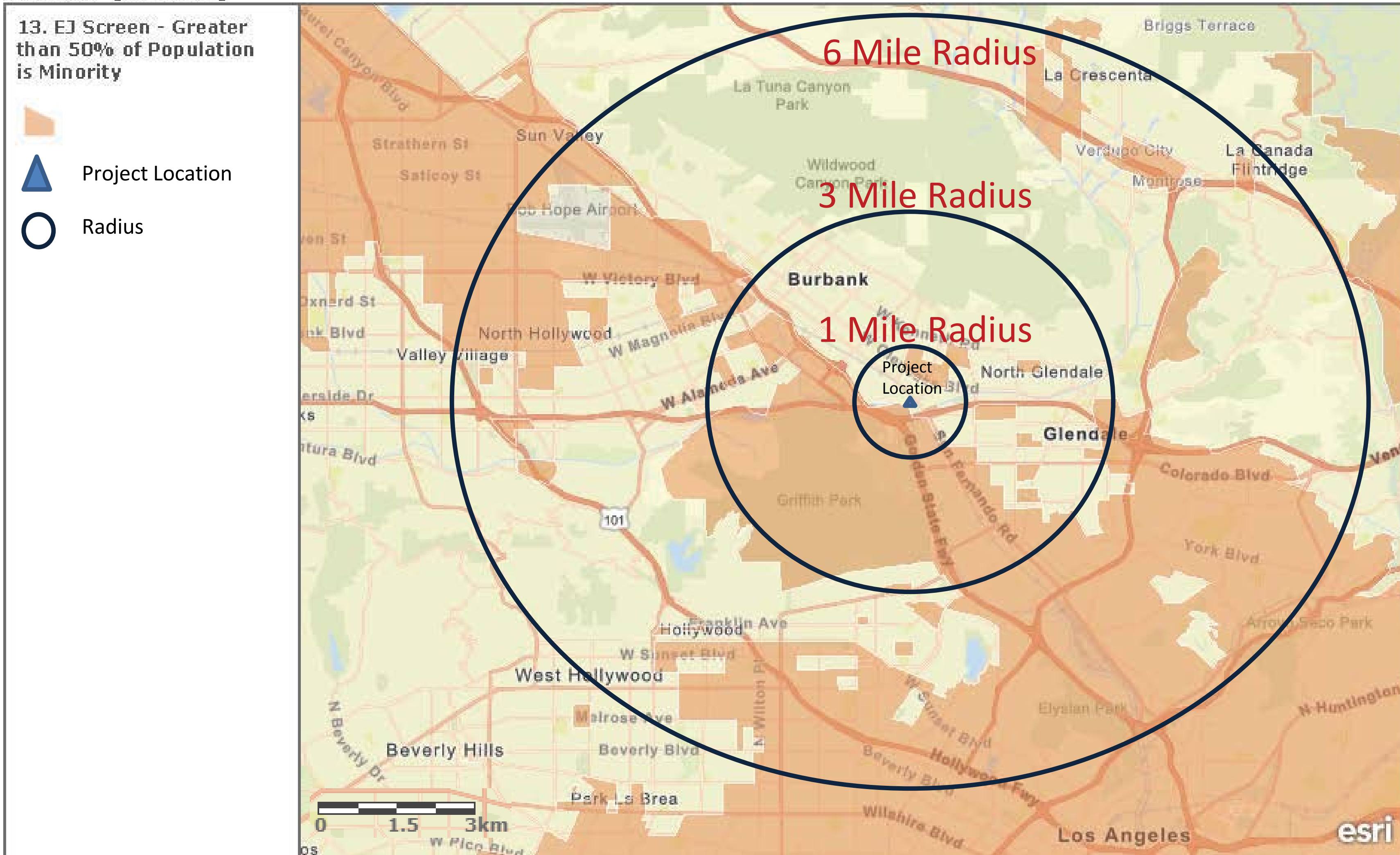

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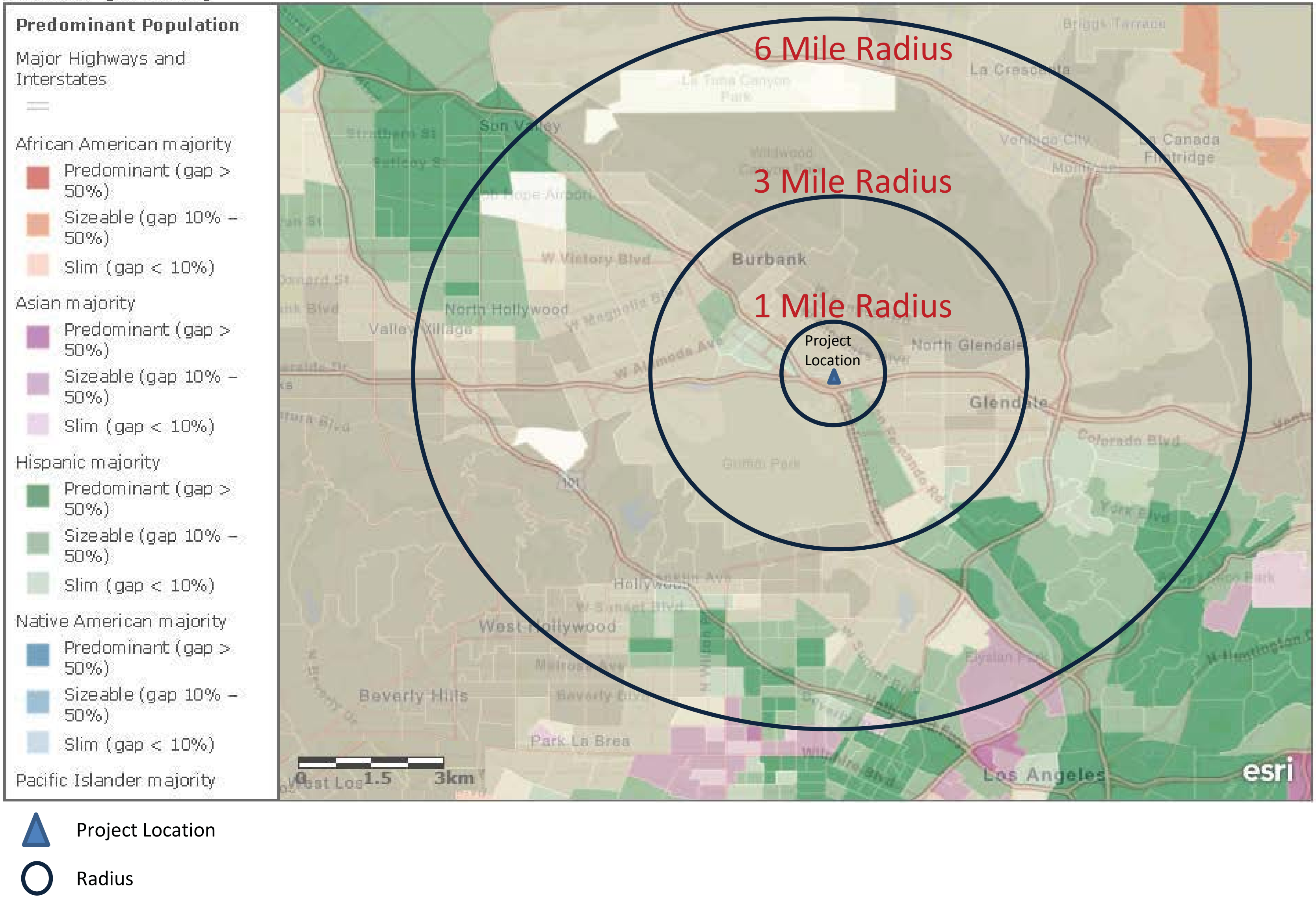

EXHIBIT 3

North American Reliability Corporation,
153 FERC ¶ 61,024, Order (Dkt No. RR15-4-001)

153 FERC ¶ 61,024
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Philip D. Moeller, Cheryl A. LaFleur,
Tony Clark, and Colette D. Honorable.

North American Electric Reliability Corporation Docket No. RR15-4-001

ORDER ON COMPLIANCE FILING

(Issued October 15, 2015)

1. On July 17, 2015, the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted a compliance filing in response to the Commission's March 19, 2015, order approving, in part, proposed revisions to NERC's Rules of Procedure that would implement NERC's Risk-Based Registration (RBR) initiative in the above referenced docket.[1] The March 19 Order generally approved the RBR proposal, but denied, without prejudice, NERC's proposal to eliminate the load-serving entity function from the registry process, finding that NERC had not adequately justified its proposal. In doing so, the Commission directed NERC to provide additional information to support this aspect of its proposal to address the Commission's concerns. For the reasons discussed below, we accept NERC's compliance filing to remove the load-serving entity as a functional registration category, and direct NERC to submit an informational filing on the actual effects of this change after it is implemented.

I. <u>Background</u>

2. On December 11, 2014, NERC submitted a petition for approval of proposed revisions to its Rules of Procedure that would implement the RBR initiative. NERC proposed major reforms to the registration process in the Rules of Procedure to include the elimination of the purchasing-selling entity, interchange authority, and load-serving entity functional registration categories. NERC also proposed modifications to the

[1] *North American Electric Reliability Corporation*, 150 FERC ¶ 61,213 (2015) (March 19 Order).

thresholds for registering entities as distribution providers and procedural improvements to the registration process.

3. In the March 19 Order, the Commission approved in part, and denied in part, NERC's RBR petition. The Commission found NERC's overall goal of ensuring entities are registered and made subject to the Reliability Standards based on the risk they pose to reliability reasonable and adequately justified. The Commission found that NERC's alignment of the registration process with the risks to the interconnected transmission network posed by different types of entities is an improvement. Further, the Commission found that NERC and stakeholders will benefit from the proposed revisions as efforts will appropriately be directed towards activities with a greater potential impact on bulk electric system reliability. The Commission agreed with NERC that it is important to achieve reliability risk mitigation while ensuring the reliability and security of the interconnected transmission network, and the RBR initiative is consistent with this pursuit.[2] Thus, the Commission approved most aspects of NERC's proposal with the exception of the removal of the load-serving entity function. The Commission also approved NERC's proposed revisions related to the registration of distribution providers, but directed that NERC must include Reliability Standard PRC-005 (Transmission and Generation Protection System Maintenance and Testing) as applicable to underfrequency load shedding-only distribution providers. Additionally, the Commission directed NERC to modify the Rules of Procedure to provide the Commission with an opportunity to review decisions by the NERC-led review panel in cases where no appeal occurs by notifying the Commission when it posts a NERC-led review panel decision.

4. With regard to removal of the load-serving entity function, the Commission concluded that NERC did not adequately justify eliminating the load-serving entity function and directed NERC to submit within 60 days a compliance filing that addressed the Commission's concerns.[3] Specifically, the Commission requested additional information regarding how: (1) the deactivation of distribution providers with peak load between 25 and 75 MW affects NERC's estimate regarding the number of load-serving entities that would be deregistered; (2) applicable entities will continue to receive necessary load information for balancing and forecasting purposes upon elimination of the load-serving entity registration category; (3) continuity of responsibility under Reliability Standards applicable to load serving entities will be ensured; and (4) deactivating load-serving entities will affect reliability over time in areas facing

[2] March 19 Order, 150 FERC ¶ 61,213 at P 16.

[3] NERC requested an additional 30 days to submit its compliance filing, which the Commission granted on April 20, 2015.

significant load growth.[4] The Commission also sought additional information on NERC's coordination with the North American Energy Standards Board (NAESB) to ensure the timely transfer of commercial-related practices affected by the proposed elimination of the load-serving entity function.[5]

II. <u>NERC Compliance Filing</u>

5. On July 17, 2015, NERC submitted its compliance filing providing additional information, stating that it satisfies the Commission's concerns described in the March 19 Order. In support of its filing, NERC also provides as Exhibit D of its petition an "Analysis Supporting Removal of Load-Serving Entities" (Technical Analysis). NERC states that it developed the Technical Analysis with input from Regional Entities, load-serving entities, reliability coordinators and balancing authorities.

6. Regarding the effect of deactivating distribution providers with peak load between 25 and 75 MW on the number of load-serving entities that would be deregistered, NERC states that out of the 461 registered load-serving entities, 419 will remain registered as another functional category, leaving 41 potential deregistration candidates.[6] NERC states that the 41 potential deregistration candidates include: (1) its estimate of fourteen load-serving entities to be deregistered as set forth in NERC's initial RBR petition; and (2) the potential deactivation of distribution providers with peak load between 25 and 75 MW based on the increase in the general distribution provider registration threshold.

7. With regard to how balancing authorities and reliability coordinators will continue to receive necessary load information for balancing and forecasting purposes, NERC begins by explaining that load-serving entity tasks generally cover two categories of information: ahead-of-time tasks and real-time tasks. According to NERC, ahead-of-time tasks include submission of load profiles and forecasts to balancing authorities, resource planners and transmission planners, arranging for transmission service from transmission service providers, and submitting requests for interchange-to-interchange coordinators. NERC adds that real-time tasks involve receiving requests for voluntary load curtailment and communicating such requests to end-use customers as directed by a balancing authority or distribution provider. NERC states that it has determined that all

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[4] March 19 Order, 150 FERC ¶ 61,213 at PP 38-41, 43.

[5] *Id*. P 42.

[6] According to NERC, the count excludes one entity that will be deregistered separate and apart from the RBR initiative.

41 entities potentially eligible for deregistration as a load-serving entity are subject to applicable market rules, tariffs, and agreements which will ensure the continuation of load-serving entity reliability activities. NERC explains that it focused on the load-serving entity's responsibility for reporting load because this task is covered by NERC Reliability Standard requirements that apply to load-serving entities. NERC evaluated whether the load data collected by load-serving entities would still be provided for under a contractual agreement or other market protocol. NERC represents that it confirmed that all entities participate in an organized market that requires load data to be provided under a market participation agreement or a Commission-approved tariff.

8. NERC provides specific tariff and agreement provisions in Appendix E of Exhibit D of its filing. NERC states that these tariffs and protocols ensure that the load serving entities' ahead-of-time and real-time tasks continue. For example, NERC explains that in the Electric Reliability Council of Texas, Inc. (ERCOT) region - where nearly half (18) of the 41 load-serving entities potentially eligible for deregistration are located - ERCOT protocols call for the development of demand forecasts and load profiles by ERCOT, partly based on the load data research conducted by transmission service providers and distribution service providers. The ERCOT protocols also require load-serving entities to designate a qualified scheduling entity to perform load shedding and interruptible load responsibilities on behalf of the load-serving entity. NERC also explains that five of the 41 are under the California Independent System Operator (CAISO) tariff, where the load serving entity is a metered subsystem which is responsible for balancing its own load and resources within its territory. The CAISO tariff also requires the load-serving entity to coordinate projected load growth for planning purposes. In the same vein, an additional five of the load-serving entities are under the Midcontinent Independent System Operator, Inc. (MISO) tariff, which mandates that transmission operators receive ahead-of-time information, including balancing authority load forecast, day-ahead schedules for all resources, and forecast commitment status, so that the transmission operator can perform local reliability analysis. With respect to real-time data, NERC states that, under the MISO tariff, market participants that are load-serving entities or are purchasing on behalf of a load serving entity must respond to transmission provider directives to curtail load. NERC also includes the remaining entities which are covered by non-ISO or RTO tariffs or agreements.

9. With respect to registered entities that were identified by NERC and the Regional Entities as potentially eligible for removal from the registry criteria, NERC requested that these registered entities provide confirmation of existing contractual obligations or other processes in place through which balancing authorities and reliability coordinators would receive load data. Furthermore, NERC inquired with these entities whether deregistration of their load-serving entity function would change their current processes for providing needed information. According to NERC, the load-serving entities responded that their loads are metered and this information is provided to the balancing authorities in real-time. NERC adds that the 41 entities potentially eligible for deregistration are located in

10 balancing authorities and that it reviewed contractual agreements of these load-serving entities and confirmed that these agreements contain sufficient load data, load forecasting, and load shedding provisions. NERC also independently reviewed potential underlying alternative sources of authority, such as responsibilities of entities that will remain on the compliance registry to cover load-serving entity tasks. Specifically, NERC reviewed: open access transmission tariffs, power purchase agreements, network integration transmission service agreements, operating agreements, ERCOT protocols, market rules and the regulatory framework in Texas, transmission planning data services agreements, and reliability assurance agreements. NERC states that these mechanisms that are already in place further assure that balancing authorities and reliability coordinators will continue to obtain needed information.

10. Further, NERC explains that it surveyed the 18 balancing authorities and reliability coordinators that NERC had identified as having load-serving entities potentially eligible for deregistration, and requested that they review the list of deregistration candidates and the impact on the balancing authority or reliability coordinator's ability to receive metered information. NERC also asked the balancing authorities and reliability coordinators to analyze whether deregistration of the potentially eligible entities would adversely affect their ability to receive such real-time and forecasted load condition data from the same load-serving entities or other entities through other contractual arrangements. According to NERC, all but two entities responded that they have contractual obligations with the relevant load-serving entity. NERC states that of the two that do not, one no longer have entities eligible for registration and the other has agreements with its load serving entities that specify load data sharing and forecasting obligations.

11. NERC also surveyed Regional Entities, balancing authorities, reliability coordinators and entities eligible for deregistration as a result of the proposed elimination of the load-serving entity registration category. NERC states that the surveys requested information on how (1) the deactivation of certain distribution providers affects NERC's estimate regarding the number of load-serving entities that would be deregistered; (2) balancing authorities and reliability coordinators will continue to receive necessary load information for balancing and forecasting purposes upon elimination of the load-serving entity registration category from the compliance registry; (3) continuity of responsibility under Reliability Standards applicable to load-serving entities would be ensured; and (4) deactivating load-serving entities would affect reliability over time in areas facing significant load growth. In addition, NERC states that it asked Regional Entities to review the registration information in their respective footprints regarding all load-serving entities that could be eligible for deregistration as a result of the RBR initiative. NERC states that all eight confirmed the loads of these entities and also verified if distribution providers meeting the peak MW criterion would remain registered as a result of application of other distribution provider registration criteria. NERC also

states that the Regional Entities confirmed the list of potential entities that could be eligible for deregistration.

12. In response to the Commission's concern that NERC did not provide adequate information regarding how certain load-serving entity reliability tasks will be performed going forward, NERC explains that of the 419 entities remaining on the compliance registry, 382 will remain registered as a distribution provider. NERC explains that, of the 38 load-serving entities not also registered as a distribution provider, all but eight are registered as either a balancing authority, generator operator or transmission operator. NERC adds that, of the remaining eight load-serving entities, seven are registered as either a generator owner, transmission owner or resource planner, and they are dispersed through three separate Regional Entity footprints. NERC states that one entity is registered only as a load-serving entity; however, that entity is in the process of deregistration due to no longer performing the function in the region it is registered.[7] NERC states that entities registered for the seven functions are also subject to the Reliability Standard requirements that currently apply to the load-serving entity function. NERC also provides a mapping document showing that, of the 72 Reliability Standard requirements applicable to load-serving entities, 55 are also applicable to distribution providers.[8]

13. NERC states that the 41 entities eligible for potential deregistration represent between 0.3 percent and 3.39 percent of their areas' peak load. NERC explains that there is no concentration of these deregistered entities in any Regional Entity footprint, other than Texas Regional Entity which has 18. NERC adds that, even in the Regional Entity footprint facing the largest load growth (projected at seven percent), the estimate of load-serving entity-only organizations that would be completely removed from the compliance registry account for approximately 0.17 percent of total load. NERC also states that the reliability coordinators and balancing authorities did not identify any concerns with respect to load or forecast changes, mitigation of contingencies, or changes in reserve margins. According to NERC, because the 41 entities represent a small percentage of load, there is little to no risk to reliability associated with their removal as a load-serving entity from the compliance registry.

14. NERC states that it has coordinated with NAESB, assuring NAESB the opportunity to develop business practice standards where appropriate in light of NERC's anticipated elimination of the load-serving entity registration category. NERC states that

[7] NERC Compliance Filing at n. 29.

[8] NERC Compliance Filing, Appendix D of Exhibit D.

it has had extensive discussions with NAESB leadership on whether removal of any of the load-serving entity Reliability Standards warranted development of a NAESB standard. NERC states that NAESB identified Reliability Standard INT-011-1 as a candidate for a standard. NERC states that Reliability Standard INT-011-1 targets older or grandfathered agreements, and none of the entities registered solely for the load-serving entity function have any of these agreements. Further, NERC states that an existing NAESB standard, Electronic Tagging Functional Specification, requires e-tag data to be included for point-to-point transactions including grandfathered agreements. NERC adds that the NAESB Wholesale Electric Quadrant (WEQ) Standards leadership conducted a thorough review and identified Reliability Standard INT-011-1 as a candidate for a commercial process standard. According to NERC, the WEQ Executive Committee Chair and Vice Chair have agreed to submit a request to NAESB to ensure that this commercially-related practice under Reliability Standard INT-011-1 is considered for standards development through the NAESB process.[9]

III. Notice of Filing and Responsive Pleadings

15. Notice of NERC's July 17, 2015 compliance filings was published in the *Federal Register*, 80 Fed. Reg. 44,950 (2015), with interventions and protests due on or before August 17, 2015. American Public Power Association, National Rural Electric Cooperative Association, and Transmission Access Policy Study Group (Joint Commenters) and Dominion Resources Services, Inc. (Dominion) filed timely motions to intervene and comments in support of NERC's filing. On August 18, 2015, MISO filed a motion to intervene out-of-time.

Comments

16. Joint Commenters and Dominion support NERC's compliance filing. Dominion agrees with NERC's rationale for removal of the load-serving entity function. Joint Commenters point to NERC's "comprehensive demonstration" that no material load information gap will be created by removing the load-serving entity function. According to Joint Commenters, in addition to the load information that will continue to be available from load-serving entities through their other registrations, and through tariff and contract

[9] Subsequent to the NERC compliance filing, the WEQ Executive Committee, at its August 18, 2015 meeting, approved modifications to WEQ-004, Coordinate Interchange Business Practice Standards, to require the tagging of Intra-Balancing Authority transactions, which is currently addressed in Reliability Standard INT-011-1. The modified business practice standard was ratified by the WEQ membership on September 18, 2015. https://www.naesb.org/weq/weq_final.asp.

obligations, the Commission's *pro forma* tariff provides the overarching framework that assures that load information is provided to those that own and operate the transmission system, and curtailments and load shedding are implemented, to ensure bulk electric system reliability. Joint Commenters argue that load-serving entity registration for NERC compliance was not and is not necessary to accomplish these objectives.

17. Joint Commenters contend that the *pro forma* tariff, combined with all of the specific agreements detailed by NERC, demonstrates that any residual reliability risk from eliminating load-serving entity registration is *de minimis*.[10] According to Joint Commenters, the *pro forma* tariff ensures the ability of transmission providers to obtain the data they need from their network customers, and most load-serving entities are network customers or network load of network customers. Joint Commenters state that under the *pro forma* tariff, load-serving entities will continue to provide their data to their transmission provider. Joint Commenters explain that the *pro forma* tariff allows all transmission providers to get the data they need from their network customers and to direct load curtailments when needed to ensure system reliability; and the network operating agreement provided for by the *pro forma* tariff covers operations, information sharing, and any other issue that might affect the provision of network service. Specifically, with respect to information sharing, *pro forma* tariff section 31.6 requires the network customer to provide the transmission provider with annual updates of its network load and network resource forecasts, as well as timely written notice of material changes in any other information provided in its application relating to any aspect of its facilities or operations affecting the transmission provider's ability to provide reliable service. Joint Commenters explain that this provision allows the entities that own and operate transmission facilities to obtain information needed for long-term planning. Joint Comments also point to section 33.6 of the *pro forma* tariff, which states that when the transmission provider determines that it is necessary for the transmission provider and network customer to shed load, the parties shall do so in accordance with the network operating agreement; and section 33.7 gives the transmission provider the authority to curtail network transmission service whenever needed to protect reliability.

IV. Commission Determination

A. Procedural Matters

18. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, the timely, unopposed motions to intervene serve to make the entities that filed them parties

[10] Joint Commenters at 11, n.15-17.

to this proceeding.[11] We also accept MISO's untimely intervention given its interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

B. Commission Determination

19. We accept NERC's compliance filing. We find that NERC has complied with the March 19 Order with respect to providing additional information justifying the removal of the load-serving entity function and including Reliability Standard PRC-005 as applicable to underfrequency load shedding-only distribution providers. We also find that NERC's modification to the Rules of Procedure to provide the Commission with an opportunity to review decisions by the NERC-led review panel in cases where no appeal occurs by notifying the Commission when it posts a NERC-led review panel decision is adequate.

20. As we discuss below, we find that NERC has addressed the concerns expressed regarding an accurate estimate of the load-serving entities to be deregistered and the reliability impact of doing so. NERC demonstrates that load data will continue to be available and reliability activities will continue to be performed even after load-serving entities would no longer be registered. We find that NERC has provided adequate additional support in its compliance filing that is responsive to the Commission's concerns described in the March 19 Order, and conclude that the proposed elimination of the load-serving entity function is reasonable. We believe that NERC has demonstrated that the risks posed by the elimination of the load-serving entity functional category registration are likely to be minimal.

21. In the March 19 Order, the Commission noted that eliminating the load-serving entity function does not remove the need to provide information required for reliable operation of the bulk electric system.[12] NERC's compliance filing includes additional information that clarifies whether and how some entities will continue to provide information or who will assume their obligations. For example, NERC notes that the number of affected entities is small, spread across all eight Regional Entity footprints and involves a small percentage of load. In addition, NERC provides explanation and specific tariff and contract language showing how load-serving entities are obligated to continue to provide information and respond to commands from various entities. NERC has also described how the load-serving entities will be required to continue to provide

[11] 18 C.F.R. § 385.214 (2015).

[12] March 19 Order, 150 FERC ¶ 61,213 at P 32.

the information through their responsibilities as other registered functions. NERC has explained which entities will continue to provide this information. Further the responses from reliability coordinators, balancing authorities, Regional Entities, and other affected entities that need the information load-serving entities indicate that these entities do not foresee any concerns if load-serving entities are no longer registered entities. Accordingly, we conclude that NERC and others have provided reasonable support that the elimination of the load-serving entity function will likely have no material impact on the reliability of the bulk electric system.

22. With regard to our concern about the revision of the distribution provider threshold from 25 MW to 75 MW peak load causing an increase in the deactivation of entities that are currently registered as distribution providers,[13] NERC indicates that an additional 27 entities could be deregistered as load-serving entities and below 75 MW distribution providers. Nevertheless, we are persuaded by NERC's technical analysis and mapping document that other functional entities will take on responsibility for compliance with many Reliability Standards currently assigned to load-serving entities. This evidence combined with NERC's specific explanation of and references to tariffs and agreements persuades us that deregistered entities will continue to perform load-serving entity-related activities.

23. In addition, we find that NERC provides adequate information to show that balancing authorities, planners, and other affected entities will continue to have access to the data to estimate demand and energy forecast for areas where the load-serving entity is deregistered. Additionally we note that NERC proposes no changes to the obligations of the balancing authorities and transmission operators to provide operating data to their reliability coordinators pursuant to the applicable Reliability Standards.[14] Further, NERC has adequately demonstrated that in areas of significant load-growth, the cumulative effect on reliability of deregistered entities not having to provide accurate load data projections is not likely to increase over time as load increases. While we believe that NERC has adequately addressed its coordination with NAESB to ensure the timely transfer of commercial-related practices affected by the proposed elimination of the load-serving entity function, because that process remains incomplete we expect NERC to keep Commission staff informed of any developments regarding the appropriate transfer of functions to NAESB.

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[13] *Id*. P 39.

[14] *See, e.g.,* Reliability Standard IRO-010-001.

24. We accept NERC's proposal to eliminate the load-serving entity as a registered function subject to the Reliability Standards. As discussed above, we do so, in part, based on NERC's explanation that entities needing information from load-serving entities will continue to receive the data needed to fulfill their operational and planning responsibilities from other registered entities subject to Reliability Standards that currently apply to the load-serving entity function, and from deactivated load-serving entities subject to other arrangements.

25. While NERC has provided adequate support on this matter, we believe that it is prudent for NERC to perform a follow-up analysis to assure that affected transmission operators and balancing authorities remain able to perform reasonably accurate next-day studies. Accordingly, we direct NERC to study and report to the Commission, within 15 months from the date of this order, the extent to which the next-day studies by a representative sample of the affected transmission operators and balancing authorities match or differ from their real-time results and, if there are any significant differences, whether those differences are attributable to the changes authorized here. In performing this analysis, NERC may choose to compare these results to results for the same entities before implementation of these changes, or to results for entities not affected by these changes, or both, if NERC deems it appropriate.

The Commission orders:

(A) The Commission hereby accepts NERC's compliance filing, as set forth in the body of this order.

(B) The Commission directs NERC to submit an informational filing within 15 months of the date of this order, as set forth in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

EXHIBIT 4

WECC Regional Reliability Standard BAL-002-WECC-3
(Contingency Reserve)

A. Introduction

1. **Title:** **Contingency Reserve**

2. **Number:** BAL-002-WECC-3

3. **Purpose:** To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.1.1 The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group, in which case, the Reserve Sharing Group becomes the responsible entity.

   4.1.2 Reserve Sharing Group

   4.1.2.1 The Reserve Sharing Group when comprised of a Source Balancing Authority becomes the source Reserve Sharing Group.

   4.1.2.2 The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the sink Reserve Sharing Group.

5. **Effective Date:** Immediately upon receipt of regulatory approval.

B. Requirements and Measures

R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is*: [Violation Risk Factor: High] [Time Horizon: Real-time operations]*

1.1. The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

1.2. Composed of any combination of the reserve types specified below:

- Operating Reserve—Spinning
- Operating Reserve—Supplemental
- Interchange Transactions designated by the Source Balancing Authority as Operating Reserve—Supplemental

- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service
- A resource, other than generation or load, that can provide energy or reduce energy consumption
- Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.
- All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.

1.3. Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).

1.4. An amount of capacity from a resource that is deployable within ten minutes.

M1. Each Balancing Authority and each Reserve Sharing Group will have documentation demonstrating its Contingency Reserve was maintained, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Part 1.1

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates its Contingency Reserve was maintained in accordance with the amounts identified in Requirement R1, Part 1.1, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Attachment A is a practical illustration showing how the generation amount may be calculated under Requirement R1.

- Where Dynamic Schedules are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1 may include, but is not limited to, documentation showing a reciprocal acknowledgement as to which entity is carrying the reserves. This transfer may be all or some portion of the physical generator and is not limited to the entire physical capability of the generator.
- Where Pseudo-Ties are used as part of the generation amount upon which Contingency Reserve is predicated, additional evidence of compliance with Requirement R1, Part 1.1, may include, but is not limited to, documentation accounting for the transfers included in the Pseudo-Ties.

Part 1.2

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.2.

Evidence may include, but is not limited to, documentation that reserves were comprised of the types listed in Requirement R1, Part 1.2 for purposes of meeting the Contingency Reserve obligation of Requirement R1. Additionally, for purposes of the last bullet of Requirement R1, Part 1.2, evidence of compliance may include, but is not limited to, documentation that the reliability coordinator had issued an energy emergency alert, indicating that firm Load interruption was imminent or was in progress.

Part 1.3

Each Balancing Authority and each Reserve Sharing Group will have dated documentation that demonstrates compliance with Requirement R1, Part 1.3. Evidence of compliance with Requirement R1, Part 1.3 may include, but is not limited to, documentation that Contingency Reserve amounts are based upon load and generating data averaged over each Clock Hour and excludes Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464.

Part 1.4

Evidence of compliance with Requirement R1, Part 1.4 may include, but is not limited to, documentation that the reserves maintained to comply with Requirement R1, Part 1.4 are fully deployable within ten minutes.

R2. Reserved.

M2. Reserved.

R3. Each Sink Balancing Authority and each sink Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve. [*Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M3. Each Sink Balancing Authority and each sink Reserve Sharing Group will have dated documentation demonstrating it maintained an amount of Operating Reserve, in addition to the Contingency Reserve identified in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, for the entire period of the transaction, except within the first sixty minutes following an event requiring the activation of Contingency Reserves, in accordance with Requirement 3.

R4. Each Source Balancing Authority and each source Reserve Sharing Group shall maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of

Operating Reserves for any Operating Reserve transactions for which it is the Source Balancing Authority or source Reserve Sharing Group. *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

M4. Each Source Balancing Authority and each source Reserve Sharing Group will have dated documentation that demonstrates it maintained an amount of additional Operating Reserves identified in Requirement R1, greater than or equal to the amount and type of that identified in Requirement 4, for the entire period of the transaction.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot-Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

Each Balancing Authority and each Reserve Sharing Group shall keep evidence for Requirement R1 through R4 for three years plus calendar current.

1.4. Additional Compliance Information:

1.4.1 This Standard shall apply to each Balancing Authority and each Reserve Sharing Group that has registered with WECC as provided in Part 1.4.2 of Section C.

Each Balancing Authority identified in the registration with WECC as provided in Part 1.4.2 of Section C shall be responsible for compliance with this Standard through its participation in the Reserve Sharing Group and not on an individual basis.

1.4.2 A Reserve Sharing Group may register as the Responsible Entity for purposes of compliance with this Standard by providing written notice to the WECC: 1) indicating that the Reserve Sharing Group is registering as the Responsible Entity for purposes of compliance with this Standard, 2) identifying each Balancing Authority that is a member of the Reserve Sharing Group, and 3) identifying the person or organization that will serve as agent on behalf of the Reserve Sharing Group for purposes of communications and data submissions related to or required by this Standard.

1.4.3 If an agent properly designated in accordance with Part 1.4.2 of Section C identifies individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission, together with the percentage of responsibility attributable to each identified Balancing Authority, then, except as may otherwise be finally determined through a duly conducted review or appeal of the initial finding of noncompliance: 1) any penalties assessed for noncompliance by the Reserve Sharing Group shall be allocated to the individual Balancing Authorities identified in the applicable data submission in proportion to their respective percentages of responsibility as specified in the data submission, 2) each Balancing Authority shall be solely responsible for all penalties allocated to it according to its percentage of responsibility as provided in subsection 1) of this Part 1.4.3 of Section C, and 3) neither the Reserve Sharing Group nor any member of the Reserve Sharing Group shall be responsible for any portion of a penalty assessed against another member of the Reserve Sharing Group in accordance with subsection 1) of this Part 1.4.3 of Section C (even if the member of Reserve Sharing Group against which the penalty is assessed is not subject to or otherwise fails to pay its allocated share of the penalty).

1.4.4 If an agent properly designated in accordance with Part 1.4.2 of Section C fails to identify individual Balancing Authorities within the Reserve Sharing Group responsible for noncompliance at the time of data submission or fails to specify percentages of responsibility attributable to each identified Balancing Authority, any penalties for noncompliance shall be assessed against the agent on behalf of the Reserve Sharing Group, and it shall be the responsibility of the members of the Reserve Sharing Group to allocate responsibility for such noncompliance.

1.4.5 Any Balancing Authority that is a member of a Reserve Sharing Group that has failed to register as provided in Part 1.4.2 of Section C shall be subject to this Standard on an individual basis.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.	The Balancing Authority or the Reserve Sharing Group that incurs one Clock Hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Contingency Reserve amount, with the characteristics specified in Requirement R1.
R2.	Reserved.			
R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R3.	The Balancing Authority or the Reserve Sharing Group that incurs one hour, during a calendar month, in which Contingency Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R3.
R4.	The Balancing Authority or the Reserve Sharing Group	The Balancing Authority or the Reserve Sharing Group	The Balancing Authority or the Reserve Sharing Group	The Balancing Authority or the Reserve Sharing Group

	that incurs one hour, during a calendar month, in which Contingency Reserve Operating Reserve is less than 100% but greater than or equal to 90% of the required Operating Reserve amount specified in Requirement R4.	that incurs one hour, during a calendar month, in which Contingency Reserve Operating Reserve is less than 90% but greater than or equal to 80% of the required Operating Reserve amount specified in Requirement R4.	that incurs one hour, during a calendar month, in which Contingency Reserve Operating Reserve is less than 80% but greater than or equal to 70% of the required Operating Reserve amount specified in Requirement R4.	that incurs one hour, during a calendar month, in which Contingency Reserve Operating Reserve is less than 70% of the required Operating Reserve amount specified in Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	October 29, 2008	Adopted by NERC Board of Trustees	
1	October 21, 2010	Order issued remanding BAL-002-WECC-1	
2	November 7, 2012	Adopted by NERC Board of Trustees	
2	November 21, 2013	FERC Order issued approving BAL-002-WECC-2. (Order becomes effective 1/28/14.)	
2a	December 1, 2015	Approved by WECC Board of Directors	Clarified resources available for use in Requirement R2
2a	January 24, 2017	FERC approved	The Interpretation provides clarification regarding the types of resources that may be used to satisfy Contingency Reserve.
3	August 15, 2019	Adopted by the NERC Board of Trustees	The Interpretation was removed. Requirement R2 was deleted. Template and formatting were updated. Syntax and verb tense in Guideline section were corrected.
3	April 15, 2021	FERC approved	Docket(s): RM19-20-000 Description: Order No. 876: Final Rule re WECC Regional Reliability Standard BAL-002-WECC-3 (Contingency Reserve) under RM19-20.
3	June 28, 2021	Effective Date of Standard	

SC_000333

Standard Attachments

Attachment A

Attachment A is illustrative only; it is not a requirement. Requirement R1 calls for an amount of Contingency Reserve to be maintained, predicated on an amount of generation and load required in Requirement R1, Part 1.1., specifically:

“**1.1** The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.”

Attachment A illustrates one possible way to account for and calculate the amount of generation upon which the Contingency Reserve amount is predicated.

Below is a practical illustration showing how the generation amount may be calculated under Requirement R1 for Balancing Authorities (BA) and Reserve Sharing Groups (RSG).

BA1 / RSG 1	**Generation**	**Part of Generator**
Generator 1	300 MWs online	Yes
Generator 2	200 MWs online	Yes
Generator 3 (Pseudo-Tied out to BA2)	100 MWs online	No
Generator 4 QF (has backup contract)	10 MWs online	No
Generator 5 QF in EMS	10 MWs online	Yes
Generator 6	0 MWs online	Yes
Dynamic Schedule to BA2 from BA1[1]	(50 MWs)	
Generation	620 MWs	(The sum of gen 1–6)
BA generation (EMS)	510 MWs	(The sum of gen 1, 2, and 5)
Generation to use Under BAL-002-WECC-1	460 MWs**	(The sum of gen 1, 2, and 5 minus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would maintain reserves based on 510 MWs Generation.

BA2 / RSG2	**Generation**	**Part of Generator**
Generator 11	100 MWs	Yes
Generator 12	100 MWs	Yes
Generator 3 (Pseudo-Tied in from BA1)	100 MWs	Yes
Dynamic Schedule from BA1 to BA2	50 MWs	Yes
Generation	300 MWs	(The sum of gen 11, 12 and 3.)
BA generation (EMS)	300 MWs	(The sum of gen 11, 12 and 3)

[1] Note: This Dynamic Schedule is not the same as the Generator 3 Pseudo-Tie.

Generation to use Under BAL-002-WECC-1	350 MWs**	(The sum of gen 11, 12 and 3 plus Dynamic Schedule)

** Assumes BA1 and BA2 agree on Dynamic Schedule treatment. If no agreement, BA1 would have to maintain reserves based on 510MWs Generation and BA2 would determine its generation to be 300 MWs.

Guideline and Technical Basis

A Guidance Document addressing implementation of this standard was filed with Version 2.

EXHIBIT 5

NERC, Glossary of Terms Used in NERC Reliability Standards

Glossary of Terms Used in NERC Reliability Standards

Updated June 28, 2021

This Glossary lists each term that was defined for use in one or more of NERC's continent-wide or Regional Reliability Standards and adopted by the NERC Board of Trustees from February 8, 2005 through June 28, 2021.

This reference is divided into four sections, and each section is organized in alphabetical order.

Subject to Enforcement
Pending Enforcement
Retired Terms
Regional Definitions

The first three sections identify all terms that have been adopted by the NERC Board of Trustees for use in continent-wide standards; the Regional definitions section identifies all terms that have been adopted by the NERC Board of Trustees for use in regional standards.

Most of the terms identified in this glossary were adopted as part of the development of NERC's initial set of reliability standards, called the "Version 0" standards. Subsequent to the development of Version 0 standards, new definitions have been developed and approved following NERC's Reliability Standards Development Process, and added to this glossary following board adoption, with the "FERC effective" date added following a final Order approving the definition.

Any comments regarding this glossary should be reported to the NERC Help Desk at https://support.nerc.net/. Select "Standards" from the Applications drop down menu and "Other" from the Standards Subcategories drop down menu.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Actual Frequency (F_A)	Project 2010-14.2.1. Phase 2		2/11/2016		7/1/2016	The Interconnection frequency measured in Hertz (Hz).
Actual Net Interchange (NI_A)	Project 2010-14.2.1. Phase 2		2/11/2016		7/1/2016	The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.
Adequacy	Version 0 Reliability Standards		2/8/2005	3/16/2007		The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adjacent Balancing Authority	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact	Coordinate Operations		2/7/2006	3/16/2007		The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.
After the Fact	Project 2007-14	ATF	10/29/2008	12/17/2009		A time classification assigned to an RFI when the submittal time is greater than one hour after the start time of the RFI.
Agreement	Version 0 Reliability Standards		2/8/2005	3/16/2007		A contract or arrangement, either written or verbal and sometimes enforceable by law.
Alternative Interpersonal Communication	Project 2006-06		11/7/2012	4/16/2015	10/1/2015	Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation.
Altitude Correction Factor	Project 2007-07		2/7/2006	3/16/2007		A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.
Ancillary Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (*From FERC order 888-A.*)
Anti-Aliasing Filter	Version 0 Reliability Standards		2/8/2005	3/16/2007		An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error	Version 0 Reliability Standards	ACE	12/19/2012	10/16/2013	4/1/2014	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection.
Area Interchange Methodology	Project 2006-07		8/22/2008	11/24/2009		The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.
Arranged Interchange	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	The state where a Request for Interchange (initial or revised) has been submitted for approval.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Attaining Balancing Authority	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.
Automatic Generation Control	Project 2010-14.2.1. Phase 2	AGC	2/11/2016	9/20/2017	1/1/2019	A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.
Automatic Time Error Correction (I_{ATEC})	Project 2010-14.2.1. Phase 2		2/11/2016		7/1/2016	• Y = Bi / BS. • H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3. B_i = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz). • B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz). Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - Bi * ΔTE/6) • II_{actual} is the hourly Inadvertent Interchange for the last hour. ΔTE is the hourly change in system Time Error as distributed by the Interconnection time monitor,where: $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$
Automatic Time Error Correction (I_{ATEC})	Project 2010-14.2.1. Phase 2		2/11/2016		7/1/2016	• TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection time monitor control center clocks. • t is the number of minutes of manual Time Error Correction that occurred during the hour. • TE_{offset} is 0.000 or +0.020 or -0.020. • PII_{accum} is the Balancing Authority Area's accumulated PIIhourly in MWh. An On-Peak and Off-Peak accumulation accounting is required, where: $\mathbf{PII}_{accum}^{on/offpeak} = last\ period's\ \mathbf{PII}_{accum}^{on/offpeak} + \mathbf{PII}_{hourly}$
Automatic Time Error Correction (I_{ATEC}) ***continued below...***	Project 2010-14.2.1. Phase 2		2/11/2016		7/1/2016	The addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection. [illegible] hen operating in Automatic Time error correction Mode.The absolute value of I_{ATEC} shall not exceed L_{max}. I_{ATEC} shall be zero when operating in any other AGC mode. • L_{max} is the maximum value allowed for I_{ATEC} set by each BA between 0.2*|B_i| and L10, 0.2*|B_i|≤ L_{max} ≤ L10 . • L_{10} =1.65 • ε10 is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-r $\varepsilon_{10}\sqrt{(-10B_i)(-10B_S)}$:ency error based on frequency performance over a given year. The bound, ε 10, is the same for every Balancing Authority Area within an Interconnection.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Available Flowgate Capability	Project 2006-07	AFC	8/22/2008	11/24/2009		A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.
Available Transfer Capability	Project 2006-07	ATC	8/22/2008	11/24/2009		A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.
Available Transfer Capability Implementation Document	Project 2006-07	ATCID	8/22/2008	11/24/2009		A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.
Balancing Authority	Project 2010-14.2.1. Phase 2		2/11/2016	9/20/2017	1/1/2019	The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area	Version 0 Reliability Standards		2/8/2005	3/16/2007		The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
Balancing Contingency Event	Project 2010-14.1 Phase 1		11/5/2015	1/19/2017	1/1/2018	Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less. A. Sudden loss of generation: a. Due to i. unit tripping, or ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or iii. sudden unplanned outage of transmission Facility; b. And, that causes an unexpected change to the responsible entity's ACE; B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection. C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.
Base Load	Version 0 Reliability Standards		2/8/2005	3/16/2007		The minimum amount of electric power delivered or required over a given period at a constant rate.
BES Cyber Asset	Project 2014-02	BCA	2/12/2015	1/21/2016	7/1/2016	A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.

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BES Cyber System	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	One or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.
BES Cyber System Information	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	Information about the BES Cyber System that could be used to gain unauthorized access or pose a security threat to the BES Cyber System. BES Cyber System Information does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to BES Cyber Systems, such as, but not limited to, device names, individual IP addresses without context, ESP names, or policy statements. Examples of BES Cyber System Information may include, but are not limited to, security procedures or security information about BES Cyber Systems, Physical Access Control Systems, and Electronic Access Control or Monitoring Systems that is not publicly available and could be used to allow unauthorized access or unauthorized distribution; collections of network addresses; and network topology of the BES Cyber System.
Blackstart Resource	Project 2015-04		11/5/2015	1/21/2016	7/1/2016	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.
Block Dispatch	Project 2006-07		8/22/2008	11/24/2009		A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).
Bulk Electric System **(continued below)**	Project 2010-17	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Imple-mentation Plan for Phase 2 Compliance obligations.)	Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. **Inclusions:** • I1 - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3. • I2 – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: a) Gross individual nameplate rating greater than 20 MVA. Or, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA. • I3 - Blackstart Resources identified in the Transmission Operator's restoration plan.

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Bulk Electric System **(continued below)**	Project 2010-17	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Imple-mentation Plan for Phase 2 Compliance obligations.)	• I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. • I5 –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.
Bulk Electric System **(continued)**	Project 2010-17	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Imple-mentation Plan for Phase 2 Compliance obligations.)	**Exclusions:** • **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: a) Only serves Load. Or, b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or, c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating). Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion. Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.
Bulk Electric System **(continued)**	Project 2010-17	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Imple-mentation Plan for Phase 2 Compliance obligations.)	• **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

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Bulk Electric System **(continued)**	Project 2010-17	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Imple-mentation Plan for Phase 2 Compliance obligations.)	• **E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following: a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating); b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and
Bulk Electric System **(continued)**	Project 2010-17	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Imple-mentation Plan for Phase 2 Compliance obligations.)	c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). • E4 – Reactive Power devices installed for the sole benefit of a retail customer(s). Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.
Bulk-Power System	Project 2015-04		11/5/2015	1/21/2016	7/1/2016	Bulk-Power System: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. (Note that the terms "Bulk-Power System" or "Bulk Power System" shall have the same meaning.)
Burden	Version 0 Reliability Standards		2/8/2005	3/16/2007		Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
Bus-tie Breaker	Project 2006-02		8/4/2011	10/17/2013	1/1/2015	A circuit breaker that is positioned to connect two individual substation bus configurations.
Capacity Benefit Margin	Version 0 Reliability Standards	CBM	2/8/2005	3/16/2007		The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer

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Capacity Benefit Margin Implementation Document	Project 2006-07	CBMID	11/13/2008	11/24/2009		A document that describes the implementation of a Capacity Benefit Margin methodology.
Capacity Emergency	Version 0 Reliability Standards		2/8/2005	3/16/2007		A capacity emergency exists when a Balancing Authority Area's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
Cascading	Project 2015-04		11/5/2015	1/21/2016	7/1/2016	The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.
CIP Exceptional Circumstance	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	A situation that involves or threatens to involve one or more of the following, or similar, conditions that impact safety or BES reliability: a risk of injury or death; a natural disaster; civil unrest; an imminent or existing hardware, software, or equipment failure; a Cyber Security Incident requiring emergency assistance; a response by emergency services; the enactment of a mutual assistance agreement; or an impediment of large scale workforce availability.
CIP Senior Manager	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	A single senior management official with overall authority and responsibility for leading and managing implementation of and continuing adherence to the requirements within the NERC CIP Standards, CIP-002 through CIP-011.
Clock Hour	Version 0 Reliability Standards		2/8/2005	3/16/2007		The 60-minute period ending at :00. All surveys, measurements, and reports are based on Clock Hour periods unless specifically noted.
Cogeneration	Version 0 Reliability Standards		2/8/2005	3/16/2007		Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
Compliance Monitor	Version 0 Reliability Standards		2/8/2005	3/16/2007		The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
Composite Confirmed Interchange	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
Composite Protection System	2010-05.1		8/14/2014	5/13/2015	7/1/2016	The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.
Confirmed Interchange	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	The state where no party has denied and all required parties have approved the Arranged Interchange.
Congestion Management Report	Version 0 Reliability Standards		2/8/2005	3/16/2007		A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.
Consequential Load Loss	Project 2006-02		8/4/2011	10/17/2013	1/1/2015	All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.
Constrained Facility	Version 0 Reliability Standards		2/8/2005	3/16/2007		A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.
Contact Path	Version 0 Reliability Standards		2/8/2005	3/16/2007		An agreed upon electrical path for the continuous flow of electrical power between the parties of an Interchange Transaction.

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Contingency	Version 0 Reliability Standards		2/8/2005	3/16/2007		The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Contingency Event Recovery Period	Project 2010-14.1 Phase 1		11/5/2015	1/19/2017	1/1/2018	A period that begins at the time that the resource output begins to decline within the first one-minute interval of a Reportable Balancing Contingency Event, and extends for fifteen minutes thereafter.
Contingency Reserve	Project 2010-14.1 Phase 1		11/5/2015	1/19/2017	1/1/2018	The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority: • is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan. • is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.
Contingency Reserve Restoration Period	Project 2010-14.1 Phase 1		11/5/2015	1/19/2017	1/1/2018	A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.
Control Center	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.
Control Performance Standard	Version 0 Reliability Standards	CPS	2/8/2005	3/16/2007		The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.
Corrective Action Plan	Phase III-IV Planning Standards - Archive		2/7/2006	3/16/2007		A list of actions and an associated timetable for implementation to remedy a specific problem.
Cranking Path	Phase III-IV Planning Standards - Archive		5/2/2006	3/16/2007		A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.
Curtailment	Version 0 Reliability Standards		2/8/2005	3/16/2007		A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.
Curtailment Threshold	Version 0 Reliability Standards		2/8/2005	3/16/2007		The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility constraint.
Cyber Assets	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	Programmable electronic devices, including the hardware, software, and data in those devices.

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Cyber Security Incident	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting		2/7/2019	6/20/2019	1/1/2021	A malicious act or suspicious event that: - For a high or medium impact BES Cyber System, compromises or attempts to compromise (1) an Electronic Security Perimeter, (2) a Physical Security Perimeter, or (3) an Electronic Access Control or Monitoring System; or - Disrupts or attempts to disrupt the operation of a BES Cyber System.
Delayed Fault Clearing	Determine Facility Ratings, Operating Limits, and Transfer Capabilities		11/1/2006	12/27/2007		Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.
Demand	Version 0 Reliability Standards		2/8/2005	3/16/2007		1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Demand-Side Management	Project 2010-04	DSM	5/6/2014	2/19/2015	7/1/2016	All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.
Dial-up Connectivity	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	A data communication link that is established when the communication equipment dials a phone number and negotiates a connection with the equipment on the other end of the link.
Direct Control Load Management	Project 2008-06	DCLM	2/8/2005	3/16/2007		Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.
Dispatch Order	Project 2006-07		8/22/2008	11/24/2009		A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.
Dispersed Load by Substations	Version 0 Reliability Standards		2/8/2005	3/16/2007		Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.
Distribution Factor	Version 0 Reliability Standards	DF	2/8/2005	3/16/2007		The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).
Distribution Provider	Project 2015-04	DP	11/5/2015	1/21/2016	7/1/2016	Provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.
Disturbance	Version 0 Reliability Standards		2/8/2005	3/16/2007		1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.
Disturbance Control Standard	Version 0 Reliability Standards	DCS	2/8/2005	3/16/2007		The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.

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Disturbance Monitoring Equipment	[Phase III-IV Planning Standards]	DME	8/2/2006	3/16/2007		Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders* : • Sequence of event recorders which record equipment response to the event • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays. • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions *Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.
Dynamic Interchange Schedule or Dynamic Schedule	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	A time-varying energy transfer that is updated in Real-time and included in the Scheduled Net Interchange (NIS) term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).
Dynamic Transfer	Version 0 Reliability Standards		2/8/2005	3/16/2007		The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.
Economic Dispatch	Version 0 Reliability Standards		2/8/2005	3/16/2007		The allocation of demand to individual generating units on line to effect the most economical production of electricity.
Electrical Energy	Version 0 Reliability Standards		2/8/2005	3/16/2007		The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
Electronic Access Control or Monitoring Systems	Project 2008-06 Order 706	EACMS	11/26/2012	11/22/2013	7/1/2016	Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Systems.
Electronic Access Point	Project 2008-06 Order 706	EAP	11/26/2012	11/22/2013	7/1/2016	A Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.
Electronic Security Perimeter	Project 2008-06 Order 706	ESP	11/26/2012	11/22/2013	7/1/2016	The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.
Element	Project 2015-04		11/5/2015	1/21/2016	7/1/2016	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.
Emergency or BES Emergency	Version 0 Reliability Standards		2/8/2005	3/16/2007		Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.
Emergency Rating	Version 0 Reliability Standards		2/8/2005	3/16/2007		The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.
Emergency Request for Interchange	Project 2007-14 Coordinate Interchange	Emergency RFI	10/29/2008	12/17/2009		Request for Interchange to be initiated for Emergency or Energy Emergency conditions.

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Energy Emergency	Version 0		11/13/2014	11/19/2015	4/1/2017	A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load obligations.
Equipment Rating	Determine Facility Ratings, Operating Limits, and Transfer Capabilities		2/7/2006	3/16/2007		The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.
Existing Transmission Commitments	Project 2006-07	ETC	8/22/2008	11/24/2009		Committed uses of a Transmission Service Provider's Transmission system considered when determining ATC or AFC.
External Routable Connectivity	Project 2008-06 Order 706		11/26/2012	11/22/2013	7/1/2016	The ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security Perimeter via a bi-directional routable protocol connection.
Facility	Determine Facility Ratings, Operating Limits, and Transfer Capabilities		2/7/2006	3/16/2007		A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)
Facility Rating	Version 0 Reliability Standards		2/8/2005	3/16/2007		The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Fault	Version 0 Reliability Standards		2/8/2005	3/16/2007		An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Fire Risk	Project 2007-07		2/7/2006	3/16/2007		The likelihood that a fire will ignite or spread in a particular geographic area.
Firm Demand	Version 0 Reliability Standards		2/8/2005	3/16/2007		That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Transmission Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Flashover	Project 2007-07		2/7/2006	3/16/2007		An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.
Flowgate	Project 2006-07		8/22/2008	11/24/2009		1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.
Flowgate Methodology	Version 0 Reliability Standards		8/22/2008	11/24/2009		The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).

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Forced Outage	Version 0 Reliability Standards		2/8/2005	3/16/2007		1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.
Frequency Bias	Version 0 Reliability Standards		2/8/2005	3/16/2007		A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error.
Frequency Bias Setting	Project 2007-12		2/7/2013	1/16/2014	4/1/2015	A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority's inverse Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.
Frequency Deviation	Version 0 Reliability Standards		2/8/2005	3/16/2007		A change in Interconnection frequency.
Frequency Error	Version 0 Reliability Standards		2/8/2005	3/16/2007		The difference between the actual and scheduled frequency. ($F_A - F_S$)
Frequency Regulation	Version 0 Reliability Standards		2/8/2005	3/16/2007		The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.
Frequency Response	Version 0 Reliability Standards		2/8/2005	3/16/2007		(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).
Frequency Response Measure	Project 2007-12	FRM	2/7/2013	1/16/2014	4/1/2015	The median of all the Frequency Response observations reported annually by Balancing Authorities or Frequency Response Sharing Groups for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.
Frequency Response Obligation	Project 2007-12	FRO	2/7/2013	1/16/2014	4/1/2015	The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz.
Frequency Response Sharing Group	Project 2007-12	FRSG	2/7/2013	1/16/2014	4/1/2015	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.
Generation Capability Import Requirement	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions	GCIR	11/13/2008	11/24/2009		The amount of generation capability from external sources identified by a Load-Serving Entity (LSE) or Resource Planner (RP) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.
Generator Operator	Version 0 Reliability Standards	GOP	11/5/2015	1/21/2016	7/1/2016	The entity that operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner	Version 0 Reliability Standards	GO	11/5/2015	1/21/2016	7/1/2016	Entity that owns and maintains generating Facility(ies).
Generator Shift Factor	Version 0 Reliability Standards	GSF	2/8/2005	3/16/2007		A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.

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Generator-to-Load Distribution Factor	Version 0 Reliability Standards	GLDF	2/8/2005	3/16/2007		The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.
Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment	Project 2013-03 Geomagnetic Disturbance Mitigation	GMD	12/17/2014	9/22/2016	7/1/2017	Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.
Host Balancing Authority	Version 0 Reliability Standards		2/8/2005	3/16/2007		1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries. 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.
Hourly Value	Version 0 Reliability Standards		2/8/2005	3/16/2007		Data measured on a Clock Hour basis.
Implemented Interchange	Coordinate Interchange		5/2/2006	3/16/2007		The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation.
Inadvertent Interchange	Version 0 Reliability Standards		2/8/2005	3/16/2007		The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. (IA – IS)
Independent Power Producer	Version 0 Reliability Standards	IPP	2/8/2005	3/16/2007		Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.
Institute of Electrical and Electronics Engineers, Inc.	Project 2007-07	IEEE	2/7/2006	3/16/2007		
Interactive Remote Access	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate System and not located within any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.
Interchange	Coordinate Interchange		5/2/2006	3/16/2007		Energy transfers that cross Balancing Authority boundaries.
Interchange Authority	Project 2015-04	IA	11/5/2015	1/21/2016	7/1/2016	The responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Interchange Distribution Calculator	Version 0 Reliability Standards		2/8/2005	3/16/2007		The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.

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Interchange Meter Error (I_{ME})	Project 2010-14.2.1. Phase 2		2/11/2016		7/1/2016	A term used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.
Interchange Schedule	Version 0 Reliability Standards		2/8/2005	3/16/2007		An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.
Interchange Transaction	Version 0 Reliability Standards		2/8/2005	3/16/2007		An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.
Interchange Transaction Tag or Tag	Version 0 Reliability Standards		2/8/2005	3/16/2007		The details of an Interchange Transaction required for its physical implementation.
Interconnected Operations Service	Project 2015-04		11/5/2015	1/21/2016	7/1/2016	A service (exclusive of basic energy and Transmission Services) that is required to support the Reliable Operation of interconnected Bulk Electric Systems.
Interconnection	Project 2015-04		11/5/2015	1/21/2016	7/1/2016	A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.
Interconnection Reliability Operating Limit	Determine Facility Ratings, Operating Limits, and Transfer Capabilities	IROL	11/1/2006	12/27/2007		A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.
Interconnection Reliability Operating Limit T_v	Determine Facility Ratings, Operating Limits, and Transfer Capabilities	IROL T_v	11/1/2006	12/27/2007		The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes.
Intermediate Balancing Authority	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
Intermediate System	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	A Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.
Interpersonal Communication	Project 2006-06		11/7/2012	4/16/2015	10/1/2015	Any medium that allows two or more individuals to interact, consult, or exchange information.
Interruptible Load or Interruptible Demand	Version 0 Reliability Standards		11/1/2006	3/16/2007		Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.
Joint Control	Version 0 Reliability Standards		2/8/2005	3/16/2007		Automatic Generation Control of jointly owned units by two or more Balancing Authorities.
Limiting Element	Version 0 Reliability Standards		2/8/2005	3/16/2007		The element that is 1.)Either operating at its appropriate rating, or 2,) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.

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Load	Version 0 Reliability Standards		2/8/2005	3/16/2007		An end-use device or customer that receives power from the electric system.
Load Shift Factor	Version 0 Reliability Standards	LSF	2/8/2005	3/16/2007		A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.
Load-Serving Entity	Project 2015-04	LSE	11/5/2015	1/21/2016	7/1/2016	Secures energy and Transmission Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Long-Term Transmission Planning Horizon	Project 2006-02		8/4/2011	10/17/2013	1/1/2015	Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.
Market Flow	Project 2006-08 Reliability Coordination - Transmission Loading Relief		11/4/2010	4/21/2011		The total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve load internal to the market.
Minimum Vegetation Clearance Distance	Project 2007-07	MVCD	11/3/2011	3/21/2013	7/1/2014	The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.
Misoperation	Project 2010-05.1		8/14/2014	5/13/2015	7/1/2016	The failure of a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation: **1. Failure to Trip – During Fault** – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct. **2. Failure to Trip – Other Than Fault** – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct. **3. Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. (continued below...)

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Misoperation (continued…)	Project 2010-05.1		8/14/2014	5/13/2015	7/1/2016	**4. Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. **5. Unnecessary Trip – During Fault** – An unnecessary Composite Protection System operation for a Fault condition on another Element. **6. Unnecessary Trip – Other Than Fault** – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.
Most Severe Single Contingency	Project 2010-14.1 Phase 1	MSSC	11/5/2015	1/19/2017	1/1/2018	The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).
Native Balancing Authority	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.
Native Load	Version 0 Reliability Standards		2/8/2005	3/16/2007		The end-use customers that the Load-Serving Entity is obligated to serve.
Near-Term Transmission Planning Horizon	Project 2010-10		1/24/2011	11/17/2011		The transmission planning period that covers Year One through five.
Net Actual Interchange	Version 0 Reliability Standards		2/8/2005	3/16/2007		The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Energy for Load	Version 0 Reliability Standards		2/8/2005	3/16/2007		Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.
Net Interchange Schedule	Version 0 Reliability Standards		2/8/2005	3/16/2007		The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Scheduled Interchange	Version 0 Reliability Standards		2/8/2005	3/16/2007		The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Network Integration Transmission Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.

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Non-Consequential Load Loss	Project 2006-02		8/4/2011	10/17/2013	1/1/2015	Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.
Non-Firm Transmission Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.
Non-Spinning Reserve	Version 0 Reliability Standards		2/8/2005	3/16/2007		1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.
Normal Clearing	Determine Facility Ratings, Operating Limits, and Transfer Capabilities		11/1/2006	12/27/2007		A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.
Normal Rating	Version 0 Reliability Standards		2/8/2005	3/16/2007		The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
Nuclear Plant Generator Operator	Project 2009-08		5/2/2007	10/16/2008		Any Generator Operator or Generator Owner that is a Nuclear Plant Licensee responsible for operation of a nuclear facility licensed to produce commercial power.
Nuclear Plant Interface Requirements	Project 2009-08	NPIRs	5/2/2007	10/16/2008		The requirements based on NPLRs and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities.
Nuclear Plant Licensing Requirements	Project 2009-08	NPLRs	5/2/2007	10/16/2008		Requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for: 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.
Nuclear Plant Off-site Power Supply (Off-site Power)	Project 2009-08		5/2/2007	10/16/2008		The electric power supply provided from the electric system to the nuclear power plant distribution system as required per the nuclear power plant license.
Off-Peak	Version 0 Reliability Standards		2/8/2005	3/16/2007		Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.
On-Peak	Version 0 Reliability Standards		2/8/2005	3/16/2007		Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.
Open Access Same Time Information Service	Version 0 Reliability Standards	OASIS	2/8/2005	3/16/2007		An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.

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Open Access Transmission Tariff	Version 0 Reliability Standards	OATT	2/8/2005	3/16/2007		Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.
Operating Instruction	Project 2007-02		5/6/2014	4/16/2015	7/1/2016	A command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)
Operating Plan	Coordinate Operations		2/7/2006	3/16/2007		A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.
Operational Planning Analysis	Project 2007-06.2 Phase 2 of System Protection Coordination	OPA	8/11/2016	6/7/2018	4/1/2021	An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to: load forecasts; generation output levels; Interchange; known Protection System and Remedial Action Scheme status or degradation, functions, and limitations; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Operating Procedure	Coordinate Operations		2/7/2006	3/16/2007		A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.
Operating Process	Coordinate Operations		2/7/2006	3/16/2007		A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.
Operating Reserve	Version 0 Reliability Standards		2/8/2005	3/16/2007		That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Operating Reserve – Spinning	Version 0 Reliability Standards		2/8/2005	3/16/2007		The portion of Operating Reserve consisting of: • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

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Operating Reserve – Supplemental	Version 0 Reliability Standards		2/8/2005	3/16/2007		The portion of Operating Reserve consisting of: • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Voltage	Project 2007-07		2/7/2006	3/16/2007		The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.
Operational Planning Analysis	Project 2014-03	OPA	11/13/2014	11/19/2015	1/1/2017	An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Operations Support Personnel	Project 2010-01		2/6/2014	6/19/2014	7/1/2016	Individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,1 in direct support of Real-time operations of the Bulk Electric System.
Outage Transfer Distribution Factor	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions	OTDF	8/22/2008	11/24/2009		In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).
Overlap Regulation Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into providing Balancing Authority's AGC/ACE equation.
Participation Factors	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions		8/22/2008	11/24/2009		A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.
Peak Demand	Version 0 Reliability Standards		2/8/2005	3/16/2007		1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.
Performance-Reset Period	Determine Facility Ratings, Operating Limits, and Transfer Capabilities		2/7/2006	3/16/2007		The time period that the entity being assessed must operate without any violations to reset the level of non compliance to zero.
Physical Access Control Systems	Project 2008-06 Cyber Security Order 706	PACS	11/26/2012	11/22/2013	7/1/2016	Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.

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Physical Security Perimeter	Project 2008-06 Cyber Security Order 706	PSP	11/26/2012	11/22/2013	7/1/2016	The physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.
Planning Assessment	Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans		8/4/2011	10/17/2013	1/1/2015	Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.
Planning Authority	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	The responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.
Planning Coordinator	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions	PC	8/22/2008	11/24/2009		See Planning Authority.
Point of Delivery	Version 0 Reliability Standards	POD	2/8/2005	3/16/2007		A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.
Point of Receipt	Project 2015-04 Alignment of Terms	POR	11/5/2015	1/21/2016	7/1/2016	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.
Point to Point Transmission Service	Version 0 Reliability Standards	PTP	2/8/2005	3/16/2007		The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.
Power Transfer Distribution Factor	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions	PTDF	8/22/2008	11/24/2009		In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer
Pre-Reporting Contingency Event ACE Value	Project 2010-14.1 Phase 1		11/5/2015	1/19/2017	1/1/2018	The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.
Pro Forma Tariff	Version 0 Reliability Standards		2/8/2005	3/16/2007		Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.
Protected Cyber Assets	Project 2014-02	PCA	2/12/2015	1/21/2016	7/1/2016	One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP.

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Protection System	Project 2007-17 Protection System Maintenance and Testing		11/19/2010	2/3/2012	4/1/2013	Protection System – • Protective relays which respond to electrical quantities, • Communications systems necessary for correct operation of protective functions • Voltage and current sensing devices providing inputs to protective relays, • Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and • Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.
Protection System Coordination Study	Project 2007-06 System Protection Coordination		11/5/2015	6/7/2018	4/1/2021	An analysis to determine whether Protection Systems operate in the intended sequence during Faults.
Protection System Maintenance Program (PRC-005-6)	Project 2007-17.4 PRC-005 FERC Order No 803 Directive	PSMP	11/5/2015	12/18/2015	1/1/2016	An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities: • Verify — Determine that the Component is functioning correctly. • Monitor — Observe the routine in-service operation of the Component. • Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems. • Inspect — Examine for signs of Component failure, reduced performance or degradation. • Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.
Pseudo-Tie	Project 2010-14.2.1. Phase 2		2/11/2016	9/20/2017	1/1/2019	A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' Reporting ACE equation (or alternate control processes).
Purchasing-Selling Entity	Version 0 Reliability Standards	PSE	2/8/2005	3/16/2007		The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Ramp Rate or Ramp	Version 0 Reliability Standards		2/8/2005	3/16/2007		(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.
Rated Electrical Operating Conditions	Project 2007-07 Transmission Vegetation Management		2/7/2006	3/16/2007		The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate

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Rated System Path Methodology	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions		8/22/2008	11/24/2009		The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.
Rating	Version 0 Reliability Standards		2/8/2005	3/16/2007		The operational limits of a transmission system element under a set of specified conditions.
Reactive Power	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive Power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	The portion of electricity that supplies energy to the Load.
Real-time	Coordinate Operations		2/7/2006	3/16/2007		Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)
Real-time Assessment	Project 2007-06.2 Phase 2 of System Protection Coordination	RTA	8/11/2016	6/8/2018	4/1/2021	An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load; generation output levels; known Protection System and Remedial Action Scheme status or degradation, functions, and limitations; Transmission outages; generator outages; Interchange; Facility Ratings; and identified phase angle and equipment limitations. (Realtime Assessment may be provided through internal systems or through third-party services.)
Receiving Balancing Authority	Version 0 Reliability Standards		2/8/2005	3/16/2007		The Balancing Authority importing the Interchange.
Regional Reliability Organization	Version 0 Reliability Standards	RRO	2/8/2005	3/16/2007		1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. 2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.
Regional Reliability Plan	Version 0 Reliability Standards		2/8/2005	3/16/2007		The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished.
Regulating Reserve	Version 0 Reliability Standards		2/8/2005	3/16/2007		An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

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Regulation Reserve Sharing Group	Project 2010-14.1 Phase 1		8/15/2013	4/16/2015	7/1/2016	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the Regulating Reserve required for all member Balancing Authorities to use in meeting applicable regulating standards.
Regulation Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by NERC for itself and the Balancing Authority for which it is providing the Regulation Service.
Reliability Adjustment Arranged Interchange	Project 2008-12 Coordinate Interchange Standards		2/6/2014	6/30/2014	10/1/2014	A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
Reliability Adjustment RFI	Project 2007-14 Coordinate Interchange - Timing Table		10/29/2008	12/17/2009		Request to modify an Implemented Interchange Schedule for reliability purposes.
Reliability Coordinator	Project 2015-04 Alignment of Terms	RC	11/5/2015	1/21/2016	7/1/2016	The entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reliability Coordinator Area	Version 0 Reliability Standards		2/8/2005	3/16/2007		The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reliability Coordinator Information System	Version 0 Reliability Standards	RCIS	2/8/2005	3/16/2007		The system that Reliability Coordinators use to post messages and share operating information in real time.
Reliability Standard	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	A requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk-Power System. The term includes requirements for the operation of existing Bulk-Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for Reliable Operation of the Bulk-Power System, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.
Reliable Operation	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	Operating the elements of the [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

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Remedial Action Scheme	Project 2010-05.2	RAS	11/13/2014	11/19/2015	4/1/2017	A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as: • Meet requirements identified in the NERC Reliability Standards; • Maintain Bulk Electric System (BES) stability; • Maintain acceptable BES voltages; • Maintain acceptable BES power flows; • Limit the impact of Cascading or extreme events. The following do not individually constitute a RAS: a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays c. Out-of-step tripping and power swing blocking d. Automatic reclosing schemes e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
Remedial Action Scheme ***Continued***	Project 2010-05.2	RAS	11/13/2014	11/19/2015	4/1/2017	f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage) k. Automatic sequences that proceed when manually initiated solely by a System Operator l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
Remedial Action Scheme ***Continued***	Project 2010-05.2	RAS	11/13/2014	11/19/2015	4/1/2017	n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

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Removable Media	Project 2016-02 Modifications to CIP Standards		2/9/2017	4/19/2018	1/1/2020	Storage media that: 1. are not Cyber Assets, 2. are capable of transferring executable code, 3. can be used to store, copy, move, or access data, and 4. are directly connected for 30 consecutive calendar days or less to a: • BES Cyber Asset, • network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or • Protected Cyber Asset associated with high or medium impact BES Cyber Systems. Examples of Removable Media include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile
Reportable Balancing Contingency Event	Project 2010-14.1 Phase 1		11/5/2015	1/19/2017	1/1/2018	Any Balancing Contingency Event occurring within a one-minute interval of an initial sudden decline in ACE based on EMS scan rate data that results in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity. • Eastern Interconnection – 900 MW • Western Interconnection – 500 MW • ERCOT – 800 MW • Quebec – 500 MW
Reportable Cyber Security Incident	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting		2/7/2019	6/20/2019	1/1/2021	A Cyber Security Incident that compromised or disrupted: - A BES Cyber System that performs one or more reliability tasks of a functional entity; - An Electronic Security Perimeter of a high or medium impact BES Cyber System; or - An Electronic Access Control or Monitoring System of a high or medium impact BES Cyber System.
Reportable Disturbance	Version 0 Reliability Standards		2/8/2005	3/16/2007		Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.

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Reporting ACE	Project 2010-14.2.1. Phase 2		2/11/2016		7/1/2016	The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC). Reporting ACE is calculated as follows: Reporting ACE = $(NI_A - NI_S) - 10B\ (F_A - FS) - I_{ME}$ Reporting ACE is calculated in the Western Interconnection as follows: Reporting ACE = $(NI_A - NI_S) - 10B\ (F_A - F_S) - I_{ME} + I_{ATEC}$ Where: • NI_A = Actual Net Interchange. • NI_S = Scheduled Net Interchange. • B = Frequency Bias Setting. • F_A = Actual Frequency. • F_S = Scheduled Frequency. • I_{ME} = Interchange Meter Error. • I_{ATEC} = Automatic Time Error Correction.
Reporting ACE (continued)	Project 2010-14.2.1. Phase 2		2/11/2016		7/1/2016	All NERC Interconnections operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation: 1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss; 2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times; 3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and, 4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)
Request for Interchange	Project 2008-12 Coordinate Interchange	RFI	2/6/2014	6/30/2014	10/1/2014	A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority.
Reserve Sharing Group	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.
Reserve Sharing Group Reporting ACE	Project 2010-14.1 Phase 1		11/5/2015	1/19/2017	1/1/2018	At any given time of measurement for the applicable Reserve Sharing Group (RSG), the algebraic sum of the ACEs (or equivalent as calculated at such time of measurement) of the Balancing Authorities participating in the RSG at the time of measurement.

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Resource Planner	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area.
Response Rate	Version 0 Reliability Standards		2/8/2005	3/16/2007		The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
Right-of-Way	Project 2010-07	ROW	5/9/2012	3/21/2013	7/1/2014	The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.
Scenario	Coordinate Operations		2/7/2006	3/16/2007		Possible event.
Schedule	Version 0 Reliability Standards		2/8/2005	3/16/2007		(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency	Version 0 Reliability Standards		2/8/2005	3/16/2007		60.0 Hertz, except during a time correction.
Scheduled Net Interchange (NI_S)	Project 2010-14.2.1 Phase 2		2/11/2016		7/1/2016	The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.
Scheduling Entity	Version 0 Reliability Standards		2/8/2005	3/16/2007		An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path	Version 0 Reliability Standards		2/8/2005	3/16/2007		The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority	Version 0 Reliability Standards		2/8/2005	3/16/2007		The Balancing Authority exporting the Interchange.
Sink Balancing Authority	Project 2008-12 Coordinate Interchange Standards		2/6/2014	6/30/2014	10/1/2014	The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.
Source Balancing Authority	Project 2008-12 Coordinate Interchange Standards		2/6/2014	6/30/2014	10/1/2014	The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.
Special Protection System (Remedial Action Scheme)	Project 2010-05.2	SPS	5/5/2016	6/23/2016	4/1/2017	See "Remedial Action Scheme"

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Spinning Reserve	Version 0 Reliability Standards		2/8/2005	3/16/2007		Unloaded generation that is synchronized and ready to serve additional demand.
Stability	Version 0 Reliability Standards		2/8/2005	3/16/2007		The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.
Stability Limit	Version 0 Reliability Standards		2/8/2005	3/16/2007		The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.
Supervisory Control and Data Acquisition	Version 0 Reliability Standards	SCADA	2/8/2005	3/16/2007		A system of remote control and telemetry used to monitor and control the transmission system.
Supplemental Regulation Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority's ACE.
Surge	Version 0 Reliability Standards		2/8/2005	3/16/2007		A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.
Sustained Outage	Project 2007-07 Transmission Vegetation Management		2/7/2006	3/16/2007		The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.
System	Version 0 Reliability Standards		2/8/2005	3/16/2007		A combination of generation, transmission, and distribution components.
System Operating Limit	Project 2015-04 Alignment of Terms	SOL	11/5/2015	1/21/2016	7/1/2016	The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings) • transient stability ratings (applicable pre- and post- Contingency stability limits) • voltage stability ratings (applicable pre- and post-Contingency voltage stability) • system voltage limits (applicable pre- and post-Contingency voltage limits)
System Operator	Project 2010-01 Training		2/6/2014	6/19/2014	7/1/2016	An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System (BES) in Real-time.
Telemetering	Version 0 Reliability Standards		2/8/2005	3/16/2007		The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.
Thermal Rating	Version 0 Reliability Standards		2/8/2005	3/16/2007		The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.

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Tie Line	Version 0 Reliability Standards		2/8/2005	3/16/2007		A circuit connecting two Balancing Authority Areas.
Tie Line Bias	Version 0 Reliability Standards		2/8/2005	3/16/2007		A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.
Time Error	Version 0 Reliability Standards		2/8/2005	3/16/2007		The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.
Time Error Correction	Version 0 Reliability Standards		2/8/2005	3/16/2007		An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value.
TLR (Transmission Loading Relief) Log (NERC added the spelled out term for TLR Log for clarification purposes.)	Version 0 Reliability Standards		2/8/2005	3/16/2007		Report required to be filed after every TLR Level 2 or higher in a specified format. The NERC IDC prepares the report for review by the issuing Reliability Coordinator. After approval by the issuing Reliability Coordinator, the report is electronically filed in a public area of the NERC Web site.
Total Flowgate Capability	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions	TFC	8/22/2008	11/24/2009		The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.
Total Internal Demand	Project 2010-04 Demand Data (MOD C)		5/6/2014	2/19/2015	7/1/2016	The Demand of a metered system, which includes the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system.
Total Transfer Capability	Version 0 Reliability Standards	TTC	2/8/2005	3/16/2007		The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.
Transaction	Version 0 Reliability Standards		2/8/2005	3/16/2007		See Interchange Transaction.
Transfer Capability	Version 0 Reliability Standards		2/8/2005	3/16/2007		The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is *not g* enerally equal to the transfer capability from "Area B" to "Area A."
Transfer Distribution Factor	Version 0 Reliability Standards		2/8/2005	3/16/2007		See Distribution Factor.

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Transient Cyber Asset	Project 2016-02 Modifications to CIP Standards	TCA	2/9/2017	4/19/2018	1/1/2020	A Cyber Asset that is: 1. capable of transmitting or transferring executable code, 2. not included in a BES Cyber System, 3. not a Protected Cyber Asset (PCA) associated with high or medium impact BES Cyber Systems, and 4. directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) for 30 consecutive calendar days or less to a: • BES Cyber Asset, • network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or • PCA associated with high or medium impact BES Cyber Systems. Examples of Transient Cyber Assets include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.
Transmission	Version 0 Reliability Standards		2/8/2005	3/16/2007		An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.
Transmission Constraint	Version 0 Reliability Standards		2/8/2005	3/16/2007		A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Customer	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	1. Any eligible customer (or its designated agent) that can or does execute a Transmission Service agreement or can or does receive Transmission Service. 2. Any of the following entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Line	Project 2007-07 Transmission Vegetation Management		2/7/2006	3/16/2007		A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.
Transmission Operator	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.
Transmission Operator Area	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions		8/22/2008	11/24/2009		The collection of Transmission assets over which the Transmission Operator is responsible for operating.
Transmission Owner	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	The entity that owns and maintains transmission Facilities.
Transmission Planner	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.

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Transmission Reliability Margin	Version 0 Reliability Standards		2/8/2005	3/16/2007		The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.
Transmission Reliability Margin Implementation Document	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions		8/22/2008	11/24/2009		A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.
Transmission Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.
Transmission Service Provider	Project 2015-04 Alignment of Terms	TSP	11/5/2015	1/21/2016	7/1/2016	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.
Undervoltage Load Shedding Program	Project 2008-02 Undervoltage Load Shedding & Underfrequency Load Shedding	UVLS Program	11/13/2014	11/19/2015	4/1/2017	An automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.
Vegetation	Project 2007-07 Transmission Vegetation Management		2/7/2006	3/16/2007		All plant material, growing or not, living or dead.
Vegetation Inspection	Project 2010-07		5/9/2012	3/21/2013	7/1/2014	The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.
Wide Area	Version 0 Reliability Standards		2/8/2005	3/16/2007		The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.
Year One	Project 2010-10 FAC Order 729		1/24/2011	11/17/2011		The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

PENDING ENFORCEMENT						
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Retired Terms							
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Adjacent Balancing Authority	Version 0 Reliability Standards		2/8/2005	3/16/2007		9/30/2014	A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact	Project 2006-06		8/4/2011	NERC withdrew the related petition 3/18/2015.			The impact of an event that results in Bulk Electric System instability or Cascading.
Area Control Error	Version 0 Reliability Standards	ACE	2/8/2005	3/16/2007		3/31/2014	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.
Arranged Interchange	Coordinate Interchange		5/2/2006	3/16/2007		9/30/2014	The state where the Interchange Authority has received the Interchange information (initial or revised).
ATC Path	Project 2006-07		8/22/2008	Not approved; Modification directed 11/24/2009			Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path. (See 18 CFR 37.6(b)(1))
Automatic Generation Control	Version 0 Reliability Standards	AGC	2/8/2005	3/16/2007		12/31/2018	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.
Available Transfer Capability	Version 0 Reliability Standards	ATC	2/8/2005	3/16/2007			A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.
Balancing Authority	Version 0 Reliability Standards	BA	2/8/2005	3/16/2007		12/31/2018	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
BES Cyber Asset	Project 2008-06		11/26/2012	11/22/2013		6/30/2016	A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems. (A Cyber Asset is not a BES Cyber Asset if, for 30 consecutive calendar days or less, it is directly connected to a network within an ESP, a Cyber Asset within an ESP, or to a BES Cyber Asset, and it is used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.)
Blackstart Capability Plan	Version 0 Reliability Standards		2/8/2005	3/16/2007		7/1/2013 Will be retired when EOP-005-2 becomes enforceable	A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.
Blackstart Resource	Project 2006-03		8/5/2009	3/17/2011		6/30/2016	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.
Bulk Electric System	Version 0 Reliability Standards	BES	2/8/2005	3/16/2007		6/30/2014	As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

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Bulk Electric System **(Continued)**	Project 2010-17	BES	1/18/2012	6/14/2013		Replaced by BES definition FERC approved 3/20/2014	**I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1. **Exclusions:** • **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: a) Only serves Load. Or, b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or, c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating). Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.
Bulk Electric System **(Continued)**	Project 2010-17	BES	1/18/2012	6/14/2013		Replaced by BES definition FERC approved 3/20/2014	• **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority. • **E3** - Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:
Bulk Electric System **(Continued)**	Project 2010-17	BES	1/18/2012	6/14/2013		Replaced by BES definition FERC approved 3/20/2014	a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating); b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and c) Not part of a Flowgate or transfer path: The LN does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). • E4 – Reactive Power devices owned and operated by the retail customer solely for its own use. Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.
Bulk Electric System (FERC issued an order on April 18, 2013 approving the revised definition with an effective date of July 1, 2013. On June 14, 2013, FERC granted NERC's request to extend the effective date of the revised definition of the Bulk Electric System to July 1, 2014.)	Project 2010-17	BES	1/18/2012	6/14/2013		Replaced by BES definition FERC approved 3/20/2014	Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. Inclusions: • I1 - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under Exclusion E1 or E3. • I2 - Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above. • I3 - Blackstart Resources identified in the Transmission Operator's restoration plan. • I4 - Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.
Bulk-Power System	Project 2012-08.1 Phase 1		5/9/2013	7/9/2013		6/30/2016	A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.

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Business Practices	Project 2006-07		8/22/2008	Not approved; Modification directed			Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices.
Cascading	Version 0 Reliability Standards		2/8/2005	3/16/2007		6/30/2016	The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.
Cascading Outages	Determine Facility Ratings, Operating Limits, and Trasfer Capabilites		11/1/2006 Withdrawn 2/12/2008			FERC Remanded 12/27/2007	~~The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre-determined area.~~
Confirmed Interchange	Coordinate Interchange		5/2/2006	3/16/2007			The state where the Interchange Authority has verified the Arranged Interchange.
Contingency Reserve	Version 0 Reliability Standards		2/8/2005	3/16/2007		12/31/2017	The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.
Critical Assets	Cyber Security (Permanent)		5/2/2006	1/18/2008		6/30/2016	Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.
Critical Cyber Assets	Cyber Security (Permanent)		5/2/2006	1/18/2008		6/30/2016	Cyber Assets essential to the reliable operation of Critical Assets.
Cyber Assets	Cyber Security (Permanent)		5/2/2006	1/18/2008		6/30/2016	Programmable electronic devices and communication networks including hardware, software, and data.
Cyber Security Incident	Cyber Security (Permanent)		5/2/2006	1/18/2008		6/30/2016	Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.
Cyber Security Incident	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	12/31/2020	A malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or, • Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System.
Demand-Side Management	Version 0 Reliability Standards	DSM	2/8/2005	3/16/2007		6/30/2016	The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.
Distribution Provider	Version 0 Reliability Standards		2/8/2005	3/16/2007		6/30/2016	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Dynamic Interchange Schedule or Dynamic Schedule	Version 0 Reliability Standards		2/8/2005	3/16/2007		9/30/2014	A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.
Electronic Security Perimeter	Cyber Security (Permanent)	ESP	5/2/2006	1/18/2008		6/30/2016	The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.
Element	Version 0 Reliability Standards		2/8/2005	3/16/2007		6/30/2016	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.
Energy Emergency	Version 0 Reliability Standards		2/8/2005	3/16/2007		3/31/2017	A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers' expected energy requirements.
Flowgate	Version 0 Reliability Standards		2/8/2005	3/16/2007			A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.
Frequency Bias Setting	Version 0 Reliability Standards		2/8/2005	3/16/2007		3/31/2015	A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.
Generator Operator		GOP	2/8/2005	3/16/2007		6/30/2016	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner		GO	2/8/2005	3/16/2007		6/30/2016	Entity that owns and maintains generating units.

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Interchange Authority		IA	5/2/2006	3/16/2007		6/30/2016	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Interconnected Operations Service	Version 0 Reliability Standards		2/8/2005	3/16/2007			A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.
Interconnection	Version 0 Reliability Standards		2/8/2005	3/16/2007		6/30/2016	When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.
Interconnection	Project 2010-14.1 Phase 1		8/15/2013	4/16/2015			When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.
Interconnection Reliability Operating Limit	Version 0 Reliability Standards	IROL	2/8/2005	3/16/2007		12/27/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.
Intermediate Balancing Authority	Version 0 Reliability Standards		2/8/2005	3/16/2007			A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.
Load-Serving Entity	Version 0 Reliability Standards		2/8/2005	3/16/2007			Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Low Impact BES Cyber System Electronic Access Point	Project 2014-02	LEAP	2/12/2015	1/21/2016	7/1/2016	12/31/2019	A Cyber Asset interface that controls Low Impact External Routable Connectivity. The Cyber Asset containing the LEAP may reside at a location external to the asset or assets containing low impact BES Cyber Systems.
Low Impact External Routable Connectivity	Project 2014-02	LERC	2/12/2015	1/21/2016	7/1/2016	12/31/2019	Direct user-initiated interactive access or a direct device-to-device connection to a low impact BES Cyber System(s) from a Cyber Asset outside the asset containing those low impact BES Cyber System(s) via a bi-directional routable protocol connection. Point-to-point communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions between Transmission station or substation assets containing low impact BES Cyber Systems are excluded from this definition (examples of this communication include, but are not limited to, IEC 61850 GOOSE or vendor proprietary protocols).
Misoperation	Phase III - IV Planning Standards - Archive		2/7/2006	3/16/2007		6/30/2016	• Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection. • Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone). • Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.
Operational Planning Analysis	Operate Within Interconnection Reliability Operating Limits		10/17/2008	3/17/2011		9/30/2014	An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).
Operational Planning Analysis	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	12/31/2016	An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).
Physical Security Perimeter	Cyber Security (Permanent)	PSP	5/2/2006	1/18/2008		6/30/2016	The physical, completely enclosed ("six-wall") border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled.
Planning Authority	Version 0 Reliability Standards	PA	2/8/2005	3/16/2007			The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Point of Receipt	Version 0 Reliability Standards	POR	2/8/2005	3/16/2007		6/30/2016	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.
Postback	Project 2006-07 ATC/TTC/AFC and CBM/TRM		8/22/2008	Not approved; Modification directed			Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

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Protected Cyber Assets	Project 2008-06 Cyber Security Order 706	PCA	11/26/2012	11/22/2013		6/30/2016	One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP. A Cyber Asset is not a Protected Cyber Asset if, for 30 consecutive calendar days or less, it is connected either to a Cyber Asset within the ESP or to the network within the ESP, and it is used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.
Protection System	Phase III-IV Planning Standards - Archive		2/7/2006	3/17/2007		4/1/2013	Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.
Protection System Maintenance Program (PRC-005-2)	Project 2007-17 Protection System Maintenance and Testing	PSMP	11/7/2012	12/19/2013		4/1/2015	An ongoing program by which Protection System components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities: Verify — Determine that the component is functioning correctly. Monitor — Observe the routine in-service operation of the component. Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems. Inspect — Examine for signs of component failure, reduced performance or degradation. Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.
Protection System Maintenance Program (PRC-005-3)	Project 2007-17.2 Protection System Maintenance and Testing - Phase 2	PSMP	11/7/2013	1/22/2015	4/1/2016		An ongoing program by which Protection System and automatic reclosing components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities: Verify — Determine that the component is functioning correctly. Monitor — Observe the routine in-service operation of the component. Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems. Inspect — Examine for signs of component failure, reduced performance or degradation. Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.
Protection System Maintenance Program (PRC-005-4)	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PSMP	11/13/2014	9/17/2015	1/1/2016		An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities: • Verify — Determine that the Component is functioning correctly. • Monitor — Observe the routine in-service operation of the Component. • Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems. • Inspect — Examine for signs of Component failure, reduced performance or degradation. • Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.
Pseudo-Tie	Version 0 Reliability Standards		2/8/2005	3/16/2007			A telemetered reading or value that is updated in real time and used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.
Pseudo-Tie	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	12/31/2018	A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' control ACE equations (or alternate control processes).
Reactive Power	Version 0 Reliability Standards		2/8/2005	3/16/2007		6/30/2016	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power	Version 0 Reliability Standards		2/8/2005	3/16/2007			The portion of electricity that supplies energy to the load.
Reallocation	Version 0 Reliability Standards		2/8/2005	3/16/2007			The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.

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Real-time Assessment	Project 2014-03		11/13/2014	Revised definition. 11/19/2015	1/1/2017	An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)	
Real-time Assessment	Operate Within Interconnection Reliability Operating Limits		10/17/2008	3/17/2011		12/31/2016	An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data
Reliability Coordinator	Version 0 Reliability Standards	RC	2/8/2005	3/16/2007		6/30/2007	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reliability Directive	Project 2006-06 Reliability Coordination		8/16/2012	11/19/2015		11/19/2015	A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impact.
Reliability Standard	Project 2012-08.1 Phase 1 of Glossary Updates: Statutory Definitions		5/9/2013	7/9/2013		6/30/2016	A requirement, approved by the United States Federal Energy Regulatory Commission under this Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System]. The term includes requirements for the operation of existing bulk-power system [Bulk-Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.
Reliable Operation	Project 2012-08.1 Phase 1 of Glossary Updates: Statutory Definitions		5/9/2013	7/9/2013		6/30/2016	Operating the elements of the bulk-power system [Bulk- Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.
Remedial Action Scheme	Version 0 Reliability Standards	RAS	2/8/2005	3/16/2007		3/31/2017	See "Special Protection System"
Removable Media	Project 2014-02		2/12/2015	1/21/2016	7/1/2016	12/31/2019	Storage media that (i) are not Cyber Assets, (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are directly connected for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a Protected Cyber Asset. Examples include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.

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Reporting Ace			8/15/2013	4/16/2015 (Will not go into effect)			The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW, which includes the difference between the Balancing Authority's Net Actual Interchange and its Net Scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC). Reporting ACE is calculated as follows: Reporting ACE = $(NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$ Reporting ACE is calculated in the Western Interconnection as follows: Reporting ACE = $(NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$ Where: **NI_A (Actual Net Interchange)** is the algebraic sum of actual megawatt transfers across all Tie Lines and includes Pseudo-Ties. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie lines in their actual interchange, provided they are implemented in the same manner for Net Interchange Schedule. **NI_S (Scheduled Net Interchange)** is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie Lines in their scheduled Interchange, provided they are implemented in the same manner for Net Interchange Actual.
Reporting Ace **(Continued)**			8/15/2013	4/16/2015 (Will not go into effect)			**B (Frequency Bias Setting)** is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority. **10** is the constant factor that converts the frequency bias setting units to MW/Hz. **F_A (Actual Frequency)** is the measured frequency in Hz. **F_S (Scheduled Frequency)** is 60.0 Hz, except during a time correction. **I_{ME} (Interchange Meter Error)** is the meter error correction factor and represents the difference between the integrated hourly average of the net interchange actual (NIA) and the cumulative hourly net Interchange energy measurement (in megawatt-hours). **I_{ATEC} (Automatic Time Error Correction)** is the addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection. $_{ATEC}$ shall be zero when operating in any other AGC mode. • Y = B / BS. • H = Number of hours used $I_{ATEC} = \frac{PII_{accum}^{on/off\ peak}}{(1-Y)*H}$ when operating in Automatic Time Error Correction control mode. rgy. The value of H is set to 3. • BS = Frequency Bias for the
Reporting Ace **(Continued)**							energy. The value of H is set to 3. B_S = Frequency Bias for the Interconnection (MW / 0.1 Hz). • Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - B * ΔTE/6) • II_{actual} is the hourly Inadvertent Interchange for the last hour. • ΔTE is the hourly change in system Time Error as distributed by the Interconnection Time Monitor. Where:ΔTE = TE_{end} hour – $TE_{begin\ hour}$ – TD_{adj} – (t)*(TE_{offset}) • TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection Time Monitor control center clocks. • t is the number of minutes of Manual Time Error Correction that occurred during the hour. • TE_{offset} is 0.000 or +0.020 or -0.020. • PII_{accum} is the Balancing Authority's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required. Where: $PII_{accum}^{on/off\ peak}$ = last period's $PII_{accum}^{on/off\ peak}$ + PII_{hourly} All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAs on an Interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation

Retired Terms							
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Reporting Ace **(Continued)**			8/15/2013	4/16/2015 (Will not go into effect)			All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all Balancing Authorities on an interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation consistent with the measures included in this standard. 1. All portions of the Interconnection are included in one area or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses. 2. The algebraic sum of all area Net Interchange Schedules and all Net Interchange actual values is equal to zero at all times. 3. The use of a common Scheduled Frequency FS for all areas at all times. 4. The absence of metering or computational errors. (The inclusion and use of the IME term to account for known metering or computational errors.)
Reportable Cyber Security Incident	Project 2008-06 Cyber Security Order 706 V5 CIP Standards		11/26/2012	11/22/2013	7/1/2016	12/31/2020	A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity.
Request for Interchange	Coordinate Interchange	RFI	5/2/2006	3/16/2007			A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.
Reserve Sharing Group	Version 0 Reliability Standards	RSG	2/8/2005	3/16/2007		6/30/2016	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.
Reserve Sharing Group Reporting ACE	Project 2010-14.1 Phase 1		8/15/2013	4/16/2015		12/31/2017	At any given time of measurement for the applicable Reserve Sharing Group, the algebraic sum of the Reporting ACEs (or equivalent as calculated at such time of measurement) of the Balancing Authorities participating in the Reserve Sharing Group at the time of measurement.
Resource Planner	Version 0 Reliability Standards	RP	2/8/2005	3/16/2007			The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
Right-of-Way	Project 2007-07	ROW	2/7/2006	3/16/2007			A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.
Right-of-Way	Project 2007-07	ROW	11/3/2011	3/21/2013		6/30/2014	The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.
Sink Balancing Authority	Version 0 Reliability Standards		2/8/2005	3/16/2007		9/30/2014	The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority	Version 0 Reliability Standards		2/8/2005	3/16/2007		9/30/2014	The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)
Special Protection System (Remedial Action Scheme)	Version 0 Reliability Standards	SPS	2/8/2005	3/16/2007 (Becomes inactive 3/31/2017)		3/31/2017	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

Retired Terms							
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
System Operating Limit	Version 0 Reliability Standards	SOL	2/8/2005	3/16/2007		6/30/2014	The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)
System Operator	Version 0 Reliability Standards		2/8/2005	3/16/2007		6/30/2016	An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.
Transient Cyber Asset	Project 2014-02		2/12/2015	1/21/2016	7/1/2016		A Cyber Asset that (i) is capable of transmitting or transferring executable code, (ii) is not included in a BES Cyber System, (iii) is not a Protected Cyber Asset (PCA), and (iv) is directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless, including near field or Bluetooth communication) for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a PCA. Examples include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.
Transmission Customer	Version 0 Reliability Standards		2/8/2005	3/16/2007			1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Operator	Version 0 Reliability Standards	TOP	2/8/2005	3/16/2007			The entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.
Transmission Owner	Version 0 Reliability Standards	TO	2/8/2005	3/16/2007			The entity that owns and maintains transmission facilities.
Transmission Planner	Version 0 Reliability Standards	TP	2/8/2005	3/16/2007			The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
Transmission Service Provider	Version 0 Reliability Standards	TSP	2/8/2005	3/16/2007			The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
Vegetation Inspection	Project 2007-07 Transmission Vegetation Management		2/7/2006	3/16/2007		3/20/2013	The systematic examination of a transmission corridor to document vegetation conditions.
Vegetation Inspection	Project 2007-07 Transmission Vegetation Management		11/3/2011	3/21/2013		6/30/2014	The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner’s control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

NPCC REGIONAL DEFINITIONS							
NPCC Regional Term	**Link to Implementation Plan**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Inactive Date**	**Definition**
Current Zero Time	PRC-002-NPCC-1 Implementation Plan		11/4/2010	10/20/2011	10/20/2013		The time of the final current zero on the last phase to interrupt.
Generating Plant	PRC-002-NPCC-1 Implementation Plan		11/4/2010	10/20/2011	10/20/2013		One or more generators at a single physical location whereby any single contingency can affect all the generators at that location.

RELIABILITYFIRST REGIONAL DEFINITIONS							
RELIABILITYFIRST Regional Term	**Link to FERC Order**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Inactive Date**	**Definition**
Resource Adequacy	BAL-502-RFC-02 Implementation Plan		8/5/2009	3/17/2011			The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)
Net Internal Demand	BAL-502-RFC-02 Implementation Plan		8/5/2009	3/17/2011			Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Management and Interruptible Demand
Peak Period	BAL-502-RFC-02 Implementation Plan		8/5/2009	3/17/2011			A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur
Wind Generating Station	BAL-502-RFC-02 Implementation Plan		11/3/2011 (Board withdrew approval 11/7/2012)	3/17/2011			A collection of wind turbines electrically connected together and injecting energy into the grid at one point, sometimes known as a "Wind Farm."
Year One	BAL-502-RFC-02 Implementation Plan		8/5/2009	3/17/2011			The planning year that begins with the upcoming annual Peak Period

TEXAS RE REGIONAL DEFINITIONS

Frequency Measurable Event	BAL-001-TRE-1 Implementation Plan	FME	8/15/2013	1/16/2014	4/1/2014		An event that results in a Frequency Deviation, identified at the BA's sole discretion, and meeting one of the following conditions: i) a Frequency Deviation that has a pre-perturbation [the 16-second period of time before t(0)] average frequency to post-perturbation [the 32-second period of time starting 20 seconds after t(0)] average frequency absolute deviation greater than 100 mHz (the 100 mHz value may be adjusted by the BA to capture 30 to 40 events per year). Or ii) a cumulative change in generating unit/generating facility, DC tie and/or firm load pre-perturbation megawatt value to post-perturbation megawatt value absolute deviation greater than 550 MW (the 550 MW value may be adjusted by the BA to capture 30 to 40 events per year).
Governor			8/15/2013	1/16/2014	4/1/2014		The electronic, digital or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.
Primary Frequency Response	BAL-001-TRE-1 Implementation Plan	PFR	8/15/2013	1/16/2014	4/1/2014		The immediate proportional increase or decrease in real power output provided by generating units/generating facilities and the natural real power dampening response provided by Load in response to system Frequency Deviations. This response is in the direction that stabilizes frequency.

WECC REGIONAL DEFINITIONS

WECC Regional Term	WECC Standards Under Development	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Area Control Error *	WECC Regional Standards Under Development	ACE	3/12/2007	6/8/2007		3/31/2014	Means the instantaneous difference between net actual and scheduled interchange, taking into account the effects of Frequency Bias including correction for meter error.
Automatic Generation Control *	WECC Regional Standards Under Development	AGC	3/12/2007	6/8/2007			Means equipment that automatically adjusts a Control Area's generation from a central location to maintain its interchange schedule plus Frequency Bias.
Automatic Time Error Correction	WECC Regional Standards Under Development		3/26/2008	5/21/2009		3/31/2014	A frequency control automatic action that a Balancing Authority uses to offset its frequency contribution to support the Interconnection's scheduled frequency.
Automatic Time Error Correction	WECC Regional Standards Under Development		12/19/2012	10/16/2013	4/1/2014		The addition of a component to the ACE equation that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error.
Average Generation *	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Means the total MWh generated within the Balancing Authority Operator's Balancing Authority Area during the prior year divided by 8760 hours (8784 hours if the prior year had 366 days).
Business Day *	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Means any day other than Saturday, Sunday, or a legal public holiday as designated in section 6103 of title 5, U.S. Code.

Commercial Operation	WECC Regional Standards Under Development		10/29/2008	4/21/2011			Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.
Contributing Schedule	WECC Regional Standards Under Development		2/10/2009	3/17/2011		9/30/2019	A Schedule not on the Qualified Transfer Path between a Source Balancing Authority and a Sink Balancing Authority that contributes unscheduled flow across the Qualified Transfer Path.
Dependability-Based Misoperation	WECC Regional Standards Under Development		10/29/2008	4/21/2011			Is the absence of a Protection System or RAS operation when intended. Dependability is a component of reliability and is the measure of a device's certainty to operate when required.
Disturbance *	WECC Regional Standards Under Development		3/12/2007	6/8/2007		Retired	Means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.
Extraordinary Contingency†	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Shall have the meaning set out in Excuse of Performance, section B.4.c. language in section B.4.c: *means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity's reasonable control; provided that prudent industry standards (e.g. maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the "Most Severe Single Contingency" as defined in the WECC Reliability Criteria or any lesser contingency).*

WECC REGIONAL DEFINITIONS

WECC Regional Term	WECC Standards Under Development	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Frequency Bias *	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Means a value, usually given in megawatts per 0.1 Hertz, associated with a Control Area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.
Functionally Equivalent Protection System	WECC Regional Standards Under Development	FEPS	10/29/2008	4/21/2011			A Protection System that provides performance as follows: • Each Protection System can detect the same faults within the zone of protection and provide the clearing times and coordination needed to comply with all Reliability Standards. • Each Protection System may have different components and operating characteristics.

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Functionally Equivalent RAS	WECC Regional Standards Under Development	FERAS	10/29/2008	4/21/2011			A Remedial Action Scheme (“RAS”) that provides the same performance as follows: • Each RAS can detect the same conditions and provide mitigation to comply with all Reliability Standards. • Each RAS may have different components and operating characteristics.
Generating Unit Capability *	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Means the MVA nameplate rating of a generator.
Non-spinning Reserve†	WECC Regional Standards Under Development		3/12/2007	6/8/2007		Retired	Means that Operating Reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.
Normal Path Rating *	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.
Operating Reserve *	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Means that capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. Operating Reserve consists of Spinning Reserve and Nonspinning Reserve.
Operating Transfer Capability Limit *	WECC Regional Standards Under Development	OTC	3/12/2007	6/8/2007			Means the maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient criteria as determined by equipment loading capability and acceptable voltage conditions, (c) transient performance criteria, and (d) post-contingency loading and voltage criteria.
Primary Inadvertent Interchange	WECC Regional Standards Under Development		3/26/2008	5/21/2009			The component of area (n) inadvertent interchange caused by the regulating deficiencies of the area (n).
Qualified Controllable Device	WECC Regional Standards Under Development		2/10/2009	3/17/2011		9/30/2019	A controllable device installed in the Interconnection for controlling energy flow and the WECC Operating Committee has approved using the device for controlling the USF on the Qualified Transfer Paths.
Qualified Path	WECC Regional Standards Under Development		2/7/2019	5/10/2019	10/1/2019		A transmission element, or group of transmission elements that has qualified for inclusion into the Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP).
Qualified Transfer Path	WECC Regional Standards Under Development		2/10/2009	3/17/2011		9/30/2019	A transfer path designated by the WECC Operating Committee as being qualified for WECC unscheduled flow mitigation.
Qualified Transfer Path Curtailment Event	WECC Regional Standards Under Development		2/10/2009	3/17/2011		9/30/2019	Each hour that a Transmission Operator calls for Step 4 or higher for one or more consecutive hours (See Attachment 1 IRO-006-WECC-1) during which the curtailment tool is functional.

WECC REGIONAL DEFINITIONS

WECC Regional Term	WECC Standards Under Development	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition

Relief Requirement	WECC Regional Standards Under Development		2/10/2009	3/17/2011		6/30/2014	The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority's Contributing Schedules by the percentages listed in the columns of WECC Unscheduled Flow Mitigation Summary of Actions Table in Attachment 1 WECC IRO-006-WECC-1.
Relief Requirement	WECC Regional Standards Under Development		2/7/2013	6/13/2014	7/1/2014	9/30/2019	The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority's Contributing Schedules by the percentages determined in the WECC unscheduled flow mitigation guideline.
Secondary Inadvertent Interchange	WECC Regional Standards Under Development		3/26/2008	5/21/2009			The component of area (n) inadvertent interchange caused by the regulating deficiencies of area (i).
Security-Based Misoperation	WECC Regional Standards Under Development		10/29/2008	4/21/2011			A Misoperation caused by the incorrect operation of a Protection System or RAS. Security is a component of reliability and is the measure of a device's certainty not to operate falsely.
Spinning Reserve†	WECC Regional Standards Under Development		3/12/2007	6/8/2007		Retired	Means unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating reserve and Contingency reserve (as each are described in Sections B.a.i and ii).
Transfer Distribution Factor	WECC Regional Standards Under Development	TDF	2/10/2009	3/17/2011		9/30/2019	The percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented. [See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]
WECC Table 2 *	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A to this Standard.

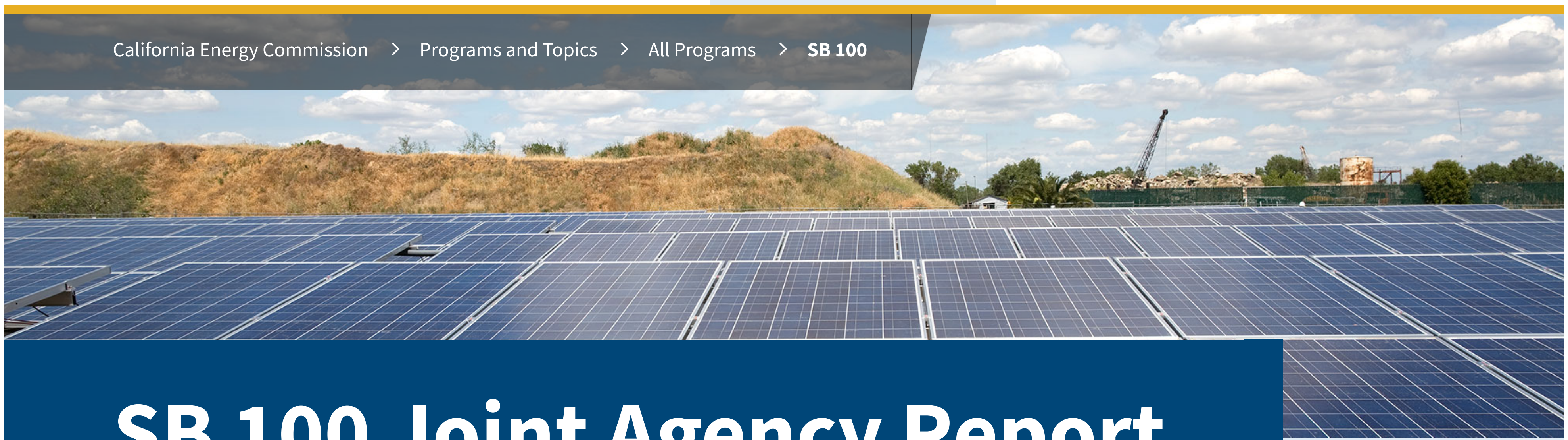
* FERC approved the WECC Tier One Reliability Standards in the Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, 119 FERC ¶ 61,260 (June 8, 2007). In that Order, FERC directed WECC to address the inconsistencies between the regional definitions and the NERC Glossary in developing permanent replacement standards. The replacement standards designed to address the shortcomings were filed with FERC in 2009

CHANGE HISTORY	
Date	**Action**
4/2/2021	Retired;moved to the Retired Terms Tab: Reportable Cyber Security Incident
3/31/2021	Retired; moved to the Retired Terms tab: 1. Operational Planning Analysis (OPA), 2. Protections System Coordination Study 3. Real-time Assessment (RTA)
3/15/2021	Moved; to Subject to Enforcement Tab 1. Operational Planning Analysis (OPA) 2. Protections System Coordination Study 3. Real-time Assessment (RTA)
1/4/2021	Effective; moved to Subject to Enforcement Tab: Cyber Security Incident
1/4/2021	Retired;moved to the Retired Terms Tab: Cyber Security Incident
10/8/2020	Retired; moved to the Retired Terms tab. 1. Automatic Generation Control 2. Balancing Authority 3. Pseudo-Tie
5/29/2020	Updated effective date for Operational Planning Analysis (OPA), Protections System Coordination Study and Real-time Assessment (RTA) to 4/21/2021 per FERC/s April 17th Order extending effective dates due to COVID-19.
2/24/2020	Added inactive Date to Qualified Transfer Path Curtailment Event, Contributing Schedule, Qualified Controllable Device, Relief Requirement and Transfer Distribution Factor.
1/2/2020	Effective; moved to the Subject to Enforcement tab: 1. Definition of Transient Cyber Asset (TCA) 2. Definition of Removable Media
1/2/2020	Retired; moved to the Retired Terms tab. 1. Low Impact BES Cyber System Electronic Access Point (LEAP) 2. Low Impact External Routable Connectivity (LERC) 3. Transient Cyber Asset (TCA) 4. Removable Media
8/12/2019	Added revised definitions of Cyber Security Incident and Reportable Cyber Security Incident to the Pending Enforcement tab.
5/10/2019	Added Inactive Date to Qualified Transfer Path. Added Qualified Path definition and Effective Date
3/8/2019	Moved "Automatic Generation Control," "Balancing Authority" and "Pseudo-tie" to Subject to Enforcement tab.
7/3/2018	Updated effective date for Operational Planning Analysis (OPA), Protections System Coordination Study and Real-time Assessment (RTA).
6/12/2018	Added revised definitions of Transient Cyber Asset and Removable Media to the Pending Enforcement tab.
1/31/2018	Fixed truncated definition for Texas RE term Primary Frequency Response
1/2/2018	**Moved to Subject to Enforcement**: Balancing Contingency Event; Contingency Event Recovery Period; Contingency Reserve; Contingency Reserve Restoration Period; Most Severe Single Contingency; Pre-Reporting Contingency Event ACE Value; Reportable Balancing Contingency Event; Reserve Sharing Group Reporting ACE **Moved to Retired tab**: Contingency Reserve; Reserve Sharing Group Reporting ACE
10/6/2017	Added the Effective date of Automatic Generation Control, Pseudo-Tie and Balancing Authority
8/1/2017	Moved to Subject to Enforcement: Reporting Ace, Actual Frequency, Actual Net Interchange, Schedule Net Interchange, Interchange Meter Error, Automatic Time Error Correction
7/24/2017	Updated project link for definitions related to Project 2014-02, board adopted 2/12/15.
7/14/2017	Updated project link to Remedial Action Scheme with an effective date of 4/1/17; Removeable Media link to project 2014-02.
7/3/2017	Moved 'Geomagnetic Disturbance Vulnerability Assessment or GMD Vunerability Assessment' to Subject to Enforcement
6/15/2017	Readded 'Governor' and 'Primary Frequency Response' to TexasRE
4/4/2017	Moved to Subject to Enforcement: Energy Emergency, Remedial Action Scheme, Special Protection System and Under3 Voltage Load Shedding Program. Moved terms inactive 3/31/17 to Retired tab.
3/16/2017	Removed Pending Inactive tab; not necessary
3/10/2017	Added **Pending Inactive** tab
2/7/2017	**Added Effective Dates for:** Balancing Contingency Event, Most Severe Single Contingency (MSSC), Reportable Balancing Contingency Event, Contingency Event Recovery Period, Contingency Reserve Restoration Period, Pre-Reporting Contingency Event ACE Value, Reserve Sharing Group Reporting ACE, Contingency Reserve
1/25/2017	Removed WECC terms 'Non-Spinning Reserve' and 'Spinning Reserve' per FERC Order No. 789. Docket No. RM13-13-000.
1/6/2017	Moved the following terms from Pending Enforcement to Subject to Enforcement: Operational Planning Analysis, Real-time Assessment (Revised Definition)
1/5/2017	**Formatting of Glossary of Terms updated.**

12/12/16	**Updated:** 'Adverse Reliability Impact' from Pending to Retired. NERC withdrew the related petition 3/18/2015
11/28/16	**Updated** ReliabilityFirst - Wind Generating Station term to inactive
9/28/16	**Updated** CIP v 5 standards effective date from 4/1/2016 to 7/1/2016 per FERC Order 822.
8/17/16	**Board Adopted:** Operational Planning Analysis and Real-time Assessment
7/13/16	Updated color coding of terms retired 6/30/2016 based on the terms becoming effective 7/1/2016.
6/24/16	**FERC approved:** Actual Frequency, Actual Net Interchange, Scheduled Net
	Interchange (NIS), Interchange Meter Error (IME), and Automatic Time Error Correction (ATEC)
	Reporting ACE: status updated
6/21/16	**Correction:** Reserve Sharing Group Reporting ACE, and Contingency Reserve changed to 11/5/2015 Board adoption date status
4/1/16	**Effective:** BES Cyber Asset, BES Cyber System, BES Cyber System Information, CIP Exceptional Circumstance, CIP Senior Manager, Cyber Assets, Cyber Security Incident, Dial-up Connectivity, Electronic Access Control or Monitoring Systems, Electronic Access Point, Electronic Security Perimeter, External Routable Connectivity, Interactive Remote Access, Intermediate System, Physical Access Control Systems, Physical Security Perimeter
3/31/16	**Inactive**: Critical Assets, Critical Cyber Assets, Cyber Assets, Cyber Security Incident, Electronic Security Perimeter, Physical Security Perimeter

EXHIBIT 6

California Energy Commission, SB 100 Webpage



SB 100 Joint Agency Report

Senate Bill (SB) 100 established a landmark policy requiring renewable energy and zero-carbon resources supply 100 percent of electric retail sales to end-use customers by 2045. It requires the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and California Air Resources Board (CARB) to prepare a report.

Senate Bill 100

Officially titled “The 100 Percent Clean Energy Act of 2018,” Senate Bill 100 (SB 100, De León):

- Sets a 2045 goal of powering all retail electricity sold in California and state agency electricity needs with renewable and zero-carbon resources — those such as solar and wind energy that do not emit climate-altering greenhouse gases.
- Updates the state’s Renewables Portfolio Standard to ensure that by 2030 at least 60 percent of California’s electricity is renewable.
- Requires the Energy Commission, Public Utilities Commission and Air Resources Board to use programs under existing laws to achieve 100 percent clean electricity and issue a joint policy report on SB 100 by 2021 and every four years thereafter.

CONTACT

Terra Weeks

EVENTS AND DOCUMENTS

Workshops and Documents

RELATED LINKS

Blog: California Agencies Lead Way to Clean Energy Future

Docket Log (19-SB-100)

Submit Comments (19 -SB-100)

Senate Bill 100

California Air Resources Board - Carbon Neutrality

California Air Resources Board - Scoping Plan

California Public Utilities Commission – IRP Process

RELATED DOCUMENTS

2021 SB 100 Joint Agency Report

The 2021 SB 100 Joint Agency Report is a first step to evaluate the challenges and opportunities in implementing SB 100. It includes an initial assessment of the additional energy resources and the resource building rates needed to achieve 100 percent clean electricity, along with the associated costs. It uses a computer model to analyze these factors under various conditions and technologies.

A diverse array of interests informed this report through a year-long series of public workshops and comment opportunities. The joint agencies also consulted with the California balancing authorities, as required by the statute, and the Disadvantaged Communities Advisory Group, which advises the Energy Commission and Public Utilities Commission on energy equity issues.

Key Takeaways from Modeling:

- This initial analysis suggests SB 100 is technically achievable through multiple pathways.
- Construction of clean electricity generation and storage facilities must be sustained at record-setting rates.
- Diversity in energy resources and technologies lowers overall costs.
- Retaining some natural gas power capacity may minimize costs while ensuring uninterrupted power supply during the transition to 100 percent clean energy.
- Increased energy storage and advancements in zero-carbon technologies can reduce natural gas capacity needs.
- Further analysis is needed.

Modeling results indicate that achieving 100 percent clean electricity will increase the total annual electricity system costs by 6 percent relative to the cost under the state's Renewables Portfolio Standard requirement of having at least 60 percent clean electricity by the end of 2030. These estimates will change over time as markets change, new technologies are commercialized, and additional factors such as grid reliability are included in future analyses.

Recommendations for Further Analysis:

- Verify that scenario results satisfy the state's grid reliability requirements.
- Continue to evaluate the potential effects of emerging resources, such as offshore wind, long-duration energy storage, green hydrogen technologies, and demand flexibility.
- Assess environmental, social, and economic costs and benefits of the additional clean electricity generation capacity and storage needed to

Electric System Reliability and the Recent Role of California's Fossil Fleet

CATEGORIES

Program

SB 100 Joint Agency Report

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implement SB 100.

Hold annual workshops to support alignment among the joint agencies and continuity between SB 100 reports.

2021 SB 100 Joint Agency Report Documents

- 2021 SB 100 Joint Agency Report and Summary
- SB 100 RESOLVE Model - ZIP (713 MB)
- News Release - California Releases Report Charting Path to 100 Percent Clean Electricity

UPCOMING EVENTS

No events are available at this time.

RELATED PROGRAMS

Renewables Portfolio Standard - RPS

The Renewables Portfolio Standard (RPS) is one of California's key programs for advancing renewable energy.

Exhibit 7

Science Article, Ramón A. Alvarez et al., *Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*

GREENHOUSE GASES

Assessment of methane emissions from the U.S. oil and gas supply chain

Ramón A. Alvarez[1*], Daniel Zavala-Araiza[1], David R. Lyon[1], David T. Allen[2], Zachary R. Barkley[3], Adam R. Brandt[4], Kenneth J. Davis[3], Scott C. Herndon[5], Daniel J. Jacob[6], Anna Karion[7], Eric A. Kort[8], Brian K. Lamb[9], Thomas Lauvaux[3], Joannes D. Maasakkers[6], Anthony J. Marchese[10], Mark Omara[1], Stephen W. Pacala[11], Jeff Peischl[12,13], Allen L. Robinson[14], Paul B. Shepson[15], Colm Sweeney[13], Amy Townsend-Small[16], Steven C. Wofsy[6], Steven P. Hamburg[1]

Methane emissions from the U.S. oil and natural gas supply chain were estimated by using ground-based, facility-scale measurements and validated with aircraft observations in areas accounting for ~30% of U.S. gas production. When scaled up nationally, our facility-based estimate of 2015 supply chain emissions is 13 ± 2 teragrams per year, equivalent to 2.3% of gross U.S. gas production. This value is ~60% higher than the U.S. Environmental Protection Agency inventory estimate, likely because existing inventory methods miss emissions released during abnormal operating conditions. Methane emissions of this magnitude, per unit of natural gas consumed, produce radiative forcing over a 20-year time horizon comparable to the CO_2 from natural gas combustion. Substantial emission reductions are feasible through rapid detection of the root causes of high emissions and deployment of less failure-prone systems.

Methane (CH_4) is a potent greenhouse gas, and CH_4 emissions from human activities since preindustrial times are responsible for 0.97 W m^{-2} of radiative forcing, as compared to 1.7 W m^{-2} for carbon dioxide (CO_2) (*1*). CH_4 is removed from the atmosphere much more rapidly than CO_2; thus, reducing CH_4 emissions can effectively reduce the near-term rate of warming (*2*). Sharp growth in U.S. oil and natural gas (O/NG) production beginning around 2005 (*3*) raised concerns about the climate impacts of increased natural gas use (*4*, *5*). By 2012, disagreement among published estimates of CH_4 emissions from U.S. natural gas operations led to a broad consensus that additional data were needed to better characterize emission rates (*4*–*7*). A large body of field measurements made between 2012 and 2016 (table S1) has markedly improved understanding of the sources and magnitude of CH_4 emissions from the industry's operations. Brandt *et al.* summarized the early literature (*8*); other assessments incorporated elements of recent data (*9*–*11*). This work synthesizes recent studies to provide an improved overall assessment of emissions from the O/NG supply chain, which we define to include all operations associated with O/NG production, processing, and transport (materials and methods, section S1.0) (*12*).

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Measurements of O/NG CH_4 emissions can be classified as either top-down (TD) or bottom-up (BU). TD studies quantify ambient methane enhancements using aircraft, satellites, or tower networks and infer aggregate emissions from all contributing sources across large geographies. TD estimates for nine O/NG production areas have been reported to date (table S2). These areas are distributed across the U.S. (fig. S1) and account for ~33% of natural gas, ~24% of oil production, and ~14% of all wells (*13*). Areas sampled in TD studies also span the range of hydrocarbon characteristics (predominantly gas, predominantly oil, or mixed), as well as a range of production characteristics such as well productivity and maturity. In contrast, BU studies generate regional, state, or national emission estimates by aggregating and extrapolating measured emissions from individual pieces of equipment, operations, or facilities, using measurements made directly at the emission point or, in the case of facilities, directly downwind.

Recent BU studies have been performed on equipment or facilities that are expected to represent the vast majority of emissions from the O/NG supply chain (table S1). In this work, we integrate the results of recent facility-scale BU studies to estimate CH_4 emissions from the U.S. O/NG supply chain, and then we validate the results using TD studies (materials and methods). The probability distributions of our BU methodology are based on observed facility-level emissions, in contrast to the component-by-component approach used for conventional inventories. We thus capture enhancements produced by all sources within a facility, including the heavy tail of the distribution. When the BU estimate is developed in this manner, direct comparison of BU and TD estimates of CH_4 emissions in the nine basins for which TD measurements have been reported indicates agreement between methods, within estimated uncertainty ranges (Fig. 1).

Our national BU estimate of total CH_4 emissions in 2015 from the U.S. O/NG supply chain is 13 (+2.1/−1.6, 95% confidence interval) Tg CH_4/year (Table 1). This estimate of O/NG CH_4 emissions can also be expressed as a production-normalized emission rate of 2.3% (+0.4%/−0.3%) by normalizing by annual gross natural gas production [33 trillion cubic feet (*13*), with average CH_4 content of 90 volume %]. Roughly 85% of national BU emissions are from production, gathering, and processing sources, which are concentrated in active O/NG production areas.

Our assessment does not update emissions from local distribution and end use of natural gas, owing to insufficient information addressing this portion of the supply chain. However, recent studies suggest that local distribution emissions exceed the current inventory estimate (*14*–*16*), and that end-user emissions might also be important. If these findings prove to be representative, overall emissions from the natural gas supply chain would increase relative to the value in Table 1 (materials and methods, section S1.5).

Our BU method and TD measurements yield similar estimates of U.S. O/NG CH_4 emissions in 2015, and both are significantly higher than the corresponding estimate in the U.S. Environmental Protection Agency's Greenhouse Gas Inventory (EPA GHGI) (Table 1 and materials and methods, section S1.3) (*17*). Discrepancies between TD estimates and the EPA GHGI have been reported previously (*8*, *18*). Our BU estimate is 63% higher than the EPA GHGI, largely due to a more than twofold difference in the production segment (Table 1). The discrepancy in production sector emissions alone is ~4 Tg CH_4/year, an amount larger than the emissions from any other O/NG supply chain segment. Such a large difference cannot be attributed to expected uncertainty in either estimate: The extremal ends of the 95% confidence intervals for each estimate differ by 20% (i.e., ~12 Tg/year for the lower bound of our BU estimate can be compared to ~10 Tg/year for the upper bound of the EPA GHGI estimate).

We believe the reason for such large divergence is that sampling methods underlying conventional inventories systematically underestimate total emissions because they miss high emissions caused by abnormal operating conditions (e.g., malfunctions). Distributions of measured emissions from production sites in BU studies are invariably "tail-heavy," with large emission rates measured at a small subset of sites at any single point in time (*19*–*22*). Consequently, the most likely hypothesis for the difference between the EPA GHGI and BU estimates derived from facility-level measurements is that measurements used to develop GHGI emission factors

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undersample abnormal operating conditions encountered during the BU work. Component-based inventory estimates like the GHGI have been shown to underestimate facility-level emissions (*23*), probably because of the technical difficulty and safety and liability risks associated with measuring large emissions from, for example, venting tanks such as those observed in aerial surveys (*24*).

Abnormal conditions causing high CH_4 emissions have been observed in studies across the O/NG supply chain. An analysis of site-scale emission measurements in the Barnett Shale concluded that equipment behaving as designed could not explain the number of high-emitting production sites in the region (*23*). An extensive aerial infrared camera survey of ~8000 production sites in seven U.S. O/NG basins found that ~4% of surveyed sites had one or more observable high–emission rate plumes (*24*) (detection threshold of ~3 to 10 kg CH_4/hour was two to seven times higher than mean production site emissions estimated in this work). Emissions released from liquid storage tank hatches and vents represented 90% of these sightings. It appears that abnormal operating conditions must be largely responsible, because the observation frequency was too high to be attributed to routine operations like condensate flashing or liquid unloadings alone (*24*). All other observations were due to anomalous venting from dehydrators, separators, and flares. Notably, the two largest sources of aggregate emissions in the EPA GHGI—pneumatic controllers and equipment leaks—were never observed from these aerial surveys. Similarly, a national survey of gathering facilities found that emission rates were four times higher at the 20% of facilities where substantial tank venting emissions were observed, as compared to the 80% of facilities without such venting (*25*). In addition, very large emissions from leaking isolation valves at transmission and storage facilities were quantified by means of downwind measurement but could not be accurately (or safely) measured by on-site methods (*26*). There is an urgent need to complete equipment-based measurement campaigns that capture these large-emission events, so that their causes are better understood.

Table 1. Summary of this work's bottom-up estimates of CH_4 emissions from the U.S. oil and natural gas (O/NG) supply chain (95% confidence interval) and comparison to the EPA Greenhouse Gas Inventory (GHGI).

Industry segment	2015 CH_4 emissions (Tg/year)	
	This work (bottom-up)	EPA GHGI (*17*)
Production	7.6 (+1.9/−1.6)	3.5
Gathering	2.6 (+0.59/−0.18)	2.3
Processing	0.72 (+0.20/−0.071)	0.44
Transmission and storage	1.8 (+0.35/−0.22)	1.4
Local distribution*	0.44 (+0.51/−0.22)	0.44
Oil refining and transportation*	0.034 (+0.050/−0.008)	0.034
U.S. O/NG total	13 (+2.1/−1.7)	8.1 (+2.1/−1.4)†

*This work's emission estimates for these sources are taken directly from the GHGI. The local distribution estimate is expected to be a lower bound on actual emissions and does not include losses downstream of customer meters due to leaks or incomplete combustion (materials and methods, section S1.5).
†The GHGI only reports industry-wide uncertainties.

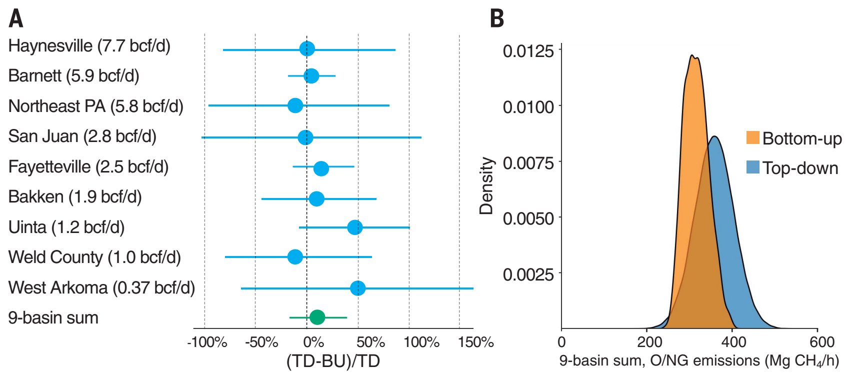

Fig. 1. Comparison of this work's bottom-up (BU) estimates of methane emissions from oil and natural gas (O/NG) sources to top-down (TD) estimates in nine U.S. O/NG production areas. (**A**) Relative differences of the TD and BU mean emissions, normalized by the TD value, rank ordered by natural gas production in billion cubic feet per day (bcf/d, where 1 bcf = 2.8 × 10^7 m^3). Error bars represent 95% confidence intervals. (**B**) Distributions of the nine-basin sum of TD and BU mean estimates (blue and orange probability density, respectively). Neither the ensemble of TD-BU pairs (A) nor the nine-basin sum of means (B) are statistically different [p = 0.13 by a randomization test, and mean difference of 11% (95% confidence interval of −17 to 41%)].

In contrast to abnormal operational conditions, alternative explanations such as outdated component emission factors are unlikely to explain the magnitude of the difference between our facility-based BU estimate and the GHGI. First, an equipment-level inventory analogous to the EPA GHGI but updated with recent direct measurements of component emissions (materials and methods, section S1.4) predicts total production emissions that are within ~10% of the EPA GHGI, although the contributions of individual source categories differ significantly (table S3). Second, we consider unlikely an alternative hypothesis that systematically higher emissions during daytime sampling cause a high bias in TD methods (materials and methods, section S1.6). Two other factors may lead to low bias in EPA GHGI and similar inventory estimates. Operator cooperation is required to obtain site access for emission measurements (*8*). Operators with lower-emitting sites are plausibly more likely to cooperate in such studies, and workers are likely to be more careful to avoid errors or fix problems when measurement teams are on site or about to arrive. The potential bias due to this "opt-in" study design is very challenging to determine. We therefore rely primarily on site-level, downwind measurement methods with limited or no operator forewarning to construct our BU estimate. Another possible source of bias is measurement error. It has been suggested that malfunction of a measurement instrument widely used in the O/NG industry contributes to underestimated emissions in inventories (*27*); however, this cannot explain the more than twofold difference in production emissions (*28*).

The tail-heavy distribution for many O/NG CH_4 emission sources has important implications for mitigation because it suggests that most sources—whether they represent whole facilities or individual pieces of equipment—can have lower emissions when they operate as designed. We anticipate that significant emissions reductions could be achieved by deploying well-designed emission detection and repair systems that are capable of identifying abnormally operating facilities or equipment. For example, pneumatic controllers and equipment leaks are the largest emission sources in the O/NG production segment exclusive of missing emission sources (38 and 21%, respectively; table S3), with malfunctioning controllers contributing 66% of total pneumatic controller emissions (materials and methods, section S1.4) and equipment leaks 60% higher than the GHGI estimate.

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Gathering operations, which transport unprocessed natural gas from production sites to processing plants or transmission pipelines, produce ~20% of total O/NG supply chain CH_4 emissions. Until the publication of recent measurements (*29*), these emissions were largely unaccounted by the EPA GHGI. Gas processing, transmission and storage together contribute another ~20% of total O/NG supply chain emissions, most of which come from ~2500 processing and compression facilities.

Our estimate of emissions from the U.S. O/NG supply chain (13 Tg CH_4/year) compares to the EPA estimate of 18 Tg CH_4/year for all other anthropogenic CH_4 sources (*17*). Natural gas losses are a waste of a limited natural resource (~$2 billion/year), increase global levels of surface ozone pollution (*30*), and substantially erode the potential climate benefits of natural gas use. Indeed, our estimate of CH_4 emissions across the supply chain, per unit of gas consumed, results in roughly the same radiative forcing as does the CO_2 from combustion of natural gas over a 20-year time horizon (31% over 100 years). Moreover, the climate impact of 13 Tg CH_4/year over a 20-year time horizon roughly equals that from the annual CO_2 emissions from all U.S. coal-fired power plants operating in 2015 (31% of the impact over a 100-year time horizon) (materials and methods, section S1.7).

We suggest that inventory methods would be improved by including the substantial volume of missing O/NG CH_4 emissions evident from the large body of scientific work now available and synthesized here. Such empirical adjustments based on observed data have been previously used in air quality management (*31*).

The large spatial and temporal variability in CH_4 emissions for similar equipment and facilities (due to equipment malfunction and other abnormal operating conditions) reinforces the conclusion that substantial emission reductions are feasible. Key aspects of effective mitigation include pairing well-established technologies and best practices for routine emission sources with economically viable systems to rapidly detect the root causes of high emissions arising from abnormal conditions. The latter could involve combinations of current technologies such as on-site leak surveys by company personnel using optical gas imaging (*32*), deployment of passive sensors at individual facilities (*33*, *34*) or mounted on ground-based work trucks (*35*), and in situ remote-sensing approaches using tower networks, aircraft, or satellites (*36*). Over time, the development of less failure-prone systems would be expected through repeated observation of and further research into common causes of abnormal emissions, followed by reengineered design of individual components and processes.

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SUPPLEMENTARY MATERIALS

www.sciencemag.org/content/361/6398/186/suppl/DC1
Materials and Methods
Additional Author Disclosures
Figs. S1 to S11
Tables S1 to S12
References (*37*–*77*)
Databases S1 and S2

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Science

Assessment of methane emissions from the U.S. oil and gas supply chain

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Science, 361 (6398),

A leaky endeavor

Considerable amounts of the greenhouse gas methane leak from the U.S. oil and natural gas supply chain. Alvarez *et al.* reassessed the magnitude of this leakage and found that in 2015, supply chain emissions were #60% higher than the U.S. Environmental Protection Agency inventory estimate. They suggest that this discrepancy exists because current inventory methods miss emissions that occur during abnormal operating conditions. These data, and the methodology used to obtain them, could improve and verify international inventories of greenhouse gases and provide a better understanding of mitigation efforts outlined by the Paris Agreement.

Science, this issue p. 186

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SC_000392

EXHIBIT 8

L.A. Times Editorial, *A Billion-Dollar Settlement Can't Erase the Aliso Canyon Methane Blowout*

OPINION

Editorial: A billion-dollar settlement can’t erase the Aliso Canyon methane blowout

Protestors hold hands as they were arrested by LAPD for failure to disperse after residents staged a sit-in blocking the entrance to the SoCal Gas Company Aliso Canyon facility in Porter Ranch in 2017 to mark the two-year anniversary of the gas leak. (Los Angeles Times)

BY THE TIMES EDITORIAL BOARD

SEPT. 29, 2021 5 AM PT

With the announcement Monday that Southern California Gas and its parent company will pay up to $1.8 billion to settle claims of residents and businesses affected by the 2015 Aliso Canyon blowout, it's worth remembering just how much the disaster rocked the Porter Ranch community.

What was initially reported as a small routine leak at a little-known underground natural gas storage field turned out to be the largest methane leak in U.S. history — right next to a residential community.

The impact was felt immediately. The sickening smell of the gas could be picked up for miles. People living and working in the area suffered from nausea, nosebleeds, rashes and breathing problems, among other symptoms. It was so bad that more than 8,000 families had to pack up and move temporarily. As the leak dragged on, an oily mist fell on the surrounding neighborhoods, and residents were warned to stay inside. Schools were relocated for a period to get kids farther from the blowout.

It took four months for SoCalGas to plug the well. By then, the leak had released more than 100,000 metric tons of methane, along with a cocktail of other chemicals, including toxic gas and particles. Methane is a potent greenhouse gas. The state has estimated the effects of the leak were equivalent to the carbon dioxide emissions released from burning more than 1 billion gallons of gasoline.

Even now, nearly six years later, some residents continue to suffer from nosebleeds, dizziness and respiratory problems. SoCalGas was required to pay $25 million for a study on short- and long-term health effects of the blowout as part of a 2019 settlement with city, county and state authorities. But the community is still waiting for Los Angeles County to start the study, and there are now concerns that analysis will be incomplete because the county will not compel SoCalGas to turn over data on the chemicals released during the blowout.

The $1.8-billion settlement is, by no means, a resolution of the Aliso Canyon saga. (The settlement itself is still tentative; it will be finalized if 97% of the 36,000 individual plaintiffs agree to the terms.)

Residents are still waiting for clarity on what will happen to the gas field. Then-Gov. Jerry Brown's administration said in 2017 that the facility's natural gas storage would be phased out in a decade. Gov. Gavin Newsom announced in 2019 that he wanted to fast-track the shutdown. But the California Public Utilities Commission is studying what it will take to close Aliso Canyon no *sooner* than 2027 — or as late as 2035, a decade before California is supposed to transition to 100% clean power. The PUC is also considering letting SoCalGas increase gas storage at the Aliso field above current levels.

Newsom cannot back down on his promises. California has to move much faster to reduce its dependence on natural gas and eliminate the need for Aliso Canyon's gas storage.

Residents affected by the blowout deserve every penny of compensation from SoCalGas. But let's be clear — the settlement won't return the sense of security and peace that people felt in their homes before the blowout. The money doesn't erase the environmental impacts from the blowout. And it doesn't absolve California leaders of fulfilling their promises to the community.

OPINION EDITORIALS

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OPINION

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Nov. 11, 2021

EXHIBIT 9

N.Y. Times Article, Lisa Friedman, *Biden Administration Moves to Limit Methane, a Potent Greenhouse Gas*

Biden Administration Moves to Limit Methane, a Potent Greenhouse Gas

The new rule was announced at a U.N. summit where the United States is facing skepticism about its commitment to climate change.

By Lisa Friedman

Published Nov. 2, 2021 Updated Nov. 5, 2021

GLASGOW — The Biden administration said Tuesday that it would heavily regulate methane, a potent greenhouse gas that spews from oil and natural gas operations and can warm the atmosphere 80 times as fast as carbon dioxide in the short term.

For the first time, the Environmental Protection Agency intends to limit the methane coming from roughly one million existing oil and gas rigs across the United States. The federal government previously had rules that aimed to prevent methane leaks from oil and gas wells built since 2015, but they were rescinded by the Trump administration. Mr. Biden intends to restore and strengthen them, aides said. Older oil and gas rigs tend to leak more methane than new systems.

The announcement came as more than 100 nations around the world joined together at a United Nations climate change summit here to promise to curb global emissions of methane 30 percent by 2030. If they succeed, that will be the equivalent of eliminating emissions from every car, truck, airplane and ship, said Fatih Birol, executive director of the International Energy Agency.

“This is huge,” Mr. Birol said at an event where countries outlined their methane plans.

President Biden called the agreement a “game-changing commitment” and insisted the new efforts will help create jobs to manufacture technologies for methane detection while employing pipefitters and welders to cap abandoned wells and plug leaking pipelines.

“It’s going to boost our economies,” he said.

Mr. Biden is in Glasgow this week for a United Nations climate summit, where he is trying to persuade other countries to reduce emissions from fossil fuels that are heating the planet to dangerous levels.

The methane announcement comes as Mr. Biden faces intense pressure both internationally and at home to show that the United States, the nation that has pumped the most greenhouse gases into the atmosphere, is serious about mitigating climate change.

Mr. Biden has set an aggressive target of cutting the emissions produced by the United States this decade about 50 percent below 2005 levels, but legislation to help him meet that goal is stalled in Congress. That leaves the administration to rely on regulations and other executive action.

The White House on Tuesday also announced other new climate initiatives, including a plan to protect tropical forests and a push to speed up clean technology.

In addition to the rule proposed by the E.P.A., the U.S. Department of Transportation introduced a regulation to reduce methane leaks from natural gas pipelines, and the U.S. Department of Agriculture announced it will work with farmers and ranchers on ways to reduce methane from livestock.

The centerpiece, however, is the proposed E.P.A. regulation on methane.

Methane is the second most abundant greenhouse gas after carbon dioxide, and it’s responsible for more than a quarter of the warming the planet is currently experiencing. It dissipates from the atmosphere faster than carbon dioxide but is more powerful at heating the atmosphere in the short run.

An odorless, colorless, flammable gas, methane is produced by landfills, agriculture, livestock and oil and gas drilling. It is sometimes intentionally burned or vented into the atmosphere during gas production.

As concentrations of methane in the atmosphere have increased, environmentalists have grown increasingly concerned about its role in climate change.

According to the E.P.A., the regulation, once finalized, will reduce 41 million tons of methane emissions from 2023 to 2035, the equivalent of 920 million metric tons of carbon dioxide. That is more than the amount of carbon dioxide emitted from all U.S. passenger cars and commercial aircraft in 2019, the agency said.

President Biden at the opening session of the COP26 summit on Monday. Mr. Biden said that 70 countries had joined a coalition to cut methane levels 30 percent by 2030. Erin Schaff/The New York Times

But Republicans in Congress said Mr. Biden's promises in Glasgow would hurt Americans at home. "The president wants to kill abundant and affordable U.S. energy sources like oil, natural gas and coal that Americans depend on," Senator John Barrasso, Republican of Wyoming, said in a statement. He called the White House plans "a recipe for disaster" that would lead to a shortage of affordable energy.

Senator Shelley Moore Capito, Republican of West Virginia, criticized the methane regulations saying they "demonize an industry that is part of the lifeblood of our economy."

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- Vanessa Nakate, speaking for a leery youth movement, offers a challenge: 'Prove us wrong.'
- Nations battered by climate change are demanding compensation from the big polluters.
- Iran says economic sanctions are hindering the country's efforts to fight climate change.

The oil and gas industry is divided over the methane regulations.

David Lawler, the president of BP America, said in a statement that the oil company "applauds" the new rules. The company called the move "a critical step toward helping the US reach net zero by 2050 or sooner" and said regulating methane emissions will help prevent leaks.

Karen Harbert, president of the American Gas Association, which represents some of the country's largest gas utilities, said her group supported new federal regulations.

Ms. Harbert noted that methane emissions from natural gas had declined 73 percent since 1990. But, she said, "we recognize we need to button up and get to that last percentage." She called regulation "the best possible approach" to creating standard rules across the industry.

Small oil and gas producers, however, are worried that the new rules will create onerous burdens that will put them out of business. The American Petroleum Institute hedged, saying in a statement that it supports the regulation of methane but is refraining from commenting on the new rule.

The proposed regulations could take time to put in place, are likely to face legal challenges and could be reversed by a future administration, observers say.

“As a president tries to use unilateral executive powers, there are immediately a set of hurdles,” said Barry Rabe, a professor of environmental policy at the University of Michigan. “It’s not going to be an easy transition.”

In addition to reducing greenhouse gases, regulating methane will protect public health, E.P.A. officials said.

When methane is released into the atmosphere, it is frequently accompanied by hazardous chemicals like benzene and hydrogen sulfide. Exposure to those pollutants has been linked to serious health problems including asthma and cancer.

Sue Franklin knows the effects firsthand. She and her husband, Jim, used to live in the West Texas town of Verhalen, where oil and gas drilling operations took off around 2014.

Gases leaked from two new wells and gave the couple headaches, nosebleeds and asthma attacks.

The Franklins eventually moved about 40 miles away, but Ms. Franklin, 70, said she feared she would have respiratory problems for the rest of her life.

“It’s never going to get better; the damage has been done,” Ms. Franklin said when she and her husband traveled to Washington, D.C., to protest new fossil fuel projects. Ms. Franklin said she thought new regulations governing oil and gas wells would help, but only up to a point.

“We were the lucky ones,” she said. “We got out. Other people still live with this. I’d like to see them actually shut down.”

The oil and gas industry is united against a separate effort in Congress to impose a fee on methane leaks from oil and gas wells as part of a broader budget bill.

The methane fee is designed both to raise revenue and to lower greenhouse pollution. Experts said that the double-pronged approach was necessary to shut down methane emissions.

The fee would apply to the largest oil and gas companies, those that emit more than 25,000 tons of greenhouse gases each year. Those companies would pay $900 per ton of leaked methane starting in 2024, ramping up to $1,500 per ton from 2026 through 2030.

Oil and gas producers are lobbying hard to remove the methane fee from the legislation that is pending on Capitol Hill.

Anne Bradbury, chief executive of the American Exploration and Production Council, which represents oil and gas companies, said: “This new, poorly constructed natural gas tax, on top of regulatory costs being imposed through compliance with forthcoming E.P.A. methane rules, would be additional costs and punitive taxes that would disadvantage American producers, increase Americans’ energy costs and cause 90,000 jobs lost across the country.”

She called the E.P.A. regulatory process “the appropriate way to address methane emissions in the U.S.”

Methane regulations have a fractured history in Washington.

President Barack Obama first proposed rules to reduce methane from new and modified gas wells in 2016, and finalized them on his way out of office. Republicans tried but failed to kill them in 2017 by using an obscure law known as the Congressional Review Act, which allows lawmakers to overturn rules within 60 legislative days after they are finalized.

The Interior Department and the E.P.A. repealed Mr. Obama’s methane regulations as President Donald J. Trump was leaving office.

In April, Democrats tried their hand at deploying the Congressional Review Act and were successful, voting to kill Mr. Trump’s rollback.

According to the E.P.A., the proposed rule will create a monitoring program under which companies will be required to find and fix methane leaks, often called “fugitive emissions,” at new and existing well sites and compressor stations.

Mark Brownstein, a senior vice president at the Environmental Defense Fund, said the technology to reduce methane emissions exists. Operators can install vapor recovery systems in storage tanks, make sure pressure relief valves don’t get stuck open and replace leaking pipes.

“This is not about rocket science,” Mr. Brownstein said. “This is auto mechanics.”

Coral Davenport contributed reporting.

EXHIBIT 10

L.A. Daily News Article, Olga Grigoryants, *6 Years After Disastrous Aliso Canyon Gas Leak, Officials Vote Unanimously to Expand Facility*

NEWS • News

6 years after disastrous Aliso Canyon gas leak, officials vote unanimously to expand facility

The proposals, officials said, were part of the agency's plan to eventually close the facility in the most effective way. Nonetheless, nearly 40 residents and activists called the agency, urging lawmakers not to increase the size of the field.

New homes in the Hillcrest development in Porter Ranch on Tuesday, August 17, 2021. (Photo by Dean Musgrove, Los Angeles Daily News/SCNG)

By **OLGA GRIGORYANTS** | ogrigoryants@scng.com | Los Angeles Daily News

PUBLISHED: November 4, 2021 at 1:01 p.m. | UPDATED: November 8, 2021 at 8:37 a.m.

A state agency that oversees operations of the Aliso Canyon underground natural gas-storage field — site of the nation's largest-ever methane leak six years ago — voted unanimously Thursday, Nov. 4, to increase the capacity of the field to 41 billion cubic feet.

Related: Major developments in the Aliso Canyon gas leak

The 2015 blowout released about 100,000 tons of methane and other chemicals into the air, sickening scores of residents and forcing them to relocate temporarily. Hundreds of lawsuits were filed, cascading into a $1.8 billion accord last month when Southern California Gas Co. and its parent company, Sempra Energy, agreed to settle the claims filed by nearly 36,000 clients. Nearly 97% of 36,000 plaintiffs need to sign up the agreement for the settlement to move forward.

On Thursday, CPUC Commissioner Martha Guzman Aceves said that she felt "compelled to propose the increase" of the storage capacity of the field from 34 billion cubic feet to 41 billion cubic feet ahead of the arrival of winter.

She added that the action the board was taking didn't mean "to diminish our ability to take steps and all of the steps that we need to take to decommission" the Aliso Canyon field.

The facility has been operating since 2018 at about 50% of capacity. Officials called Thursday's decision an effort to ensure that the regional energy supply would be sufficient for consumers during the upcoming colder months.

Commissioners considered two proposals for the field's increase:

–The plan that was approved will allow the utility to increase its storage capacity to 41 billion cubic feet, about 60% of its capacity.

–The proposal rejected would have allowed the gas company to beef up its storage capacity to 68.6 billion cubic feet, which would be closer to 100% capacity.

CPUC Commissioner Guzman Aceves said in a statement ahead of the meeting that bringing the capacity to 41 billion cubic feet limit would be "safe and reliable."

She added that while the agency was planning to reduce or eliminate the use of Aliso Canyon by 2027 or 2035, or anytime in between, the increase in storage capacity will help the region to get through the winter.

The news about the proposals comes as the agency, public officials, San Fernando Valley residents and environmental activists all wrestle over the future of the facility, the largest gas storage facility of its kind in California.

A representative with SoCalGas said in a statement that "with projections for higher than normal natural gas prices nationwide and repair work on an interstate pipeline limiting natural gas supplies to our region, SoCalGas storage facilities, including Aliso Canyon, will play a key and essential role in delivering reliable energy and keeping energy prices stable for Southern Californians this winter."

She added: "In the last two years, Aliso Canyon has provided support to the region's electric and gas systems on more than 150 days. The use of this facility has helped keep energy prices stable and prevent outages during periods of peak energy demand."

During Thursday's meeting, residents who live near Aliso Canyon said they still smell gas and have been haunted by memories of the disastrous 2015 leak that forced them to flee their homes. One Porter Ranch resident said she feared to open her windows and felt like she lived in a prison because of that. Another caller said thinking about potential Aliso Canyon expansion made him experience emotional distress.

Helen Attai, a resident of Granada Hills called the Aliso Canyon site dangerous and asked commissioners to vote against expanding the field.

"It's gonna be more withdrawals and more injections," she said. "Every time there's an injection, we get affected by that."

Food & Water Watch's California Director Alexandra Nagy said that "allowing any increase in storage capacity at SoCalGas' Aliso Canyon facility is not only dangerous; it is needless. SoCalGas and its shareholders are the only ones who profit from this disastrous glut of natural gas in the backyard of their ratepayers."

Los Angeles City Councilman John Lee, whose district includes communities impacted by the gas leak, said "the PUC decision today is disappointing and the complete opposite of what our state leaders owe this community. The gas leak at Aliso six years ago upended the lives and tens of thousands of residents. I will continue to stand with our community and demand for the expedited closure of this facility."

U.S. Senators Alex Padilla and Dianne Feinstein issued a joint statement ahead of the vote, calling the state agency to draft a plan to permanently phase out the facility while ensuring uninterrupted utility services.

"It is increasingly clear that we must close this facility in order to protect the safety of Californians. It is critical that the California Public Utility Commission outline concrete steps to close this facility while ensuring the reliability of our power grid as we continue the transition to cleaner electricity, heating and cooling," the statement said.

Congressman Brad Sherman also sent a letter to the CPUC, saying the decision to increase the working gas storage capacity at Aliso Canyon was "a poor indication of the progress towards the closure of Aliso Canyon, that the commission is this week entertaining proposals for expanding its use. Rather than increase pressure within the same facility that six years ago became the site of the nation's largest methane blowout, I urge you to act swiftly and to take additional measures to permanently close Aliso Canyon."

Following the leak, former Gov. Jerry Brown directed the CPUC to come up with a plan to close the facility by 2027. Gov. Gavin Newsom endorsed the decision in 2019.

In September, SoCalGas agreed to a settlement payout of $1.8 billion to the 36,000 plaintiffs involved in litigation against the utility spurred by the mammoth 2015 blowout.

At a recent press conference devoted to the six-year anniversary of the gas leak, Senator Henry Stern, who represents communities impacted by the blowout,said the settlement was good news for the victims impacted by the leak but the risks remained while Aliso Canyon remained open.

“To assume that that’s the end of the problem is a big mistake,” he said. “It’s not just for the people of the North Valley, it’s for the entire state of California and the future of climate policy. This CPUC decision will just be one more test of our will to actually shut Aliso Canyon down. I don’t want to see the public utility commissioners further add weight to the lie that we depend on fossil fuels and we will be lost without them.”

Tags: business, Community, energy, Environment, government, Health, San Fernando Valley, Top Stories Breeze, Top Stories IVDB, Top Stories LADN, Top Stories LBPT, Top Stories PSN, Top Stories SGVT, Top Stories WDN, utilities

Olga Grigoryants | Reporter

Olga Grigoryants is a multimedia reporter focusing on urban development, business and culture. She also supports the paper in its watchdog role to hold San Fernando Valley power players accountable and loves digging for public records. After studying writing in Moscow, she moved to Los Angeles in 2007 and has called it home ever since. She earned her master’s degree from the USC Annenberg School for Communication and Journalism, and has published articles with Reuters, Bloomberg, the Los Angeles Business Journal and LA Weekly. Along the way, she picked up awards from the Los Angeles Press Club and Society of Professional Journalists. If you want to get on her bright side, she loves a perfect cup of matcha latte.

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L24

Webster, McKinsey & Lea
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Mr. Eric Krause
Glendale Community Development Department
633 E. Broadway, Room 103
Glendale, CA 91206

10 November 2021

Re: Comments on the 2019 IRP and Partially Restated Draft EIR

Dear Mr. Krause,

Please find attached our comments regarding the subject documents.

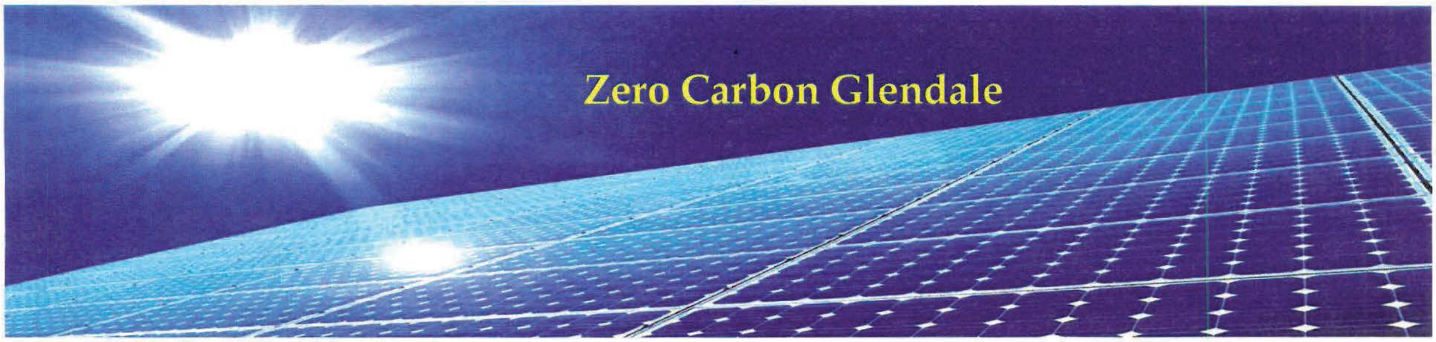
We advance 13 arguments as to why the EIR should not be approved by the City Council. In essence these arguments show:

1. Excessive generation of Greenhouse Gas emissions both locally and from imported fossil-fuel energy right up to 2045 in violation of SB 100. L24-1
2. Insufficient Battery Storage to meet reliability requirements and ancillary service needs.
3. No efforts by GWP to secure additional transmission resources, which they maintain is necessary to achieve a 100% clean electric grid for Glendale.

We look forward to GWP's response to these arguments and to the many other questions raised by the GEC, the Sierra Club, and the many concerned residents of Glendale who are looking for leadership and a path to Zero Carbon Glendale.

Best Regards,

Glenn T. Webb



Arguments Against Approval of the "Partially Recirculated Draft Environmental Impact Report" and the Associated "Integrated Resources Plan for Grayson Repowering"

Prepared by
Webster, McKinsey & Lea
10 November 2021

L24-2

Anything else you're interested in is not going to Happen if you can't breathe the air and drink the water. Don't sit this one out. Do something.

CARL SAGAN

Our cover depicts the largest residential solar installation in Glendale. It happens to be that of the author, who is a firm believer that our energy future lies with the sun, the original source of all of our energy, past, present and future. It is best that we commit to using its energy directly (as solar, wind, geothermal, and hydro) instead of poisoning our planet by continuing to burn fossil fuels.

L24-2

Forward

The Grayson Power Plant has served the electric energy needs of Glendale for over 70 years, but it cannot continue to meet those needs in the coming years without major change. Reliability concerns of an aging plant and the environmental concerns of continuing to burn fossil fuels to generate electric energy demand that we reimagine our approach to the delivery of electric energy to Glendale residents. SB100 requires that the electric energy generation and distribution system of California be 100% Zero Carbon by 2045, and that date is likely to be moved earlier in coming years. ***The time for us to act is now.***

GWP's current 2019 Integrated Resources Plan is a start, but it will get us only to 68% renewables by 2030 and offers ***NO plan to get us to zero carbon by 2045***. Its first major failing is a ***lack of planning for new transmission*** which GWP (and all others who have studied the issue) acknowledge is necessary to achieve zero carbon electric energy delivery in Glendale. Its second major failing is in ***lack of planning for local storage***; the currently planned 300 MW hours is completely inadequate to achieve the required level of reliability and provide the ancillary services necessary to deliver electric energy to the City. The third major failing is ***continued reliance on fossil fuels*** (up to 35% of our total generation and import) right up to December 31, 2045) These three major failings must be addressed immediately if we are to achieve our clean air goals and comply with State Law. L24-3

This document presents arguments as to why the current **"Partially Recirculated Draft Environmental Impact Report"** and the associated **Integrated Resources Plan** for Grayson Repowering ***should not be approved*** by the Glendale City Council. Instead, the Council should direct GWP to prepare a plan showing a clear path to a zero carbon electric grid for Glendale by 2035, as have most jurisdictions in the U. S. (or **at the very least by 2045 to comply with California Law.**

Respectfully Submitted to the City of Glendale, 10 November 2021

Webster, Mckinsey & Lea

Glenn T. Webb, Chief Scientist

gtw@ZeroCarbonGlendale.com

818-241-7436

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Argument 1 – The GWP Plan and associated PR/DEIR are Non-Compliant with State Law

The Requirements of SB100 ("The 100 Percent Clean Energy Act of 2018") are quite clear:

"The Legislature finds and declares that the Public Utilities Commission, State Energy Resources Conservation and Development Commission, and State Air Resources Board should plan for 100 percent of total retail sales of electricity in California to come from eligible renewable energy resources and zero-carbon resources by December 31, 2045."

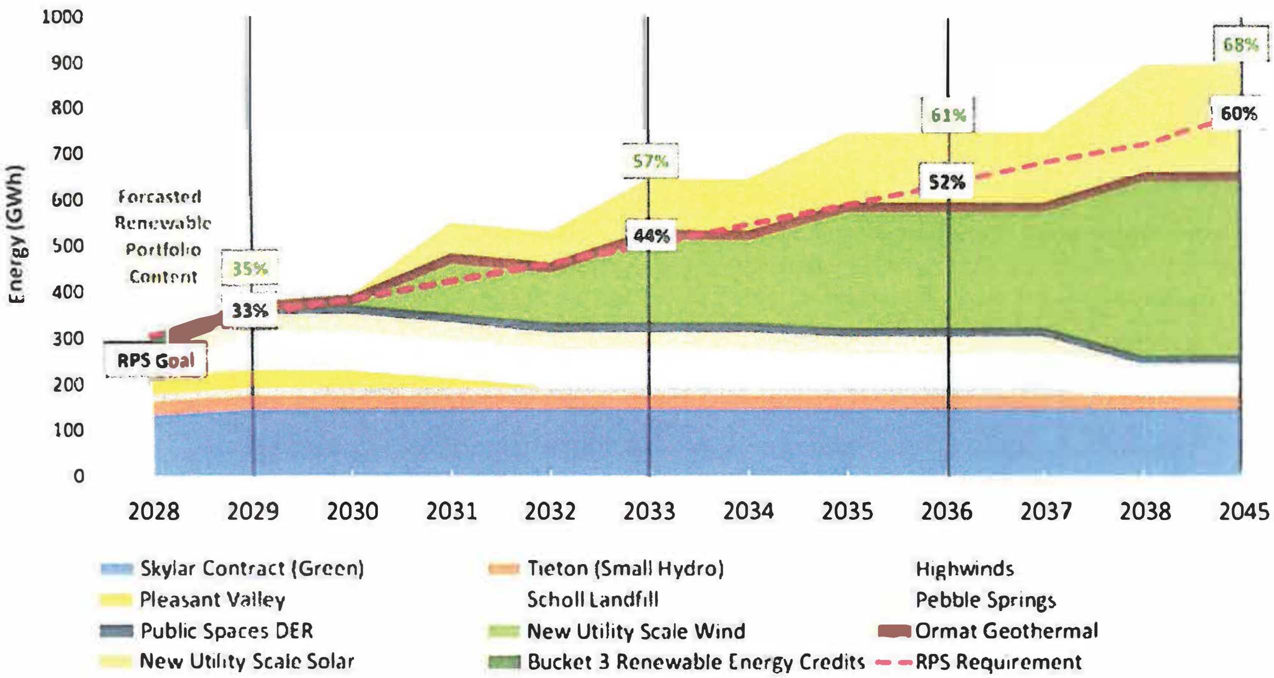
A cursory look at GWP's plan (figure 1 from the 2019 IRP, shown on the facing page, clearly shows that GWP has no intention of complying with this State law. Recent actions by GWP (such as contractually obligating the City to purchase fossil-fuel generated energy from the repowered Intermountain gas project through the year 2077) lend further evidence to this conclusion. L24-5

A further statement (page 23 of the 2019 IRP) that: "Carbon-free retail sales by 2045 … translates to approximately 90% Green-House-Gas free total energy when accounting for system losses." is incomprehensible, incorrect and completely absurd. It misstates both the letter and the intent of SB100 and purports to say that somehow ***energy delivered to retail customers and energy consumed by system losses (about 7% in Glendale, and about 3% on our incoming transmission lines) are different, and that the energy consumed by system losses can be fossil-fuel derived.***

GWP has spent millions of dollars in studies and planning, and the current state of the art of that planning, the 2019 IRP, gets us to only 60-68% renewables by 2045 (12% more when zero-carbon Hoover and Palo Verde are considered). ***In what mathematical universe does 72-80% equal or exceed a goal of 100%?*** Very recently, consulting contracts were extended by hundreds of thousands of dollars ***with no requirement to produce a zero-carbon plan. It is time for this complete waste of City funds to end!***

A Zero-Carbon Glendale Plan is Needed Immediately. Zero-Carbon 2045 is the Minimum Acceptable, Zero-Carbon 2035 is Achievable

Figure 1: Exceeding Renewable Goals



L24-5

The GWP IRP Does Not Exceed Renewables Goals
And It Does Not Meet SB100 Requirements for Zero Carbon at 2045

Argument 2 – The amount of fossil-fuel energy which GWP will generate and import through 2045 is misrepresented in the IRP and PR/DEIR

Over the past 10 years GWP has been generating ***(with fossil fuels) or importing*** 500 GW hrs more of energy annually than is needed by Glendale and selling this excess energy on the wholesale market at a significant financial loss to the City. There are valid reasons for such action in a fossil-fuel oriented energy environment. In a zero-carbon environment, required by 2045, this will no longer be permitted. In 2017, for example, we generated or imported 1,710 GW hrs of energy to service a Glendale load of only 1,062 GW hrs. Only 31% of the total was zero-carbon. GWP ***claims*** a much higher percentage of renewables or zero-carbon by completely ignoring the 522 GW hrs of our total energy supply which was sold to other utilities at a large financial loss to the City.

Why then does the practice persist at GWP? There are valid reasons to continue this practice in a gas-oriented electric utility environment: voltage and frequency regulation; long power-up and power-down times for large gas turbines; spinning reserve requirements; and "take or pay" clauses in power purchase agreements among others. ***But These are fossil-fuel oriented reasons.*** L24-6

The fundamental underlying issue is that we have no storage in our system ***and no plan to add an optimum amount of storage to eliminate the need to generate or import excess fossil-fuel energy and sell it to other utilities.***

An optimally sized battery energy storage system is crucial to our clean energy goals.

We must stop burning fossil fuels to generate electric energy in Glendale and selling excess generation on the wholesale market. In the process we will save $ 45 M annually and eliminate 99% of the greenhouse gas emissions and pollutants we are currently adding to the environment.

GWP Energy -- Generation, Purchases, Sales

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	10-YEAR Average
Generated GW-hrs	940	960	928	847	794	905	918	914	876	826	891
Purchased GW-hrs	533	451	1196	1290	769	1000	1131	769	834	740	871
TOTAL	1473	1411	2034	2137	1563	1905	2049	1683	1710	1566	1753
Sold Retail GW-hrs (Glendale Usage)	1152	1102	1050	1094	1127	1061	1080	1090	1062	1048	1087
Sold Whsale GW-hrs (Outside Utilities)	204	186	885	898	297	683	687	461	522	404	523
TOTAL SALES GW-hrs	1356	1288	1935	1992	1424	1744	1767	1551	1584	1452	1609
System Losses GW-hrs	117	123	99	145	139	161	282	132	126	114	144

L24-6

Source: Comprehensive Annual Financial Report, City of Glendale, 2018

GWP Energy -- Costs & Revenue (2017)

Energy Type	Energy Giga-Watt hrs	% of TOTAL	Cost / Revenue ($Millions)	% of TOTAL	Cost / Revenue (¢ per kW hr)
Generated Fossil Fuel	876	51%	$ 68 M	71%	12.8 ¢ per kW hr
Purchased Fossil Fuel	311	18%	$ 11 M	12%	3.6 ¢ per kW hr
Purchased Zero Carbon	523	31%	$ 16 M	17%	5.4 ¢ per kW hr
TOTAL	1710	100%	$ 95 M	100%	5.6 ¢ (Average)
Sold Retail (Glendale Usage)	1062	62%	$ 199 M	91%	18.7 ¢ per kW hr
Sold Wholesale (Other Utilities)	522	31%	$ 20 M	9%	3.8 ¢ per kW hr
System Losses	126	7%			
TOTAL	1710	100%	$ 219 M	100%	

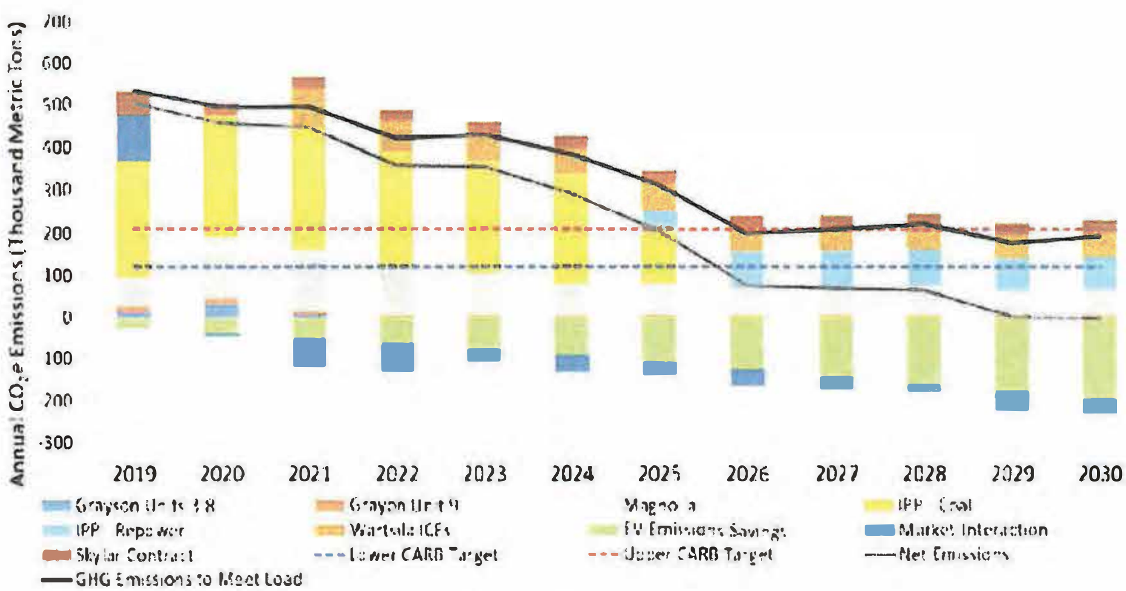
Argument 3 – With the IRP 2019 and associated PR/DEIR GWP Continues its Practice of fossil fuel Overgeneration and Falsely Claims Compliance with CARB GHG Emissions Limits.

Figure 3 from the IRP shows GWP's projected GHG emissions from its fossil fuel energy production, both local and imported. Please observe the 2030 projection, which shows generation of GHG at 250,000 metric tons. Using the EPA equivalency standard of 1022 pounds (0.46 metric tons) CO2 per MegaWatt hr delivered energy, this equates to 543 GW hrs of fossil fuel energy generation, somewhat more than the average of the previous 10-year period or 523 GW hrs per year. ***Is This Progress?***

A further misrepresentation in the figure is GWP's treatment of EV's and tailpipe emissions. Please observe the green bar in the 2030 section of figure 3. This segment represents 200,000 metric tons of GHG emissions which GWP mysteriously claims credit for avoiding. It is as if these EV's are driving around the City sucking up 200,000 metric tons of GHG per year and getting rid of them. The reality is quite the contrary. Not only do the EV's not remove GHG's, but tailpipe emissions are not a factor in the EIR evaluation of a new gas plant in Glendale. Furthermore, ***every MW hr of the energy these EV's use must be generated locally or imported, and our use of locally generated or imported fossil fuel based energy is increasing not decreasing.*** L24-7

We must again emphasize that GWP's continued use of the rationale that only energy delivered to "retail" customers need be zero carbon is just that: An EXCUSE for its fossil-fuel emphasis in planning. This, along with other false statements such as "We need new gas to firm the nature of the renewables we want to import", is doing nothing but delaying our planning for the main event, that of a 100% Clean Glendale electric grid.

Figure 3. Annual Greenhouse Gas Emissions



Annual greenhouse gas emissions from Market Purchases, Grayson, IPP, Magnolia, and ICEs are shown as positive bars on the graph above while an emissions savings from tailpipe emissions avoided through the adoption of EVs is shown as negative. Net emissions are shown through the gray line.

L24-7

Argument 4 – With the existing IRP 2019 and associated PR/DEIR GWP continues excessive Fossil Fuel generation with no plan to meet 2045 zero carbon goals and comply with SB100.

Figure 22 of the IRP shows Glendale's Green House Gas emissions for the years 2019 through 2038 for all seven alternate portfolios considered.

In 2019, for GWP's proposed Portfolio E, Glendale is responsible for 540,000 metric tons of GHG emissions or the equivalent of 1,174 GW hrs of electric energy generation. By 2030 this figure is reduced to 191,000 tons of GHG, showing definite progress. ***But from 2030 to 2038 GHG emissions rise from that 191,000 tons to 270,000 metric tons, well in excess of the CARB upper limit of 200,000*** metric tons.

L24-8

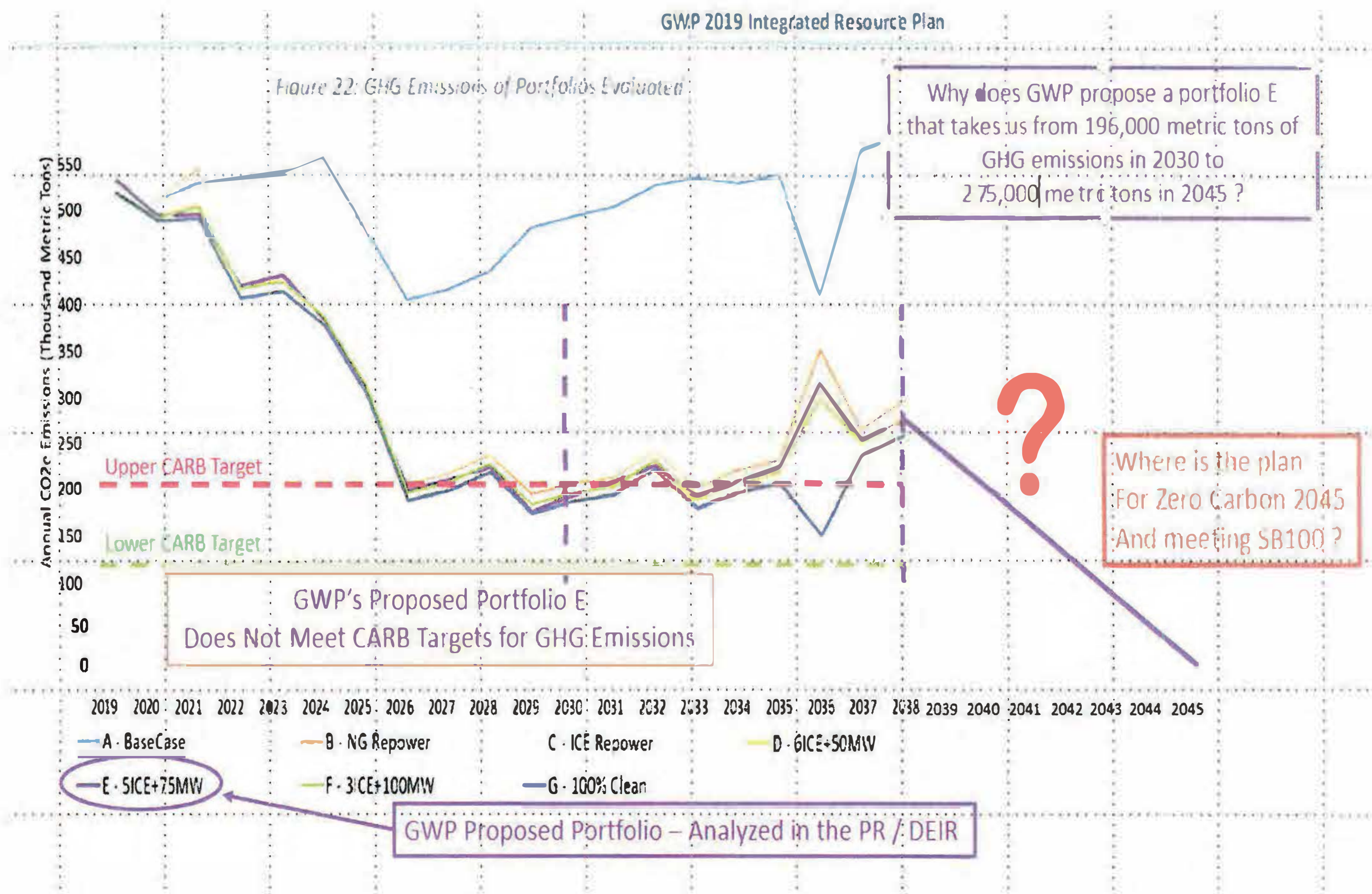
But What Then? How do we go from over 270,000 metric tons of CO2 emissions per year in 2038 to Zero in the next seven years? What magic will occur on New Year's Eve of 2045

to bring us in compliance with SB100 ?

GWP rationalizes this approach by stating that only energy delivered to meet our retail load need be "counted" in the zero carbon requirement. ***But where will there be a wholesale market for this fossil fuel energy*** when the entire California grid becomes zero carbon in 2045***? Will we build new transmission lines to states where fossil fuel energy is still permitted?***

A further curiosity of GWP's approach is that the so called "100% Clean" alternative is still emitting 250,000 metric tons of GHG up to their planning horizon of 2038, a clear indication that GWP is not serious about looking at alternatives to Plan E.

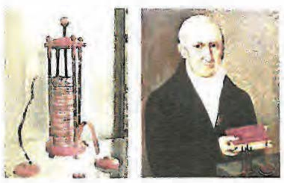
It is premature and irresponsible to approve any plan (and associated EIR) that does not get us to zero carbon by 2045



GWP 2019 Integrated Resource Plan
Figure 22: GHG Emissions of Portfolios Evaluated
Why does GWP propose a portfolio E that takes us from 196,000 metric tons of GHG emissions in 2030 to 275,000 metric tons in 2045 ?
Annual CO2e Emissions (Thousand Metric Tons)
550
500
450
400
350
300
250
200
150
100
50
0
Upper CARB Target
Lower CARB Target
?
Where is the plan For Zero Carbon 2045 And meeting SB100 ?
GWP's Proposed Portfolio E Does Not Meet CARB Targets for GHG Emissions
2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045
A - BaseCase
B - NG Repower
C - ICE Repower
D - 6ICE+50MW
E - 5ICE+75MW
F - 3ICE+100MW
G - 100% Clean
GWP Proposed Portfolio – Analyzed in the PR / DEIR

L24-8

Argument 5 – The IRP and PR/DEIR fail to analyze and optimally size the BESS in any of the alternate systems considered. The 300 MW hr battery in the proposed system is significantly undersized and will not provide the required reliability or Ancillary Services required for a modern, repowered Grayson.



The First Battery   Alessandro Volta

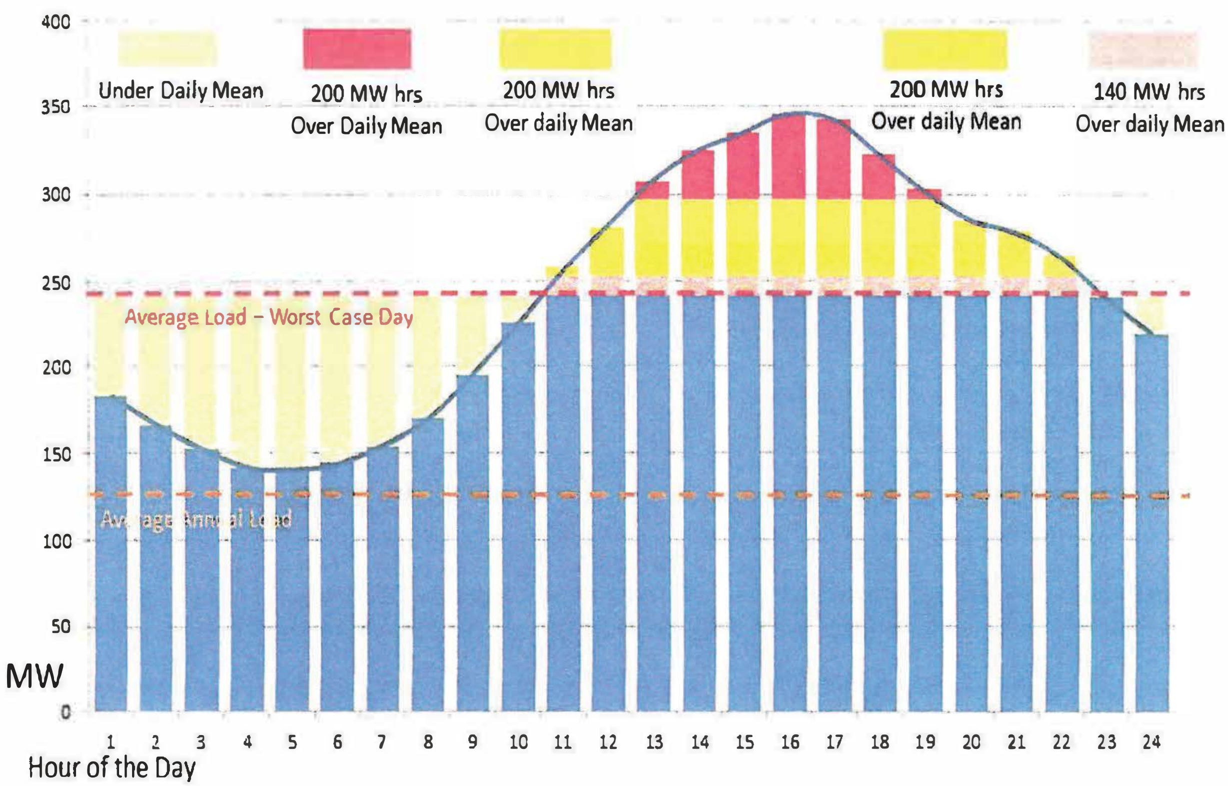
Since the invention of the battery in 1799 by the Italian physicist Alessandro Volta we have come a long way in battery technology. But only in the past few years has lithium ion battery technology become a practical and economical solution to many of the problems that have plagued fossil-fuel based power systems for a hundred years. Problems of voltage and frequency regulation, source/load balancing, long start-up times for gas turbines and boilers, emergency backup, and firming the intermittent nature of solar PV and wind energy are readily solved with an effective Battery Storage System. ***But how much battery is needed in an optimally sized system for Glendale?*** L24-9

Our current Grayson system met the needs of Glendale's worst-in-history day, September 1, 2017, on which we reached a peak load of 346 MW and a daily energy demand of 5,784 MW hrs. With no storage, the peak load of 346 MW must be met with import or local generation, and must be met in the presence of N – 1 – 1 failures (150 MW of source failure). ***The current system would have experienced significant blackouts had we experienced an N – 1 – 1 event at peak load.***

Adding battery to the system reduces the need to import or generate power to meet the peak power demand. Adding 300 MW hrs of storage (which is what is called for in the current IRP) reduces the peak import or generation need by about 50 MW, a small but meaningful start. Adding an additional 200 MW hrs, another 200 MW hrs, and a final 140 MW hrs brings the peak import or generation need down to the average power need for the worst–case day or 241 ***MW (a reduction in import or generation need of 105 MW)***. An additional increment of 25% must be considered to provide charge and discharge margins consistent with best reliability and longevity of the battery system. This brings us to the optimum sizing of 925 MW hours.

The optimum size for the BESS in Glendale's Zero-Carbon Electric System is 925 MW hours

Glendale -- Peak Power and Energy -- September 1 2017



L24-9

Argument 6 - Statements by GWP that a 300 MW hr battery sizing is the largest that can be charged with their proposed configuration E are not correct.

We have modeled the GWP configurations extensively to determine if the optimally sized battery system at 925 MW hrs https://www.msn.com/en-us/feedcan be charged with the proposed configuration E resources. For any system configuration our model determines three factors, ***all of which must be present,*** for the system to support Glendale's load at peak demand and in the present of N – 1 – 1 failures and avoid rolling blackouts:

1. Sufficient power (MW capacity) must be available at peak load.
2. Sufficient energy (MW hrs) must be available (either locally generated or Imported) each and every day of the year to support the load and to maintain battery charge.
3. Sufficient energy must be available annually to support the annual load. L24-10

With GWP's Portfolio E parameters ***and the 625 additional MW hrs of battery***, the system has excess capacity to meet the peak load, has excess energy available to meet the total annual load, but is slightly deficient in meeting the worst-case day energy need. We therefore added one additional 18.6 MW ICE to the configuration, which makes the system fully capable of avoiding blackouts on any worst-case day and maintaining battery charge.

If our newly-acquired Eland 25 MW comes with 25 MW of transmission capability ***(which it would seem to need for it to be usable in Glendale)*** then the additional 18.6 MW ICE unit would not be needed and GWP's portfolio E ***(with the addition of 625 MW hrs of battery)*** will serve our energy needs reliability ***although relying heavily on fossil fuel generation.***

An optimally sized BESS of 925 MW hrs of storage can be charged with GWP's configuration E and will prevent blackouts at peak load on worst-case days in the presence of N – 1 – 1 Failure Conditions.

	GWP Proposed Configuration E Performance -- 1,600,000 MW Hrs Annual Load Emergency operations -- 347 MW Peak Load, N - 1 - 1 Failures							
	2030 Resource	Power MW	Yearly Resource MW Hrs	Percent Yearly Resource	Storage MW Hrs	Daily Resource MW hrs	Worst-Case % Util.	Worst-Case Day Energy MW-Hrs
1	Pacific DC Intertie (N-1)	100	876,000	25%	0	2,400	0%	0
2	Magnolia (N-1-1)	48	420,480	12%	0	1,152	0%	0
3	Southwest Intertie LADWP	100	876,000	25%	0	2,400	100%	2,400
4	Grayson Rebuild (6 X ICE)	111	972,360	27%	0	2,664	100%	2,664
5	Grayson Battery	150	0	0%	925	0		0
6	New Transmission	0	0	0%	0	0	100%	0
7	Scholl LFG	12	105,120	3%	0	288	100%	288
8	Residential DER	13	113,880	3%	0	312	100%	312
9	Public Sps DER	10	87,600	2%		240	100%	240
10	BTM Residential & Commercial Solar	Load Reduction Only	0	0%	140	0		0
11	Efficiency & Demand/Response	27.9	87,600	2%				240
	Totals	544	3,539,040	100%	1065	9,456		9,456
	Totals(N - 1 - 1) Emergency Operations	396	2,242,560	63%		5,904	100%	5,904
	Required Resource	350	1,600,000			5,784		5,784

GWP Configuration E Performance with an additional 625 MW hrs of BESS

L24-10

Argument 7 – None of the Alternates of the IRP / PR/DEIR Consider Adding New Transmission to the System Design Approaches

GWP stated in the *2019 Integrated Resources Plan* :

"...getting to 100% Greenhouse Gas Free energy does not appear to be possible without additional transmission capacity."

Our studies indicate the same! If we cannot get to a zero-carbon electric utility without new transmission, then ***we must look to new transmission***, and we must begin immediately if we are to achieve this capability, even by 2045!

The ratepayers of Glendale paid Stantec millions of dollars to study this issue, and the results of that study were presented to the Council in February of 2018, ***along with GWP's recommendation to ignore them completely*** and build a new fossil fuel plant at Grayson. Pace / Stantec studied four potential approaches (and their costs) to gain new transmission for Glendale. The results are shown in the chart on the facing page. The conclusion of GWP, Pace, and Stantec: L24-11

Conclusion: "An interconnection between GWP Kellogg Substation and SCE Eagle Rock can provide 100 MW of capacity at a cost of $65,853,000. It is the most straightforward and viable of the interconnects studied based on engineering, constructability and environmental considerations. "

But their conclusion is not the whole story. All the players in the Southern California energy game are in the same boat. To one degree or another ***we all need new transmission and a better Statewide integration approach***. Many options other than the four studied by Pace and Stantec are available.

New gas is not only polluting and GHG emitting, but it is also 2-10 times as expensive as the development of new transmission. With Stantec's recommended approach, ***100MW of new transmission*** is available at a cost ***of $ 65 Million or $650 per kiloWatt.*** With GWP's preferred approach for repowering Grayson, 93 MW of ***new local fossil-fuel capacity (with 200MW hrs of battery)*** is available at a cost of ***$350 Million or $ 2,650 per kiloWatt.***

New Transmission -- Four Approaches

Source: GWP / Stantec/Pace IRP

Options	Description	Estimated Cost	Comments
1	Interconnection between GWP Kellogg Substation to step up transformer and connection to SCE Eagle Rock Substation Capacity about 150 MW	$65,853.000	The most straight forward and viable interconnection. Costly, depending on determination of mitigation measures required on existing facilities from Short Circuit Studies. Need space info from SCE on Eagle Rock Sub. Ranked1, based on engineering, constructability and environmental considerations.
2	Interconnection to SCE 220 kV Double circuit Eagle Rock- Sylmar Line Near Glorietta St and Oakmont. Capacity 150 MW	59.758,000	Interconnection facilities would be constructed on available land near Transmission line ROW. Space is limiting factor. Awaiting determination from SCE but may not be feasible.
3	Hillside above Cresenta Valley Park. A new Substation 220/69 kV, Similar to Option 2. 69 kV Overhead double circuit line from interconnection point to Western Substation.	$41,608,000	Space is available to meet SCE Bus Clearance Requirement. Environmental and Siting concerns. Mitigation of possible impacts to GWP and BWP Systems must be determined.
4	Rossmoyne Substation. Additional 69 kV breakers and 69 kV double circuit underground line in duct bank and step up transformer to connect SCE Eagle Rock Station	No Detailed Estimate Rough Estimate about $45,000,000	Additional breakers and Bus Connects would limit access to existing equipment in Rossmoyne Substation The three lines serving Rossmoyne from Kellogg are already loaded and would limit load Flow to SCE and back to Kellogg to about 100 MW

L24-11

Argument 8 – Other Options for New Transmission were not considered.

In Fact, No options for new Transmission were considered.

Options other than those studied by GWP / Pace / Stantec in 2016 for new transmission are available. Some are complex, and all involve extensive interface and cooperation with the other stakeholders in California (especially LADWP). The California Independent System Operator is the entity in California which is responsible for coordination, development, and operation of electric energy resources in our state. But Glendale is not a member of CAISO, and for some reason has avoided becoming involved with this organization for years.

Option 1 presented above would involve interface with SCE and likely mean joining CAISO. While there are pros and cons to joining CAISO, it is inevitable that all the power companies need the coordination and other benefit that CAISO provides. GWP cannot continue to operate as a self-described "island" in the midst of the state's push to zero carbon and with SB100 looming on the near horizon. ***This "isolation" mentality has led us to many false conclusions such as "We need a new 262 MW gas plant at Grayson to keep the lights on."*** L24-12

What really is needed is more communications and interchange with the other stakeholders in California to identify and participate in new transmission developments, of which there are many.

Right of way issues have been raised by GWP on many occasions over the past three years as major obstacles to obtaining or developing new transmission. ***But new transmission capability can be obtained without new right of way!*** Increasing transmission voltage can increase energy transmission up to five-fold within the same right of way. This does require significant upgrade of equipment (lines, transformers, inverters, switches, breakers, insulators, etc.), but has been employed successfully nationwide for years.

85 MW of new transmission is required in a Zero-Carbon Glendale System. GWP must take more initiative and immediately pursue new transmission capability. Without aggressive action we will never achieve a zero-carbon electric grid in Glendale.

New Transmission -- Other Options

L24-12

In the U. S. We are somewhat constrained to maximum transmission voltages of 500 kV (such as the PDIC) and that will not likely change for a long time due to the massive bureaucracies involved. But within California, we have more flexibility to upgrade lower voltage transmission to increase capacity without new rights of way.

Internationally, the situation is different. China is currently developing 800 kV and 1000 kV grids nationwide. Hundreds of billions of dollars are being spent in these developments, and Ultra-high-voltage grids are coming on line as we speak. With an upgrade to 1000kV on the Pacific DC Intertie, its ***capacity could increase four-fold with no new right of way.***

With the current administration's plan to spend up to $550 Billion on climate change initiatives we have a unique opportunity to capture funding to ease the transmission problems of Glendale and the rest of the West Coast. ***It won't be easy***. It will involve the Governors and Legislatures of California, Oregon, and Washington and ,obviously, a lot of hard work. But for the naysayers, who might maintain that such an undertaking is impossible, we have only to look at the original PDIC project ***which was completed in 1970 over the objections of nearly all of Southern California's electric energy producers.***

New Transmission options are available.

Argument 9 – GWP proposes import of 130 MW (nameplate) Solar and 130 MW (nameplate) of Wind and yet has transmission capability for only 200 MW total *or less.*

Nameplate power refers to the peak power which can be generated by the energy resource. GWP proposes to import a total of 260 MW nameplate of solar and wind power. Our only import transmission resources are the Pacific DC Intertie (at 100 MW) and the South West Transmission System (at 100 MW) for a total peak capacity of 200 MW. GWP has explained to the council and Glendale residents on numerous occasions that transmission capacity must be available to handle the peak nameplate generation capability of the renewable source. When the wind and solar systems are not generating at peak then the balance of transmission is not necessarily available to other energy resources. This is one of the reasons that GWP has always maintained that "We can not get to zero carbon without new transmission".

A good example of this dilemma of transmission availability is our use of the transmission capability that accompanies our participation in the Intermountain repowering project. GWP maintains that we participated in this new gas project in order to maintain a share in the transmission capability that comes with it. But we have no guarantees that this transmission capability will be available to us for import of zero carbon energy. After all, ***Intermountain will be a new gas facility, and GWP has committed to purchase their fossil fuel energy through 2077. Why would they permit this valuable transmission capability to be used to transmit someone else's energy products to their customers?*** L24-13

The "Proposed Resource Portfolio" also indicates Energy Efficiency and Demand Response resources as if they are energy generators. This is misleading. Although EE and DR are important in our future energy planning, They are not sources of energy; rather, they contribute to load reduction. They should not be included in any energy resource portfolio. This inclusion contributes to confusion when evaluating alternative resource portfolios, and leads to the many false conclusions reached in the IRP and PR/DEIR.

GWP does not have the transmission capability to import even the renewable or zero carbon energy resources they have included in their proposed portfolio E.

Table 1 Proposed Resource Portfolio

Proposed Portfolio Composition		
Candidate Resource		**Capacity (MW)**
Imported Renewable Resources	Residential DER	13
	Public Spaces DER	10
	Residential and Large Commercial LL+DR	7.5
	Small Commercial LL+DR	20.4
Imported Renewable Resources	Solar	32.5 (130 nameplate)
	Wind	52 (130 nameplate)
Storage	Battery Energy Storage System (BESS) (4 hour)	75
Conventional Generation	Internal Combustion Engines (ICE) (5x 18.6 MW)	93
Total		303 MW

Composition of Proposed Portfolio with nameplate capacities of selected resources and corresponding 20-year present value costs of assets (capital + O&M; fuel and emissions costs excluded). Description of how these costs were derived is included in section 5.3 Lifetime Present Value Costs.

L24-13

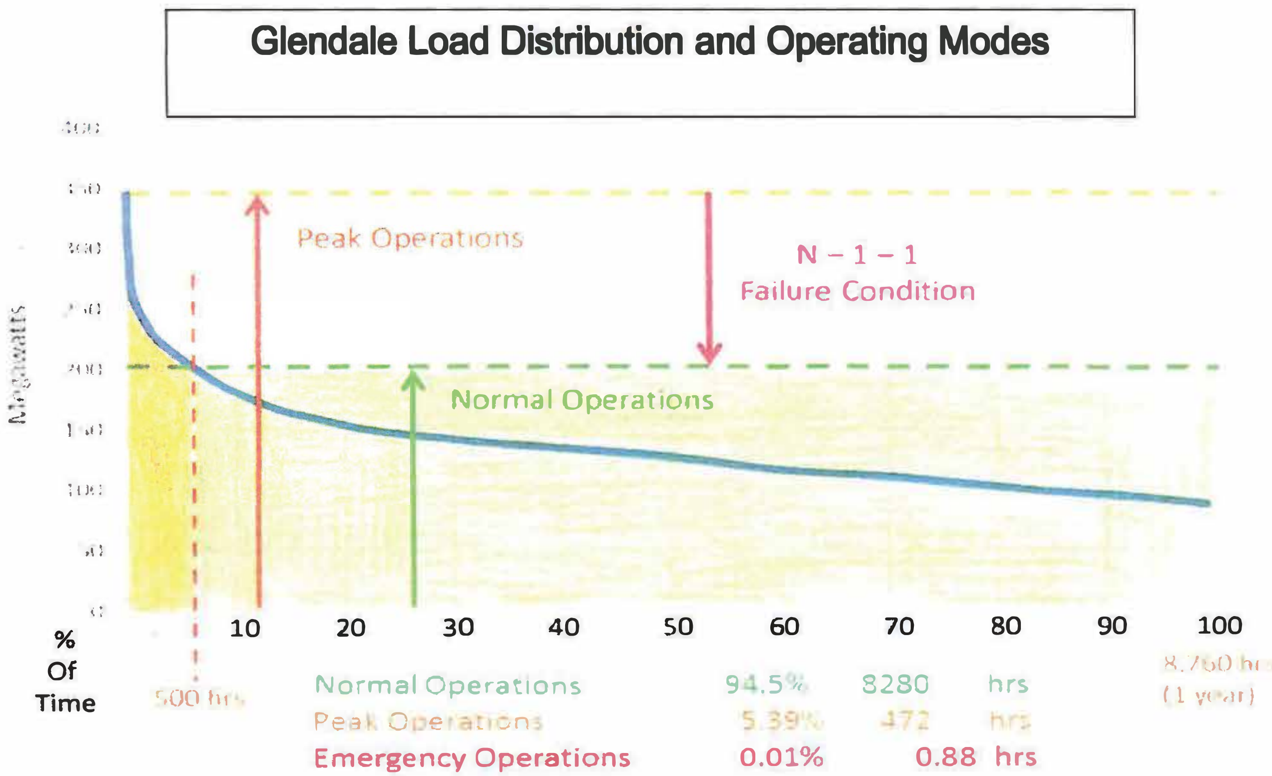
Argument 10 – GWP Plans for Excessive Use of Fossil Fuel Emergency Backup Generation As well as normal operations.

Glendale's electric power system operates with a load of 200 MW or more only 500 hours per year (5.4% of the time) which we define as peak operations. We define emergency operations as peak operations in the presence of an N – 1 – 1 failure event (150 MW of supply failure) which we estimate to occur less than 0.1% of the time or 8 hours per year. We must maintain full energy supplies to Glendale during these emergency conditions, but this ***need not be accomplished with zero-carbon energy. When GWP supply fails, hospitals, police stations, residential and commercial customers will turn on their generators.***

GWP's current 2019 Resources Plan calls for 93 MW of internal combustion engines to provide this emergency backup function. Unfortunately, in Argument 5, we show that GWP plans to make use of fossil fuel generation at over 500 GW hours per year (approximately one third of our energy needs) up through their planning horizon of 2038. A reasonable plan would show how emergency generation with fossil fuels could be limited to less than one per cent of the time. L24-14

An effective municipal power system must be designed with total reliability approaching that of the unavoidable outages such as blown transformers, downed power lines, mylar balloon encounters, and planned outages for maintenance. The state standard is 2.5 hours per year for an average customer. This equates to about 99.98% reliability.

With an optimally-sized battery storage system of 925 MW hrs, new transmission of 85 MW, and the currently planned 93 MW of emergency backup ICE generation, Glendale will experience a reliability of 99.98% (Loss of supply of less than 2 hours per year); fossil-fuel emergency generation will be needed less than 10 hours per year; and Unit 9 will not be needed at all.


Glendale Load Distribution and Operating Modes
Megawatts
Peak Operations
N – 1 – 1
Failure Condition
Normal Operations
10
20
30
40
50
60
70
80
90
100
% Of Time
500 hrs
8,760 hrs (1 year)
Normal Operations 94.5% 8280 hrs
Peak Operations 5.39% 472 hrs
Emergency Operations 0.01% 0.88 hrs

L24-14

Argument 11 – GWP Fails to consider Reasonable Alternatives to their proposed Approach as Required by the California Environmental Quality Act

L24-15

GWP's 2019 IRP once again sets out to prove that a zero-carbon system cannot meet system reliability requirements of less than 2.4 hours per year of loss of supply. The GWP approach is to design a system (Portfolio G, the so-called "100% clean" system that is designed from the start to fail in the flawed modeling programs of Ascend Analytics. The reason for this failure is simple. Their flawed strawman Portfolio G ***fails to provide any of the three critical elements*** which we have proven are needed in a successful zero-carbon system:

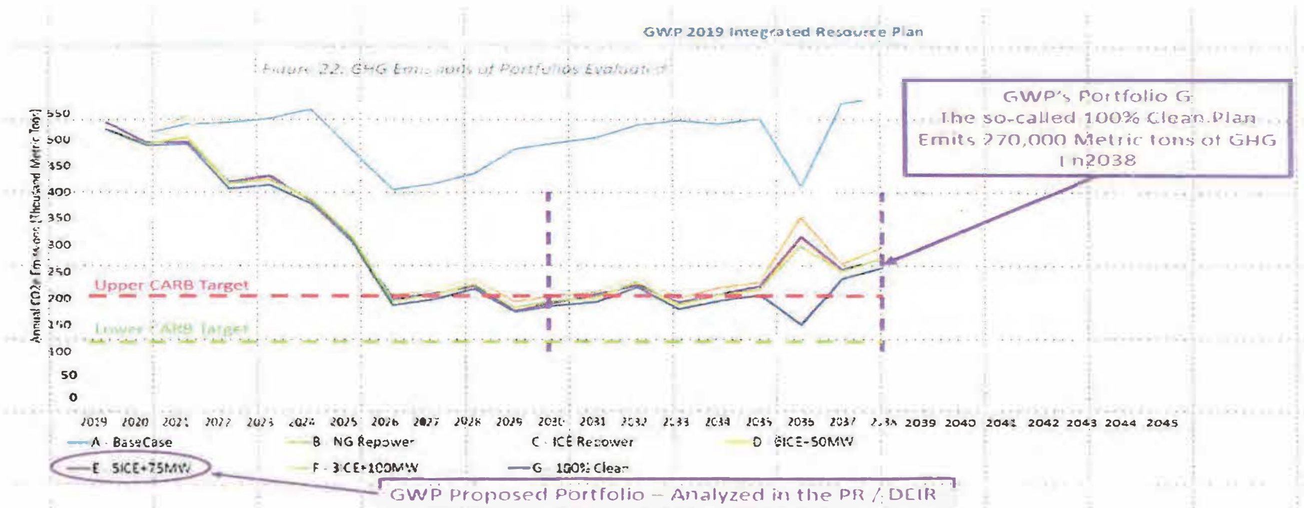
1. ***Sufficient Battery Storage (925 MW hrs)***
2. ***New Transmission (85 MW minimum)***
3. ***Sufficient Emergency Backup Generation (93 MW, with utilization of less than 1% per year)***

Furthermore, GWP's Portfolio G, the so-called "100% Clean" approach is anything but clean. A cursory examination of their figure 22 in the IRP ("Greenhouse Gas Emissions of the Seven portfolios examined") shows that this "clean" system emits 250,000 tons of GHG at their planning horizon of 2038.

Ascend modeled GWP's strawman 100% Clean Portfolio G to show that it does not meet their criterion of less than 2.4 hours per year loss of load. But their modeling results show significant variations in reliability from year to year ***with the identical system resources.*** With the same system resources available, the same peak load, and the same supply system failure (N – 1 – 1, or 150 MW) how can the reliability of the system design fluctuate from year to year. The gray bar appearing in 2036 is said to be a modeling of a transmission failure, but that failure criterion (N – 1 – 1) is already built in to the basic system parameters to be modeled. Are they not double-booking transmission failures to put their strawman system in a bad light and justify further their fossil-fuel-heavy preferred portfolio E?

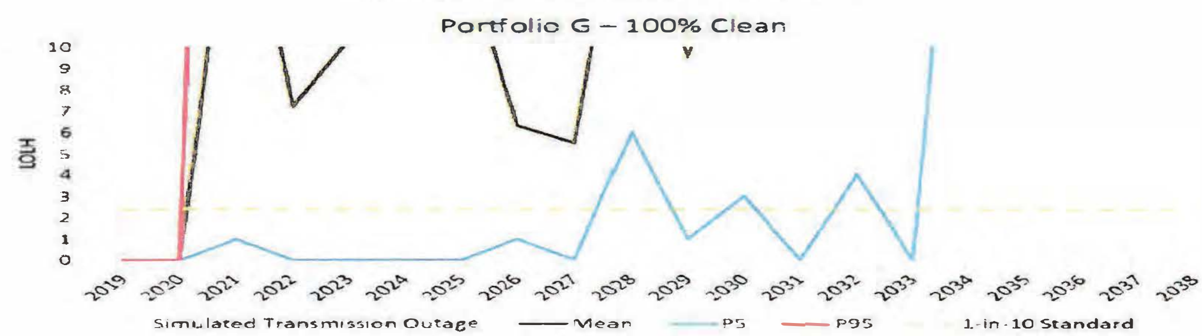
GWP' modeling techniques for reliability are not valid and lead to the false

Conclusion that a 100% Clean System does not meet reliability needs.



GWP's 100% Clean Option is not really clean at all. L24-15

Figure 19: LOLH of Portfolio G and Portfolio F



Reliability Modeling of the 100% Clean Plan is Flawed

Argument 12 - A 100% Clean plan is feasible and must be considered as an alternative to GWP's fossil-fuel heavy plan.

A Zero Carbon 2030 plan was provided to GWP and to the Council in March of 2019 and updated in November of 2020:

This plan may be viewed at: **www.ZeroCarbonGlendale.com**

The plan includes 925 MW hrs of battery storage vs. GWP's 300 MW hrs.

The plan includes 85 MW of new transmission vs. GWP's Zero MW.

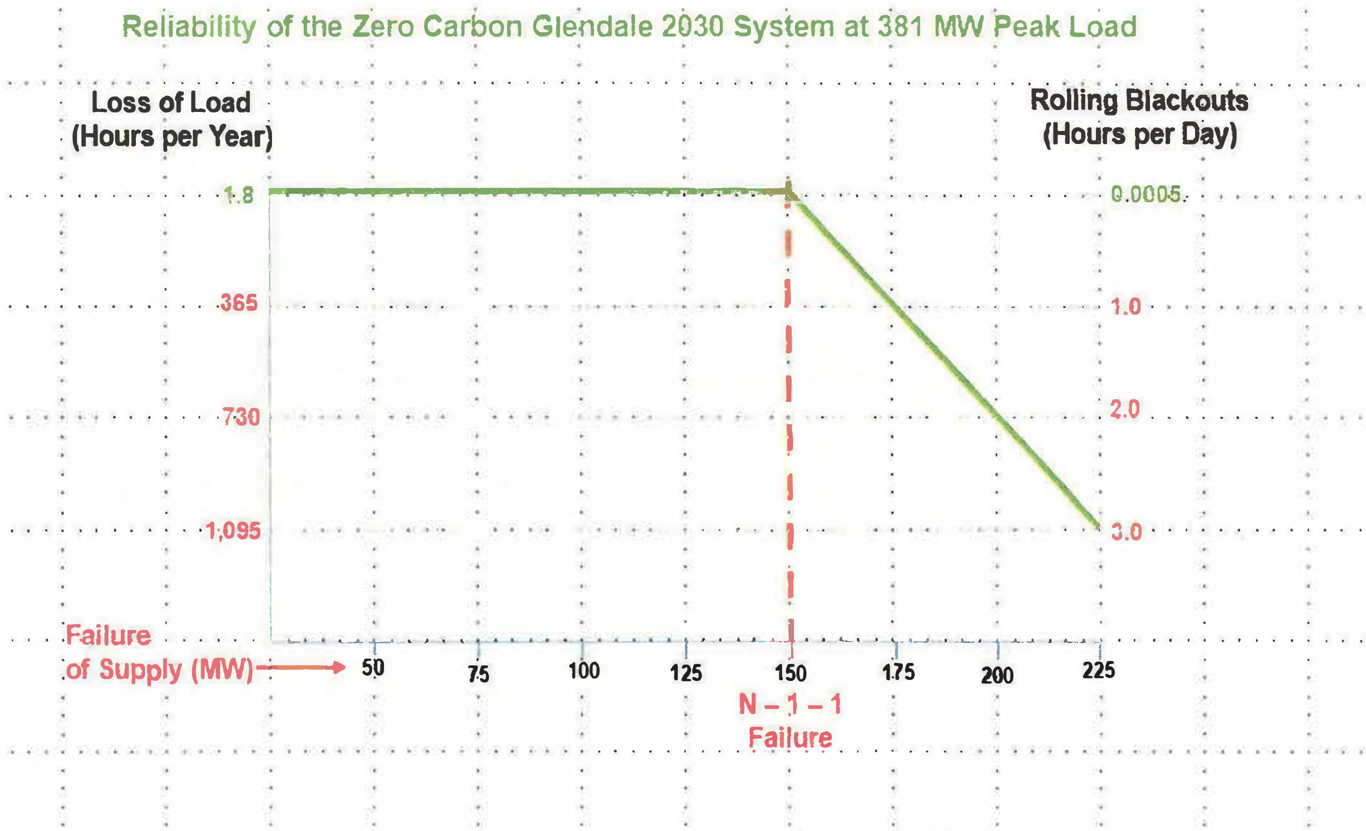
The plan includes 93 MW of ICE emergency backup generation with the requirement that this generation be used no more than 1% of the time. GWP has not stated their planned usage of the 93 MW of ICE or 47MW of unit #9, or 47 MW of Magnolia, or gas generation from IPP. L24-16

The plan gets us to 100% zero carbon (excepting certain emergencies) by 2030. GWP's plan gets us to 72-80% zero carbon by 2045 and is *not even close to meeting State law.*

This zero carbon resources plan has been analyzed and modeled extensively and provides 99.98% reliability (Loss of Load hours of 1.8 per year) at 381 MW peak load (GWP's p50 load) in the presence of an N – 1 – 1 failure condition (150 MW of supply failure). It also shows the effects of rolling blackouts on the average Glendale residential customer when failures past the N – 1 – 1 level (150 MW) occur. This model also shows that the failure rate of the system remains constant at 1.8 hours LOL per year right up to the N – 1 – 1 level. It does not fluctuate from year to year as indicated in the model used by GWP in attempting to prove that a 100% Clean system can not exhibit the required reliability.

A Zero Carbon 2030 Plan has been provided to GWP and the Glendale City Council.

That plan should be considered as an Alternate in the EIR, not be completely ignored.



A Zero Carbon System can exhibit the same high reliability as GWP's preferred fossil-fuel heavy Portfolio E with 625 MW hrs of additional storage.

L24-16

Argument 13 – A Majority of the City Council Promised the Voters of Glendale a Zero Carbon 2030 Plan

Prior to the last City Council Election, at a meeting of the Women's Civic League of Glendale, a candidates' forum was held and one of the questions asked of the seven candidates present (Including Mr. Brotman, Ms. Devine, and Mr. Kassakhian) was: L24-17

> ***"Would you support a resolution by the Council calling for a 100% Greenhouse Gas Free electric power system for Glendale by the year 2030?"***

Their unanimous answer was: "Yes"

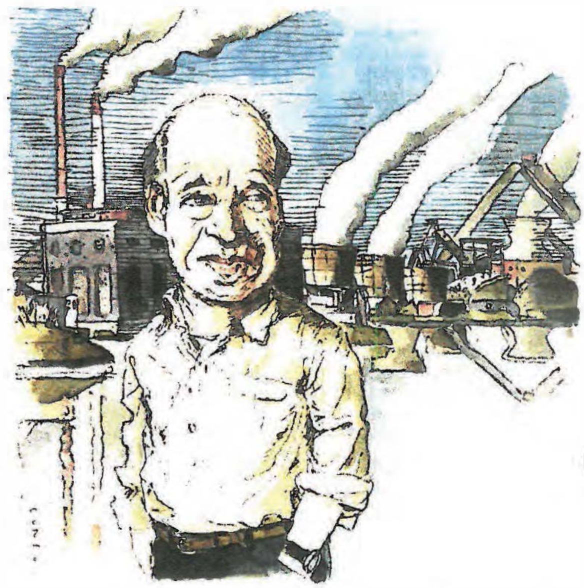
GWP's Integrated Resource Planning effort is proceeding at a snail's pace and currently is not in compliance with SB100, the law of the land.

The Glendale City Council should follow through with their promise to provide direct guidance to GWP in the form of a resolution requiring GWP to develop a plan to meet the zero-carbon requirement of SB100. Our analysis and modeling indicate that this goal is readily achievable by 2030.

A Final Word

One of the world's preeminent climate scientists, James Hansen, often called the Grandfather of climate science,

delivers us a final word:



***THE NEW YORKER*, July 27,2020**
Illustration by John Cuneo

L24-18

"Carbon dioxide isn't just approaching dangerous levels; it is already there. Unless immediate action is taken -- including shutdown of all of the world's coal plants within the next two decades, the planet will be committed to change on a scale society won't be able to cope with.

The problem has become an emergency."

Contact Us

We welcome any and all comment and feedback regarding these arguments and the associated analysis and modeling. Our objective is simply a 100% clean electric grid for Glendale.

By eMail: [*gtw@ZeroCarbonGlendale.com*]

By telephone: 818-241-7436

Also, please don't hesitate to call or eMail if you have questions or need explanation of the any of the material we have presented.

If you believe, as we do, that Glendale can do better than wait until the zero-carbon hammer of SB100 falls in 2045, then contact your City Council and recommend that they give the required direction to GWP. L24-19

Glenn T. Webb

L25

From: Rachel Ridgway
To: Krause, Erik
Cc: Devine, Paula; Agajanian, Vrej; Najarian, Ara; Kassakhian, Ardashes; Brotman, Daniel
Subject: Grayson Repowering Project PR-DEIR
Date: Monday, November 15, 2021 3:30:37 PM

CAUTION: This email was delivered from the Internet. Do not click links, open attachments, or reply if you are unsure as to the sender.

L25-1

Dear Mr. Krause and Esteemed Councilmembers:

As faculty advisor for Glendale Students for Sustainability, I am writing to comment on the PR-DEIR for the Grayson Repowering Project.

It may seem like a long-distant memory with all that has passed since, but in 2017, the City of Glendale unanimously resolved to join the Mayors National Climate Action Agenda, in support of the Paris climate accord.

In light of this fact, I urge you to halt the Grayson Repowering Project and redouble your efforts to identify alternative scenarios to support Glendale's growing energy needs.

L25-2

Consider, for example, the plans underway in Denver, to convert an old coal-powered fire plant into an energy storage facility using molten salt to hold energy collected from a growing network of green energy sources.

L25-3

The PR-DEIR states that emission credits would be purchased to offset the increase in greenhouse gas emissions that would result from this project. This is money that the City could use to further expand its distributed network of green energy. Not only will this save money, it will save lives, thanks to the reduction in air pollution and a contribution to decelerate global warming and ocean acidification.

L25-4

Glendale, the Jewel City, has a choice to make for future of its citizenry. I urge you to reject the use of fossil fuels for power generation.

Please choose wisely. Our lives are in your hands.

Thank you for your consideration.

Sincerely,
Rachel Ridgway

Rachel Ridgway
Instructor of Oceanography & Geology (CR-142)
Glendale Community College
1500 North Verdugo Road Glendale, California 91208

Cell Phone (Call/Text): 657-667-3423
Campus Phone: 818-240-1000 ext. 5768
rridgway@glendale.edu

Want to chat on Zoom? Please click here to schedule a time to visit during student office hours.

Happy Trails: Little wonders at hideaway lake in Boulder

Yc

https://denvergazette.com/news/environment/xcel-energy-looking-at-preserving-hayden-plant-as-molten-salt-energy-storage-facility/article_ec5214b4-1711-11ec-b906-572e9935def7.html

L25-5

Xcel Energy looking at preserving Hayden plant as r energy storage facility

Scott Weiser The Denver Gazette
Sep 23, 2021

Xcel Energy Hayden powerplant in northwestern Colorado.

Scott Weiser - The Denver Gazette

Facing Gov. Jared Polis' mandate to eliminate coal as a source for electrical power generation by 2050, Xcel Energy is looking into repurposing its Hayden coal-fired power plant in northwestern Colorado to preserve its investment in the plant and aid the economic health of nearby communities including Hayden and Craig -- and store carbon-free solar energy to generate electricity.

The plant provides nearly half the property tax base for Hayden schools
L25-5 districts, and the threat of losing the plant left the town staring econom
face.

What U.S. government surveyor, F.V. Hayden reported in the 1870s as or
coal reserves in the country, coal has been the mainstay of the region's e
1887.

Peter Brixius, Craig Town Manager, told The Denver Gazette, "Anything
keep some of the employees and to utilize that infrastructure will assist
both Routt County and Moffat County."

Hayden Unit 1, built in 1965, and Hayden Unit 2, built in 1976, were orig
for shutdown in 2036. Xcel accelerated the schedule to stop burning coa
of its current energy resource plan approved by the Public Utilities Comı
March.

Now the utility is looking at repurposing the plant to use renewable energy to spin the existing generators.

One of three renewable sources being studied is molten salt.

Molten salt energy storage works by concentrating solar power (CSP) using parabolic reflectors focused on pipes carrying molten salt that convert the light into heat in the salt. The salt is kept fluid at about 525 degrees F and is stored in tanks where it can be used to quickly generate the steam needed to produce electricity.

The need for ways to store energy for use when it's dark or the wind isn't blowing is the focus of major investment worldwide. Right now, utility-scale lithium ba
much as 90 times as much as coal or natural gas of equivalent capacity a
only last a few minutes to several hours.

L25-5 Molten salt can store 10 to 12 hours worth of energy and storage scales u
by adding more salt storage.

The Chilean government intends to shutter 30 coal-fired power plants co
of its national generating capacity by 2024, and is studying using CSP st
the plants operating.

Xcel is only in phase one of its planning process and hasn't decided on which, if any of the renewable fuel options might be used to rescue the Hayden plant, says Hollie Velasquez Horvath, senior director of state affairs and community relations for Xcel.

Speaking of CSP installations in Nevada's Mojave Desert, Velasquez Horvath told The Denver Gazette, "There's a lot of challenges that they've had with that concentrated solar and their positioning of that generation. So that is something that we're also factoring into in trying to understand as we explore it."

Developers of one facility thought that the sun always shines in the Mojave Desert, but discovered that from November through February clouds create overcast much as 50% of the time. Without storage, this resulted in dismal overal electricity.

L25-5 According to the EIA, solar panels, which can still produce power even w cloud cover, have a 5% capacity factor advantage over non-storage CSP u conditions, as well as much lower, and still declining capital costs.

The costs of building a CSP energy storage plant are high compared to so According to BloombergNEF, a strategic research company, from 2009 to utility-scale solar panels dropped from $355 per MW hour to $51 per MW the Crescent Dunes CEP project in Nevada, built with $737 million in U.S Energy loan guarantees, came in at $135 per MW hour and was reported Greentechmedia.com as being shut down.

But, like Chile, Xcel already has the generators and distribution infrastru and it doesn't really matter how the steam to spin the generators is proc may produce significant cost savings.

Xcel's plan is more than a little experimental, but House Bill 21-1234, si Polis July 6, says investor-owned utilities "should pursue opportunities to develop new energy technologies or moify existing generation resources with new technologies..."

While ratepayers will have to pay Xcel's costs for building the storage infrastructure, and pay off any existing debt on the plant, if the CSP project is "abandoned whole or in part," and the Public Utilities Commission finds that the cos "prudently incurred," the PUC can deny cost recovery.

The law also protects ratepayers somewhat by saying that Xcel cannot earn a total return on the project that exceeds what it would have earned from a "photovoltaic…or wind generation facility of equivalent capacity."

L25-5

MORE INFORMATION

Colorado utility watchdog office gets a new name, newer responsibilities

U.S. Forest Service in Colorado to waive fees for two days this fall

IREA switches to CORE, sunny new image

Scott Weiser
Enterprise Reporter

L25-5

Around the Web

L26

-----Original Message-----
From: Jennifer Pinkerton <jenniferpinkerton@fastmail.fm>
Sent: Monday, September 13, 2021 4:22 PM
To: Young, Mark <MYoung@Glendaleca.gov>
Cc: van Muyden, Gillian <GVanMuyden@Glendaleca.gov>; Alek Bartrosouf <alekbartrosouf@gmail.com>; Jones, David <DJones@Glendaleca.gov>
Subject: Follow up questions re Grayson

CAUTION: This email was delivered from the Internet. Do not click links, open attachments, or reply if you are unsure as to the sender.

L26-1 Dear Mr. Young:

Thank you again for the recent presentations and for correcting my misunderstanding re LADWP's IPP project.

1. A resident presented the following Grayson question to me, and I realized I'm unclear on the same issue.

Specifically, the DEIR indicates that there will be 1120 operating hours and start ups. (Criteria, page 4.3, page 392; Appendix Table B4, page 483, and Appendix Table B5, page 484).

L26-2 And 1,260 is a number which includes startup times that appears in Table 5-2 page 510

The resident said: "What I don't see in the PERMITS is any mention of operation limits."

Can you please provide a copy of the permit that shows the limitation on the number of hours of operation and start-ups.

L26-3 2.Also, I heard from some residents who said they previously submitted comments on the DEIR. They were surprised because they were not a) contacted to submit comments for the PR-DEIR or notified that b) there would be another comment period. They said they thought a) and/or b) was required.

Can you please explain what the procedure is?

L26-4 3. I have copied Ms. Van Muyden, Mr. Jones, and Mr. Bartrosouf on an FYI basis.

Best
--

Jennifer Pinkerton
jenniferpinkerton@fastmail.fm
818 588 2354
Member, Glendale Sustainability Commission

L27

-----Original Message-----
From: patlarrym@aol.com
To: PDevine@glendaleca.gov <PDevine@glendaleca.gov>
Cc: vagajanian@glendaleca.gov <vagajanian@glendaleca.gov>
Sent: Tue, Sep 21, 2021 10:15 pm
Subject: Grayson and Scholl LF

L27-1 Hello Mayor, please be advised that my comments are being sent to all of the council members, thank you.

L27-2 Before I approved any removals or tare downs of any parts of our Grayson Power Plant I would do the following.

1. I would see if the land fill gas could be sent back to the Grayson PP. The LFG allows the boilers to burn cleaner and provide more energy output and meet the SCAQMD environmental rules.

L27-3 2. If it can be, then I would see what it would take for ALL of the old steam units to be brought up to reliable standards for every day use and the total cost.

L27-4 3. If all this can be done then you will not have to build a power plant at the land fill site saving millions of dollars and 500 million on the Grayson power plant

L27-5 Our city council members are being totally over whelm by the GWP staff and its contractors with the EIRs for both Grayson and the PP at Scholl

Even if this all is totally wrong, then our council can say for sure that they have looked at every aspect of both EIRs and then afterwards make a final approval.

L27-6 After having been the Grayson Power Plant Supt. for 20 years with over 50 years of experience in building and managing power plants of every kind it is my recommendation to you that we all take the time to make sure we will do the right thing for our beautiful Glendale and People

L28

From: Brotman, Daniel <dbrotman@Glendaleca.gov>
Sent: Wednesday, September 22, 2021 2:46:51 PM
To: Young, Mark <MYoung@Glendaleca.gov>
Subject: Re: Grayson and Scholl LF

L28-1 I meant to bring this up. Can I get your thoughts on Larry's argument?

From: patlarrym@aol.com <patlarrym@aol.com>
Sent: Tuesday, September 21, 2021 10:19 PM
To: Brotman, Daniel
Subject: Fwd: Grayson and Scholl LF

-----Original Message-----
From: patlarrym@aol.com
To: PDevine@glendaleca.gov <PDevine@glendaleca.gov>
Cc: vagajanian@glendaleca.gov <vagajanian@glendaleca.gov>
Sent: Tue, Sep 21, 2021 10:15 pm
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After having been the Grayson Power Plant Supt. for 20 years with over 50 years of experience in building and managing power plants of every kind it is my recommendation to you that we all take the time to make sure we will do the right thing for our beautiful Glendale and People

L29

From: Brotman, Daniel <dbrotman@Glendaleca.gov>
Sent: Sunday, September 26, 2021 9:52 PM
To: Young, Mark <MYoung@Glendaleca.gov>
Subject: Grayson Qs

Hi Mark,

L29-1 Thanks for the time over lunch last week.

I thought I'd write out some of the questions you weren't able to answer on the spot, just so we're on the same page. I also have one or two things we didn't get a chance to discuss. Here goes...

On the need for 5 RICE units

L29-2 The big question is why GWP is still recommending the same/similar mix of thermal, BESS and DERs as it did in 2019 even though there have been some important developments that were not part of the original modeling? These include (i) 25MW of solar/storage from Eland in 2024 coming with new, albeit limited, transmission rights, (ii) 73MW of new transmission on the STS line starting in 2027, (iii) an increase in the Sunrun VPP from 13MW to 25MW. Related to that are some questions about other resources:

L29-3
- What's the potential for commercial solar/storage through a Commercial VPP or FiT program? Ascend plugged 20MW into the 2030 Plan, but if we did something along the lines of LADWP's FiT we would be looking at closer to 25MW. Why isn't this factored into the model for determining the thermal-BESS-DER mix?

L29-4
- The 2019 IRP assumed 10MW of solar/storage on City sites. What's the current expectation based on projects we're working on today and any other available sites?

L29-5
- The 2019 IRP assumed 28MW of residential/commercial EE and DR. What's the current expectation based on the programs with Lime and Franklin? How much more could we do in EE and DR if we went at this harder (e.g. DR programs for other appliances, including EV charging, EE and DR for our largest customers, etc.)?

L29-6
- Are we doing anything for people who already have solar that want batteries and are willing to allow GWP to control them? I thought I remember Craig talking about this.

Costs of Alternatives 7 and 8

L29-7

- I'd like to see estimated costs for the two alternatives asap, disaggregated as much as possible to break out equipment costs, site prep and engineering costs; etc.; it's fine if they are rough figures now—I won't hold you to them.

L29-8

- I'd also like to know the assumptions we're making for cost of carbon, gas prices, and equipment depreciation.

Permitting & Run Time Protocols

L29-9

- If you have any thoughts on how to lay out operating protocols for our thermal assets that make them a last resort resource, only used if we cannot otherwise meet load with imports, stored energy or DERs, I'd love to see that.

COSA

L29-10

- We didn't talk about this but I'd like to know when I will get to weigh in, formally or informally, on elements of the COSA, such as a FiT program, changes to NEM (which make me very nervous!), TOU rates, etc.

AQMD Rule 1135

- My notes on this weren't the best. Can you explain again why the permit application we put in doesn't satisfy the July 1, 2022 requirements? For e.g.,

L29-11

1. what exactly is required to satisfy the deadline, what have we already done, and what do we still need to do?

2. How long do you need to prepare and submit the parts of the application that aren't already complete once you get the Council's direction on the project?

3. Can the application be modified after July 1 (e.g., if there are changes to the number of gas-burning units) without being out of compliance with the deadline?

Thanks,
Dan

L30

From: patlarrym@aol.com
Date: October 15, 2021 at 10:13:11 PM PDT
To: "Devine, Paula" <PDevine@glendaleca.gov>
Reply-To: patlarrym@aol.com

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L30-1

On the news tonight it was mentioned that the president was maybe going to pull the money out of the funds that Democrats are trying to get through pertaining to Energy and Power Grids. If they do then all of our big electric projects won't be developed. Which means that our city should be thinking of all this and make sure it makes all the right decisions with our GWP.

L31

-----Original Message-----
From: patlarrym@aol.com
To: PDevine@glendaleca.gov <PDevine@glendaleca.gov>
Sent: Tue, Oct 26, 2021 10:54 pm

L31-1 Hello Mayor Devine, I was watching the council meeting and I thought our GWP Manager made a very good responce right at the last of the meeting. He was exactly correct in all of his statements. However he did not say what our Utility is going to do for us to get out of the big problem that we are going to have with our energy supply line. Nor does he know what the cost is going to be to get there. He also has no indication of what our rates are going to be to be able to pay for any changes (500-700 Million$) cost. He also does not mention outages and what will happen if they tare down Grayson during the 3 to 4 year rebuild time. The bottom line is GWP has to have enough back of generation to keep our lights on at any time. This is becuase we are limited with only one large connection to the outside grid and when we loose this we have to have our own generation or we go into the black.

L31-2 I highly recommend that we look at what can be done with the old plant. Maybe tare a part of it down to add some new units and keeping some of them to run. And the over all cost comparison of doing this. Also run the land fill gas back to Grayson in the mean time.

L31-3 We have run out of time!!!!!

L32

From: patlarrym@aol.com <patlarrym@aol.com>
Sent: Tuesday, October 26, 2021 11:00 PM
To: Young, Mark <MYoung@Glendaleca.gov>
Subject: Fwd:

L32-1 Hello Mark, This is where we all are at!!!!!

L33

From: patlarrym@aol.com
Date: November 2, 2021 at 8:41:51 PM PDT
To: "PDevine@glendaleca.gov" <PDevine@glendaleca.gov>
Reply-To: patlarrym@aol.com

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Hello Mayor,
I just wanted to comment on to nights meeting regarding Grayson.
Not having a Grayson power plant is just one of the big problems. If we could buy all of our energy from reliable resources and not need a Grayson it would be great. However Glendale is restricted with the single big connection that we have only to be able to bring
L33-1 the power into our city from the outside and if we don't have a Grayson when we loose this outside inflow of power we will go into the BLACK.. Our City can reduce the amount that would be required to flow into us but only a certain amount . We will never get to a point where we can supply our city load by solar on top of every ones house. Everyone thinks that all we have to do is turn everything green an all set. This will never work and this why nothing has been done which we should have started 10 years ago and nothing has changed. My last e-mail to you is a way we should be thinking hard about along with doing what we can with green energy. Also everyone needs to know that a large battery after it gets discharged will need to be charged back up the the next cycle and this is where Grayson would help. I use to know how long our Hospital would run if they had to generate with their own generators and as I remember they were only able to do this for a few hours
L33-2 without running out of their own fuel. To be able to do the right thing for our city is going to require some very smart thinking. And so far I am not seeing this happening. You and our council needs help with all of this and you are not getting it. You have one council member that thinks he is right but he is not. And buy the way if all of this gets to hard for any of our GWP exec's all they have to do is fill out their retirement papers and now you will have another year or two of more delays.

Larry Moorehouse-retired GWP Grayson Power Plant Supt.

L34

Mail

Grayson Repowering Project

HS Hank Schlinger <hschling@hankschlinger.com>
10/21/2021 9:08 AM

To: Paula Devine; Dan brotman; Ardy Kassakhian; vagajanian@glendaleca.gov; anajarian@glendaleca.gov

L34-1

Dear Mayor Devine and City Council Members,

My wife and I want to expres our objection to repowering the existing Grayson Power Plant and support instead an Alternative Energy Project.

Thank you,

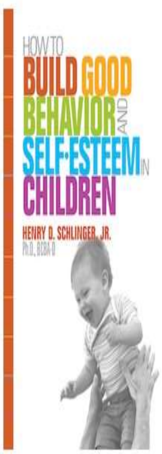
Dr. Schlinger

Henry D. Schlinger, Jr., Ph.D.
1755 W. Mountain St.
Glendale, CA 91201

See my new book at www.buildgoodbehavior.com

Amazon.com

Vroman's Bookstore



L35

-----Original Message-----
From: patlarrym@aol.com
To: PDevvine@glendaleca.gov <PDevvine@glendaleca.gov>
Sent: Sun, Oct 31, 2021 2:53 pm

L35-1 Hello Mayor, I have been thinking about our power plant and what I believe we should being doing to provide our city with a reliable source of energy at least for the next 10 to 20 years and here it is. I will not bring this up anymore.

L35-2

1. Tare down the south end of Grayson which contains the 3 old boilers which are non usable. And old steam units 1 & 2 along with units 8A & 8BC gas turbines.

2. Restore boiler #3 and upgrade boiler # 5. Boiler #4 has already been rebuilt for a secure operation.

3. Run the land fill gas back to Grayson into boilers 3,4 or 5.

4. Add one more LM600 and 2 LM2500 simple cycle General Electric gas turbines.

If our City would do all of this it will provide us the electric energy for several years and there would be room to add several more gas turbine when needed. And this will be a lower cost than what GWP's proposal is.

L35-3 All of this will provide a cheaper cost and a better operation and our current staff will be very familiar with operations and maintenance of all of these units. And by doing this it will have a less impact on the community You may share these ideas with anyone that you like. I would make myself available to discuss these with you or anyone else at your request.. Thank you.

Larry Moorehouse, retired Grayson Supt

L36

From: Adrienne Griffin <adrienne.ardistree@gmail.com>
Sent: Sunday, August 15, 2021 10:00 AM
To: Devine, Paula <PDevine@Glendaleca.gov>; Brotman, Daniel <dbrotman@Glendaleca.gov>; Najarian, Ara <ANajarian@Glendaleca.gov>; Agajanian, Vrej <VAgajanian@Glendaleca.gov>; Kassakhian, Ardashes <AKassakhian@Glendaleca.gov>
Cc: aadejamian@glendaleca.gov
Subject: Grayson

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Hi Mayor Devine, City Council Members and City Clerk,

L36-1

It seems like the Rally to turn Grayson Power Plant to Solar battery storage was just yesterday. It has been a couple of years. Employees at GWP who report to City Council have allowed a deadline to expire in order to continue to fire up Grayson powered by fossil fuels. Glendaleans have spoken and will continue to speak up against using fossil fuels at Grayson and for cleaner solar battery storage. Please stand with Glendaleans and demand solar storage. Do not 'pass gas' (or any fossil fuel products) at Grayson for a clean future.

Thank you,

Adrienne Griffin

Sent from my iPhone

ATTACHMENT B SUMMARY AND TIMELINE OF HISTORICAL RESOURCES EVALUATION

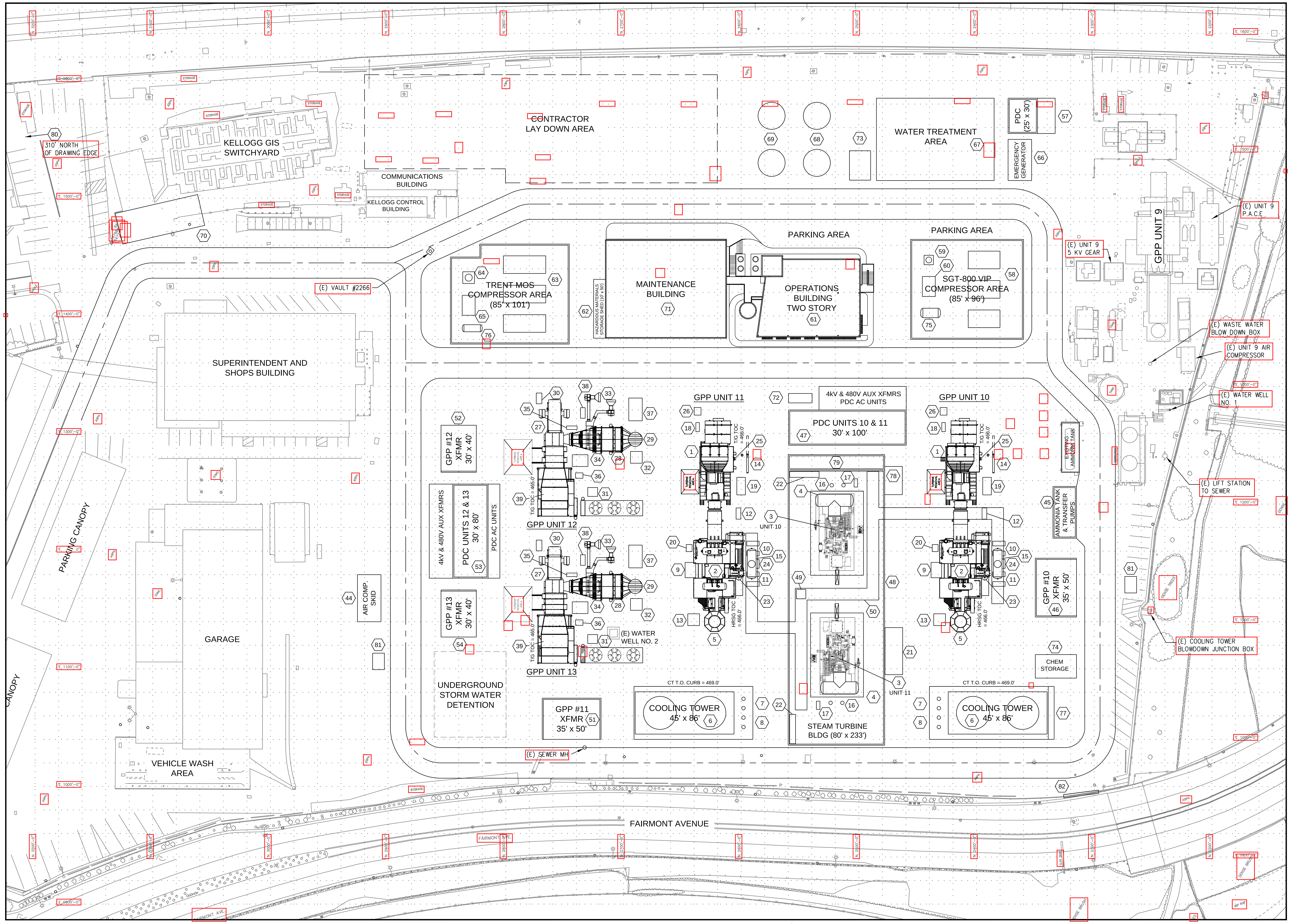
HISTORICAL RESOURCES EVALUATION OVERVIEW

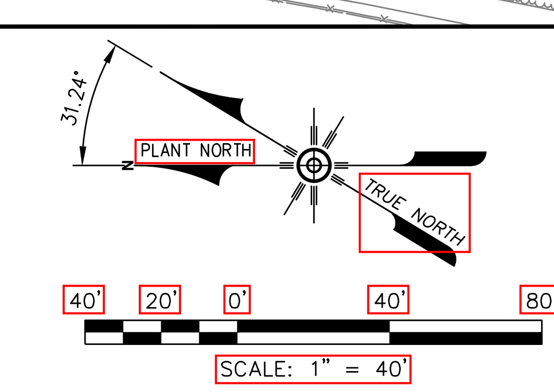
The City conducted a thorough, multi-year evaluation of potential historical resource impacts that would result from the proposed Project. These evaluations included, but were not limited to, use of qualified consultants to lead technical studies with City oversight and review, consultation with The Glendale Historical Society (TGHS), and correspondence from the State Historic Preservation Office. The following is an overview of the historical resources evaluation conducted by the City during CEQA review of the proposed Project.

Calendar	Historical Resources Evaluation Milestone	CEQA Section Reinforced
August 2015 - February 2016	Conducted an Historical Resources Evaluation of the Grayson Power Plant and Boiler Building based on federal, state, and City eligibility criteria. Determined not eligible for listing as historical resource.	Initial Study: Appendix A
December 2016	Noticed Draft Initial Study and Notice of Preparation of an Environmental Impact Report with CEQA finding of no or less than significant impacts to cultural/historical resources.	Initial Study: Section 2.5 & Appendix A
September 2017 - November 2017	Noticed Draft Environmental Impact Report with CEQA finding of no or less than significant impacts to cultural/historical resources. Alternatives 1 (No Project) and 3 (Alternative Energy Alternative) would result in retaining the Boiler Building. Additional alternatives including an alternative Project site that would also retain the Boiler Building were considered but not carried forward for evaluation because they would not meet the Project objectives or would have greater environmental impacts.	Draft EIR: Sections 5.3.1, 6.3, & Appendix A
November 2017 - April 2018	Responded to comments and presented Final Environmental Impact Report to City Council with CEQA finding of no or less than significant impacts to cultural/historical resources. City Council elected not to certify the Final Environmental Impact Report and directed City staff to evaluate additional alternatives to the proposed Project that involve increased reliance on renewable energy and less natural gas fueled generation.	Final EIR: Sections 6.3, 9.3 (Response to Comment No. L781), & Appendix A
August – December 2020	The Draft Environmental Impact Report for the Los Angeles to Burbank Segment of the California High Speed Rail Project identified the Grayson Power Plant Boiler Building as a potential historic resource, including eligibility for listing in the National Register of Historic Places. This potential eligibility finding was based on a screening level evaluation without the benefit of an on-site survey of the Grayson Power Plant property and Boiler Building. The City submitted comments to the California High Speed Rail Authority during the public review period and shared the evaluation that was conducted for the Grayson Repowering EIR. The California High Speed Rail Authority in consultation with the State Historic Preservation Office subsequently concurred that Grayson Power Plant was not eligible for listing in the National Register of Historic Places.	Partially Recirculated Draft EIR: Section 4.12

Calendar	Historical Resources Evaluation Milestone	CEQA Section Reinforced
December 2020	After conclusion of the Clean Energy Request for Proposals process, City staff presented summaries of Alternatives 7and 8 to City Council and requested direction on alternatives to evaluate in a Partially Recirculated Environmental Impact Report. The City considered and presented two variations of Alternative 7, with one of the variations retaining the Boiler Building. The challenges and constraints of retaining the boiler building and need to demolish it as part of the proposed Project and specific alternatives is summarized in Topical Response No. 3. As a result, City Council did not support advancing evaluation of the Alternative 7 variation that would evaluate retaining the Boiler Building in the Partially Recirculated Environmental Impact Report. Retaining the Boiler Building as a variation of Alternative 7 was therefore removed from further consideration and Alternatives 7 and 8 that would both result in demolition of the Boiler Building were advanced for evaluation. City Council additionally directed City staff to meet with TGHS to discuss consideration of historical resources.	Partially Recirculated Draft EIR: Executive Summary
February - August 2021	City staff coordinated and participated in teleconference meetings and a Grayson Power Plant site visit with TGHS. The City correspondingly elected to consider the Boiler Building a discretionary historical resource. Meetings with TGHS additionally resulted in incorporation of numerous historical resources related mitigation measures.	Partially Recirculated Draft EIR: Executive Summary & Section 4.12
August – October 2021	The City Noticed a Partially Recirculated Draft Environmental Impact Report that included a cultural resources section. The partially recirculated document considered the Boiler Building a discretionary historical resource. After incorporating mitigation measures, demolition of the Boiler Building from the proposed Project and Alternatives 3, 4, 5, 7, or 8 would result in a significant and unavoidable cultural resources impact requiring a Statement of Overriding Considerations.	Partially Recirculated Draft EIR: Executive Summary, Sections 4.11.12, 4.12, 5 (Response to Comment No. L781), & Appendix A
January 2022	City staff plans to present the 2022 Final Environmental Impact Report to the Glendale Historic Preservation Commission, Water and Power Commission and Sustainability Commission.	
February 2022	City staff plans to present the 2022 Final Environmental Impact Report to City Council for consideration.	

ATTACHMENT C GENERAL ARRANGEMENTS FOR THE PROPOSED PROJECT, ALTERNATIVES 7 AND 8





EQUIPMENT LIST

UNITS 10 & 11

1. SGT-800 TURBINE GENERATOR
2. HEAT RECOVERY STEAM GENERATOR
3. STEAM TURBINE GENERATOR
4. SURFACE CONDENSER
5. HRSG STACK
6. COOLING TOWER
7. CIRCULATING WATER PUMPS (2)
8. AUXILIARY COOLING WATER PUMPS (2)
9. AMMONIA FLOW CONTROL UNIT
10. HIGH PRESSURE BOILER FEEDWATER PUMPS (2)
11. LOW PRESSURE BOILER FEEDWATER PUMPS (2)
12. SGT-800 CO2 BOTTLES
13. CEMS SKID
14. FUEL GAS HEATER & K.O. VESSEL
15. DEAREATING VESSEL
16. CONDENSATE PUMPS (2)
17. VACUUM PUMP SKIDS
18. MINERAL LUBE OIL COOLER
19. GAS CONDITIONING UNIT
20. AMMONIA INJECTION PUMPS (2)
21. UNIT 10/11 CONDENSATE POLISHERS
22. BEARING COOLING WATER EXCHANGER
23. BLOW DOWN TANK & SUMP
24. CONDENSATE PREHEATER
25. EVAPORATION TANK & DEHUMIDIFIER
26. 690V TRANSFORMER

UNITS 12 & 13

27. INDUSTRIAL TRENT 60 TURBINE GENERATOR (SGT-A65 TR)
28. SCR
29. SCR STACK
30. MINERAL LUBE OIL SKID
31. CLOSED LOOP AIR COOLER AND PUMP SKID
32. CEMS SKID
33. TEMPERING AIR FANS (2)
34. WATER INJECTION SKID
35. INDUSTRIAL TRENT 60 C02 BOTTLES
36. FUEL GAS FILTER SKID
37. AMMONIA FLOW CONTROL UNIT
38. SEAL AIR FANS (2)
39. ISI SKID (UNDER FILTER STRUCTURE)
40. (not used)
41. (not used)
42. (not used)
43. (not used)

BALANCE OF PLANT

44. AIR COMPRESSOR PACKAGE SKID
45. AMMONIA TANK SYSTEM
46. UNIT 10 GENERATOR STEP-UP TRANSFORMER
47. PDC-CC UNIT 10/11 POWER DISTRIBUTION CENTER
48. STEAM TURBINE BUILDING
49. AUXILIARY BOILER
50. PIPE RACK
51. UNIT 11 GENERATOR STEP-UP TRANSFORMER
52. UNIT 12 GENERATOR STEP-UP TRANSFORMER
53. PDC-SC UNIT 12/13 POWER DISTRIBUTION CENTER
54. UNIT 13 GENERATOR STEP-UP TRANSFORMER
55. (not used)
56. (not used)
57. PDC-WTA WATER TREATMENT AREA POWER DISTRIBUTION CENTER
58. UNIT 10/11 FUEL GAS COMPRESSORS (3)
59. UNIT 10/11 GAS SUCTION SCRUBBER
60. UNIT 10/11 GAS DEMISTER (2)
61. OPERATIONS BUILDING
62. HAZMAT STORAGE SHED
63. UNIT 12/13 FUEL GAS COMPRESSORS (3)
64. UNIT 12/13 GAS SUCTION SCRUBBER
65. UNIT 12/13 GAS DEMISTER (2)
66. EMERGENCY GENERATOR
67. WATER TREATMENT UNIT
68. REVERSE OSMOSIS FEED TANKS 23'Ø x 16'H (2)
69. DEMINERALIZED WATER STORAGE TANK 23'Ø x 24'H (2)
70. SoCalGas MSA 25'x75'
71. MAINTENANCE BUILDING (103'x82')
72. OILY WATER SEPARATOR (UNDERGROUND)
73. POWER DEPARTMENT WATER LABORATORY (18'x25')
74. CHEMICAL STORAGE AND INJECTION SKIDS
75. SGT-800 BUFFER VESSEL 8'Ø x 13' LONG
76. TRENT BUFFER VESSEL 6'Ø x 14' LONG
77. PROCESS SEWER REJECT BASIN
78. PDC-STB BATTERY ROOM (440V)
79. PDC-STB STG BUILDING POWER DISTRIBUTION CENTER
80. WATER DEPARTMENT WATER LABORATORY (18'x25')
81. WATER DEPARTMENT TREATMENT SLAB (10'x14') (2)
82. NEW 30 FOOT SLIDING GATE

NOTES:

1. BOTH SGT-800 AND TRENT 60 STACK COORDINATES ARE FIXED.
2. BOTH COOLING TOWER FAN STACK COORDINATES ARE FIXED.
3. THE EMERGENCY GENERATOR COORDINATES ARE FIXED.

Stantec

REVISIONS

DATE	NO.	DESCRIPTION	BY	CH'K	APP
01/30/17	J	PRELIMINARY FOR DISCUSSION	DS	TE	CH
04/14/17	K	PRELIMINARY FOR DISCUSSION	DS	TE	CH
04/25/17	L	PRELIMINARY FOR DISCUSSION	DS	TE	CH
06/13/17	M	PRELIMINARY FOR DISCUSSION	DS	TE	CH
08/15/17	N	ISSUED FOR RFP	DS	TE	CH
09/11/17	O	REVISE UNIT 9 EXISTING LOCATIONS	DS	TE	CH
10/05/17	P	REVISE ITEM 70; ADD JUNCTION LOCATION	DS	TE	CH
10/20/17	Q	REVISE ITEM 57, 66, 67, 68, 69 LOCATION	DS	TE	CH

DES:
DWN: CH'K:
APPROVED:

SCALE: 1" = 40'-0"
DATE: 08/31/16

(AutoCAD)

GRAYSON REPOWERING PROJECT
GENERAL ARRANGEMENT

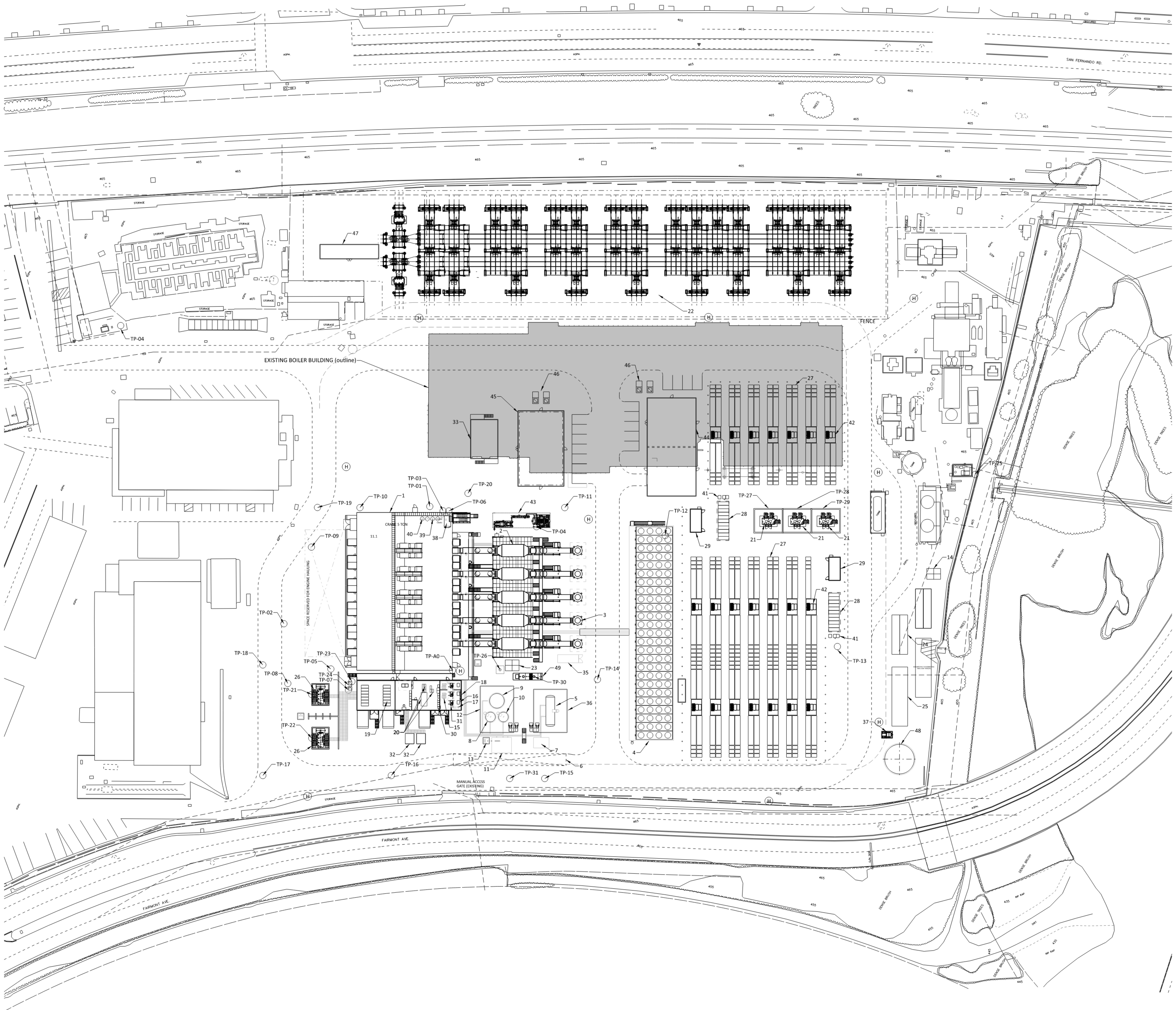
GLENDALE WATER & POWER
CITY OF GLENDALE
CALIFORNIA

City of Glendale Water & Power GWP Your Trusted Community Utility

SHEET: G-1011

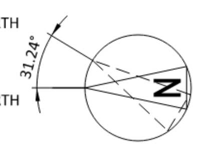
GPP-00

SAVED: 10/19/17 10:37 AM PLOTTED: 10/19/2017 10:50 AM USERNAME: dstitt FILE LOCATION: V:\2057\active\2057123300\Grayson Repowering\10Dwgs\4Mech FILENAME: GPP-00-G-1011 RQ.dwg



NOTES

1. THIS DRAWING IS THE BASIS FOR THE SITE ARRANGEMENT AND IS SUBJECT TO REVISIONS AS A RESULT OF DETAILED DESIGN AND DUE TO VARIATIONS IN SUPPLIERS OF MAJOR EQUIPMENT.
2. COORDINATE SYSTEM IS NAD83 CALIFORNIA ZONE 5.
3. NOTE THAT ELECTRICAL TIE POINTS INDICATE TIE POINTS OF RACEWAY INTERCONNECTION AND NOT CIRCUIT TERMINATIONS.



FACILITIES LEGEND

ID	FACILITY	ARRANGEMENT	TIEDOWN LOCATION NORTH	TIEDOWN LOCATION EAST	REMARKS
1	RECIPROCATING INTERNAL COMBUSTION ENGINE HALL	-	-	-	
2	SELECTIVE CATALYST REDUCTION (SCR) UNIT	-	-	-	
3	EXHAUST STACK - W/SILENCER	-	-	-	
4	RADIATORS	-	-	-	
5	SCR REAGENT (19% AQUEOUS AMMONIA) STORAGE TANK AREA	-	-	-	
6	SCR REAGENT UNLOADING AREA	-	-	-	
7	SCR REAGENT FORWARDING PUMPS	-	-	-	
8	CLEAN LUBE OIL STORAGE TANK	-	-	-	
9	USED/SERVICE LUBE OIL STORAGE TANK	-	-	-	
10	SLUDGE TANK	-	-	-	
11	PUMP SHELTER	-	-	-	
12	LUBE OIL & SLUDGE TANKS SECONDARY CONTAINMENT	-	-	-	
13	TANK AREA OILY WATER COLLECTION SUMP	-	-	-	
14	WELL PUMP #1 DISINFECTION SKID	-	-	-	
15	STARTING AIR UNIT	-	-	-	
16	AIR DRYER	-	-	-	
17	INTRUMENT AIR BOTTLE	-	-	-	
18	UTILITY BUILDING	-	-	-	
19	MEDIUM VOLTAGE SWITCHGEAR	-	-	-	
20	LOW VOLTAGE SWITCHGEAR	-	-	-	
21	69kV GSU TRANSFORMER	-	-	-	
22	SWITCHYARD	-	-	-	
23	WELL PUMP #2 DISINFECTION SKID	-	-	-	
24	DEMIN WATER EQUIPMENT	-	-	-	
25	DEMIN WATER TRAILER PARKING	-	-	-	
26	69kV GSU TRANSFORMER	-	-	-	
27	TESLA MEGAPACK2	-	-	-	
28	GATHERING SYSTEM SWITCHGEAR	-	-	-	
29	CONTROL HOUSE	-	-	-	
30	VARIBLE FREQUENCY DRIVE FOR RADIATOR	-	-	-	
31	INSTRUMENT AND WORKING AIR UNIT	-	-	-	
32	AUXILIARY TRANSFORMER	-	-	-	
33	BOP POWER DISTRIBUTION CENTER	-	-	-	
34	NOT USED	-	-	-	
35	CONTINUOUS EMISSIONS MONITORING SYSTEM ENCLOSURE	-	-	-	
36	REAGENT TANK SECONDARY CONTAINMENT	-	-	-	
37	STORM WATER PUMPS	-	-	-	
38	INSTRUMENT AIR BOTTLE	-	-	-	
39	STARTING AIR BOTTLE	-	-	-	
40	COOLING WATER STORAGE TANK	-	-	-	
41	COMMS VAULT	-	-	-	
42	GATHERING SYSTEM TRANSFORMER	-	-	-	
43	GAS PRESSURE REDUCING STATION (GPRS)	-	-	-	
44	ADMIN/MAINTENANCE BUILDING (workshop/warehouse)	-	-	-	
45	CONTROL BUILDING	-	-	-	
46	HVAC	-	-	-	
47	SWITCHYARD CONTROL HOUSE	-	-	-	
48	STORMWATER STORAGE TANK	-	-	-	
49	OILY WATER SEPERATOR	-	-	-	

GENERAL LEGEND

- AGGREGATE SURFACING
- ASPHALT SURFACING
- EXISTING BOILER BLDG AND RELATED MAJOR EQUIPMENT
- CONCRETE
- SEEDING
- NEW ROAD EDGE
- HYDRANT
- EXISTING ROAD EDGE

TERMINAL POINTS

TP-A0	REFERENCE COORDINATE
TP-01	CONNECTION TO FIRE MAIN
TP-02	CONNECTION TO FIRE MAIN
TP-03	PROCESS WATER INTERCONNECTION
TP-04	GAS (ABOVE GROUND INTERCONNECTION)
TP-05	POTABLE WATER INTERCONNECTION
TP-06	COMPRESSED AIR INTERCONNECTION
TP-07	ELECTRICAL COMMUNICATION INTERCONNECTION
TP-08	GROUNDING INTERCONNECTION POINT TO NORTH
TP-09	GROUNDING INTERCONNECTION POINT TO NORTH
TP-10	GROUNDING INTERCONNECTION POINT TO EAST
TP-11	GROUNDING INTERCONNECTION POINT TO EAST
TP-12	GROUNDING INTERCONNECTION POINT TO SOUTH
TP-13	GROUNDING INTERCONNECTION POINT TO SOUTH
TP-14	RAIN WATER SYSTEM INTERCONNECTION POINT 1 HORIZONTAL PIPE 15"
TP-15	RAIN WATER SYSTEM INTERCONNECTION POINT 2 HORIZONTAL PIPE 15"
TP-16	RAIN WATER SYSTEM INTERCONNECTION POINT 3 HORIZONTAL PIPE 15"
TP-17	RAIN WATER SYSTEM INTERCONNECTION POINT 4 HORIZONTAL PIPE 15"
TP-18	RAIN WATER SYSTEM INTERCONNECTION POINT 5 HORIZONTAL PIPE 15"
TP-19	RAIN WATER SYSTEM INTERCONNECTION POINT 6 HORIZONTAL PIPE 15"
TP-20	RAIN WATER SYSTEM INTERCONNECTION POINT 7 HORIZONTAL PIPE 15"
TP-21	69kV INTERCONNECTION 1
TP-22	69kV INTERCONNECTION 2
TP-23	480V LV INTERCONNECTION
TP-24	480V LV INTERCONNECTION
TP-25	EXISTING #1 WATER WELL AND NEW LINE TIE POINT
TP-26	EXISTING #2 WATER WELL AND NEW LINE TIE POINT
TP-27	69kV INTERCONNECTION 1
TP-28	69kV INTERCONNECTION 2
TP-29	69kV INTERCONNECTION 3
TP-30	CONNECTION TO OILY WATER SEPARATOR
TP-31	SANITARY EFFLUENT INTERCONNECTION

NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

40' 20' 0 40' 80'

1"=40'

REVISIONS

DATE	NO.	DESCRIPTION	BY	CH'K	APP
03/FEB/21	A	ISSUED FOR REFERENCE			
09/APR/21	B	ISSUED FOR PERMIT APPLICATION	TMC		
26/APR/21	C	ISSUED PER OWNER REVIEW	TMC		
21/JUL/21	D	ISSUED FOR REVIEW	DJL		
15/DEC/21	E	UPDATED TESLA ARRANGEMENT	JSH		

DES: ERC
DWN: MJW CH'K:
APPROVED:
SCALE:
DATE:

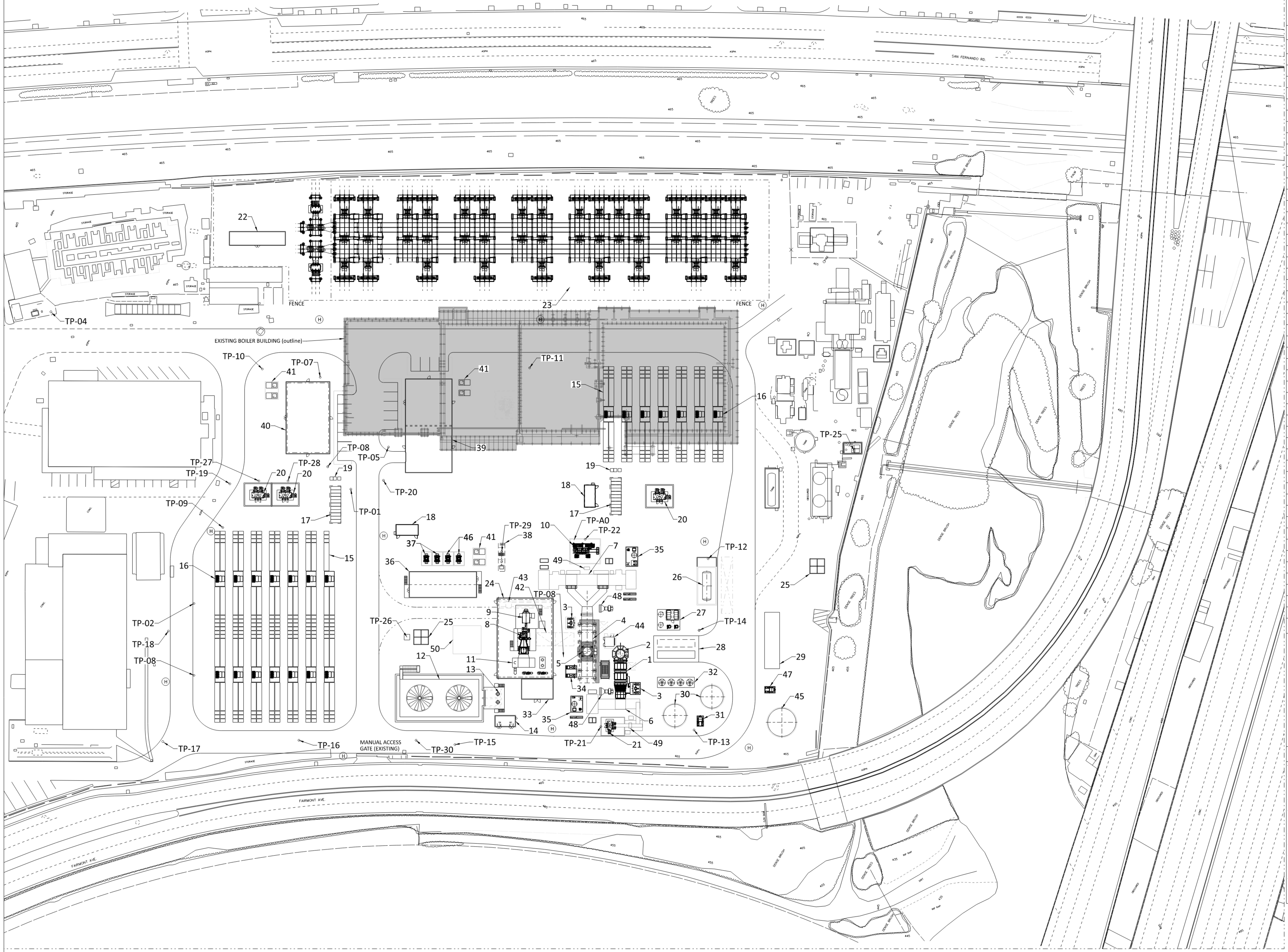
DWG_TYPE (AutoCAD)

GRAYSON REPOWERING PROJECT ALTERNATIVE 7 GENERAL ARRANGEMENT SITE

GLENDALE WATER & POWER
CITY OF GLENDALE
CALIFORNIA

SHEET: G1002

GPP-00



NOTES

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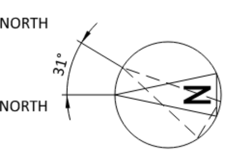

FACILITIES LEGEND

ID	FACILITY	ARRANGEMENT	TIEDOWN LOCATION		REMARKS
			NORTH	EAST	
1	SELECTIVE CATALYST REDUCTION (SCR) UNIT	-	-	-	
2	EXHAUST STACK (SCR)	-	-	-	
3	AMMONIA FLOW AND CONTROL UNIT	-	-	-	
4	ONCE THRU BOILER	-	-	-	
5	EXHAUST STACK (OTB)	-	-	-	
6	EXISTING COMBUSTION TURBINE UNIT 8A	-	-	-	
7	EXISTING COMBUSTION TURBINE UNITS 8B - 8C	-	-	-	
8	STEAM TURBINE	-	-	-	
9	STEAM TURBINE GENERATOR	-	-	-	
10	GENERATOR STEP-UP TRANSFORMER	-	-	-	
11	CONDENSER	-	-	-	
12	COOLING TOWER	-	-	-	
13	CIRCULATING WATER PUMPS	-	-	-	
14	CIRCULATING WATER CHEMICAL FEED	-	-	-	
15	TESLA MEGAPACK2	-	-	-	
16	GATHERING SYSTEM TRANSFORMER	-	-	-	
17	GATHERING SYSTEM SWITCHGEAR	-	-	-	
18	TESLA CONTROL HOUSE	-	-	-	
19	COMMS VAULT	-	-	-	
20	69kV GSU TRANSFORMER	-	-	-	
21	GENERATOR STEP-UP TRANSFORMER	-	-	-	
22	SWITCHYARD CONTROL HOUSE	-	-	-	
23	SWITCHYARD	-	-	-	
24	STEAM TURBINE BUILDING	-	-	-	
25	WELL PUMP DISINFECTION SKID	-	-	-	
26	AMMONIA STORAGE TANK	-	-	-	
27	COMPRESSED AIR EQUIPMENT	-	-	-	
28	WATER TREATMENT EQUIPMENT TRAILER	-	-	-	
29	DEMINERALIZED WATER TRAILER PARKING	-	-	-	
30	DEMINERALIZED WATER STORAGE TANK	-	-	-	
31	DEMINERALIZED WATER PUMPS SKID	-	-	-	
32	AIR COOLED HEAT EXCHANGER	-	-	-	
33	CONDENSATE POLISHING EQUIPMENT ROOM	-	-	-	
34	BOILER FEEDWATER PUMPS (LOCATED BELOW HRSG)	-	-	-	
35	FOGGING EQUIPMENT	-	-	-	
36	UNIT 8A/8BC POWER DISTRIBUTION CENTER	-	-	-	
37	13.8/4.16 kV TRANSFORMER	-	-	-	
38	OIL/WATER SEPARATOR	-	-	-	
39	ADMIN/MAINTENANCE BUILDING (workshop/warehouse)	-	-	-	
40	CONTROL BUILDING	-	-	-	
41	HVAC	-	-	-	
42	UTILITY RACK	-	-	-	
43	OVERHEAD CRANE	-	-	-	
44	CONTINUOUS EMISSIONS MONITORING SYSTEM (COMMON)	-	-	-	
45	STORMWATER STORAGE TANK	-	-	-	
46	13.8/0.48 kV TRANSFORMER	-	-	-	
47	STORM WATER PUMPS	-	-	-	
48	TEMPERING AIR FANS	-	-	-	
49	13 kV GENERATOR BREAKER/SWITCHGEAR	-	-	-	
50	AUX BOILER (ELECTRIC)	-	-	-	

GENERAL LEGEND

AGGREGATE SURFACING

ASPHALT SURFACING

EXISTING BOILER BLDG AND RELATED MAJOR EQUIPMENT

CONCRETE

SEEDING

NEW ROAD EDGE

EXISTING ROAD EDGE

H HYDRANT

TERMINAL POINTS

TP-A0	REFERENCE COORDINATE
TP-01	CONNECTION TO FIRE MAIN
TP-02	CONNECTION TO FIRE MAIN
TP-03	NOTE USED
TP-04	GAS (ABOVE GROUND INTERCONNECTION)
TP-05	POTABLE WATER INTERCONNECTION
TP-06	NOT USED
TP-07	ELECTRICAL COMMUNICATION INTERCONNECTION
TP-08	GROUNDING INTERCONNECTION POINT TO NORTH
TP-09	GROUNDING INTERCONNECTION POINT TO NORTH
TP-10	GROUNDING INTERCONNECTION POINT TO EAST
TP-11	GROUNDING INTERCONNECTION POINT TO EAST
TP-12	GROUNDING INTERCONNECTION POINT TO SOUTH
TP-13	GROUNDING INTERCONNECTION POINT TO SOUTH
TP-14	RAIN WATER SYSTEM INTERCONNECTION POINT 1 HORIZONTAL PIPE 15"
TP-15	RAIN WATER SYSTEM INTERCONNECTION POINT 2 HORIZONTAL PIPE 15
TP-16	RAIN WATER SYSTEM INTERCONNECTION POINT 3 HORIZONTAL PIPE 15"
TP-17	RAIN WATER SYSTEM INTERCONNECTION POINT 4 HORIZONTAL PIPE 15"
TP-18	RAIN WATER SYSTEM INTERCONNECTION POINT 5 HORIZONTAL PIPE 15"
TP-19	RAIN WATER SYSTEM INTERCONNECTION POINT 6 HORIZONTAL PIPE 15"
TP-20	RAIN WATER SYSTEM INTERCONNECTION POINT 7 HORIZONTAL PIPE 15"
TP-21	69kV INTERCONNECTION 1
TP-22	69kV INTERCONNECTION 2
TP-23	NOT USED
TP-24	NOT USED
TP-25	EXISTING #1 WATER WELL AND NEW LINE TIE POINT
TP-26	EXISTING #2 WATER WELL AND NEW LINE TIE POINT
TP-27	69kV INTERCONNECTION 1
TP-28	69kV INTERCONNECTION 2
TP-29	CONNECTION TO OILY WATER SEPARATOR
TP-30	SANITARY EFFLUENT INTERCONNECTION

NOT TO BE USED FOR CONSTRUCTION

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40' 20' 0 40' 80'

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REVISIONS

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09/MAR/21	A	ISSUED FOR OWNER REVIEW			
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21/JUL/21	D	ISSUED FOR OWNER REVIEW			
15/DEC/21	E	UPDATED TESLA ARRANGEMENT	JSH		

DES:

DWN: DJL CH'K:

APPROVED:

SCALE:

DATE:

DWG_TYPE (AutoCAD)

GRAYSON REPOWERING PROJECT
ALTERNATIVE 8 GENERAL ARRANGEMENT
SITE

GLENDALE WATER & POWER
CITY OF GLENDALE
CALIFORNIA

SHEET: G1003

GPP-00

ATTACHMENT D STATE HISTORIC PRESERVATION OFFICER (SHPO) LETTER TO THE HSR AUTHORITY DATED DECEMBER 3, 2020

1

State of California • Natural Resources Agency

Gavin Newsom, *Governor*

DEPARTMENT OF PARKS AND RECREATION
OFFICE OF HISTORIC PRESERVATION

Lisa Ann L. Mangat, *Director*

Julianne Polanco, State Historic Preservation Officer

1725 23rd Street, Suite 100, Sacramento, CA 95816-7100
Telephone: (916) 445-7000 FAX: (916) 445-7053
calshpo.ohp@parks.ca.gov www.ohp.parks.ca.gov

December 3, 2020

Reference Number: FRA_2017_0516_001

Submitted Via Electronic Mail

Brett Rushing
Cultural Resources Program Manager
California High-Speed Rail Authority
770 L Street, Suite 620
Sacramento, CA 95814

Re: High-Speed Rail Program, Burbank to Los Angeles Project Section, Additional Information and Request for Review and Concurrence on Revised National Register of Historic Places Determination of Eligibility for Grayson Steam-Electric Generating Station (Grayson Power Plant)

Dear Mr. Rushing:

The California High-Speed Rail Authority (Authority) is continuing consultation with the State Historic Preservation Officer (SHPO) regarding the Burbank to Los Angeles Project Section of the High-Speed Rail (HSR) Project. This consultation is undertaken in accordance with the *Programmatic Agreement Among the Federal Railroad Administration, the Advisory Council on Historic Preservation, the California State Historic Preservation Officer, and the California High-Speed Rail Authority* (PA 2011). In support of this consultation, the authority has provided following documentation:

Updated California Department of Parks and Recreation Site Record Form (DPR 523) for Grayson Power Plant, 2015 (revised 2017)

City of Glendale Community Development Department Comment Letter on the California High-Speed Rail Program Burbank to Los Angeles Project Section Draft Environmental Impact Report/Environmental Impact Statement, August 31, 2020

In a letter dated May 2, 2019, SHPO concurred that the Grayson Power Plant was eligible for listing on the National Register of Historic Places (NRHP) under Criteria A at the local level of significance for its association with power generation in Glendale. Subsequently, new information on the history of the Grayson Power Plant has come to light: a comprehensive 2018 evaluation undertaken for an Environmental Impact Report by Stantec Consulting Services for the City of Glendale found that the property did not retain sufficient integrity to considered eligible for listing on the NRHP under all criteria. Having considered this information, the Authority agrees with the conclusions with the 2018 evaluation and request SHPO concurrence with the revised determination of eligibility.

Having reviewed your submittal, SHPO concurs that the Grayson Power Plant is ineligible for listing on the NRHP under all criteria for the reasons outlined in the revised DPR 523 form.

If you have any questions, please contact State Historian Tristan Tozer at (916) 445-7027 or Tristan.Tozer@parks.ca.gov.

Sincerely,

Julianne Polanco
State Historic Preservation Officer

CALIFORNIA
High-Speed Rail Authority

November 3, 2020

Julianne Polanco
State Historic Preservation Officer
Attention: Tristan Tozer
Office of Historic Preservation
1725 23rd Street, Suite 100
Sacramento, CA 95816

OHP Project #FRA_2017_0516_001

Subject: High-Speed Rail Program, Burbank to Los Angeles Project Section – additional information and request for review and concurrence on revised determination of National Register of Historic Places eligibility for Grayson Steam-Electric Generating Station (Grayson Power Plant)

Dear Ms. Polanco:

The California High-Speed Rail Authority (Authority) is continuing consultation with the State Historic Preservation Officer (SHPO) and other consulting parties regarding the Burbank to Los Angeles Project Section of the California High-Speed Rail (HSR) Program. This consultation is undertaken in accordance with the 2011 *Programmatic Agreement Among the Federal Railroad Administration, the Advisory Council on Historic Preservation, the California State Historic Preservation Officer, and the California High-Speed Rail Authority* (PA). In support of this consultation, the Authority is providing the enclosed documentation:

Updated California Department of Parks and Recreation Site Record Form (DPR 523) for Grayson Power Plant, 2015 (revised 2017)

City of Glendale Community Development Department Comment Letter on the California High-Speed Rail Program Burbank to Los Angeles Project Section Draft Environmental Impact Report/Environmental Impact Statement, August 31, 2020

On December 12, 2016, the Authority provided your office and consulting parties the Burbank to Los Angeles Project Section Historic Architectural Survey Report, which evaluated the eligibility of properties for listing in the National Register of Historic Places (NRHP). In a letter dated May 2, 2019, you concurred with the Authority's findings, including the Authority's determination that the Grayson Steam-Electric Generating Station (Grayson Power Plant) in Glendale was eligible for listing in the NRHP.

On August 31, 2020, in response to the circulation of the Burbank to Los Angeles Project Section Public Draft EIR/EIS, the Glendale Community Development Department provided the Authority additional information on the Grayson Power Plant.

The information provided included an updated DPR form for the Grayson Power Plant recommending the power plant ineligible for listing in the NRHP. The DPR form provided information previously unknown to the Authority including documentation of substantial physical alterations to the power plant that have diminished its integrity and ability to convey its historical significance. The Authority has reviewed the additional information, has reevaluated its previous NRHP eligibility determination, and now considers Grayson Power Plant ineligible for listing in the NRHP.

REQUEST FOR CONCURRENCE

The Authority is requesting SHPO concurrence with the determination that Grayson Power Plant is ineligible for listing in the NRHP. While the PA does not specify review duration for NRHP reevaluations, we respectfully request your response **within 30 days** of receipt of this submittal.

By copy of this letter, this report is also being transmitted to the Burbank to Los Angeles Consulting Parties for review and comment. If you require any additional information, please contact Jeff Carr by phone at (213) 443-7458 or by email at jeff.carr@hsr.ca.gov. Thank you very much for your ongoing assistance with this undertaking.

Sincerely,

Brett Rushing
Cultural Resources Program Manager
California High-Speed Rail Authority
(916) 403-0061
brett.rushing@hsr.ca.gov

Encl: Updated California Department of Parks and Recreation Site Record Form (DPR 523) for Grayson Power Plant, 2015 (revised 2017)

City of Glendale Community Development Department Comment Letter on the California High-Speed Rail Program Burbank to Los Angeles Project Section Draft Environmental Impact Report/Environmental Impact Statement, August 31, 2020

cc: Stephanie Perez, Federal Railroad Administration
Sarah Stokely, Advisory Council on Historic Preservation
David Navecky, Surface Transportation Board
Danielle Storey, U.S. Army Corps of Engineers, Los Angeles District
Claudia Harbert, Caltrans District 7
Ken Bernstein, Office of Historic Resources, Los Angeles Department of City Planning
Steve Fox, Southern California Association of Governments
Adrian Scott Fine, Los Angeles Conservancy
Erik Krause, City of Glendale Community Development Department

CITY OF GLENDALE, CALIFORNIA
Community Development
Planning

633 E. Broadway, Suite 103
Glendale, CA 91206-4311
Tel. (818) 548-2140 Fax (818) 240-0392
glendaleca.gov

August 31, 2020

Mr. Mark McLoughlin
California High-Speed Rail Authority
770 L Street, Suite 620 MS-1
Sacramento, CA 95814
Info@hsr.ca.gov

On behalf of the City of Glendale (City), we are providing comments on the California High Speed Rail (HSR) Authority's "California High-Speed Rail Project, Burbank to Los Angeles Project Section Draft EIR." (Project).[1] We understand, GPA Consulting prepared a Historic Architectural Survey Report (Report) for the Project which was completed in March 2019. Using the HSR Section 106 Programmatic Agreement in the Cultural Resources Technical Memorandum #1, GPA defined the Project Area of Potential Effect (APE) based on the November 2018 footprint. Through delineation of the APE, the City of Glendale's Grayson Power Plant (Power Plant) was included within the defined APE.

We recognize the Power Plant had no listings for previous studies and no historical determination under any criteria for either the National Register of Historic Places (NRHP) or California Register of Historical Resources (CRHR). Therefore, the Power Plant was surveyed and recorded by GPA on a DPR-523 Series Form in which they identified the boiler building as being constructed in 1941. GPA recommended

> "…the main building located at 901 Fairmont Avenue[2] meets the criteria for listing in the [NRHP] and the [CRHR] as a locally significant example of a property associated with developmental history of power generation in Glendale under NRHP Criterion A and CRHR Criterion 1, with a period of significance of 1941-1955 (its years of operation prior to the redevelopment of the Grand Central Air Terminal to the Grand Central Industrial Center)."

We understand that, based on this recommendation, the EIR considers the Power Plant to be an historical resource for the purposes of CEQA. GPA's prepared DPR-523 Form included a detailed physical description of the Power Plant, as well as, a short historic context, brief property history, historical photographs, and aerials, limited contemporary photographs from the public right-of-way, and full evaluation per the NRHP and CRHR criteria. Based on their data, GPA considered the Power Plant a California Historical Resource Status Code of 2S2, which represents "Individual property determined eligible for [NRHP] by a consensus through Section 106 process. Listed in the [CRHR]."

On October 9, 2018, the "California High-Speed Rail Authority, Burbank to Los Angeles Project Station Historic Architectural Survey Report" was submitted to the California State Historic Preservation Officer (SHPO) for review. The report was reviewed and revised multiple times, in October 2018, March 2019,

[1] California High-Speed Rail Project, Burbank to Los Angeles Project Section, State Clearing House 2014071073, https://ceqanet.opr.ca.gov/2014071073/2 (accessed 8/29/2020).
[2] The correct address is 800 Air Way.

and on April 3, 2019, for a final SHPO review and concurrence.[3] On May 2, 2019, Kathleen Forrest, acting on behalf of California SHPO Julianne Polanco , concurred with the findings presented in the April 2019 submittal. This included the finding that the Grayson Power Plant is eligible for the NRHP as a locally significant example of a property associated with developmental history of power generation in Glendale under NRHP Criterion A.[4]

In 2016, prior to the High Speed Rail Study, the City of Glendale contracted, Stantec Consulting Services Inc. to prepare a Historic Resources Inventory and Evaluation Report (attached) and DPR-523 Forms for Grayson Power Plant in support of an EIR (Grayson Repowering Project) on the Grayson Power Plant. In 2018, this report was revised to reflect comments received during the public review of the draft EIR and preparation of the final EIR. The report documents the entire property, rather than just the boiler buildings. The 2018 revised report included an introduction with the project location and description, identified APE for the redevelopment project, team qualifications, research and field methods, and an in-depth historic context which covers the history of electricity in California, steam generation in Los Angeles County, Glendale history, and the history and evolution of the power plant. Additionally, the report included an in-depth discussion of the power plant, boiler building, boiler units, cooling towers, switchyards, as well as adjacent and new construction. The extensive written documentation was supported by photographic documentation, crucial for identification of property modifications and included tables chronologically illustrating modifications, citing building information provided by the City and through aerial photography to show change over time. The property includes an evaluation of potential eligibility for the NRHP, CRHR, and the City of Glendale Register based upon full evaluations per the applicable significance criteria.

The 2018 effort recommended the Grayson Power Plant <u>not</u> eligible for listing on the NRHP, CRHR, or the Glendale Register of Historic Resources. The report found the Grayson Power Plant significant under Criteria C and 3; however, it lacks sufficient integrity to convey that significance. The report states:

> "The Grayson Power Plant property as first constructed in 1941 represented the designs of the 1920s, this was soon realized as the plant underwent numerous upgrades and additions through the 1940s, 1950s, 1960s, 1970s, and 1980s to keep pace with the larger, semi-outdoor boiler types that proliferated across California in the 1950s and 1960s. Therefore, Grayson Power Plant is ineligible, under NRHP Criteria A, CRHR Criterion 1 and GRHR as it is not associated with important events in national, state, or city history, or exemplifies significant contributions to the broad cultural, political, economic, social, or historic heritage of the nation, state, or city. Rather, the plant is a continuation of electrical generation themes in a city that had been using electricity for 32 years.... There is no evidence that Grayson Power Plant has any important association with any person or persons who made significant contributions to history at the local, state, or national level. The power plant is not eligible

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[3] Brett Rushing, Cultural Resources Program Manager for the California High-Speed Rail Authority to Kathleen Forrest, State Historic Preservation Officer California Office of Historic Preservation re: "High-Speed Rail Program, Burbank to Los Angeles Project Section (FRA_2017_0516_001), request for review and concurrence on revised Historic Architectural Survey Report; Notification of Modification to the Area of Potential Effects," April 3, 2019.

[4] Julianne Polanco, SHPO to Brett Rushing, Cultural Resource Program Manager for the California High-Speed Rail Authority, re: "Historical Architectural Survey Report (HASR) Burbank to Los Angeles Project Section High-Speed Train Project, County of Los Angeles, California," FRA_2017_0516_001, May 2, 2019.

> under NRHP Criteria B, CRHR Criterion 2 or for the GRHR… An article noted its design as earthquake resistant meaning its generators were located outside on a concrete foundation that was resistant to earthquakes with metal coverings to protect it from weather. R.R. Martell noted earthquake engineer consulted on the project stating the generator could be constructed outside the main boiler building. Through time the power plant has withstood earthquakes, as have other power plants with varied designs. This design is important in the greater advancement of power plant designs. Unfortunately, multiple additions and modifications have degraded its integrity and it can no longer convey this significance under NRHP Criteria C or CRHR Criterion 3. As noted, before, the GRHR does not assess integrity. The evolution of earthquake resistant power plant is important to the context of power plant design in California, however it is within the context of Glendale is lessened… The property does not appear likely to yield significant informational associations under NRHP Criteria D, CRHR Criterion 4 or the GRHR as the plant does not yield information important to archaeological pre-history or history of the nation, state, region, or city.[5]

It continues, through

> …numerous building additions and continued evolution of the property there has been a loss of integrity of design, materials, workmanship, and feeling. The property retains integrity of location, setting, and association. The power plant has not moved, the overall setting has remained industrial, and it maintains its association as a power plant. However, numerous alterations have removed its integrity of design to the original plant conceived by Elliott, materials as the building materials, while similar are different in type and massing from the original section. The plant has lost its association of workmanship as the additions have fundamentally altered the physical characteristics of the building as original constructed in 1941 and finally the plant has lost its original feeling. Aside from the numerous building additions continued addition of non-attached boiler units with modern cooling towers and ancillary buildings have removed the original feeling of the property. Therefore, the building has lost integrity coupled with lack of significance the building is not eligible for the NRHP or CRHR under any criterion.[6]

These findings were preliminary and were included in, and frame the discussion in, the City's EIR for the proposed redevelopment Grayson Repowering Project. The EIR concluded that the proposed Project would not result in potentially significant and unavoidable environmental impacts relating to historical resources.

The City has recognized some data gaps and/or inaccuracies in the GPA preparation; of importance is that the GPA study mischaracterized the period of significance, 1941-1955, as it correlates to the identified historic property. The earliest iteration of the boiler building dates to 1941; however, the building identified by GPA was constructed between 1941 and 1964, with a significant portion of the building constructed between 1959 and 1964. This is relevant because the modifications, would constitute a loss of integrity as most of the building was constructed after 1955.

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[5] Stantec Consulting Services (Stantec), Historic Resources Inventory and Evaluation, Grayson Power Plant, City of Glendale, California 2016, (revised 2018).
[6] Stantec, Historic Resources Inventory and Evaluation, Grayson Power Plant (revised 2018).

The map in the DPR-523 Building, Structure, Object (BSO) Form identifies the “NRHP-Eligible Historic Property Boundary highlighted in white.” GPA expands stating “The boundaries of the historic property are limited to the main building. The later additions, such as the modern buildings and infrastructure as well as the replaced steam turbines, do not contribute to the property because they were most likely constructed outside the period of significance, 1941-1955, at which point the Grand Central Air Terminal was redeveloped as the Grand Central Industrial Center. This redevelopment incited major alterations throughout the subject property, bust most noticeable the northern portion of the property which was formerly part of the airfield.”

The challenge is, the identified property was constructed between 1941 and 1964, not 1955. The original boiler building which housed Unit 1 was completed in 1941, with Unit 2 added in 1948. In 1953 the building was expanded to accommodate Unit 3, with the design remaining consistent with the original building. Between 1959 and 1964 a multi-story addition on the north end of the building was added to accommodate Unit 4 in 1959 and Unit 5 in 1964. Additions to the property continued with Unit 6 in 1972 and Unit 7 in 1974, they were separate structures constructed north of the main boiler building.

Up until 1959, the Power Plant remained a single-story-structure. In 1959, the addition of Unit 4 and 5 resulted in the much larger and taller structure which remains today. Despite these alterations, GPA inaccurately states that the “main building marked by signage stating ‘City of Glendale Public Service Department Steam Electric Generating Plant,’ retains integrity of location, materials, design, workmanship, feeling, and association; however, the integrity has been diminished by ongoing development on the site and in the area since the property’s construction according to historic aerials maps.”

GPA provides that the entire building identified dates from 1941 to 1955 and that it retains the integrity of a building competed in 1955, when in actuality a significant portion of the building dates from 1959 to 1964. These modifications should have been identified as a loss of integrity as the building clearly no longer retains the design, materials, and workmanship of a building constructed between 1941 and 1955. With this, the loss of four of the seven aspects (setting, design, materials, and workmanship), they could have concluded the building was significant under Criteria A and 1, but because of a loss of integrity unable to convey this significance and thusly ineligible for the NRHP and CRHR.

Additionally, the historic context considered in the GPA study does not address the significance of this end date. By choosing 1955, it would suggest that the Power Plant’s significance is derived to its association with the Grand Central Air Terminal. However, there is no historic context to support this assertion; the airfield was developed in 1928, whereas the Power Plant was constructed 13 years later. In addition, the report states that it retains all aspects of integrity, despite the Power Plant having undergone multiple additions since the original plan construction in 1941. Most notably, the GPA report does not include the fact that the two story-addition was added in 1959, with ongoing work occurring into 1964. Given this, the structure cannot convey its significance from 1941 through 1955 since the northernmost portion of the building is an addition constructed outside the identified period of significance, 1941-1955.

A detailed review of the 2016 DPR revealed the evaluation conducted GPA does not address several key aspects in developing a proper historic resource evaluation, as outlined in *National Register*

Bulletin No.15. Primarily, the historic context included in the DPR-523 Form is largely incomplete, and does not provide sufficient information to form the basis for an accurate historical significance evaluation of the property, specifically under Criterion A/1 for the property's association with the Grand Central Air Terminal, nor does it fully support the assertion that construction of a steam plant benefited the region. It does not explain the history of electrical generation in the region or place the construction of the Grayson Power Plant within that context. Second, the GPA report does not provide a well-developed analysis of historical integrity. While the report does provide a cursory list of alternations, which appear to be based upon the included historic aerials, it does not identify or account for many of the modifications to the property, which largely occurred outside the period of significance. This does not adhere to the integrity analysis outlined in N*ational Register Bulletin No.15.*

We ask the HSR Authority, given this new information, to reconsider the previous determination. We ask that, based on the lack of integrity through multiple additions from 1959 through 1964, outside the GPA period of significance, the authority find Grayson Power Plant ineligible for listing on the CRHR and as a historical resource for the purposes of CEQA. Further, we ask the Authority reconsult with SHPO regarding the property's status on the NRHP.

Sincerely,

Erik Krause
Deputy Director of Community Development

State of California - The Resources Agency
DEPARTMENT OF PARKS AND RECREATION
PRIMARY RECORD

Primary #
HRI #
Trinomial
NRHP Status Code 6Z

Other Listings
Review Code Reviewer Date

***Resource Name or #:** (Assigned by recorder) Grayson Power Plant

P1. Other Identifier:

***P2. Location:** ☐ Not for Publication ☒ **Unrestricted** ***a. County** Los Angeles
and (P2c, P2e, and P2b or P2d. Attach a Location Map as necessary.)
b. USGS 7.5' Quad Burbank, CA
Date 2015 **T** 1N; **R** 13W **Sec** 7 S.B. **B.M.**
c. Address 800 Air Way City Glendale Zip 91201
d. UTM: (Give more than one for large and/or linear resources) Zone, 10S 382154 mE/ 3780132 mN
e. Other Locational Data: (e.g., parcel #, directions to resource, elevation, decimal degrees, etc., as appropriate)

From downtown Glendale, travel 2.3 miles west on Elk Avenue to San Fernando Road, proceed northwest of 2.8 miles on San Fernando Road to Flower Street. Travel southwest on Flower Street to Air Way, the power plant is located on Air Way at the convergence of the Los Angeles River and Fairmont Avenue. APN: 5593-003-906.

***P3a. Description:** (Describe resource and its major elements. Include design, materials, condition, alterations, size, setting, and boundaries)

Glendale Water and Power's Grayson Power Plant is a steam electric power plant located in Glendale, CA. The approximately 11-acre property is bounded by Union Pacific Railroad tracks and San Fernando Road to the northeast, Fairmont Avenue to the southwest, south, and southeast. The property contains numerous elements of power generating infrastructure including a boiler building with nine boilers, generators, five cooling towers, two switch yards, and multiple auxiliary buildings amounting to approximately 17 permanent buildings and structures (**Photograph 1**) (see Continuation Sheet).

***P3b. Resource Attributes:** (List attributes and codes) HP8 – Industrial Building, HP11 – Engineering Feature

***P4. Resources Present:** ☒ Building ☒ Structure ☐ Object ☐ Site ☐ District ☐ Element of District ☐ Other (Isolates, etc.)

P5a. Photograph or Drawing (Photograph required for buildings, structures, and objects.)

P5b. Description of Photo: (view, date, accession #)
Photograph 1: Grayson Power Plant, camera facing southwest, August 17, 2015.

***P6. Date Constructed/Age and Source:**
☒ Historic ☐ Prehistoric ☐ Both
1941, Glendale Water and Power

***P7. Owner and Address:**
City of Glendale, Glendale Water and Power
800 Air Way
Glendale, CA 91201

***P8. Recorded by:** (Name, affiliation, and address)
Meagan Kersten and John Terry
Stantec, Inc.
555 Capitol Avenue, Suite 650
Sacramento, CA 95814

***P9. Date Recorded:** August 17, 2015

***P10. Survey Type:** (Describe) Intensive

***P11. Report Citation**: (Cite survey report and other sources, or enter "none.")
Historic Resource Inventory and Evaluation Report, Grayson Power Plant, Glendale, CA, Stantec, 2015 (Revised 2017)

***Attachments:** ☐NONE ☐Location Map ☒Continuation Sheet ☒Building, Structure, and Object Record ☐Archaeological Record ☐District Record ☐Linear Feature Record ☐Milling Station Record ☐Rock Art Record ☐Artifact Record ☐Photograph Record ☐ Other (List):

State of California - The Resources Agency Primary #
DEPARTMENT OF PARKS AND RECREATION HRI#
BUILDING, STRUCTURE, AND OBJECT RECORD

***Resource Name or #** (Assigned by recorder) Grayson Power Plant ***NRHP Status Code** 6Z

B1. Historic Name: Glendale Public Service Department, Steam Electric Generating Plant
B2. Common Name: Grayson Power Plant
B3. Original Use: Power Plant B4. Present Use: Power Plant
***B5. Architectural Style:** Streamline Moderne
***B6. Construction History:** (Construction date, alterations, and date of alterations) Grayson Power Plant was constructed in 1941 with additions added to the main boiler building in 1952, 1963, 1972, and 1977. The site has continuously evolved as technology changed and more units were brought online (see detailed history below)

***B7. Moved?** ☒**No** ☐**Yes** ☐**Unknown Date:** ________ **Original Location:** ________
***B8. Related Features: none**
B9a. Architect: Daniel A. Elliott b. Builder: Glendale Public Service Department
***B10. Significance: Theme** n/a **Area** n/a
Period of Significance n/a **Property Type** n/a **Applicable Criteria** n/a (Discuss importance in terms of historical or architectural

This intensive level survey and evaluation finds that Grayson Power Plant, while significant, lacks integrity to convey this significance for listing in the National Register of Historic Places (NRHP), California Register of Historical Resources (CRHR) or Glendale Register of Historic Resources (GRHR). The property has been evaluated in accordance with Section 15064.5(a)(2)-(3) of the California Environmental Quality Act Guidelines (CEQA), using the criteria outlined in Section 5024.1 of the California Public Resources Code and does not appear to be a historical resource for the purpose of CEQA (see continuation sheet).

B11. Additional Resource Attributes: (List attributes and codes) ________

***B12. References:** See footnotes

B13. Remarks:

***B14. Evaluator:** Corri Jimenez and Garret Root, Stantec Inc.

***Date of Evaluation:** December 2015 and December 2017

This space reserved for official comments.

P3a. Description (Continued):

Grayson Power Plant's boiler building faces southeast, on a northwest-southeast axis and massing is predominantly rectangular divided into three levels and each elevation asymmetrical (**Photograph 2** and **3**). Architecturally, the boiler building is 2-3-stories high and is framed with structural steel set on a poured concrete pier foundation (**Photograph 4**). The lower floor extends up a floor level on a poured concrete structure with a steel-framed superstructure set on top of the concrete walls; a second steel-framed structure is set on the northwest corner, which houses Unit 3. Streamline Moderne character-defining details are evident as linear lines in the cementitious paneling, illuminating stringcourses on the building's upper southeast corner addition, added during a 1953 expansion to building for Unit #3.

The building has a flat roof with metal coping at the top. The exterior of the building is clad with multiple building materials that include horizontal asbestos siding and horizontal metal sheathing that are bolted to the steel framing. The cementitious siding are visible on the interior of the building as well. A Streamline Moderne style-rolling directional crane, which services the boilers, turbines, and generators, is located on the northeast elevation. Each of the five turbines is covered with a Streamline Moderne enclosure (**Photograph 5**). Copper box lettering in the same style are located on the corner and state: "CITY OF GLENDALE/PUBLIC SERVICE DEPARTMENT/STEAM ELECTRIC GENERATING PLANT" (see Figure 20-21). The northeast elevation of the building has a dock with boilers and equipment located on the northwest elevation (**Photograph 6**). The northwest elevation is where all the mechanical equipment and numerous boiler stacks for Boilers 1, 2, and 3. New equipment is evident for Boiler Unit #3 on the northwest corner.

Multiple openings punctuate the elevations of the boiler building on all elevations. The boiler building retains its original windows, which include structural glass blocks on the northeast elevation and metal-framed industrial awning windows on the southeast elevation (**Photograph 7**). Currently the building houses six boilers and is centrally located near the control room. The interior of the building is open with a catwalk or mezzanine floor of metal grating constructed on the west wall in operating the power equipment that include the boilers above and turbines, which attached to the concrete floor platforms. The corresponding boiler stacks and scrubbers are located on the exterior of building along the west wall (**Photograph 8**).

The Grayson Power Plant had eleven boiler units with seven intact. Units 1 and 2 are located within the boiler building and have been mothballed. Units 3, 4, and 5 are located along the southwest elevation of the boiler building. Units 6 and 7, built between 1972-1974, have since been demolished. Units 8A, 8B, and 8C, were constructed in 1977 and Unit 9, built in 2003. Units 1 through 4 are housed in the main boiler building with additions. Structures 8A, 8B, 8C, and 9 are located within utilitarian metal structures (**Photograph 9** and **10**).

Located west of Grayson Power Plant's boiler units are five cooling towers. Each cooling tower correlates to one boiler. The cooling towers consists of a sub grade water tank is enclosed by two-to-three-foot-thick concrete walls. Each cooling unit has a series of vent stacks. Cooling Towers 1 and 2 are designed with four stacks, which has splayed concrete sidewalls, while Cooling Tower 3 is constructed with six stacks, Cooling Tower 4 has eight stacks, and Cooling Tower 5 with five stacks (**Photograph 12, 13,** and **14**). Additional features of the cooling towers include a louvered wall, which provides air circulation to cool the water from the boilers and wooden roof decks. There are two switching yards, east of the boiler building and are labeled as Kellogg and the Glendale switching yards. The yards are not historic and are not part of this inventory. Five miscellaneous utilitarian buildings are located on the property northwest of the boiler building. These buildings were not inventoried or evaluated as part of this study.

B10. Significance (Continued):

Historic Context

The Glendale Public Service Department steam electric generation plant, renamed Grayson Power Plant in 1972, was constructed in Glendale in 1941, Since construction the power plant has undergone numerous alterations and expansions. The Streamline Moderne boiler building has more than tripled in size since originally conceived by architect Daniel A. Elliott. Fuel fired steam electric units have been common power generators in California since the 1920s. The design and power output changed dramatically by the end of World War II as municipalities and utilities moved towards semi-outdoor fuel fired steam plant. This reduction in building material cost drove exponential growth in the post-war years, becoming common fixtures across California. The Grayson Power Plant represents a transition in fuel fired power plant design that is more associative with the early 1920s designs rather than the more prominent post-war designs.

Electricity in California

California's growth in the first half of the twentieth century was due in part to the development of ambitious hydroelectric systems. Long-distance transmission lines linked the power generating mountainous regions with valley farms, coastal centers, and distant cities, allowing a pace and scale of development that was previously unimaginable. By the 1920s, this intricate system of hydroelectric facilities, coupled with a growing number of fuel-fired steam plants, fed into long distance transmission lines and a series of substations that transferred and distributed power to locations throughout the state for widespread public use (Root and Herbert 2013: 1; Department of Energy 2015). Within this burgeoning energy context, the long-distance transmission lines were of vital importance, serving as the nexus between the state's abundant hydro supplies and the distant urban and agricultural markets. The technological advancement and development of transmission technology enabled greater and greater supplies of readily available energy, occurring with striking rapidity during the period (Root and Herbert 2013: 1-2).

In the late nineteenth century and into the twentieth, electrical transmission covered small distances, typically limited to tens of miles. During this period, the technological debate raged between two key concepts: Direct Current (DC), championed by General Electric and Thomas Edison, and Alternating Current (AC), championed by Westinghouse and electrical engineer Nikola Tesla (Department of Energy 2015; Williams 1997: 90). The critical limitation to DC was its inability to be transmitted over great distances, as the current could not be converted to higher and lower voltages and rapidly lost energy along any distances. In contrast, Tesla's AC stepped up voltage for transmission and stepped down voltages for local distribution, creating a system that avoided the energy seepage of DC. Ultimately, Tesla's vision of AC prevailed and soon transmission lines could carry more power over greater distances, a development that undergirded much of the state and nation's early twentieth century growth. Rapid innovation during the first decades of the twentieth century allowed for increasingly higher voltages, with heavier insulators, multi-phase lines, and other mechanical methods adapted to carry greater supplies more efficiently, following the adoption of AC. By the early-1910s, California's hydroelectric industry was carrying hundreds of kV of electrical power over hundreds of miles (**Figure 1**) (Root and Herbert 2013: 1-3; Hayes 2014: 237-270).

In the 1880s, hydroelectric plants provided small-scale electrical development to only isolated companies, such as Standard Consolidated Mining Company in Bodie, CA and other localized concerns (Hubbard 2006).

However, by the early 1890s AC technological advancement allowed for a more effective means of transmitting electricity over ever-increasing distances. At the outset of this development, the San Antonio Light and Power Company constructed a 13 mile, 5,000-volt, transmission line in 1892, with PG&E constructing the Folsom Hydroelectric Plant's 22 mile, 11,000-volt transmission line in 1895 (Coleman 1952: 138-140). These distances soon gave way to ever larger transmission capability, with Pacific Light and Power Company's Big Creek Hydroelectric Project running at 150 kV by 1913. Several small companies began constructing independent and local power plants a transmission systems (JRP 2004).

Figure 1. A 1925 map depicting the growth of the transmission system (Vincent 1925).

Rise of Fuel-Fired Steam Electric

British designer Sir Charles Parsons built the first steam turbine-generator in 1884. At the beginning of the twentieth century, engineers designed steam turbines to replace the aging steam engine power plants. Aegidius Elling of Norway is credited in 1903-1904 as being the first to apply the method of injecting steam into the combustion chambers of a gas turbine engine (Termuehlen 2001: 11, 21-28; Beck and Wilson 1996: 30). The greater Los Angeles region had multiple examples of early fuel fired steam plants including the Banning Street Electrical Plant in Los Angles completed in 1883, Los Angeles Steam Plant No. 1 constructed in 1896, Pacific Light and Power Company's steam plant in Redondo Beach was completed in 1902 and the Glenram Power Plant constructed in Pasadena in 1906 (Water and Power Associates 2017; City of Pasadena 2015). Within a relatively short time, the technology and capacity of these engines to supply power and electricity grew exponentially. These advances brought electricity to a wide range of industrial and domestic applications; however, the materials needed to withstand the high temperatures of modern turbines were not yet available. Improvements in steam turbines advanced throughout the 1920s and 1930s, leading to a generation of more efficient turbine power plants in the 1950s. During this time, utilities closed or replaced many of the older steam-electric plant generators and constructed more modern units (Myers 1984: 8).

Steam power generation was part of California's power production throughout the twentieth century, though it declined considerably in the period leading up to World War II as large hydroelectric generating plants came online throughout the state. As early as 1920, hydroelectric power accounted for 69% of all electrical power generated. In 1930, that figure had risen to 76%, and by 1940 hydroelectric sources provided 89% of California's electricity. After World War II this trend reversed and construction of steam-powered electric generating units grew, accounting for most of the new construction. By 1950, hydroelectricity accounted for only 59% of the total power generated, falling to 27% in 1960. Some new hydroelectric plants were built during the 1960s, chiefly associated with federal and state water projects, but by 1970, hydroelectric plants accounted for only 31% of all electricity generated in California. A combination of drought, discovery and tapping of natural gas, and lack of new hydroelectric sites led to its decline (Williams 1997: 374).

A persistent drought in California caused the major utilities to question the reliability of systems dependent on abundant water flows, like hydroelectricity. This drought began in 1924 and continued, on and off, for a decade. Concurrently, in the 1920s new natural gas discoveries were made and provided both Northern and Southern California with ample fuel for steam electric power generation. The confluence of these various factors – drought, new steam generator technologies, and new supplies of natural gas – prompted California utilities to begin constructing large steam plants. Steam plants built across the state shared design characteristics including locations close to load centers to reduce transmission costs, easy and efficient access to fuel supplies, near a water supply, on inexpensive land, and on geological formations that could provide a good foundation (Steele 1950: 17-21). By 1920, the cities of Burbank, Pasadena, Los Angeles, and Glendale restructured their original charters to allow municipality owned power generation facilities and distribution lines (Williams 1997:261; Water and Power Associates 2015; Electrical West 1929). In 1928, LA Gas and Electric Corporation constructed the Seal Bach Power Plant and PG&E constructed Station C in Oakland. In 1929, Great Western Power Company built a large steam plant on San Francisco Bay, near the Hunters Point shipyard, fitted with two 55 MW generators. In 1930, fuel-fired steam power plant accounted for more than half of all new plants under construction in California. The fuel-fired steam generation capacity jumped from 1924 at 407,000 kW to over 1 million kW a mere six years later. (Williams 1997: 279-280; City of Pasadena 2015; Burbank Water & Power 2015; Water and Power Associates 2017; Spencer 1961). These factors prompted many municipalities, like Glendale to construct power plants of their own.

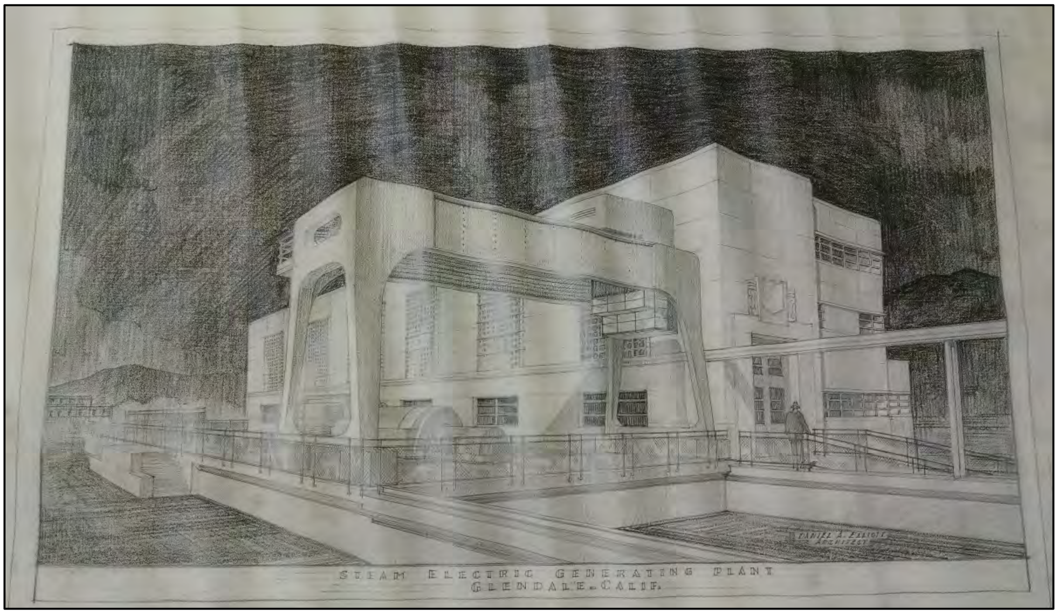
Early Glendale History

By the turn of the twentieth century, Glendale had already experienced rapid growth resulting, in part, from the promotional efforts of Edgar D. Goode and Dr. D. W. Hunt and their Glendale Improvement Society in 1902 (City of Glendale 2012a). The growth continued with the opening of the Pacific Electric Railroad in 1904, connecting Glendale to Los Angeles (City of Glendale 2012a). Glendale incorporated in 1906 and by 1910 had a population of 2,742 residents (Glendale News-Press 1953c; Los Angeles Almanac 2015). Power generation in the City of Glendale began in earnest early when the citizens voted in favor of a $60,000 bond to create the Glendale Public Service Division that purchased the Glendale Light & Power Company generating facility in 1909. By 1910, the system was already strained as power output was a mere 107,000 kilowatts. To supplement, the city purchased additional electricity from Pacific Power & Light, now part of the Southern California Edison Company (Glendale Public Service Commission 1951).

By 1920, Glendale began annexing neighboring communities boasting the city's population to over 13,000 residents (City of Glendale 2012b; Los Angeles Almanac 2015). From 1930 to 1952, Glendale added Whiting Woods and Verdugo Mountains to their city limits a total of 23.6 square miles; two major annexations included New York Avenue (in the La Crescenta area) and Upper Chevy Chase Canyon, and several smaller annexations, which enlarged the city to 29.2 square miles by 1952. By 1950 the population was over 95,700 residents and was considered at the time to be "the fastest growing city in America" (City of Glendale 2012b; Los Angeles Almanac 2015). However, by the late 1930s the Glendale Public Service Commission, Electric Division could not keep pace with the population increases (Glendale Public Service Commission 1951). Prior to 1937, Glendale purchased their power from Southern California Edison Company. This supply was supplemented with completion Hoover Dam however, continued growth indicated another plant would be necessary to supplement demand [Glendale News-Press 1953a; Glendale Public Services Department 1974).

Glendale Steam Electric Generating Plant

Building off the success of the 1920s and early-1930s and seeing the impending probability of an outbreak of hostilities, utilities and municipalities began constructing a series of fuel-fired steam plants across California. Northern California PG&E began construction of three, fuel-fired steam -plants located adjacent to oil refineries, in 1939. Southern California municipalities, in Burbank, Glendale (study property), and San Diego each completed power plants, in 1941 (Williams 1997: 279-280). The City of Glendale began planning for construction of a new power plant in 1937. However, the city's plans were met with immediate opposition by Los Angeles Bureau of Power and Light and the Southern California Edison Company, both which supplied the city with electricity and claimed had surplus electricity which could be sold to the city (Los Angeles Times 1938). Despite these assertions, the city, led by industrial entities pushed forward with their plan for construction of a $1.8 million-dollar plant. The City secured the services of Architect Daniel A. Elliott to design the power plant, referred as the "Glendale Power & Light" or "Steam Electric Generating Plant" (**Figure 2**) (LA Conservancy 2015).



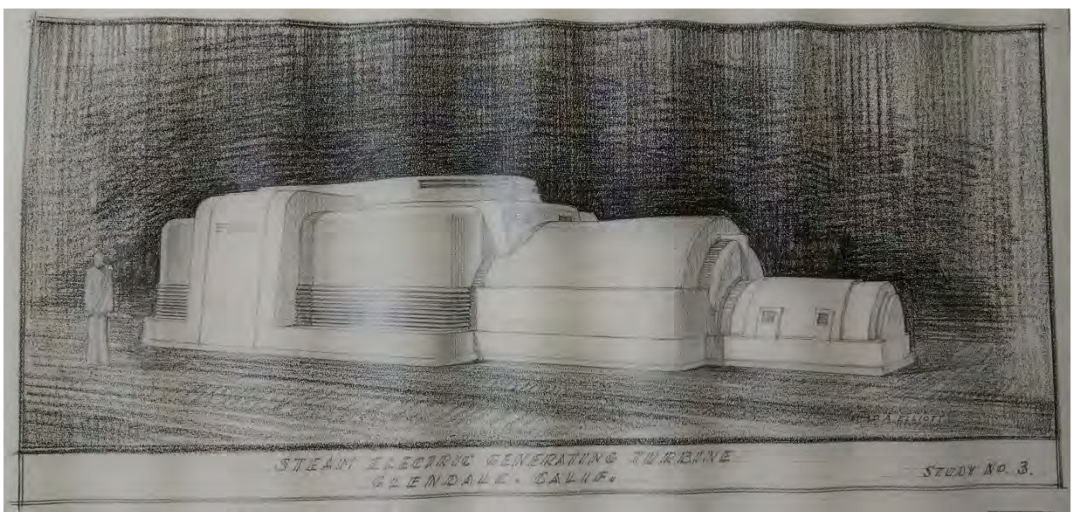


Figure 2. Original Daniel Elliott renderings show the exaggerated streamline moderne details, much of which did not make it onto the building.

Elliott designed the boiler structure in the Streamline Moderne-style, built to house two boilers (Boilers 1A and 1B). Located outside on a full length concrete pedestal were the generators, manufactured by Combustion Engineering Company Inc., New York and with Streamline Moderne detailing. Elliott was born in Las Vegas, New Mexico in 1898. He attended University of California at Berkley, earning an architecture degree in 1925. From 1925 through 1932 he served as a designer at the Los Angeles architecture firm of Gilbert Stanley Underwood before getting his architecture license and becoming an architect at the Metropolitan Water District of Southern California. He remained at the water district from 1932 through 1939. During World War II he worked at Hoover and Montgomery, a firm that specialized in water-related construction projects. Following the end of the war he formed his own architecture practice, one he maintained until his retirement in 1962. Principle examples of his work are water focused designs most notably the Colorado River Aqueduct Pumping Plants and F.E. Weymouth Memorial Water Softening and Filtration Plant completed in 1939 (**Figure 3**) and the Burbank Water & Power administrative building in 1949 (LA Conservancy 2015; AIA 1956: 155).

Elliott's original design laid claim to being the world's first earthquake-proof plant, with a 22 foot deep concrete basement, turbo-generator on an uncovered open deck with a metal covering over the generator from to protect from inclement weather, and a building shell built of light steel and stucco filler walls (Los Angeles Times 1940). At its start-up in 1941, the plant produced 20,000 kilowatts of power. The city had already secured funding for a second unit set to be added in 1945 (Lost Angeles Times 1941; Glendale Public Service Commission 1951). To meet increasing demands for electricity, a second unit was added in 1947, which included an additional 20,000-kilowatt generator and single boiler increasing the plant's combined kilowatt capacity of 40,000 kilowatts (Glendale News Press 1953e; Glendale News Press 1953f; and Glendale Public Service Commission 1951).

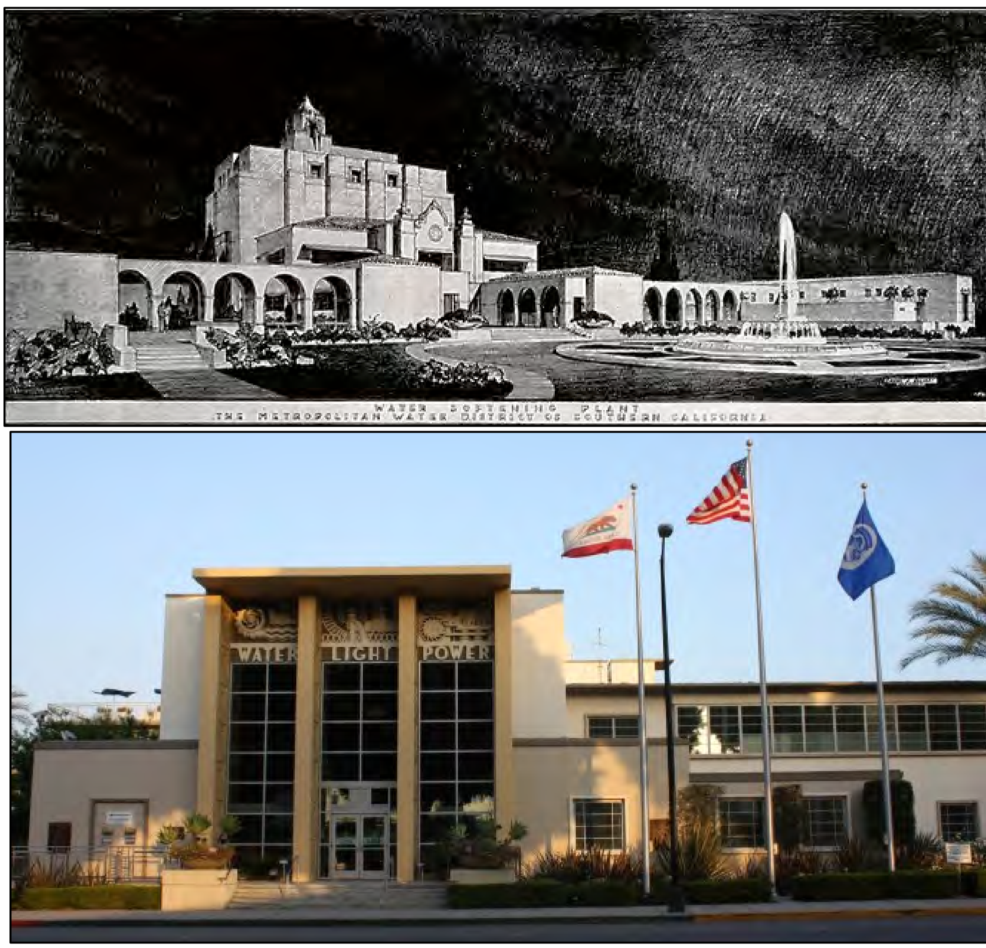


Figure 3. Top, the 1939 Metropolitan Water District of Southern California Water Softening Plant in La Verne and below the Burbank Water Light and Power Administration building built in 1949.

As demand increased a third unit were added in 1953, which constituted the first of several additions to the boiler building on its north end; the third unit at the plant was completed at a cost of over $3 million. The integral furnace boiler and superheater steam boiler was manufactured by the Babcock & Wilcox Company and the turbine generator by General Electric. The company of Foster & Wheeler constructed the cooling tower and provided the condenser for Unit 3. Unit 3 also utilized the most up-to date engineering replicated in fuel-fired plants across California. The turbine for Unit 3 is located outside the main building under a removable housing (Glendale News Press 1953e).

California utility companies' steam generating capacity expanded during the period of 1950 through 1970. PG&E operated 15 steam electric plants in 1950. Conversely, Southern California utilities built large steam plants at a much slower rate than with Northern California, constructing the Valley Steam Plant in 1953 and Scattergood Steam Plant in 1957. By the late 1970s, there were more than 20 fossil fuel steam-generating plants in California owned by various power companies and clustered near urban areas such as San Francisco Bay, the greater Los Angeles area, San Diego County, along with a few interior plants in San Bernardino, Riverside, and Imperial Counties. Happening concurrently, in the mid-1960s large scale intertie projects such as the 500 kV California Oregon Intertie (also known as Path 66) were completed. Additionally, utility companies began to pool their resources, creating a larger interconnected grid. Dictated by Federal power policy, utility companies came together to form bulk transmission entities. In 1967, the Western Systems Coordinating Council formed, consisting of 40 power systems located in western states and remained in existence until 2002 when it merged with three regional transmission associations forming the Western System Coordinating Council (WSCC). In addition to WSCC in the mid-1960s was the California Power Pool. This entity gave rise to the current California Independent Service Operator (CAISO). These large intertie projects brought the death of independent, locally sourced electricity as CAISO and its predecessors controlled operation of the various plants (Transmission Agency of Northern California 2017; Water and Power Associates 2017); Southwest Builder and Contractor 1962).

Between 1953-54, the plant generated a total of 122,649,440 kilowatts per hour, supplemented by electricity generated at Hoover Dam, supplied all the power needed for the City (Glendale Public Service Commission 1951). Five more units were constructed after 1953 including Unit 4 (1959), Unit 5 (1964), Unit 6 (1972), and Unit 7 (1974). The boiler for Unit 4 was manufactured by Riley Stoker Corporation; Unit 6 was manufactured by General Electric; and Unit 7 by the Curtiss-Wright Company. Units 1 through 3 maintain Elliott's the style aesthetics, however the structure shape and detailing shifts with the addition of Units 4 & Unit 5, to a significantly taller, less detailed utilitarian structure that we see to the north. As the building was expanded north, lower level fenestration of the first three phases was repeated but without the vertical glass block panels. Little significant architectural detail was included in Unit 4 & Unit 5's building expansion. In 1972 The plant was renamed the "L.W. Grayson Steam-Electric Generating Station" after the City of Glendale General Manager and Chief Engineer, Lauren W. (L.W.) Grayson who at the time was the longest serving employee. Grayson accepted a position at the City of Glendale in 1951 (City of Glendale 1972; Glendale News-Press 1972). His most notable achievement was in bringing power to Southern California through the Pacific Northwest Intertie (Glendale News-Press 1972).

Unit 8 (Unit 8A, 8B, and 8C) was constructed in 1977 and was one of the last to be installed at the power plant and the most efficient of the group while producing fewer emissions than the earlier generators at the plant (Cook 1977). Initially, it was called a "combined cycle repowering unit" in producing more energy and fewer emissions with conventional units that provide better combustion controls and higher efficiency

(Cook 1977). The new system cost $20 million dollars and at the time, lessened air pollution (Ralph 1977). Further environmental improvements to the plant resulted from the construction of a phosphate removal and treatment plant in 1978. The treatment plant was connected to the steam plant by a pipeline, which directly pumps the reclaimed water into the Grayson Power Plant's cooling towers (Rees 1978). In addition, since 1994 the plant has utilized methane gas from the Scholl Canyon Landfill mixed with natural gas to generate power in Units 3, 4, and 5 (Scholl Canyon Landfill 2015).

Continuous improvements in efficiency and power generation capacity have been one of the priorities at the Grayson Power Plant throughout its history including the construction of a new 50 megawatt power generator was completed in 2004, at a cost of $33.5 million dollars, replaced two of the older, outdated units. The new structure consists of a generator, a gas turbine and compressor, and an emissions control tower to filter out pollutants throughout the system. The generator runs entirely on computers and operates during peak hours (Moskowitz 2004).

In July 2010, a fire at Cooling Tower 3 caused severe damage to the structure, although service was not effected (Wells 2010). Repairs to other portions of the plant included the replacement of the superheater tubes in Boiler No. 4 in 2001, wall tubes in Boiler No. 4 in 2011, an upgrade of the burner management and boiler control systems, also in Unit 4 in 2011, among other updates (City of Glendale 2011). According to the City of Glendale, California Report to the City Council in April 2014, the boilers for Units 1 and 2 have been mothballed (City of Glendale 2014). In 2015, the Glendale City Council commissioned plans to upgrade Grayson Power Plant to make the plant more efficient, reliable and cost effective. According to the June article in the Glendale News-Press, seven of the eight turbines would be decommissioned and replaced by 4 more efficient turbines, which would be able to produce power more quickly (Mikailian 2015). Currently the power plant generates approximately 18% of the power needed for the City of Glendale with the remaining power coming from a combination of both local and remote generation (owned and leased), coupled with spot market purchases from a variety of suppliers throughout the Western United States (Mikailian 2015).

Evaluation

Glendale's Grayson Power Plant served as a regional power source since construction. While the power plant has maintained this role, it has not directly contributed to the early growth of the city, further it only supplemented electricity supplied by other utilities and by the 1937 constructed Hoover Dam. The power plant did supply the region with localized power, however, it is just a continuation of existing power supplies. By the time the power plant came online, in 1941, the city had been electrified for 32 years. Further, articles exaggerated the need for a localized power plant to sustain growth. Supply was high, the city, understandably preferred control of their own power supply. California, like much of the west had begun interconnection a series of previously independent transmission systems into an interconnected grid. When originally conceived, the plant would provide a localized source of power, however by the 1940s the state had already begun interconnection. Further, fuel-fired steam plants were well established across California by 1941, that utilized proven technologies. The Grayson Power Plant as first constructed in 1941 represented the designs of the 1920s, this was soon realized as the plant underwent numerous upgrades and additions through the 1940s, 1950s, 1980s, 1970s, and 1980s to keep pace with the larger, semi-outdoor boiler types that proliferated across California in the 1950s and 1960s. Therefore, Grayson Power Plant is ineligible, under NRHP Criteria A, CRHR Criterion 1 and GRHR as it is not associated with important events in national, state, or city history, or exemplifies significant contributions to the broad cultural, political, economic, social, or historic heritage of the nation, state, or city. Rather, the plant is a continuation of electrical generation themes in a city that had been using electricity for 32 years.

There is no evidence that Grayson Power Plant has any important association with any person or persons who made significant contributions to history at the local, state, or national level. It was designed to supplement and create a localized power source that involved several key institutions and individuals. Research did not reveal any notable figures specifically associated with the alignment or its related infrastructure, and research did not indicate the potential for significant associations in this regard. While the power plant is currently named Grayson Power Plant for L.W Grayson, a longtime Glendale employee. The name change, occurred in 1972, was in recognition of Grayson 19 years of service to the city. Grayson was important in management of the city but had no association with development, construction, or early operation of the plant. The power plant is not eligible under NRHP Criteria B, CRHR Criterion 2 or for the GRHR.

The subject property is not eligible for NRHP Criteria C, CRHR Criterion 3 nor the GRHR. Grayson Power Plant when originally constructed as a small, two-unit boiler house with Streamline Moderene styling. Since originally constructed, the power plant main boiler building has undergone numerous additions and alterations. These additions, mimic Elliott's design but with each addition are farther removed from the original (**Figure 4** and **5**).

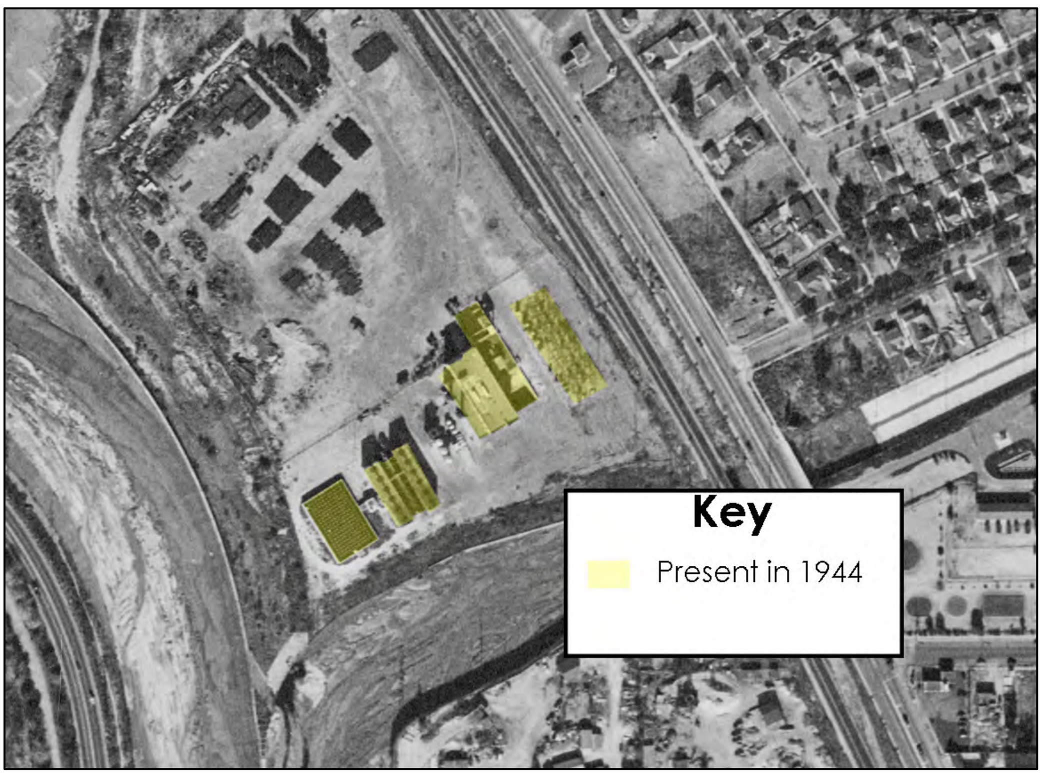


Figure 4. Glendale Steam Electric Power Plant Property in 1944.

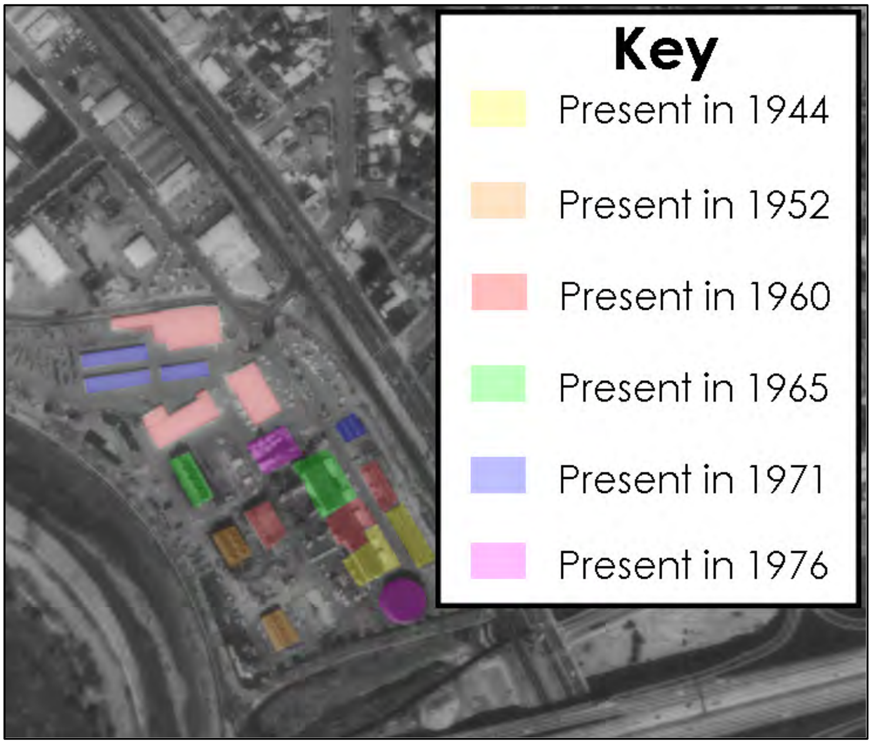


Figure 5. A graphic showing the numerous plant modifications since construction in 1941. The information is overlaid on a 1976 aerial with changes noted on historic aerials in 1944, 195, 1960, 1965,1971, and 1976.

Daniel Anthony Elliott, who is arguably a master architect. His noteworthy designs focus on water related infrastructure including the Colorado River Aqueduct Pumping Plants and F.E. Weymouth Memorial Water Softening and Filtration Plant completed in 1939 (**Figure 3,** above) and later the Burbank Water & Power administrative building in 1949. The F.E. Weymouth Memorial Water Softening and Filtration Plant is the earliest extant example of Elliott's work, further it is the best example of monumental water and power architecture. Built in a Spanish Revival design, this building exemplifies the style, prominent of the time and best showcases Elliott's ability to make infrastructure into beautiful architecture. They original design of the Grayson Power Plant followed these design tenants. Elliott used prominent architectural styles on infrastructure. Elliott's design followed established power plant and substation design principles emblematic of the 1910s and 1920s. Power company architects designed substations and powerhouses in prominent public-building architectural styles like Beaux-Arts and Classical Revival. Urban power houses and substations housed the electrical equipment within buildings in order to accommodate the congested urban surroundings and to buffer the public from the sounds and activities associated with operation. The power plants and substations were constructed to meet both aesthetic and functional mandates (Frickstad 1916). Elliott's design of the Streamline Moderne power plant is a 1940s continuation of these design principles. Further, the 1941 building designed by Elliott has been manipulated and changed beyond his original vision through multiple building modifications. Further, the F.E. Weymouth Memorial Water Softening and Filtration Plant is far more intact example of his early designs.

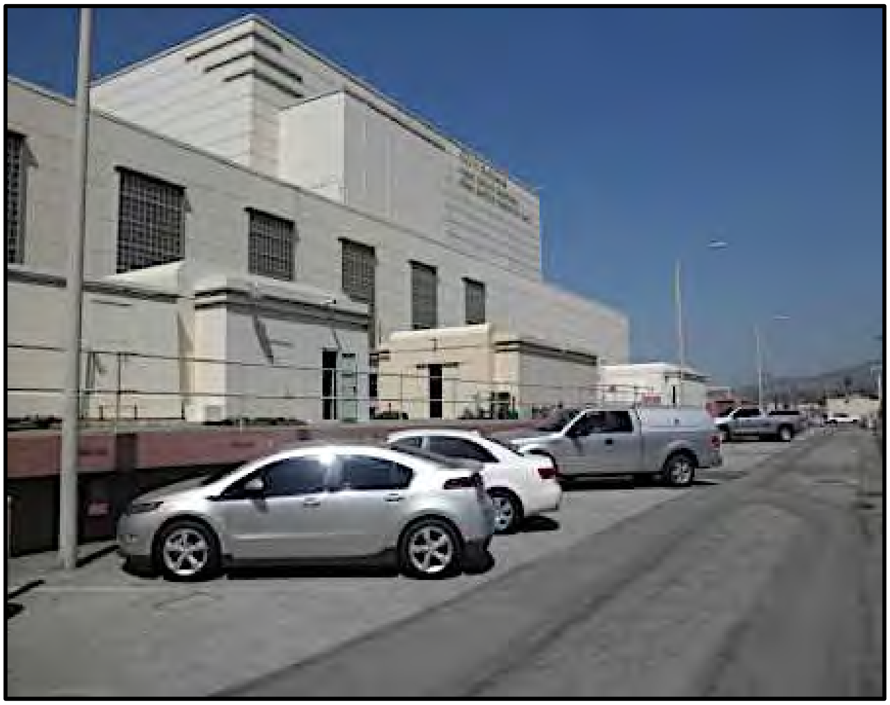
An article noted its design as earthquake resistant meaning its generators were located outside on a concrete foundation that was resistant to earthquakes with metal coverings to protect it from weather. R.R. Martell, noted earthquake engineer consulted on the project stating the generator could be constructed outside the main boiler building. Through time the power plant has withstood earthquakes, as have other power plants with varied designs. This design is important in the greater advancement of power plant designs. Unfortunately, multiple additions and modifications have degraded its integrity and it can no longer convey this significance under NRHP Criteria C or CRHR Criterion 3. As noted before, the GRHR does not assess integrity. The evolution of earthquake resistant power plant is important to the context of power plant design in California, however it's within the context of Glendale is lessened.

The property does not appear likely to yield significant informational associations under NRHP Criteria D, CRHR Criterion 4 or the GRHR as the plant does not yield information important to archaeological pre-history or history of the nation, state, region, or city. In contrast, the extant archival record regarding the site presents a wealth of specific and informative material, including maps, photographs, aerials, and building permits that provides significant material for interpretation. Thus, the extant physical structures of the site do not convey significant informational material that would inform the rather robust archival record regarding the Grayson Power Plant.

The Grayson Power Plant was constructed approximately 60 years after the early development of the City of Glendale and 35 years after the City incorporated electricity in 1906. Due to this passage of time it is not associated with the early heritage of the City and not eligible for listing on the GRHR.

While the GRHR does not account for integrity, both the NRHP and CRHR do. Due to numerous building additions and continued evolution of the property there has been a loss of integrity of design, materials, workmanship, and feeling. The property retains integrity of location, setting, and association. The power plant has not moved, the overall setting has remained industrial, and it maintains its association as a power plant. However, numerous alterations have removed its integrity of design to the original plant conceived by Elliott, materials as the building materials, while similar are different in type and massing from the original section. The plant has lost its association of workmanship as the additions have fundamentally altered the physical characteristics of the building as original constructed in 1941 and finally the plant has lost its original feeling. Aside from the numerous building additions continued addition of non-attached boiler units with modern cooling towers and ancillary buildings have removed the original feeling of the property. Therefore, the building has lost integrity coupled with lack of significance the building is not eligible for the NRHP or CRHR under any criterion.

Photographs (Continued):



Photograph 2. Grayson Boiler Building, View Looking Northwest (Photo by J. Terry).

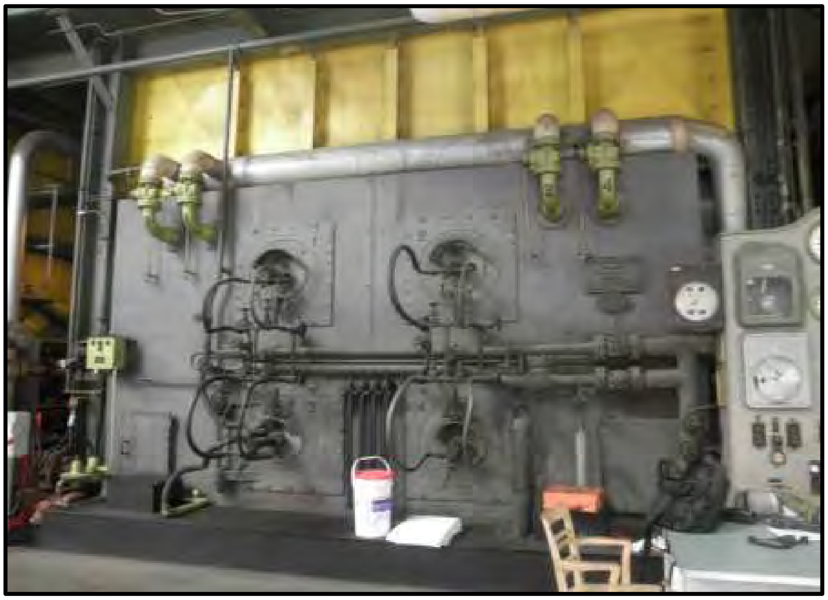
Photograph 3. Grayson Boiler Building, View Looking Northwest (Photo by J. Terry).

Photograph 4. Grayson Boiler Building, View Looking Southwest (Photo by J. Terry).

Photograph 5. Grayson Boiler Building, View Looking Southeast (Photo by J. Terry).

Photograph 6. Boiler Stacks (Boilers 1 and 2 Center Rear of Photograph; Boiler 3 to Left), View Looking South. (Photo by J. Terry).

Photograph 7. Overview of Basement Floor Level, View Looking North (Photo by J. Terry).



Photograph 8. View of Boiler 1B, Looking West (Photo by J. Terry).

Photograph 9. Unit 8A, Looking West (Photo by J. Terry).

Photograph 10. Units 8A & 8B, View Looking Northeast (Photo by J. Terry**).**

Photograph 12. Cooling Tower No. 2 (No. 1 in background), View Looking Southeast (Photo by J. Terry).

Photograph 13. Cooling Tower No. 3 (No. 5 in Background), View Looking Northwest (Photo by J. Terry).

Photograph 14. Cooling Tower No. 4, View Looking Northeast (Photo by J. Terry).

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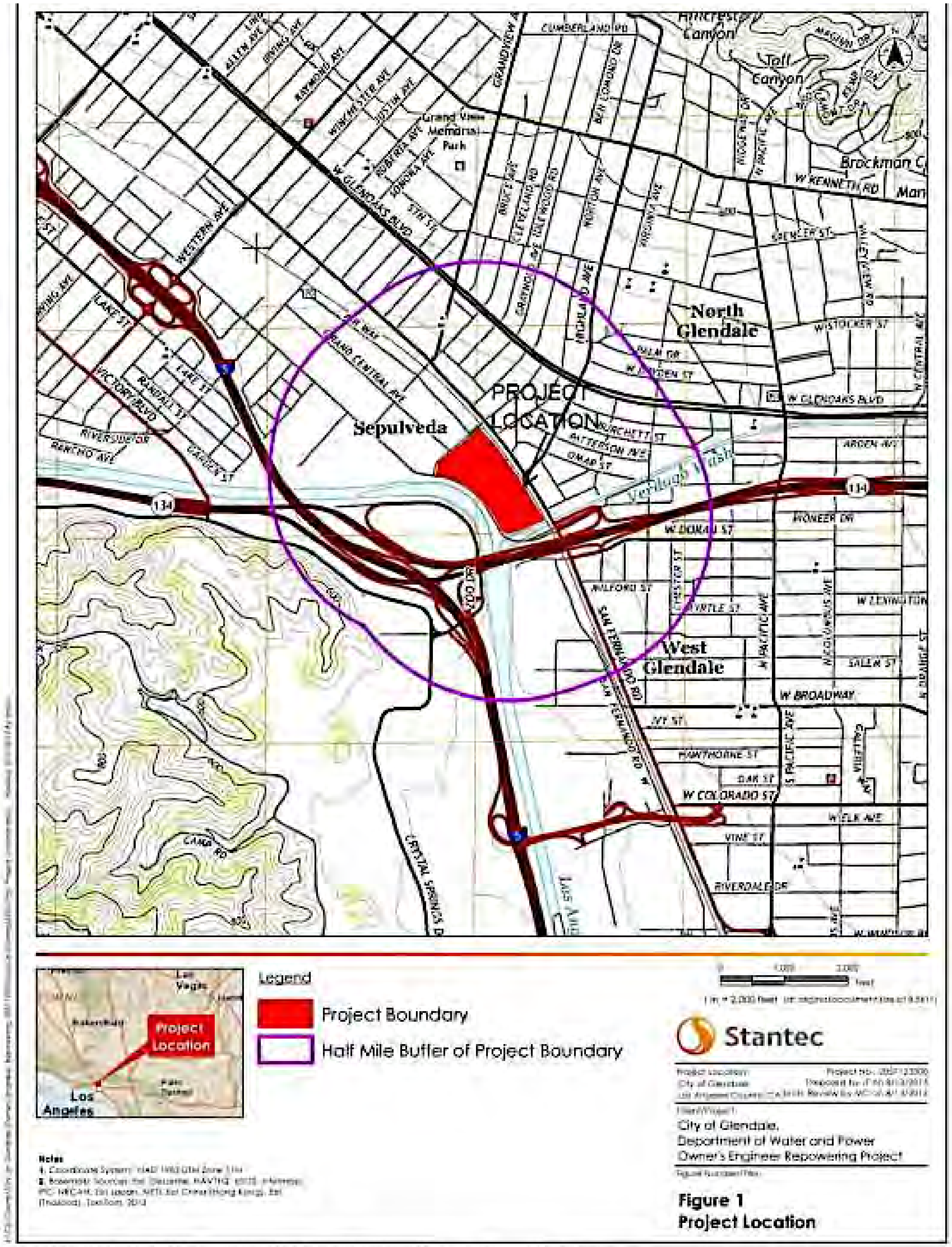
State of California - The Resources Agency
DEPARTMENT OF PARKS AND RECREATION
LOCATION MAP

Primary#
HRI#
Trinomial

Page 25 **of** 25 ***Resource Name or #** (Assigned by recorder) Grayson Power Plant

***Map Name:** Grayson Power Plant Location Map ***Scale:** 1:24,000 ***Date of map:** 2015



ATTACHMENT E ALTERNATIVE 8 AQIA MODEL INPUT

ALTERNATIVE 8
AIR QUALITY IMPACT ANALYSIS (AQIA) - MODEL INPUT

Model Input Stack Parameters

Model ID	Source Description	UTME (m)	UTMN (m)	Elevation (m)	Stack Height (ft)	Temperature (F)	Exit Velocity (ft/s)	Stack Dia. (ft)
CT1_1	Cooling Tower 1 Cell 1	382087.6	3780122.1	142.50	43.00000	87.40000	69.89154	28.00000
CT1_2	Cooling Tower 1 Cell 2	382094.0	3780110.6	142.50	43.00000	87.40000	69.89154	28.00000
UNIT8A	Unit 8A Gas Turbine	382112.2	3780119.5	142.60	115.00000	378.00000	118.46221	10.00000
UNIT8B/8C	Unit 8B/8C Gas Turbine	382142.5	3780068.4	142.60	115.00000	857.00000	156.60846	10.00000
UNIT9	Existing Unit 9 Gas Turbine	382238.2	3780061.8	142.70	85.00000	799.40000	116.05108	10.00000

Model Input Criteria Pollutant Emission Rates

Model ID	Source Description	NOx 1Hr Max Emission (lbs/hr)	CO 1Hr Max Emission (lbs/hr)	SO2 1Hr Max Emission (lbs/hr)	CO 8Hr Emission (lbs/hr)	SO2 24Hr Emission (lbs/hr)	PM 24Hr Emission (lbs/hr)	NOx Annual Emission (lbs/hr)	PM Annual Emission (lbs/hr)
CT1_1	Cooling Tower 1 Cell 1						0.05500		0.01000
CT1_2	Cooling Tower 1 Cell 2						0.05500		0.01000
UNIT8A	Unit 8A Gas Turbine	15.60000	82.79000	0.24000	33.72000	0.09000	0.38000	0.76000	0.15000
UNIT8B/8C	Unit 8B/8C Gas Turbine	61.52000	328.42000	0.48000	328.42000	0.17000	0.75000	1.72000	0.30000
UNIT9	Existing Unit 9 Gas Turbine	31.23000	14.92000	1.02000	8.36000	0.86000	3.50000	14.46000	3.48000

ATTACHMENT F ALTERNATIVE 8 AQIA MODEL RESULTS

ALTERNATIVE 8
AIR QUALITY IMPAC ANALYSIS (AQIA) RESULTS

Description	Pollutant	Averaging Period	Highest	Source Group	Conc (ug/m3)	UTME	UTMN	Conc Date mm/dd/yy/hh	Conc (ppm)	Background	Unit	Total	Unit	NAAQS	Unit	SCAQMD	Unit
CO State Standard/NAAQS																	
Grayson_2012-2016_CO1hrmax	CO	1-HR	1ST	ALL	67.84	382000.0	3779650.0	01/24/15/09	0.05949	2.6	PPM	2.6595	PPM	35	PPM	20	PPM
				UNIT8A	19.09	382141.4	3780347.4	06/02/13/11	0.01674			2.6167	PPM				
				UNIT8BC	49.80	382000.0	3779650.0	01/24/15/09	0.04366			2.6437	PPM				
				UNIT9	3.51	382056.3	3780137.0	07/04/13/11	0.00307			2.6031	PPM				
Grayson_2012-2016_CO8hr	CO	8-HR	1ST	ALL	33.38	382140.0	3780440.0	06/02/13/16	0.02927	1.6	PPM	1.6293	PPM	9	PPM	9	PPM
				UNIT8A	4.87	382140.0	3780460.0	06/02/13/16	0.00427			1.6043	PPM				
				UNIT8BC	27.89	382140.0	3780440.0	06/02/13/16	0.02446			1.6245	PPM				
				UNIT9	1.12	382260.0	3780380.0	06/02/13/16	0.00098			1.6010	PPM				
NO_2 State Standard - ARM2																	
Grayson_2012-2016_NO21hrmax	NO2	1-HR	1ST	ALL	14.97	381900.0	3780260.0	5 YEARS	0.00799	0.0719	PPM	0.0799	PPM		PPM	0.18	PPM
				UNIT8A	3.09	381909.7	3780264.7	5 YEARS	0.00165			0.0736	PPM				
				UNIT8BC	7.29	381880.0	3780260.0	5 YEARS	0.00389			0.0758	PPM				
				UNIT9	6.17	382047.0	3780152.0	5 YEARS	0.00329			0.0752	PPM				
NO_2 NAAQS - ARM2																	
Grayson_2012-2016_NO21hrmax	NO2	8TH-HIGHEST MAX DAILY 1-HR	1ST	ALL	12.95	381940.0	3780240.0	5 YEARS	0.00691	0.0593	PPM	0.0662	PPM	0.10	PPM		PPM
				UNIT8A	2.77	381920.0	3780240.0	5 YEARS	0.00148			0.0608	PPM				
				UNIT8BC	6.12	381920.0	3780240.0	5 YEARS	0.00327			0.0626	PPM				
				UNIT9	5.09	382028.3	3780174.7	5 YEARS	0.00272			0.0620	PPM				
PM10/PM2.5 State Standard																	
Grayson_2012-2016_PM24hr.	PM10/PM2.5	24-HR	1ST	ALL	0.213	382240.0	3780440.0	6/2/2013				0.213	UG/M3		UG/M3	Threshold PM10 - 2.5 PM2.5 - 2.5	UG/M3
				CT_1	0.085	381940.0	3780100.0	10/9/2015				0.085	UG/M4				
				CT_2	0.086	381940.0	3780080.0	10/9/2015				0.086	UG/M5				
				UNIT8A	0.023	382140.0	3780480.0	6/2/2013				0.023	UG/M4				
				UNIT8BC	0.025	382140.0	3780460.0	6/2/2013				0.025	UG/M5				
				UNIT9	0.186	382240.0	3780400.0	6/2/2013				0.186	UG/M6				
PM10 NAAQS Standard																	
Grayson_2012-2016_PM24hr.	PM10	24-HR	6TH	ALL	0.192	382220.0	3780440.0	6/12/2013		96	UG/M3	96.19	UG/M3	150	UG/M3		UG/M3
				CT_1	0.046	382252.0	3780040.5	9/13/2014				96.05	UG/M4				
				CT_2	0.047	382300.0	3780000.0	9/13/2014				96.05	UG/M5				
				UNIT8A	0.021	382140.0	3780480.0	7/3/2012				96.02	UG/M6				
				UNIT8BC	0.022	382140.0	3780460.0	6/13/2012				96.02	UG/M7				
				UNIT9	0.168	382260.0	3780380.0	6/13/2012				96.17	UG/M8				
PM2.5 NAAQS Standard																	
Grayson_2012-2016_PM24hr.	PM2.5	24-HR	8TH	ALL	0.190	382220.0	3780460.0	6/3/2012		30.5	UG/M3	30.69	UG/M3	35	UG/M3		UG/M3
				CT_1	0.040	382314.3	3780076.1	9/13/2014				30.54	UG/M4				
				CT_2	0.041	382252.0	3780040.5	9/13/2012				30.54	UG/M5				
				UNIT8A	0.020	382120.0	3780480.0	6/12/2013				30.52	UG/M6				
				UNIT8BC	0.022	382140.0	3780480.0	6/3/2012				30.52	UG/M7				
				UNIT9	0.165	382240.0	3780380.0	6/13/2012				30.66	UG/M8				
SO_2 State Standard																	
Grayson_2012-2016_SO21hrmax	SO2	1-HR	1ST	ALL	0.297	381960.0	3780220.0	5 YEARS	0.00011	0.018	PPM	0.0181	PPM		PPM	0.25	PPM
				UNIT8A	0.053	381909.7	3780264.7	5 YEARS	0.00002			0.0180	PPM				
				UNIT8BC	0.063	381880.0	3780260.0	5 YEARS	0.00002			0.0180	PPM				
				UNIT9	0.224	382047.0	3780152.0	5 YEARS	0.00009			0.0181	PPM				
Grayson_2012-2016_SO21hrmax	SO2	3-HR	1ST	ALL	0.260	381980.0	3780200.0	6/5/16/12	0.00010	0.002	PPM	0.0021	PPM		PPM	0.04	PPM
				UNIT8A	0.047	381920.0	3780240.0	6/9/14/12	0.00002			0.0020	PPM				
				UNIT8BC	0.054	381920.0	3780240.0	6/9/14/12	0.00002			0.0020	PPM				
				UNIT9	0.202	382037.7	3780163.3	6/5/16/12	0.00008			0.0021	PPM				
Grayson_2012-2016_SO224hr	SO2	24-HR	1ST	ALL	0.051	382240.0	3780440.0	6/2/2013	0.00002	0.002	PPM	0.0020	PPM	0.5	PPM	0.04	PPM
				UNIT8A	0.005	382140.0	3780480.0	6/2/2013	0.00000			0.0020	PPM				
				UNIT8BC	0.006	382140.0	3780460.0	6/2/2013	0.00000			0.0020	PPM				
				UNIT9	0.046	382240.0	3780400.0	6/2/2013	0.00002			0.0020	PPM				

ALTERNATIVE 8
AIR QUALITY IMPAC ANALYSIS (AQIA) RESULTS

Description	Pollutant	Averaging Period	Highest	Source Group	Conc (ug/m3)	UTME	UTMN	Conc Date mm/dd/yy/hh	Conc (ppm)	Background	Unit	Total	Unit	NAAQS	Unit	SCAQMD	Unit
SO_2 NAAQS																	
Grayson_2012-2016_SO21hrmax	SO2	4TH-HIGHEST MAX DAILY 1-HR	4TH	ALL	0.272	381980.0	3780220.0	5 YEARS	0.00010	0.0094	PPM	0.0095	PPM	0.075	PPM		PPM
				UNIT8A	0.050	381909.7	3780264.7	5 YEARS	0.00002			0.0094	PPM				
				UNIT8BC	0.057	381900.0	3780260.0	5 YEARS	0.00002			0.0094	PPM				
				UNIT9	0.199	382028.3	3780174.7	5 YEARS	0.00008			0.0095	PPM				

CO 1 Hour NAAQS = Not to be exceeded more than once per year. Design values based on highest 1 hour model result over 5 years and highest 1 hour monitored background 2017 - 2019.

CO 1 Hour SCAQMD = Not to be exceeded. Design values based on highest 1 hour model result over 5 years and highest 1 hour monitored background 2017 - 2019.

CO 8 Hour NAAQS = Not to be exceeded more than once per year. Design values based on highest 8 hour model result over 5 years and highest 8 hour monitored background 2017 - 2019.

CO 8 Hour SCAQMD = Not to be exceeded. Design values based on highest 8 hour model result over 5 years and highest 8 hour monitored background 2017 - 2019.

NO2 1 Hour NAAQS = 98th percentile of 1-hour daily maximum concentrations, averaged over 3 years (approx 8th highest). Design value based on 98th percentile of 1-hour daily maximum concentrations, averaged over 5 years and the highest 98th percentile monitored concentration for years 2(

NO2 1 Hour SCAQMD = Not to be exceeded. Design values based on highest 1 hour model result over 5 years and highest 1 hour monitored background 2017 - 2019.

PM10/PM2.5 24 Hour SCAQMD = Not to exceeded significant threshold. Design value based on 1st highest max 5 year model result.

PM10 24 Hour NAAQS = Not to be exceeded more than once per year on average over 3 years (2nd Highest). Design value based on 6th highest max 5 year model result and highest monitored background 2017-2019.

PM2.5 24 Hour NAAQS = 98th percentile, averaged over 3 years (8th highest not including secondary). Design value based on 98th percentile, averaged over 5 years, and the highest 98th percentile 24 hour monitored background 2017 - 2019. No secondary emissions included.

SO2 1 Hour NAAQS = 99th percentile of 1-hour daily maximum concentrations, averaged over 3 years (approx 4th highest). Design value based on 99th percentile of 1-hour daily maximum concentrations, averaged over 5 years and the highest 99th percentile 1 hour monitored background 2017

SO2 1 Hour SCAQMD = Not to be exceeded. Design values based on highest 1 hour model result over 5 years and highest 1 hour monitored background 2017 - 2019.

SO2 24 Hour SCAQMD = Not to be exceeded. Design values based on highest 24 hour model result over 5 years and highest 24 hour monitored background 2017 - 2019.

ALTERNATIVE 8
AIR QUALITY IMPAC ANALYSIS (AQIA) RESULTS

Description	Pollutant	Averaging Period	Highest	Source Group	Conc (ug/m3)	UTME	UTMN	Conc Date	Conc (ppm)	Background	Unit	Total	Unit	NAAQS	Unit	SCAQMD	Unit
NO_2 State Standard/NAAQS Normal Operations - ARM																	
Grayson_2012_NO2yr	NO2	ANNUAL	1ST	ALL	0.2456	382180.0	3780420.0	2012	0.00013	0.0154	PPM	0.0155	PPM	0.053	PPM	0.03	PPM
Grayson_2013_NO2yr	NO2	ANNUAL	1ST	ALL	0.2539	382200.0	3780420.0	2013	0.00014			0.0155	PPM				
Grayson_2014_NO2yr	NO2	ANNUAL	1ST	ALL	0.2570	382180.0	3780440.0	2014	0.00014			0.0155	PPM				
Grayson_2015_NO2yr	NO2	ANNUAL	1ST	ALL	0.2329	382180.0	3780440.0	2015	0.00012			0.0155	PPM				
Grayson_2016_NO2yr	NO2	ANNUAL	1ST	ALL	0.2351	382180.0	3780420.0	2016	0.00013			0.0155	PPM				
								5 Year Max	**0.00014**			**0.0155**	**PPM**				
Grayson_2012_NO2yr	NO2	ANNUAL	1ST	UNIT8A	0.0140	382060.0	3780480.0	2012	0.000007	0.0154	PPM	0.0154	PPM	0.053	PPM	0.03	PPM
Grayson_2013_NO2yr	NO2	ANNUAL	1ST	UNIT8A	0.0145	382080.0	3780480.0	2013	0.000008			0.0154	PPM				
Grayson_2014_NO2yr	NO2	ANNUAL	1ST	UNIT8A	0.0146	382060.0	3780500.0	2014	0.000008			0.0154	PPM				
Grayson_2015_NO2yr	NO2	ANNUAL	1ST	UNIT8A	0.0133	382060.0	3780500.0	2015	0.000007			0.0154	PPM				
Grayson_2016_NO2yr	NO2	ANNUAL	1ST	UNIT8A	0.0136	382080.0	3780500.0	2016	0.000007			0.0154	PPM				
								5 Year Max	**0.000008**			**0.0154**	**PPM**				
Grayson_2012_NO2yr	NO2	ANNUAL	1ST	UNIT8BC	0.0172	382080.0	3780500.0	2012	0.000009	0.0154	PPM	0.0154	PPM	0.053	PPM	0.03	PPM
Grayson_2013_NO2yr	NO2	ANNUAL	1ST	UNIT8BC	0.0179	382080.0	3780500.0	2013	0.000010			0.0154	PPM				
Grayson_2014_NO2yr	NO2	ANNUAL	1ST	UNIT8BC	0.0183	382080.0	3780500.0	2014	0.000010			0.0154	PPM				
Grayson_2015_NO2yr	NO2	ANNUAL	1ST	UNIT8BC	0.0165	382080.0	3780500.0	2015	0.000009			0.0154	PPM				
Grayson_2016_NO2yr	NO2	ANNUAL	1ST	UNIT8BC	0.0161	382080.0	3780500.0	2016	0.000009			0.0154	PPM				
								5 Year Max	**0.000010**			**0.0154**	**PPM**				
Grayson_2012_NO2yr	NO2	ANNUAL	1ST	UNIT9	0.2243	382200.0	3780400.0	2012	0.000120	0.0154	PPM	0.0155	PPM	0.053	PPM	0.03	PPM
Grayson_2013_NO2yr	NO2	ANNUAL	1ST	UNIT9	0.2325	382200.0	3780400.0	2013	0.000124			0.0155	PPM				
Grayson_2014_NO2yr	NO2	ANNUAL	1ST	UNIT9	0.2345	382200.0	3780400.0	2014	0.000125			0.0155	PPM				
Grayson_2015_NO2yr	NO2	ANNUAL	1ST	UNIT9	0.2117	382200.0	3780420.0	2015	0.000113			0.0155	PPM				
Grayson_2016_NO2yr	NO2	ANNUAL	1ST	UNIT9	0.2169	382200.0	3780400.0	2016	0.000116			0.0155	PPM				
								5 Year Max	**0.000125**			**0.0155**	**PPM**				

ALTERNATIVE 8
AIR QUALITY IMPAC ANALYSIS (AQIA) RESULTS

Description	Pollutant	Averaging Period	Highest	Source Group	Conc (ug/m3)	UTME	UTMN	Conc Date	Conc (ppm)	Background	Unit	Total	Unit	NAAQS	Unit	SCAQMD	Unit
PM10/PM2.5 State Standard Normal																	
Grayson_2012_PMyr	PM10, PM2.5	ANNUAL	1ST	ALL	0.0646	382180.0	3780420.0	2012				0.065	UG/M3	Non-Attainment PM2.5 SIL - 0.2	UG/M3	Threshold PM10 - 1.0 PM2.5 - 1.0	UG/M3
Grayson_2013_PMyr	PM10, PM2.5	ANNUAL	1ST	ALL	0.0669	382200.0	3780420.0	2013				0.067	UG/M3				
Grayson_2014_PMyr	PM10, PM2.5	ANNUAL	1ST	ALL	0.0676	382180.0	3780440.0	2014				0.068	UG/M3				
Grayson_2015_PMyr	PM10, PM2.5	ANNUAL	1ST	ALL	0.0613	382180.0	3780440.0	2015				0.061	UG/M3				
Grayson_2016_PMyr	PM10, PM2.5	ANNUAL	1ST	ALL	0.0619	382180.0	3780420.0	2016				0.062	UG/M3				
				5 Year Max	**0.068**							**0.064**	**UG/M3**				
Grayson_2012_PMyr	PM10, PM2.5	ANNUAL	1ST	CT_1	0.0003	382020.0	3780500.0	2012				0.0003	UG/M3	Non-Attainment PM2.5 SIL - 0.2	UG/M3	Threshold PM10 - 1.0 PM2.5 - 1.0	UG/M3
Grayson_2013_PMyr	PM10, PM2.5	ANNUAL	1ST	CT_1	0.0004	382040.0	3780500.0	2013				0.0004	UG/M3				
Grayson_2014_PMyr	PM10, PM2.5	ANNUAL	1ST	CT_1	0.0004	382025.0	3780501.0	2014				0.0004	UG/M3				
Grayson_2015_PMyr	PM10, PM2.5	ANNUAL	1ST	CT_1	0.0004	382010.0	3780488.3	2015				0.0004	UG/M3				
Grayson_2016_PMyr	PM10, PM2.5	ANNUAL	1ST	CT_1	0.0003	382040.0	3780500.0	2016				0.0003	UG/M3				
				5 Year Max	**0.0004**							**0.0004**	**UG/M3**				
Grayson_2012_PMyr	PM10, PM2.5	ANNUAL	1ST	CT_2	0.0003	382036.6	3780485.6	2012				0.0003	UG/M3	Non-Attainment PM2.5 SIL - 0.2	UG/M3	Threshold PM10 - 1.0 PM2.5 - 1.0	UG/M3
Grayson_2013_PMyr	PM10, PM2.5	ANNUAL	1ST	CT_2	0.0004	382048.3	3780470.3	2013				0.0004	UG/M3				
Grayson_2014_PMyr	PM10, PM2.5	ANNUAL	1ST	CT_2	0.0004	382036.6	3780485.6	2014				0.0004	UG/M3				
Grayson_2015_PMyr	PM10, PM2.5	ANNUAL	1ST	CT_2	0.0004	382036.6	3780485.6	2015				0.0004	UG/M3				
Grayson_2016_PMyr	PM10, PM2.5	ANNUAL	1ST	CT_2	0.0003	382040.0	3780500.0	2016				0.0003	UG/M3				
				5 Year Max	**0.0004**							**0.0004**	**UG/M3**				
Grayson_2012_PMyr	PM10, PM2.5	ANNUAL	1ST	UNIT8A	0.0031	382060.0	3780480.0	2012				0.003	UG/M3	Non-Attainment PM2.5 SIL - 0.2	UG/M3	Threshold PM10 - 1.0 PM2.5 - 1.0	UG/M3
Grayson_2013_PMyr	PM10, PM2.5	ANNUAL	1ST	UNIT8A	0.0032	382080.0	3780480.0	2013				0.003	UG/M3				
Grayson_2014_PMyr	PM10, PM2.5	ANNUAL	1ST	UNIT8A	0.0032	382060.0	3780500.0	2014				0.003	UG/M3				
Grayson_2015_PMyr	PM10, PM2.5	ANNUAL	1ST	UNIT8A	0.0029	382060.0	3780500.0	2015				0.003	UG/M3				
Grayson_2016_PMyr	PM10, PM2.5	ANNUAL	1ST	UNIT8A	0.0030	382080.0	3780500.0	2016				0.003	UG/M3				
				5 Year Max	**0.0032**							**0.003**	**UG/M3**				
Grayson_2012_PMyr	PM10, PM2.5	ANNUAL	1ST	UNIT8BC	0.0033	382080.0	3780500.0	2012				0.003	UG/M3	Non-Attainment PM2.5 SIL - 0.2	UG/M3	Threshold PM10 - 1.0 PM2.5 - 1.0	UG/M3
Grayson_2013_PMyr	PM10, PM2.5	ANNUAL	1ST	UNIT8BC	0.0035	382080.0	3780500.0	2013				0.003	UG/M3				
Grayson_2014_PMyr	PM10, PM2.5	ANNUAL	1ST	UNIT8BC	0.0035	382080.0	3780500.0	2014				0.004	UG/M3				
Grayson_2015_PMyr	PM10, PM2.5	ANNUAL	1ST	UNIT8BC	0.0032	382080.0	3780500.0	2015				0.003	UG/M3				
Grayson_2016_PMyr	PM10, PM2.5	ANNUAL	1ST	UNIT8BC	0.0031	382080.0	3780500.0	2016				0.003	UG/M3				
				5 Year Max	**0.0035**							**0.003**	**UG/M3**				
Grayson_2012_PMyr	PM10, PM2.5	ANNUAL	1ST	UNIT9	0.0600	382200.0	3780400.0	2012				0.060	UG/M3	Non-Attainment PM2.5 SIL - 0.2	UG/M3	Threshold PM10 - 1.0 PM2.5 - 1.0	UG/M3
Grayson_2013_PMyr	PM10, PM2.5	ANNUAL	1ST	UNIT9	0.0622	382200.0	3780400.0	2013				0.062	UG/M3				
Grayson_2014_PMyr	PM10, PM2.5	ANNUAL	1ST	UNIT9	0.0627	382200.0	3780400.0	2014				0.063	UG/M3				
Grayson_2015_PMyr	PM10, PM2.5	ANNUAL	1ST	UNIT9	0.0566	382200.0	3780420.0	2015				0.057	UG/M3				
Grayson_2016_PMyr	PM10, PM2.5	ANNUAL	1ST	UNIT9	0.0580	382200.0	3780400.0	2016				0.058	UG/M3				
				5 Year Max	**0.0627**							**0.060**	**UG/M3**				

NO2 Annual NAAQS = Annual mean. Design value based on highest annual mean over 5 years of model result and highest annual monitored background 2017 - 2019. ARM Method = 80% of model results.

PM10/PM2.5 Annual SCAQMD = Not to exceeded significant threshold. Design value based on the 5 year average of annual mean model result.

PM Annual NAAQS = Equal to the annual mean averaged over 3 years. Design value based on the 5 year average of annual mean model result and highest annual monitored background 2017 - 2019.

ATTACHMENT G ALTERNATIVE 8 SCAQMD PERMIT APPLICATION REPORT

MONTROSE
ENVIRONMENTAL

August 17, 2021

Permit Services
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Subject: **Permit Applications to Modify Existing Gas Turbines and to Construct Aqueous Ammonia Transfer System.**
Glendale City, Glendale Water & Power (FID 800327)

Dear Reader,

Montrose Environmental Solutions (Montrose) on behalf of Glendale City, Glendale Water & Power (GWP) is submitting the enclosed permit application package to modify the existing gas turbines 8A, 8B, and 8C at its facility located at 800 Air Way in Glendale, California. The facility is proposing these modifications in order to demonstrate compliance with Rule 1135. The modifications will also include installing new air pollution control system and a new aqueous ammonia storage and transfer system. GWP currently has not selected specific equipment vendors. Montrose will communicate with assigned permit engineer to provide updates during the application process.

Enclosed you will find the following items:

- One Form 400CEQA
- One Form 400 XPP
- Seven Forms 400A
- Two Forms 400E5
- Three Forms 400E12
- One Form 400E18
- Title V Forms (Form 500A2, 500B, 500F1, 500H)
- Permit Application Report
- SCAQMD fee check in the amount of **$54,329.70**

Should the Air District have any questions or concerns related to this submittal, please contact A. Edward Krisnadi directly at (909)261.2927, or ekrisnadi@montrose-env.com.

Sincerely,
Montrose Environmental Solutions.

A. Edward Krisnadi
Principal
Permitting & Compliance

PROJ-006860.ltr1

South Coast Air Quality Management District

Form 400 - XPP

Express Permit Processing Request

Form 400-A, Form 400-CEQA and one or more 400-E-xx form(s) must accompany all submittals.

South Coast AQMD

Mail To:
SCAQMD
P.O Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator To Appear On The Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Section B - Equipment Location Address

3. (●) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

Street Address: 800 AIR WAY
City: GLENDALE, State: CA, Zip: 91201
Contact Name: MARK YOUNG, Title: GENERAL MANAGER
Phone #: 8185482107, Ext.: , Fax #:
E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

4. Permit and Correspondence Information:
☐ Check here if same as equipment location address

Address: 141 N. GLENDALE AVENUE
City: GLENDALE, State: CA, Zip: 91206
Contact Name: MARK YOUNG, Title: GENERAL MANAGER
Phone #: 8185482107, Ext.: , Fax #:
E-Mail: myoung@glendaleca.gov

Section D - Authorization/Signature

I understand that the Expedited Permit Processing fees must be submitted at the time of application submittal, and that the application may be subject to additional fees per Rule 301. I understand that requests for Express Permit Processing neither guarantees action by any specific date nor does it guarantee permit approval; that Express Permit Processing is subject to availability of qualified staff; and that once Express Permit Processing has commenced, the expedited fees will not be refunded. I hereby certify that all information contained herein and information submitted with the application are true and correct.

5. Signature of Responsible Official: Mark Young	**6. Title of Responsible Official:** GENERAL MANAGER
7. Print Name of Responsible Official: MARK YOUNG	**8. Date:** 08-09-2021
9. Phone #: 8185482107	**10. Fax #:**

AQMD USE ONLY	APPLICATION TRACKING #	TYPE B C	EQUIPMENT CATEGORY CODE	FEE SCHEDULE $		VALIDATION
ENG. DATE A R	ENG. DATE A R	CLASS I III	ASSIGNMENT Unit Engineer	CHECK/MONEY ORDER #	AMOUNT $	TRACKING #

South Coast AQMD

South Coast Air Quality Management District
Form 400-CEQA
California Environmental Quality Act (CEQA) Applicability

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

The SCAQMD is required by state law, the California Environmental Quality Act (CEQA), to review discretionary permit project applications for potential air quality and other environmental impacts. This form is a screening tool to assist the SCAQMD in clarifying whether or not the project [1] has the potential to generate significant adverse environmental impacts that might require preparation of a CEQA document [CEQA Guidelines § 15060(a)]. Form 400-CEQA and the instructions for guidance on completing this form are available at http://www.aqmd.gov/home/regulations/ceqa/ceqa-permit-forms or http://www.aqmd.gov/home/permits/permit-application-forms. For each Form 400-A application, also complete and submit one Form 400-CEQA. If submitting multiple Form 400-A applications for the same project at the same time, only one Form 400-CEQA is necessary for the entire project. If you need assistance completing this form, contact Permit Services at (909) 396-3385.

Section A – Facility Information

1. Facility Name (Business Name of Operator to Appear on the Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. SCAQMD Facility ID: 800327

3. Project Description: TURBINE 8A, 8B, AND 8C MODIFICATIONS, INCLUDING ITS AIR POLLUTION CONTROL SYSTEMS.

Section B – Review For Exemption From Further CEQA Action

Check "Yes" or "No" as applicable. If "Yes" is checked for any question in Section B, skip Section C and proceed to page 2 and complete Section D - Signatures.

	Yes	No	Is this application for:
1.	○	⦿	A request for a change of operator only (without equipment or process change modifications)?
2.	○	⦿	A functionally identical permit unit replacement with no increase in equipment unit rating or emissions?
3.	○	⦿	A change of daily VOC permit limit to a monthly VOC permit limit?
4.	○	⦿	Equipment damaged as a result of a disaster during state of emergency?
5.	○	⦿	A Title V (e.g., SCAQMD Regulation XXX) permit renewal without equipment or process change modifications?
6.	○	⦿	A Title V administrative permit revision?
7.	○	⦿	The conversion of an existing permit into an initial Title V permit?

Section C – Review of Impacts Which May Trigger Further CEQA Review

Check "Yes" or "No" as applicable. To avoid delays in processing your application(s), explain all "Yes" responses on a separate sheet and attach it to this form.

	Yes	No	
1.	⦿	○	**Is this project specifically evaluated in a previously certified or adopted CEQA document?** If "Yes" is checked, attach a copy of the signed Notice of Determination to this form.
2.	○	⦿	**Is this project specifically exempted from CEQA by another entity (e.g., city or agency)?** If "Yes" is checked, attach a copy of the signed Notice of Exemption or other documentation from the entity to this form.
3.	○	⦿	**Is this project part of a larger project?** If "Yes" is checked, attach a separate sheet to briefly describe the larger project.
4.	○	⦿	**Will the project increase the QUANTITY of hazardous materials stored aboveground onsite or transported by mobile vehicle to or from the site by greater than or equal to the amounts associated with each compound listed on Form 400-CEQA, Table 1 - Regulated Substances List and Threshold Quantities for Accidental Release Prevention [http://www.aqmd.gov/home/regulations/ceqa/ceqa-permit-forms]?** If "Yes" is checked, attach a separate sheet to identify each hazardous material and corresponding quantity to be transported, stored, or used.
5.	○	⦿	**Will the project emit any air toxic listed on Form 400-CEQA, Table 2 - Other Air Toxics and Their Screening Levels [http://www.aqmd.gov/home/regulations/ceqa/ceqa-permit-forms] [2]?** If "Yes" is checked, attach a separate sheet to identify each air toxic and corresponding quantity to be emitted.
6.	○	⦿	**Will the project require any demolition, excavation, and/or grading construction activities that encompass an area exceeding 20,000 square feet?**

[1] A "project" means the whole of an action which has a potential for resulting in physical change to the environment, including construction activities, clearing or grading of land, improvements to existing structures, and activities or equipment involving the issuance of a permit. For example, a project might include installation of a new, or modification of an existing internal combustion engine, dry cleaning facility, boiler, gas turbine, spray coating booth, solvent cleaning tank, etc

[2] Form 400-CEQA, Table 2 – Other Air Toxics and Their Screening Levels, contains a list of air toxics that either do not have a cancer potency (CP) or reference exposure level (REL) approved by the Office of Environmental Health Hazards Assessment (OEHHA) or have a combination of OEHHA-approved and non-approved CPs or RELs.

Section C – Review of Impacts Which May Trigger Further CEQA (concluded)			
	Yes	No	
7.	⊙	O	**Will the project utilize a boiler, engine, or other combustion equipment that uses fuel (e.g., gasoline, diesel, natural gas, liquefied petroleum gas (LPG), or landfill gas)?** If "Yes" is checked, then the applicant will need to calculate the amount of GHGs from fuel use via on the Greenhouse Gas (GHG) online estimator [http://www.aqmd.gov/home/regulations/ceqa/ceqa-permit-forms], and attaching the printout or by conducting hand calculations and providing the documentation. Refer to the Instructions for Form 400-CEQA for guidance.
8.	O	⊙	**Will the project utilize other types of equipment not addressed in Question 7 that require the use of, or will generate, any chemicals listed on Form 400-CEQA, Table 3 - Greenhouse Gases [http://www.aqmd.gov/home/regulations/ceqa/ceqa-permit-forms]?** If "Yes" is checked, attach a separate sheet to identify each equipment unit, the chemical name(s), and the quantity of each chemical identified.
9.	O	⊙	**Will the project include the open outdoor storage of dry bulk solid materials that could generate dust?** If "Yes" is checked, include a plot plan with the application package.
10.	O	⊙	**Will the project result in or make worse noticeable off-site odors from activities that may not be subject to SCAQMD permit requirements?** For example, landfills, materials recovery/recycling facilities (MRF), and compost materials or other types of greenwaste (e.g., lawn clippings, tree trimmings, etc.) have the potential to generate odor complaints subject to SCAQMD Rule 402 – Nuisance.
11.	O	⊙	**Will the project cause an increase of emissions from marine vessels, trains and/or airplanes?**
12.	O	⊙	**Will the project increase demand for potable water at the facility by more than 262,820 gallons per day?** The following examples identify some, but not all, types of projects that may result in a "Yes" answer to this question: 1) a project that generates steam; 2) a project that uses water as part of operating air pollution control equipment; 3) a project that requires water as part of the production process; 4) a project that requires a new, or the expansion of an existing, sewage treatment facility, new water lines, sewage lines, sewage hook-ups etc.; 5) a project where the water demand exceeds the capacity of the local water purveyor to supply sufficient water for the project; 6) a project that requires new or the expansion of existing, water supply and conveyance facilities; and, 7) a project that requires water to hydrotest pipelines, storage tanks etc. for structural integrity.
13.	O	⊙	**Will the project create an increase in the mass inflow of effluents to a public wastewater treatment facility that would require a new, or revision to an existing, National Pollutant Discharge Elimination System (NPDES) or other related permit at the facility?**
14.	O	⊙	**Will the project result in the need for more than 350 new employees?**
15.	O	⊙	**Will the project result in an increase in heavy-duty transport truck traffic to and/or from the facility by more than 350 truck round-trips per day?**
16.	O	⊙	**Will the project result in an increase in customer traffic by more than 700 visits per day?**
17.	O	⊙	**Will the project result in temporary or permanent noise or vibration in excess of what is allowed by the applicable local noise ordinance?**
18.	O	⊙	**Will the project create a permanent need for new or additional solid waste disposal?** Check "No" if the projected potential amount of solid waste to be generated by the project is less than five tons per day.
19.	O	⊙	**Will the project create a permanent need for new or additional hazardous waste disposal?** Check "No" if the projected potential amount of hazardous wastes to be generated by the project is less than 42 cubic yards per day (or equivalent in pounds).
20.	O	⊙	**Will the project include equipment that after installation or modification will change the visual character of the site and its surroundings or block views?**
21.	O	⊙	**Will the project have equipment that will create a new source of external lighting that will be visible at the property line?**

Section D – SIGNATURES

I HEREBY CERTIFY THAT ALL INFORMATION CONTAINED HEREIN AND INFORMATION SUBMITTED WITH THIS APPLICATION IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE. I UNDERSTAND THAT THIS FORM IS A SCREENING TOOL AND THAT THE SCAQMD RESERVES THE RIGHT TO CONSIDER OTHER PERTINENT INFORMATION IN DETERMINING CEQA APPLICABILITY.

1. Signature of Responsible Official of Firm:		2. Title of Responsible Official of Firm: GENERAL MANAGER
3. Print Name of Responsible Official of Firm: MARK YOUNG		4. Date Signed: 08-09-2021
5. Phone # of Responsible Official of Firm: 8185482107	6. Fax # of Responsible Official of Firm:	7. Email of Responsible Official of Firm: myoung@glendaleca.gov
8. Signature of Preparer, (If prepared by person other than responsible official of firm):		9. Title of Preparer: PRINCIPAL (CONSULTANT)
10. Print Name of Preparer: A. EDWARD KRISNADI		11. Date Signed: 08-10-2021
12. Phone # of Preparer: (909) 261-2927	13. Fax # of Preparer:	14. Email of Preparer: ekrisnadi@montrose-env.com

THIS CONCLUDES FORM 400-CEQA. INCLUDE THIS FORM AND ANY ATTACHMENTS WITH FORM 400-A.

South Coast Air Quality Management District

Form 400-A
Application Form for Permit or Plan Approval

List only one piece of equipment or process per form.

South Coast AQMD

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit):
GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD):
800327

3. Owner's Business Name (If different from Business Name of Operator):

Section B - Equipment Location Address

4. Equipment Location Is: (◉) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

800 AIR WAY
Street Address
GLENDALE, CA 91201
City, Zip
MARK YOUNG — Contact Name
GENERAL MANAGER — Title
8185482107 — Phone #, Ext., Fax #
E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

141 N. GLENDALE AVENUE
Address
GLENDALE, CA 91206
City, State, Zip
MARK YOUNG — Contact Name
GENERAL MANAGER — Title
8185482107 — Phone #, Ext., Fax #
E-Mail: myoung@glendaleca.gov

Section D - Application Type

6. The Facility Is: ( ) Not In RECLAIM or Title V ( ) In RECLAIM (◉) In Title V ( ) In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:
- (◉) New Construction (Permit to Construct)
- ( ) Equipment On-Site But Not Constructed or Operational
- ( ) Equipment Operating Without A Permit *
- ( ) Compliance Plan
- ( ) Registration/Certification
- ( ) Streamlined Standard Permit

7b. Facility Permits:
- ( ) Title V Application or Amendment (Refer to Title V Matrix)
- ( ) RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:
- ( ) Administrative Change
- ( ) Alteration/Modification
- ( ) Alteration/Modification without Prior Approval *
- ( ) Change of Condition
- ( ) Change of Condition without Prior Approval *
- ( ) Change of Location
- ( ) Change of Location without Prior Approval *
- ( ) Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number:

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy):
8b. Estimated End Date of Construction (mm/dd/yyyy):
8c. Estimated Start Date of Operation (mm/dd/yyyy):

9. Description of Equipment or Reason for Compliance Plan (list applicable rule):
NEW AMMONIA STORAGE TANK

10. For identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / process)
0

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-for-profit training center)
(◉) No ( ) Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? If Yes, provide NOV/NC#:
(◉) No ( ) Yes

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location?
ELECTRICAL POWER GENERATION

14. What is your business primary NAICS Code? (North American Industrial Classification System)
221112

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator?
( ) No (◉) Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line?
(◉) No ( ) Yes

Section F - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application are true and correct.

17. Signature of Responsible Official: Mark Young

18. Title of Responsible Official: GENERAL MANAGER

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.)
( ) No (◉) Yes

20. Print Name: MARK YOUNG

21. Date: 08-09-2021

22. Do you claim confidentiality of data? (If Yes, see instructions.)
(◉) No ( ) Yes

23. Check List: ☒ Authorized Signature/Date ☒ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TRACKING #	CHECK #	AMOUNT RECEIVED	PAYMENT TRACKING #	VALIDATION
			$		

DATE	APP REJ	DATE	APP REJ	CLASS I III	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN

South Coast Air Quality Management District

Form 400-A

Application Form for Permit or Plan Approval

List only one piece of equipment or process per form.

South Coast AQMD

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit):
GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD):
800327

3. Owner's Business Name (If different from Business Name of Operator):

Section B - Equipment Location Address

4. Equipment Location Is: ◉ Fixed Location ○ Various Location
(For equipment operated at various locations, provide address of initial site.)

800 AIR WAY
Street Address

GLENDALE, CA 91201
City, Zip

MARK YOUNG — GENERAL MANAGER
Contact Name, Title

8185482107
Phone #, Ext., Fax #

E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

141 N. GLENDALE AVENUE
Address

GLENDALE, CA 91206
City, State, Zip

MARK YOUNG — GENERAL MANAGER
Contact Name, Title

8185482107
Phone #, Ext., Fax #

E-Mail: myoung@glendaleca.gov

Section D - Application Type

6. The Facility Is: ○ Not In RECLAIM or Title V ○ In RECLAIM ◉ In Title V ○ In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:
- ○ New Construction (Permit to Construct)
- ○ Equipment On-Site But Not Constructed or Operational
- ○ Equipment Operating Without A Permit *
- ○ Compliance Plan
- ○ Registration/Certification
- ○ Streamlined Standard Permit

7b. Facility Permits:
- ○ Title V Application or Amendment (Refer to Title V Matrix)
- ○ RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:
- ○ Administrative Change
- ◉ Alteration/Modification
- ○ Alteration/Modification without Prior Approval *
- ○ Change of Condition
- ○ Change of Condition without Prior Approval *
- ○ Change of Location
- ○ Change of Location without Prior Approval *
- ○ Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number:
370621

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy):

8b. Estimated End Date of Construction (mm/dd/yyyy):

8c. Estimated Start Date of Operation (mm/dd/yyyy):

9. Description of Equipment or Reason for Compliance Plan (list applicable rule):
GAS TURBINE 8A (D4) MODIFICATION; CONVERT TO SIMPLE CYCLE OPERATION; CONTROL TECH. MODIFICATIONS

10. For identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / process)
0

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-for-profit training center) ◉ No ○ Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? ◉ No ○ Yes
If Yes, provide NOV/NC#:

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location?
ELECTRICAL POWER GENERATION

14. What is your business primary NAICS Code? (North American Industrial Classification System)
221112

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator? ○ No ◉ Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line? ◉ No ○ Yes

Section F - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application are true and correct.

17. Signature of Responsible Official: [signature]

18. Title of Responsible Official: GENERAL MANAGER

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.) ○ No ◉ Yes

20. Print Name: MARK YOUNG

21. Date: 08-09-2021

22. Do you claim confidentiality of data? (If Yes, see instructions.) ◉ No ○ Yes

23. Check List: ☒ Authorized Signature/Date ☒ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TRACKING #	CHECK #	AMOUNT RECEIVED	PAYMENT TRACKING #	VALIDATION
			$		

DATE	APP REJ	DATE	APP REJ	CLASS I III	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN

South Coast Air Quality Management District

Form 400-A

Application Form for Permit or Plan Approval

List only one piece of equipment or process per form.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944
Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. Owner's Business Name (If different from Business Name of Operator):

Section B - Equipment Location Address

4. Equipment Location Is: (●) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

800 AIR WAY
Street Address
GLENDALE, CA 91201
City, Zip
MARK YOUNG — GENERAL MANAGER
Contact Name, Title
8185482107
Phone # Ext. Fax #
E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

141 N. GLENDALE AVENUE
Address
GLENDALE, CA 91206
City, State, Zip
MARK YOUNG — GENERAL MANAGER
Contact Name, Title
8185482107
Phone # Ext. Fax #
E-Mail: myoung@glendaleca.gov

Section D - Application Type

6. The Facility Is: ( ) Not In RECLAIM or Title V ( ) In RECLAIM (●) In Title V ( ) In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:
- ( ) New Construction (Permit to Construct)
- ( ) Equipment On-Site But Not Constructed or Operational
- ( ) Equipment Operating Without A Permit *
- ( ) Compliance Plan
- ( ) Registration/Certification
- ( ) Streamlined Standard Permit

7b. Facility Permits:
- ( ) Title V Application or Amendment (Refer to Title V Matrix)
- ( ) RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:
- ( ) Administrative Change
- (●) Alteration/Modification
- ( ) Alteration/Modification without Prior Approval *
- ( ) Change of Condition
- ( ) Change of Condition without Prior Approval *
- ( ) Change of Location
- ( ) Change of Location without Prior Approval *
- ( ) Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number: 344955

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy):
8b. Estimated End Date of Construction (mm/dd/yyyy):
8c. Estimated Start Date of Operation (mm/dd/yyyy):

9. Description of Equipment or Reason for Compliance Plan (list applicable rule):
GAS TURBINE 8B (D5) MODIFICATION; REPLACING STEAM TURBINE; CONTROL TECH. MODIFICATIONS

10. For identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / process) 1

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-for-profit training center) (●) No ( ) Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? (●) No ( ) Yes
If Yes, provide NOV/NC#:

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location? ELECTRICAL POWER GENERATION

14. What is your business primary NAICS Code? (North American Industrial Classification System) 221112

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator? ( ) No (●) Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line? (●) No ( ) Yes

Section F - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application are true and correct.

17. Signature of Responsible Official: [signature]

18. Title of Responsible Official: GENERAL MANAGER

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.) ( ) No (●) Yes

20. Print Name: MARK YOUNG

21. Date: 08-09-2021

22. Do you claim confidentiality of data? (If Yes, see instructions.) (●) No ( ) Yes

23. Check List: ☒ Authorized Signature/Date ☒ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TRACKING #	CHECK #	AMOUNT RECEIVED $	PAYMENT TRACKING #	VALIDATION

DATE	APP REJ	DATE	APP REJ	CLASS I III	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN

South Coast Air Quality Management District

Form 400-A

Application Form for Permit or Plan Approval

List only one piece of equipment or process per form.

South Coast AQMD

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. Owner's Business Name (If different from Business Name of Operator):

Section B - Equipment Location Address

4. Equipment Location Is: (●) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

800 AIR WAY
Street Address

GLENDALE, CA 91201
City, Zip

MARK YOUNG — GENERAL MANAGER
Contact Name, Title

8185482107
Phone #, Ext., Fax #

E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

141 N. GLENDALE AVENUE
Address

GLENDALE, CA 91206
City, State, Zip

MARK YOUNG — GENERAL MANAGER
Contact Name, Title

8185482107
Phone #, Ext., Fax #

E-Mail: myoung@glendaleca.gov

Section D - Application Type

6. The Facility Is: ( ) Not In RECLAIM or Title V ( ) In RECLAIM (●) In Title V ( ) In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:

- ( ) New Construction (Permit to Construct)
- ( ) Equipment On-Site But Not Constructed or Operational
- ( ) Equipment Operating Without A Permit *
- ( ) Compliance Plan
- ( ) Registration/Certification
- ( ) Streamlined Standard Permit

7b. Facility Permits:

- ( ) Title V Application or Amendment (Refer to Title V Matrix)
- ( ) RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:

- ( ) Administrative Change
- (●) Alteration/Modification
- ( ) Alteration/Modification without Prior Approval *
- ( ) Change of Condition
- ( ) Change of Condition without Prior Approval *
- ( ) Change of Location
- ( ) Change of Location without Prior Approval *
- ( ) Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number: 344956

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy):
8b. Estimated End Date of Construction (mm/dd/yyyy):
8c. Estimated Start Date of Operation (mm/dd/yyyy):

9. Description of Equipment or Reason for Compliance Plan (list applicable rule):
GAS TURBINE 8C (D6) MODIFICATION; REPLACING STEAM TURBINE; CONTROL TECH. MODIFICATIONS

10. For identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / process) 1

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-for-profit training center) (●) No ( ) Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? (●) No ( ) Yes
If Yes, provide NOV/NC#:

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location? ELECTRICAL POWER GENERATION

14. What is your business primary NAICS Code? (North American Industrial Classification System) 221112

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator? ( ) No (●) Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line? (●) No ( ) Yes

Section F - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application are true and correct.

17. Signature of Responsible Official: Mark Young

18. Title of Responsible Official: GENERAL MANAGER

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.) ( ) No (●) Yes

20. Print Name: MARK YOUNG

21. Date: 08-09-2021

22. Do you claim confidentiality of data? (If Yes, see instructions.) (●) No ( ) Yes

23. Check List: ☒ Authorized Signature/Date ☒ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TRACKING #	CHECK #	AMOUNT RECEIVED $	PAYMENT TRACKING #	VALIDATION

DATE	APP REJ	DATE	APP REJ	CLASS I III	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN

South Coast Air Quality Management District

Form 400-A

Application Form for Permit or Plan Approval

List only one piece of equipment or process per form.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. Owner's Business Name (If different from Business Name of Operator):

Section B - Equipment Location Address

4. Equipment Location Is: (●) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

800 AIR WAY
Street Address

GLENDALE, CA 91201
City, Zip

MARK YOUNG — GENERAL MANAGER
Contact Name, Title

8185482107
Phone #, Ext., Fax #

E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

141 N. GLENDALE AVENUE
Address

GLENDALE, CA 91206
City, State, Zip

MARK YOUNG — GENERAL MANAGER
Contact Name, Title

8185482107
Phone #, Ext., Fax #

E-Mail: myoung@glendaleca.gov

Section D - Application Type

6. The Facility Is: ( ) Not In RECLAIM or Title V ( ) In RECLAIM (●) In Title V ( ) In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:
- (●) New Construction (Permit to Construct)
- ( ) Equipment On-Site But Not Constructed or Operational
- ( ) Equipment Operating Without A Permit *
- ( ) Compliance Plan
- ( ) Registration/Certification
- ( ) Streamlined Standard Permit

7b. Facility Permits:
- ( ) Title V Application or Amendment (Refer to Title V Matrix)
- ( ) RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:
- ( ) Administrative Change
- ( ) Alteration/Modification
- ( ) Alteration/Modification without Prior Approval *
- ( ) Change of Condition
- ( ) Change of Condition without Prior Approval *
- ( ) Change of Location
- ( ) Change of Location without Prior Approval *
- ( ) Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number:

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy):

8b. Estimated End Date of Construction (mm/dd/yyyy):

8c. Estimated Start Date of Operation (mm/dd/yyyy):

9. Description of Equipment or Reason for Compliance Plan (list applicable rule):
REPLACING EXISTING CONTROL TECHNOLOGY (C51,C52) WITH NEW SCR&CATOX UNIT

10. For identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / process) 0

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-for-profit training center) (●) No ( ) Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? (●) No ( ) Yes
If Yes, provide NOV/NC#:

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location?
ELECTRICAL POWER GENERATION

14. What is your business primary NAICS Code? (North American Industrial Classification System) 221112

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator? ( ) No (●) Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line? (●) No ( ) Yes

Section F - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application are true and correct.

17. Signature of Responsible Official: Mark Young

18. Title of Responsible Official: GENERAL MANAGER

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.) ( ) No (●) Yes

20. Print Name: MARK YOUNG

21. Date: 08-09-2021

22. Do you claim confidentiality of data? (If Yes, see instructions.) (●) No ( ) Yes

23. Check List: ☒ Authorized Signature/Date ☒ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TRACKING #	CHECK #	AMOUNT RECEIVED $	PAYMENT TRACKING #	VALIDATION

DATE	APP REJ	DATE	APP REJ	CLASS I III	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN

South Coast Air Quality Management District

Form 400-A

Application Form for Permit or Plan Approval

List only one piece of equipment or process per form.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944
Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. Owner's Business Name (If different from Business Name of Operator):

Section B - Equipment Location Address

4. Equipment Location Is: (●) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

800 AIR WAY
Street Address
GLENDALE, CA 91201
City, Zip
MARK YOUNG — GENERAL MANAGER
Contact Name, Title
8185482107
Phone # Ext. Fax #
E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

141 N. GLENDALE AVENUE
Address
GLENDALE, CA 91206
City, State, Zip
MARK YOUNG — GENERAL MANAGER
Contact Name, Title
8185482107
Phone # Ext. Fax #
E-Mail: myoung@glendale.ca.gov

Section D - Application Type

6. The Facility Is: ( ) Not In RECLAIM or Title V ( ) In RECLAIM (●) In Title V ( ) In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:
- (●) New Construction (Permit to Construct)
- ( ) Equipment On-Site But Not Constructed or Operational
- ( ) Equipment Operating Without A Permit *
- ( ) Compliance Plan
- ( ) Registration/Certification
- ( ) Streamlined Standard Permit

7b. Facility Permits:
- ( ) Title V Application or Amendment (Refer to Title V Matrix)
- ( ) RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:
- ( ) Administrative Change
- ( ) Alteration/Modification
- ( ) Alteration/Modification without Prior Approval *
- ( ) Change of Condition
- ( ) Change of Condition without Prior Approval *
- ( ) Change of Location
- ( ) Change of Location without Prior Approval *
- ( ) Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number:

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy):
8b. Estimated End Date of Construction (mm/dd/yyyy):
8c. Estimated Start Date of Operation (mm/dd/yyyy):

9. Description of Equipment or Reason for Compliance Plan (list applicable rule):
REPLACING EXISTING CONTROL TECHNOLOGY (C53,C54) WITH NEW SCR&CATOX UNIT

10. For identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / process) 0

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-for-profit training center) (●) No ( ) Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? (●) No ( ) Yes
If Yes, provide NOV/NC#:

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location? ELECTRICAL POWER GENERATION

14. What is your business primary NAICS Code? (North American Industrial Classification System) 221112

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator? ( ) No (●) Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line? (●) No ( ) Yes

Section F - Authorization/Signature *I hereby certify that all information contained herein and information submitted with this application are true and correct.*

17. Signature of Responsible Official: [signature]

18. Title of Responsible Official: GENERAL MANAGER

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.) ( ) No (●) Yes

20. Print Name: MARK YOUNG

21. Date: 08-09-2021

22. Do you claim confidentiality of data? (If Yes, see instructions.) (●) No ( ) Yes

23. Check List: ☒ Authorized Signature/Date ☒ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TRACKING #	CHECK #	AMOUNT RECEIVED $	PAYMENT TRACKING #	VALIDATION

DATE	APP REJ	DATE	APP REJ	CLASS I III	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN

South Coast Air Quality Management District

Form 400-A

Application Form for Permit or Plan Approval

List only one piece of equipment or process per form.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. Owner's Business Name (If different from Business Name of Operator):

Section B - Equipment Location Address

4. Equipment Location Is: (●) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

Street Address: 800 AIR WAY
City: GLENDALE, CA Zip: 91201
Contact Name: MARK YOUNG Title: GENERAL MANAGER
Phone #: 8185482107 Ext. Fax #
E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

Address: 141 N. GLENDALE AVENUE
City: GLENDALE, State: CA Zip: 91206
Contact Name: MARK YOUNG Title: GENERAL MANAGER
Phone #: 8185482107 Ext. Fax #
E-Mail: myoung@glendaleca.gov

Section D - Application Type

6. The Facility Is: ( ) Not In RECLAIM or Title V ( ) In RECLAIM (●) In Title V ( ) In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:
- ( ) New Construction (Permit to Construct)
- ( ) Equipment On-Site But Not Constructed or Operational
- ( ) Equipment Operating Without A Permit *
- ( ) Compliance Plan
- ( ) Registration/Certification
- ( ) Streamlined Standard Permit

7b. Facility Permits:
- (●) Title V Application or Amendment (Refer to Title V Matrix)
- ( ) RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:
- ( ) Administrative Change
- ( ) Alteration/Modification
- ( ) Alteration/Modification without Prior Approval *
- ( ) Change of Condition
- ( ) Change of Condition without Prior Approval *
- ( ) Change of Location
- ( ) Change of Location without Prior Approval *
- ( ) Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number:

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy):
8b. Estimated End Date of Construction (mm/dd/yyyy):
8c. Estimated Start Date of Operation (mm/dd/yyyy):

9. Description of Equipment or Reason for Compliance Plan (list applicable rule): TITLE V FACILITY AMENDMENT

10. For identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / process) 0

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-for-profit training center) (●) No ( ) Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? (●) No ( ) Yes
If Yes, provide NOV/NC#:

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location? ELECTRICAL POWER GENERATION

14. What is your business primary NAICS Code? (North American Industrial Classification System) 221112

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator? ( ) No (●) Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line? (●) No ( ) Yes

Section F - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application are true and correct.

17. Signature of Responsible Official: [signature]

18. Title of Responsible Official: GENERAL MANAGER

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.) ( ) No (●) Yes

20. Print Name: MARK YOUNG

21. Date: 08-09-2021

22. Do you claim confidentiality of data? (If Yes, see instructions.) (●) No ( ) Yes

23. Check List: ☒ Authorized Signature/Date ☒ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TRACKING #	CHECK #	AMOUNT RECEIVED	PAYMENT TRACKING #	VALIDATION
			$		

DATE	APP REJ	DATE	APP REJ	CLASS I III	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN

South Coast Air Quality Management District

Form 500-A2
Title V Application Certification

South Coast AQMD

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section I - Operator Information

1. Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. This Certification is submitted with a (Check one):
- a. ◉ Title V Application (Initial, Revision or Renewal)
- b. ○ Supplement/Correction to a Title V Application
- c. ○ MACT Part 1

4. Is Form 500-C2 included with this Certification? ○ Yes ◉ No

Section II - Responsible Official Certification Statement

*Read each statement carefully and check each that applies – **You must check 3a or 3b.***

1. For Initial, Permit Renewal, and Administrative Application Certifications:

a. ○ The facility, including equipment that are exempt from written permit per Rule 219, is currently operating and will continue to operate in compliance with all applicable requirement(s) identified in Section II and Section III of Form 500-C1,

i. ☐ except for those requirements that do not specifically pertain to such devices or equipment and that have been identified as "Remove" on Section III of Form 500-C1.

ii. ☐ except for those devices or equipment that have been identified on the completed and attached Form 500-C2 that will not be operating in compliance with the specified applicable requirement(s).

b. ○ The facility, including equipment that are exempt from written permit per Rule 219, will meet in a timely manner, all applicable requirements with future effective dates.

2. For Permit Revision Application Certifications:

a. ☑ The equipment or devices to which this permit revision applies, will in a timely manner comply with all applicable requirements identified in Section II and Section III of Form 500-C1.

3. For MACT Hammer Certifications:

a. ○ The facility is subject to Section 112(j) of the Clean Air Act (Subpart B of 40 CFR part 63), also known as the MACT "hammer." The following information is submitted with a Title V application to comply with the Part 1 requirements of Section 112(j).

b. ◉ The facility is not subject to Section 112(j) of the Clean Air Act (Subpart B of 40 CFR part 63).

Section III - Authorization/Signature

I certify under penalty of law that I am the responsible official for this facility as defined in AQMD Regulation XXX and that based on information and belief formed after reasonable inquiry, the statement and information in this document and in all attached application forms and other materials are true, accurate, and complete.

1. Signature of Responsible Official: Mark Young	**2. Title of Responsible Official:** GENERAL MANAGER
3. Print Name: MARK YOUNG	**4. Date:** 08-09-2021
5. Phone #: (818) 548-2107	**6. Fax #:**

7. Address of Responsible Official:

Street #	City	State	Zip
141 N. GLENDALE AVE	GLENDALE	CA	91206

Acid Rain Facilities Only: Please Complete Section IV

Acid Rain facilities must certify their compliance status of the devices subject to applicable requirements under Title IV by an individual who meets the definition of Designated (or Alternate) Representative in 40 CFR Part 72.

Section IV - Designated Representative Certification Statement	
***For Acid Rain Facilities Only*: I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.**	
1. Signature of Designated Representative or Alternate: Mark Y	2. Title of Designated Representative or Alternate: GENERAL MANAGER
3. Print Name of Designated Representative or Alternate: MARK YOUNG	4. Date: 08-09-2021
5. Phone #: (818) 548-2107	6. Fax #:
7. Address of Designated Representative or Alternate: 141 N. GLENDALE AVE (Street #), GLENDALE (City), CA (State), 91206 (Zip)	

South Coast Air Quality Management District

Form 400-E-5
Selective Catalytic Reduction (SCR) System, Oxidation Catalyst, and Ammonia Catalyst

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Address where the equipment will be operated (for equipment which will be moved to various location in AQMD's jurisdiction, please list the initial location site): 800 AIR WAY, GLENDALE, CA 91201

(•) Fixed Location ( ) Various Locations

Section B - Equipment Description

Selective Catalytic Reduction (SCR)

SCR Catalyst	Manufacturer: TO BE DETERMINED Catalyst Active Material: ____ Model Number: ____ Type: ____ Size of Each Layer or Module: L: ____ ft. ____ in. W: ____ ft. ____ in. H: ____ ft. ____ in. No. of Layers or Modules: ____ Total Volume: ____ cu. ft. Total Weight: ____ lbs.
Reducing Agent	( ) Urea ( ) Anhydrous Ammonia (•) Aqueous Ammonia 19.00 % Injection Rate: ____ lb/hr
Reducing Agent Storage*	Diameter: ____ ft. ____ in. Height: ____ ft. ____ in. Capacity: 15000 gal Pressure Setting: 40 psia * A separate permit may be needed for the storage equipment.
Space Velocity	Gas Flow Rate/Catalyst Volume: ____ per hour
Area Velocity	Gas Flow Rate/Wetted Catalyst Surface Area: ____ ft/hr
Manufacturer's Guarantee	NOx: 2.5 ppm $\%O_2$: 15.00 NOx: ____ gm/bhp-hr Ammonia Slip: 5 ppm @ 15.00 $\%O_2$
Catalyst Life	5 years (expected)
Cost	Capital Cost: ____ Installation Cost: ____ Catalyst Replacement Cost: ____

Oxidation Catalyst

Oxidation Catalyst	Manufacturer: ____ Catalyst Active Material: ____ Model Number: TO BE DETERMINED Type: ____ Size of Each Layer or Module: L: ____ ft. ____ in. W: ____ ft. ____ in. H: ____ ft. ____ in. No. of Layers or Modules: ____ Total Volume: ____ cu. ft. Total Weight: ____ lbs.
Space Velocity	Gas Flow Rate/Catalyst Volume: ____ per hour
Manufacturer's Guarantee	VOC: ____ ppm VOC: ____ gm/bhp-hr $\%O_2$: ____ CO: 25 ppm CO: ____ gm/bhp-hr $\%O_2$: 15.00
Catalyst Life	5 years (expected)
Cost	Capital Cost: ____ Installation Cost: ____ Catalyst Replacement Cost: ____

Form 400-E-5
Selective Catalytic Reduction (SCR) System, Oxidation Catalyst, and Ammonia Catalyst

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section B - Equipment Description (cont.)

Ammonia Catalyst

Ammonia Catalyst	**Manufacturer:**____ **Catalyst Active Material:**____ **Model Number:**____ **Type:**____ **Size of Each Layer or Module: L:**____ ft.____ in. **W:**____ ft.____ in. **H:**____ ft.____ in. **No. of Layers or Modules:**____ **Total Volume:**____ cu. ft. **Total Weight:**____ lbs.
Space Velocity	**Gas Flow Rate/Catalyst Volume:**____ per hour
Manufacturer's Guarantee	**NH_3:**____ ppm **$\%O_2$:**____
Catalyst Life	____ years (expected)
Cost	**Capital Cost:**____ **Installation Cost:**____ **Catalyst Replacement Cost:**____

Section C - Operation Information

Operating Temperature	**Minimum Inlet Temperature:**____ °F (from cold start) **Maximum Temperature:**____ °F **Warm-up Time:** 1 hr. ____ min. (maximum)
Operating Schedule	**Normal:** ____ hours/day ____ days/week ____ weeks/yr **Maximum:** 9 hours/day 7 days/week 52 weeks/yr

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info	**Signature:** [signature] **Date:** 08/17/2021 **Title:** CONSULTANT **Company Name:** MONTROSE	**Name:** A. EDWARD KRISNADI **Phone #:** (909) 261-2927 **Fax #:** **Email:** ekrisnadi@montrose-env.com
Contact Info	**Name:** A. EDWARD KRISNADI **Title:** CONSULTANT **Company Name:** MONTROSE	**Phone #:** (909) 261-9297 **Fax #:** **Email:** ekrisnadi@montrose-env.com

THIS IS A PUBLIC DOCUMENT

Pursuant to the California Public Records Act, your permit application and any supplemental documentation are public records and may be disclosed to a third party. If you wish to claim certain limited information as exempt from disclosure because it qualifies as a trade secret, as defined in the District's Guidelines for Implementing the California Public Records Act, you must make such claim at the time of submittal to the District.

Check here if you claim that this form or its attachments contain confidential trade secret information. ☒

South Coast Air Quality Management District

Form 400-E-5
Selective Catalytic Reduction (SCR) System, Oxidation Catalyst, and Ammonia Catalyst

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Address where the equipment will be operated (for equipment which will be moved to various location in AQMD's jurisdiction, please list the initial location site): 800 AIR WAY, GLENDALE, CA 91201

(●) Fixed Location ( ) Various Locations

Section B - Equipment Description

Selective Catalytic Reduction (SCR)

SCR Catalyst	Manufacturer: TO BE DETERMINED Catalyst Active Material: ______ Model Number: ______ Type: ______ Size of Each Layer or Module: L: ___ ft. ___ in. W: ___ ft. ___ in. H: ___ ft. ___ in. No. of Layers or Modules: ______ Total Volume: ______ cu. ft. Total Weight: ______ lbs.
Reducing Agent	( ) Urea ( ) Anhydrous Ammonia (●) Aqueous Ammonia 19.00 % Injection Rate: ______ lb/hr
Reducing Agent Storage*	Diameter: ___ ft. ___ in. Height: ___ ft. ___ in. Capactity: 15000 gal Pressure Setting: 40 psia * A separate permit may be needed for the storage equipment.
Space Velocity	Gas Flow Rate/Catalyst Volume: ______ per hour
Area Velocity	Gas Flow Rate/Wetted Catalyst Surface Area: ______ ft/hr
Manufacturer's Guarantee	NOx: 2.0 ppm $\%O_2$: 15.00 NOx: ______ gm/bhp-hr Ammonia Slip: 5 ppm @ 15.00 $\%O_2$
Catalyst Life	5 years (expected)
Cost	Capital Cost: ______ Installation Cost: ______ Catalyst Replacement Cost: ______

Oxidation Catalyst

Oxidation Catalyst	Manufacturer: TO BE DETERMINED Catalyst Active Material: ______ Model Number: ______ Type: ______ Size of Each Layer or Module: L: ___ ft. ___ in. W: ___ ft. ___ in. H: ___ ft. ___ in. No. of Layers or Modules: ______ Total Volume: ______ cu. ft. Total Weight: ______ lbs.
Space Velocity	Gas Flow Rate/Catalyst Volume: ______ per hour
Manufacturer's Guarantee	VOC: ______ ppm VOC: ______ gm/bhp-hr $\%O_2$: ______ CO: 25 ppm CO: ______ gm/bhp-hr $\%O_2$: 15.00
Catalyst Life	5 years (expected)
Cost	Capital Cost: ______ Installation Cost: ______ Catalyst Replacement Cost: ______

South Coast Air Quality Management District

Form 400-E-5
Selective Catalytic Reduction (SCR) System, Oxidation Catalyst, and Ammonia Catalyst

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section B - Equipment Description (cont.)

Ammonia Catalyst

Ammonia Catalyst	Manufacturer: ____ Catalyst Active Material: ____ Model Number: ____ Type: ____ Size of Each Layer or Module: L: ____ ft. ____ in. W: ____ ft. ____ in. H: ____ ft. ____ in. No. of Layers or Modules: ____ Total Volume: ____ cu. ft. Total Weight: ____ lbs.
Space Velocity	Gas Flow Rate/Catalyst Volume: ____ per hour
Manufacturer's Guarantee	NH_3: ____ ppm %O_2: ____
Catalyst Life	____ years (expected)
Cost	Capital Cost: ____ Installation Cost: ____ Catalyst Replacement Cost: ____

Section C - Operation Information

Operating Temperature	Minimum Inlet Temperature: ____ °F (from cold start) Maximum Temperature: ____ °F Warm-up Time: 1 hr. ____ min. (maximum)
Operating Schedule	Normal: ____ hours/day ____ days/week ____ weeks/yr Maximum: 9 hours/day 7 days/week 52 weeks/yr

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info	Signature: [signature] Date: 08/17/2021 Title: CONSULTANT Company Name: MONTROSE	Name: A. EDWARD KRISNADI Phone #: (909) 261-2927 Fax #: Email: ekrisnadi@montrose-env.com
Contact Info	Name: A. EDWARD KRISNADI Title: CONSULTANT Company Name: MONTROSE	Phone #: (909) 261-9297 Fax #: Email: ekrisnadi@montrose-env.com

South Coast Air Quality Management District

Form 400-E-12
Gas Turbine

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Address where the equipment will be operated (for equipment which will be moved to various location in AQMD's jurisdiction, please list the initial location site): 800 AIR WAY, GLENDALE, CA 91201

(●) Fixed Location ( ) Various Locations

Section B - Equipment Description

Turbine	**Manufacturer:** TURBO POWER & MARINE **Model:** FT4C3FLF **Serial No.:** TURBINE 8A (D4) Size (based on Higher Heating Value - HHV): **Manufacturer Maximum Input Rating:** 350.00 MMBTU/hr ______ kWh **Manufacturer Maximum Output Rating:** ______ MMBTU/hr 30,000.00 kWh
Function (Check all that apply)	[X] Electrical Generation [ ] Driving Pump/Compressor [ ] Emergency Peaking Unit [ ] Steam Generation [ ] Exhaust Gas Recovery [ ] Other (specify): ______
Cycle Type	(●) Simply Cycle ( ) Regenerative Cycle ( ) Combined Cycle ( ) Other (specify): ______
Combustion Type	( ) Tubular ( ) Can-Annular (●) Annular
Fuel (Turbine)	[X] Natural Gas [ ] LPG [ ] Digester Gas* [ ] Landfill Gas* [ ] Propane [ ] Refinery Gas* [ ] Other*: ______ * (If Digester Gas, Landfill Gas, Refinery Gas, and/or Other are checked, attach fuel analysis indicating higher heating value and sulfur content).
Heat Recovery Steam Generator (HRSG)	Steam Turbine Capacity: ______ MW Low Pressure Steam Output Capacity: ______ lb/hr @ ______ °F High Pressure Steam Output Capacity: ______ lb/hr @ ______ °F Superheated Steam Output Capacity: ______ lb/hr @ ______ °F
Duct Burner	**Manufacturer:** NOT APPLICABLE (NO DUCT BURNER) **Model:** ______ **Number of burners:** ______ **Rating of each burner** (HHV): ______ **Type:** (●) **Low NOx** (please attach manufacturer's specifications) ( ) **Other:** ______ Show all heat transfer surface locations with the HRSG and temperature profile
Fuel (Duct Burner)	( ) Natural Gas ( ) LPG ( ) Digester Gas* ( ) Landfill Gas* ( ) Propane ( ) Refinery Gas* (●) Other*: NONE * (If Digester Gas, Landfill Gas, Refinery Gas, and/or Other are checked, attach fuel analysis indicating higher heating value and sulfur content).

Form 400-E-12
Gas Turbine

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section B - Equipment Description (Cont.)

Air Pollution Control

- ○ Selective Catalytic Reduction (SCR)*
- ○ Selective Non-Catalytic Reduction (SNCR)*
- ○ Oxidation Catalyst*
- ◉ Other (specify)*: SCR AND OXIDATION CAT IN SERIES
- ○ Steam/Water Injection: Injection Rate: ______ lbs. water/lbs. fuel, or ______ mole water/mole fuel

* Separate application is required.

Capital Cost: ______ Installation Cost: ______ Annual Operating Cost: ______

Oxidation Catalyst Data (If Applicable)

Manufacturer: TBD

Model: TBD

Catalyst Dimensions: Length: ______ ft. ______ in. Width: ______ ft. ______ in. Height: ______ ft. ______ in.

Catalyst Cell Density: ______ cells/sq.in. Pressure Drop Across Catalyst: ______

Manufacturer's Guarantee: CO Control Efficiency: 50.00 % Catalyst Life: 5 yrs

VOC Control Efficiency: 30.00 % Operating Temp. Range: ______ °F

Space Velocity (gas flow rate/catalyst volume): ______ Area Velocity (gas flow/wetted catalyst surface area): ______

VOC Concentration into Catalyst: ______ PPMVD@ 15%O_2 CO Concentration inot Catalyst: ______ PPMVD@ 15%O_2

Section C - Operation Information

On-line Emissions Data

Pollutants	Maximum Emissions Before Control*		Maximum Emissions After Control	
	PPM@15% O_2, dry	lb/hour	PPM@15% O_2, dry	lb/hour
ROG				13.91
NOx			2.5	3.27
CO			25	19.92
PM_{10}				1.05
SOx				0.24
NH_3			5	

* Based on temperature, fuel consumption, and MW output.

Reference (attach data):

☒ Manufacturer Emission Data ☐ EPA Emission Factors ☒ AQMD Emission Factors ☐ Source Test

Stack or Vent Data

Stack Height: 115 ft. ______ in. Stack Diameter: 10 ft. 0 in.

Exhaust Temperature: 857 °F Exhaust Pressure: 0.2 inches water column

Exhaust Flow Rate: 558240 CFM Oxygen Level: ______ %

Form 400-E-12
Gas Turbine

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section C - Operation Information (cont.)

Startup Data

No. of Startups per day: 2 No. of Startups per year: 125 Duration of each startup: 1 hrs.

Shutdown Data

No. of Shutdowns per day: 2 No. of Shutdowns per year: 125 Duration of each Shutdown: 0.25 hrs.

Startup and Shutdown Emissions Data

Pollutants	Startup Emissions		Shutdown Emissions	
	PPM@15% O_2, dry	lb/hour	PPM@15% O_2, dry	lb/hour
ROG		13.91		13.91
NOx		15.60		15.40
CO		84.39		9.96
PM_{10}		0.20		0.20
SOx		0.24		0.24
NH_3				

Monitoring and Reporting

Continuous Emission Monitoring System (CEMS): CEMS Make: TBD

CEMS Model: TBD

Will the CEMS be used to measure both on-line and startup/shutdown emissions? ☒ Yes ☐ No

The following parameters will be continuously monitored:

☒ NOx ☒ CO ☒ O_2

☒ Fuel Flow Rate ☒ Ammonia Injection Rate ☐ Other (specify): ______

☐ Ammonia Stack Concentration: Ammonia CEMS Make: ______

Ammonia CEMS Model: ______

Operating Schedule

Normal:	______ hours/day	______ days/week	______ weeks/yr
Maximum:	9 hours/day	7 days/week	52 weeks/yr

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info

Signature: [signature] Date: 08/17/2021

Name: A. EDWARD KRISNADI

Phone #: (909) 261-2927 Fax #: ______

Title: CONSULTANT Company Name: MONTROSE

Email: ekrisnadi@montrose-env.com

Contact Info

Name: A. EDWARD KRISNADI

Phone #: (909) 261-2927 Fax #: ______

Title: CONSULTANT Company Name: MONTROSE

Email: ekrisnadi@montrose-env.com

South Coast Air Quality Management District

Form 400-E-12
Gas Turbine

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

South Coast AQMD

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Address where the equipment will be operated (for equipment which will be moved to various location in AQMD's jurisdiction, please list the initial location site): 800 AIR WAY, GLENDALE, CA 91201

(•) Fixed Location ( ) Various Locations

Section B - Equipment Description

Turbine	**Manufacturer:** TURBO POWER & MARINE **Model:** FT4C3FLF **Serial No.:** TURBINE 8B (D5) **Size** (based on Higher Heating Value - HHV): **Manufacturer Maximum Input Rating:** 350.00 MMBTU/hr ______ kWh **Manufacturer Maximum Output Rating:** ______ MMBTU/hr 30,000.00 kWh
Function (Check all that apply)	[X] Electrical Generation [ ] Driving Pump/Compressor [ ] Emergency Peaking Unit [X] Steam Generation [ ] Exhaust Gas Recovery [ ] Other (specify): ______
Cycle Type	( ) Simply Cycle ( ) Regenerative Cycle (•) Combined Cycle ( ) Other (specify): ______
Combustion Type	( ) Tubular ( ) Can-Annular (•) Annular
Fuel (Turbine)	[X] Natural Gas [ ] LPG [ ] Digester Gas* [ ] Landfill Gas* [ ] Propane [ ] Refinery Gas* [ ] Other*: ______ * (If Digester Gas, Landfill Gas, Refinery Gas, and/or Other are checked, attach fuel analysis indicating higher heating value and sulfur content).
Heat Recovery Steam Generator (HRSG)	**Steam Turbine Capacity:** ______ MW **Low Pressure Steam Output Capacity:** ______ lb/hr @ ______ °F **High Pressure Steam Output Capacity:** ______ lb/hr @ ______ °F **Superheated Steam Output Capacity:** ______ lb/hr @ ______ °F
Duct Burner	**Manufacturer:** NOT APPLICABLE (NO DUCT BURNER) **Model:** ______ **Number of burners:** ______ **Rating of each burner** (HHV): ______ **Type:** (•) **Low NOx** (please attach manufacturer's specifications) ( ) **Other:** ______ Show all heat transfer surface locations with the HRSG and temperature profile
Fuel (Duct Burner)	( ) Natural Gas ( ) LPG ( ) Digester Gas* ( ) Landfill Gas* ( ) Propane ( ) Refinery Gas* (•) Other*: NONE * (If Digester Gas, Landfill Gas, Refinery Gas, and/or Other are checked, attach fuel analysis indicating higher heating value and sulfur content).

South Coast Air Quality Management District

Form 400-E-12
Gas Turbine

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section B - Equipment Description (Cont.)

Air Pollution Control

○ Selective Catalytic Reduction (SCR)* ○ Selective Non-Catalytic Reduction (SNCR)*

○ Oxidation Catalyst* ◉ Other (specify)*: SCR AND OXIDATION CAT IN SERIES

○ Steam/Water Injection: Injection Rate:______ lbs. water/lbs. fuel, or______ mole water/mole fuel

* Separate application is required.

Capital Cost:______ Installation Cost:______ Annual Operating Cost:______

Oxidation Catalyst Data (If Applicable)

Manufacturer: TBD Model: TBD

Catalyst Dimensions: Length:____ ft.____ in. Width:____ ft.____ in. Height:____ ft.____ in.

Catalyst Cell Density:______ cells/sq.in. Pressure Drop Across Catalyst:______

Manufacturer's Guarantee: CO Control Efficiency: 50.00 % Catalyst Life: 5 yrs

VOC Control Efficiency: 30.00 % Operating Temp. Range:______ °F

Space Velocity (gas flow rate/catalyst volume):______ Area Velocity (gas flow/wetted catalyst surface area):______

VOC Concentration into Catalyst:______ PPMVD@ 15%O_2 CO Concentration inot Catalyst:______ PPMVD@ 15%O_2

Section C - Operation Information

On-line Emissions Data

Pollutants	Maximum Emissions Before Control *		Maximum Emissions After Control	
	PPM@15% O_2, dry	lb/hour	PPM@15% O_2, dry	lb/hour
ROG				13.91
NOx			2	2.62
CO			25	19.92
PM_{10}				0.20
SOx				0.24
NH_3			5	

* Based on temperature, fuel consumption, and MW output.

Reference (attach data):

☒ Manufacturer Emission Data ☐ EPA Emission Factors ☒ AQMD Emission Factors ☐ Source Test

Stack or Vent Data

Stack Height: 115 ft.______ in. Stack Diameter: 10 ft. 0 in.

Exhaust Temperature: 378 °F Exhaust Pressure: 0.2 inches water column

Exhaust Flow Rate: 738000 CFM Oxygen Level:______ %

Form 400-E-12
Gas Turbine

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section C - Operation Information (cont.)

Startup Data

No. of Startups per day: 2 No. of Startups per year: 250 Duration of each startup: 1 hrs.

Shutdown Data

No. of Shutdowns per day: 2 No. of Shutdowns per year: 250 Duration of each Shutdown: 0.25 hrs.

Startup and Shutdown Emissions Data

Pollutants	Startup Emissions		Shutdown Emissions	
	PPM@15% O_2, dry	lb/hour	PPM@15% O_2, dry	lb/hour
ROG		13.91		13.91
NOx		15.30		15.40
CO		84.39		9.96
PM_{10}		0.20		0.20
SOx		0.24		0.24
NH_3				

Monitoring and Reporting

Continuous Emission Monitoring System (CEMS): CEMS Make: TBD

CEMS Model: TBD

Will the CEMS be used to measure both on-line and startup/shutdown emissions? (●) Yes ( ) No

The following parameters will be continuously monitored:

☒ NOx ☒ CO ☒ O_2

☒ Fuel Flow Rate ☒ Ammonia Injection Rate ☐ Other (specify): ______

☐ Ammonia Stack Concentration: Ammonia CEMS Make: ______

Ammonia CEMS Model: ______

Operating Schedule

	hours/day	days/week	weeks/yr
Normal:			
Maximum:	9	7	52

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info

Signature: [signature] Date: 08/17/2021

Name: A. EDWARD KRISNADI

Title: CONSULTANT Company Name: MONTROSE

Phone #: (909) 261-2927 Fax #:

Email: ekrisnadi@montrose-env.com

Contact Info

Name: A. EDWARD KRISNADI

Title: CONSULTANT Company Name: MONTROSE

Phone #: (909) 261-2927 Fax #:

Email: ekrisnadi@montrose-env.com

THIS IS A PUBLIC DOCUMENT

Pursuant to the California Public Records Act, your permit application and any supplemental documentation are public records and may be disclosed to a third party. If you wish to claim certain limited information as exempt from disclosure because it qualifies as a trade secret, as defined in the District's Guidelines for Implementing the California Public Records Act, you must make such claim at the time of submittal to the District.

Check here if you claim that this form or its attachments contain confidential trade secret information. ☒

South Coast Air Quality Management District

Form 400-E-12
Gas Turbine

South Coast AQMD

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Address where the equipment will be operated (for equipment which will be moved to various location in AQMD's jurisdiction, please list the initial location site): 800 AIR WAY, GLENDALE, CA 91201

(●) Fixed Location ( ) Various Locations

Section B - Equipment Description

Turbine	**Manufacturer:** TURBO POWER & MARINE **Model:** FT4C3FLF **Serial No.:** TURBINE 8C (D6) Size (based on Higher Heating Value - HHV): **Manufacturer Maximum Input Rating:** 350.00 MMBTU/hr ________ kWh **Manufacturer Maximum Output Rating:** ________ MMBTU/hr 30,000.00 kWh
Function (Check all that apply)	[X] Electrical Generation [ ] Driving Pump/Compressor [ ] Emergency Peaking Unit [X] Steam Generation [ ] Exhaust Gas Recovery [ ] Other (specify): ________
Cycle Type	( ) Simply Cycle ( ) Regenerative Cycle (●) Combined Cycle ( ) Other (specify): ________
Combustion Type	( ) Tubular ( ) Can-Annular (●) Annular
Fuel (Turbine)	[X] Natural Gas [ ] LPG [ ] Digester Gas* [ ] Landfill Gas* [ ] Propane [ ] Refinery Gas* [ ] Other*: ________ * (If Digester Gas, Landfill Gas, Refinery Gas, and/or Other are checked, attach fuel analysis indicating higher heating value and sulfur content).
Heat Recovery Steam Generator (HRSG)	**Steam Turbine Capacity:** ________ MW **Low Pressure Steam Output Capacity:** ________ lb/hr @ ________ °F **High Pressure Steam Output Capacity:** ________ lb/hr @ ________ °F **Superheated Steam Output Capacity:** ________ lb/hr @ ________ °F
Duct Burner	**Manufacturer:** NOT APPLICABLE (NO DUCT BURNER) **Model:** ________ **Number of burners:** ________ **Rating of each burner** (HHV): ________ **Type:** (●) **Low NOx** (please attach manufacturer's specifications) ( ) **Other:** ________ Show all heat transfer surface locations with the HRSG and temperature profile
Fuel (Duct Burner)	( ) Natural Gas ( ) LPG ( ) Digester Gas* ( ) Landfill Gas* ( ) Propane ( ) Refinery Gas* (●) Other*: NONE * (If Digester Gas, Landfill Gas, Refinery Gas, and/or Other are checked, attach fuel analysis indicating higher heating value and sulfur content).

Form 400-E-12
Gas Turbine

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section B - Equipment Description (Cont.)

Air Pollution Control

- ◯ Selective Catalytic Reduction (SCR)*
- ◯ Selective Non-Catalytic Reduction (SNCR)*
- ◯ Oxidation Catalyst*
- ◉ Other (specify)*: SCR AND OXIDATION CAT IN SERIES
- ◯ Steam/Water Injection: Injection Rate:_____ lbs. water/lbs. fuel, or_____ mole water/mole fuel

* Separate application is required.

Capital Cost:_____ Installation Cost:_____ Annual Operating Cost:_____

Oxidation Catalyst Data (If Applicable)

Manufacturer: TBD

Model: TBD

Catalyst Dimensions: Length:_____ ft._____ in. Width:_____ ft._____ in. Height:_____ ft._____ in.

Catalyst Cell Density:_____ cells/sq.in. Pressure Drop Across Catalyst:_____

Manufacturer's Guarantee: CO Control Efficiency: 50.00 % Catalyst Life: 5 yrs

VOC Control Efficiency: 30.00 % Operating Temp. Range:_____ °F

Space Velocity (gas flow rate/catalyst volume):_____ Area Velocity (gas flow/wetted catalyst surface area):_____

VOC Concentration into Catalyst:_____ PPMVD@ 15%O_2 CO Concentration inot Catalyst:_____ PPMVD@ 15%O_2

Section C - Operation Information

On-line Emissions Data

Pollutants	Maximum Emissions Before Control *		Maximum Emissions After Control	
	PPM@15% O_2, dry	lb/hour	PPM@15% O_2, dry	lb/hour
ROG				13.91
NOx			2	2.62
CO			25	19.92
PM_{10}				0.20
SOx				0.24
NH_3			5	

* Based on temperature, fuel consumption, and MW output.

Reference (attach data):

☒ Manufacturer Emission Data ☐ EPA Emission Factors ☒ AQMD Emission Factors ☐ Source Test

Stack or Vent Data

Stack Height: 115 ft._____ in. Stack Diameter: 10 ft. 0 in.

Exhaust Temperature: 378 °F Exhaust Pressure: 0.2 inches water column

Exhaust Flow Rate: 738000 CFM Oxygen Level:_____ %

South Coast Air Quality Management District

Form 400-E-12
Gas Turbine

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section C - Operation Information (cont.)

Startup Data: No. of Startups per day: 2 No. of Startups per year: 250 Duration of each startup: 1 hrs.

Shutdown Data: No. of Shutdowns per day: 2 No. of Shutdowns per year: 250 Duration of each Shutdown: 0.25 hrs.

Startup and Shutdown Emissions Data

Pollutants	Startup Emissions		Shutdown Emissions	
	PPM@15% O_2, dry	lb/hour	PPM@15% O_2, dry	lb/hour
ROG		13.91		13.91
NOx		15.30		15.40
CO		84.39		9.96
PM_{10}		0.20		0.20
SOx		0.24		0.24
NH_3				

Monitoring and Reporting

Continuous Emission Monitoring System (CEMS): CEMS Make: TBD

CEMS Model: TBD

Will the CEMS be used to measure both on-line and startup/shutdown emissions? ☑ Yes ☐ No

The following parameters will be continuously monitored:

☒ NOx ☒ CO ☒ O_2

☒ Fuel Flow Rate ☒ Ammonia Injection Rate ☐ Other (specify): ______

☐ Ammonia Stack Concentration: Ammonia CEMS Make: ______

Ammonia CEMS Model: ______

Operating Schedule

Normal: ______ hours/day ______ days/week ______ weeks/yr

Maximum: 9 hours/day 7 days/week 52 weeks/yr

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info

Signature: [signature] Date: 08/17/2021

Name: A. EDWARD KRISNADI

Title: CONSULTANT Company Name: MONTROSE

Phone #: (909) 261-2927 Fax #:

Email: ekrisnadi@montrose-env.com

Contact Info

Name: A. EDWARD KRISNADI

Title: CONSULTANT Company Name: MONTROSE

Phone #: (909) 261-2927 Fax #:

Email: ekrisnadi@montrose-env.com

Check here if you claim that this form or its attachments contain confidential trade secret information. ☒

South Coast Air Quality Management District

Form 400-E-18
Storage Tank

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Address where the equipment will be operated (for equipment which will be moved to various locations in AQMD's jurisdiction, please list the initial location site): 800 AIR WAY, GLENDALE, CA 91201

(●) Fixed Location ( ) Various Locations

Tank Type (Select ONE)	( ) External Floating Roof Tank (EFRT) ( ) Internal Floating Roof Tank (IFRT) (●) Horizontal Tank (HT) ( ) Vertical Fixed Roof Tank (VFRT) ( ) Domed External Roof Tank (DEFRT)
Identification	**Tank Identification Number:** TBD **Tank Contents/Product (include MSDS):** 19% AQUEOUS AMMONIA

Section B - Tank Information

Tank Characteristics	**Shell Diameter (ft.):** ___ **Shell Length (ft.):** ___ **Shell Height (ft.):** ___ **Turnovers Per Year:** ___ **Is Tank Heated?** ( ) Yes (●) No **Is Tank Underground?** ( ) Yes ( ) No **Net Throughput (gal/year):** ___ **Self Support Roof:** ( ) Yes ( ) No **Number of Columns?** ___ **Effective Column Diameter:** ( ) 9" by 7" Built Up Column - 1.1 ( ) 8" Diameter Pipe - 0.7 ( ) Unknown - 1 **External Shell Condition:** (●) Good ( ) Poor **Internal Shell Color:** ( ) Light Rust ( ) Dense Rust ( ) Gunite Lining **External Shell Color:** (●) White/White ( ) Aluminum/Specular ( ) Aluminum/Diffuse ( ) Gray/Light ( ) Gray/Medium ( ) Red/Primer **Average Liquid Height (ft.) (Vertical Only):** ___ **Maximum Liquid Height (ft.) (Vertical Only):** ___ **Working Volume (gal.) (Vertical Only):** ___ **Actual Volume (gal.) (Vertical Only):** ___ **Paint Condition:** ( ) Good ( ) Poor **Paint Color/Shade:** (●) White/White ( ) Gray/Light ( ) Gray/Medium ( ) Aluminum/Diffuse ( ) Aluminum/Specular ( ) Red/Primer
Roof Characteristics (Floating Roof Tank)	**Roof Type:** ( ) Pontoon ( ) Double Deck ( ) Dome Roof (Height___ ft.) ( ) Cone Roof (Height___ ft.) **Roof Fitting Category:** ( ) Typical ( ) Detail **Roof Height (ft.):** ___ **Roof Paint Condition:** ( ) Good ( ) Poor **Roof Color/Shade:** ( ) White/White ( ) Gray/Light ( ) Gray/Medium ( ) Aluminum/Diffuse ( ) Aluminum/Specular ( ) Red/Primer
Deck Characteristics (Floating Roof Tank)	**Deck Type:** ( ) Welded ( ) Bolted **Deck Fitting Characteristics:** ( ) Typical ( ) Detailed (Complete Deck Seam) **Construction:** ( ) Sheet ( ) Panel **Deck Seam Length (ft.):** ___ ___ **Deck Seam:** ( ) 5 ft. wide ( ) 6 ft. wide ( ) 7 ft. wide ( ) 5 x 7.5 ft. ( ) 5 x 12 ft.
Tank Construction and Rim -Seal System (Floating Roof Tank)	**Tank Construction:** ( ) Welded ( ) Riveted **Primary Seal:** ( ) Mechanical Shoe ( ) Liquid Mounted ( ) Vapor Mounted **Secondary Seal:** ( ) Rim Mounted ( ) None ( ) Shoe Mounted
Breather Vent Setting	**Vacuum Setting (psig):** -1.25 **Pressure Setting (psig):** 25

* Section D of the application MUST be completed.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

South Coast AQMD

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Section B - Tank Information (cont.)

Site Selection

Nearest Major City: GLENDALE

Daily Average Ambient Temperature (˚F): 65 Annual Average Minimum Temperature (˚F): 50

Annual Average Maximum Temperature (˚F): 85 Average Wind Speed (mph): ______

Annual Average Solar Insulation Factor (Btu / (ft^3 * ft * day)): ______

Tank Contents

Chemical Category: ◯ Organic Liquids ◯ Crude Oil ◯ Petroleum Distillates

Liquid: ◉ Single ◯ Multiple

If Multiple, Select Speciation Option: ◯ Full Speciation ◯ Partial Speciation ◯ Various Weight Speciation ◯ None

Section C - Operation Information

Vapor Control

Vapor Control During Loading or Unloading: ☐ Sparger ☒ Vapor Balance System ☐ Vapor Return Line ☐ Vented to Air Pollution Control Equipment [1]

[1] A separate permit is required. If APC equipment is already permitted, provide Permit or Device Number: ______

Vent Valve Data

Indicate Type of Setting and Vapor Disposal

	Number	Pressure Setting	Vaccum Setting	Discharging to (Check Appropriate Box)		
				Atmosphere	Vapor Control	Flare
Combination				☐	☐	☐
Pressure	1	25	-1.25	☒	☐	☐
Vaccum				☐	☐	☐
Open				☐	☐	☐

Materials

Name all liquids, vapors, gases, or mixtures of such material to be stored in this tank:
19% AQUEOUS AMMONIA

If material is stored in a solution, supply the following information:

Name of Solvent: WATER Name of Materials Dissolved: AMMONIA

Concentration of Materials Dissolved: 19.00 % by Weight OR ______ % by Volume OR ______ lbs/gal

Section D - Roof/Deck Fitting

Section D is required for the following tanks: External Floating Roof Tank, Internal Floating Roof Tanks, or Domed External Floating Roof Tanks.

Select the number of fittings for each applicable question. Examples: __3__ Unbolted Cover, Ungasketed
______ Unbolted Cover, Gasketed

Roof/Deck Fitting Details

1. Access Hatch (24" diameter well)
   - ______ Bolted Cover, Gasketed
   - ______ Unbolted Cover, UnGasketed
   - ______ Unbolted Cover, Gasketed

2. Automatic Gauge Float Well (20" diameter well)
   - ______ Bolted Cover, Gasketed
   - ______ Unbolted Cover, Ungasketed
   - ______ Unbolted Cover, Gasketed

3. Column Well (24" diameter well)
   - ______ Built-Up Col - Sliding Cover, Gasketed
   - ______ Built-Up Col - Sliding Cover, Ungasketed
   - ______ Pipe Col - Flex, Fabric Sleeve Seal
   - ______ Pipe Col - Sliding Cover, Gasketed
   - ______ Pipe Col - Sliding Cover, Ungasketed

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section D - Roof/Deck Fitting (cont.)

Roof/Deck Fitting Details (cont.)

4. Gauge Hatch/Sample Well (8" diameter well)
- ________ Weighted Mechanical Actuation, Gasketed
- ________ Weighted Mechanical Actuation, Ungasketed

5. Ladder Well (36" diameter)
- ________ Sliding Cover, Gasketed
- ________ Sliding Cover, Ungasketed

6. Rim Vent (6" diameter)
- ________ Weighted Mechanical Actuation, Gasketed
- ________ Weighted Mechanical Actuation, Ungasketed

7. Roof Drain (3" diameter)
- ________ Open
- ________ 90% Close

8. Roof Leg (3" diameter leg)
- ________ Adjustable, Pontoon Area, Ungasketed
- ________ Adjustable, Center Area, Ungasketed
- ________ Adjustable, Double-Deck Roofs
- ________ Fixed
- ________ Adjustable, Pontoon Area, Gasketed
- ________ Adjustable, Pontoon Area, Sock
- ________ Adjustable, Center Area, Gasketed
- ________ Adjustable, Center Area, Sock

9. Roof Leg or Hang Well
- ________ Adjustable
- ________ Fixed

10. Sample Pipe (24" diameter)
- ________ Slotted Pipe – Sliding Cover, Gasketed
- ________ Slotted Pipe – Sliding Cover, Ungasketed
- ________ Slit Fabric Seal, 10% Open

11. Guided Pole/Sample Well
- ________ Ungasketed, Sliding Cover, Without Float
- ________ Ungasketed Sliding Cover, With Float
- ________ Gasketed Sliding Cover, Without Float
- ________ Gasketed Sliding Cover, With Float
- ________ Gasketed Sliding Cover, With Pole Sleeve
- ________ Gasketed Sliding Cover, With Pole Wiper
- ________ Gasketed Sliding Cover, With Float, Wiper
- ________ Gasketed Sliding Cover, With Float, Sleeve, Wiper
- ________ Gasketed Sliding Cover, With Pole Sleeve, Wiper

12. ________ **Stub Drain (1" diameter)**

13. Unslotted Guide – Pole Well
- ________ Ungasketed, Sliding Cover
- ________ Gasketed Sliding Cover
- ________ Ungasketed Sliding Cover with Sleeve
- ________ Gasketed Sliding Cover with Sleeve
- ________ Gasketed Sliding Cover with Wiper

14. Vacuum Breaker (10" diameter well)
- ________ Weighted Mechanical Actuation, Gasketed
- ________ Weighted Mechanical Actuation, Ungasketed

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info	**Signature:** [signature]	**Date:** 08/17/2021	**Name:** A. EDWARD KRISNADI	
	Title: CONSULTANT	**Company Name:** MONTROSE	**Phone #:** (909) 261-2927	**Fax #:**
			Email: ekrisnadi@montrose-env.com	
Contact Info	**Name:** A. EDWARD KRISNADI		**Phone #:** (909) 261-9297	**Fax #:**
	Title: CONSULTANT	**Company Name:** MONTROSE	**Email:** ekrisnadi@montrose-env.com	

South Coast Air Quality Management District
Form 500-B
Title V List of Exempt Equipment

South Coast AQMD

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944
Tel: (909) 396-3385
www.aqmd.gov

Use this form for all application submittals requesting an initial Title V permit or permit renewal. If you are applying for a permit revision, you may also use this form to have your exempt equipment listing updated prior to renewing your permit.

This form is designed to summarize all of the equipment at a facility that is exempt per SCAQMD Rule 219 from SCAQMD permit requirements (e.g., I.C. Engines ≤ 50 BHP, Boilers < 2 MM BTU/hr etc.). This equipment can be listed according to category. However, if there is a specific device that is vented to control equipment, then the equipment must be listed separately. Trivial activities listed on the back of this form or the Technical Guidance Document do not have to be listed on this form. Note: If your facility is in the RECLAIM program, it is not necessary to repeat any equipment currently listed in Appendix A of the RECLAIM permit.

Section I - Operator Information

1. Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. Check box if facility is in RECLAIM program: ☐

4. Provide Current Permit Issue Date: 12/03/2019 **5. Permit Revision No.:** 10

Section II - Summary of Equipment Exempt from Permit Requirements (Including Portable)

Exempt Equipment Description [e.g., Small Boilers (75,000 BTU/hr-2,000,000 BTU/hr)]	Venting to Control (Device# or Application#)	Control Device Description	Basis for Exemption [e.g., Rule 219 (b)(2), 05/19/00]	Source Specific Rule [e.g., Rule 1146.2]
Blasting Cabinet < 53 ft3 w/ Filter	N/A	N/A	Rule 219(f)(2)	
Portable Coating Equipment	N/A	N/A	Rule 219(l)(9)	
Air Conditioning Unit	N/A	N/A	Rule 219(d)(1)	
Refrigerant Recycling & Recovery	N/A	N/A	Rule 219(d)(11)	
Cleaning Equipment	N/A	N/A	Rule219(o)	

South Coast Air Quality Management District

Form 500-F1 (Title V)
Title IV - Acid Rain Phase II Facility Information Summary

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

This form shall be completed by Acid Rain facilities ONLY and shall accompany all requests for Phase II permit actions unique to Acid Rain facilities. Also attach a completed Form 500-A2. In addition, if an initial Title V permit, permit renewal, or permit revision is requested, attach Form 500-A1 and any supplemental Acid Rain forms (Forms 500-F2, 500-F3, and 500-F4), as appropriate.

Section I - General Information

1. Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. ORIS Code (5-Digit): ______

4. This is an application for a (Check all that apply to the facility):

a. ☑ Phase II Acid Rain Permit or Revision (Complete Section II of this form)

b. ☐ Repowering Extension Plan or Revision (Complete Form 500-F2)

c. ☐ New Unit Exemption or Revision (Complete Form 500-F3)

d. ☐ Retired Unit Exemption or Revision (Complete Form 500-F4)

5. The requested permit action involves a(n) (Check one):

a. ○ Administrative Permit Revision

b. ◉ Significant Permit Revision

c. ○ Fast Track Permit Revision

d. ○ Automatic Permit Revision

e. ○ Other (specify): ______

6. For all applications requesting a permit revision, provide a general description of the proposed changes (Attach additional sheets as necessary):

Section II - Phase II Acid Rain Device Summary

1. The following information is (Check one): a. ○ New b. ○ Revised

AQMD Device #	EPA Unit #	Will device need a Repowering Extension Plan?	Has device started operations on or after 11/15/90?	Device Operations Start Date (mo/day/yr)	For devices starting-up after 11/15/90, provide date when Monitoring Certification will begin (mo/day/yr)
TBD	TBD	○ Yes ○ No	○ Yes ○ No		
		○ Yes ○ No	○ Yes ○ No		
		○ Yes ○ No	○ Yes ○ No		
		○ Yes ○ No	○ Yes ○ No		
		○ Yes ○ No	○ Yes ○ No		

South Coast Air Quality Management District

Form 500-H

Title V - Compliance Assurance Monitoring (CAM) Applicability Determination for Initial, Renewal, & Significant Permit Revision

This form is required as part of an initial, significant permit revision, or renewal Title V application. If your Title V facility has control devices in use, the CAM rule may apply.
Follow the instructions on the reverse side of this form to determine whether your facility is subject to CAM requirements.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section I - Operator Information

1. Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER AND POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Section II - CAM Status Summary for Emission Units

3. Based on the criteria in the instructions (check one and attach additional pages as necessary):

a. ☐ The emission units identified below are subject to the CAM rule[1] and a CAM plan[2] is attached for each affected emissions unit:

b. ☑ There are no emission units with control devices at this Title V facility that are subject to the CAM rule.

Emission Unit[3] (Application, Permit or Device No.)	Equipment Description[4]	Uncontrolled Emissions		Connected to Control Unit[3] (Application, Permit or Device No.)	Equipment Description[4]	Controlled Emissions	
		Pollutant	PTE[5] (tons/year)			Pollutant	PTE[5] (tons/year)

1 For more detailed information regarding the CAM rule applicability, refer to Title 40, Chapter I, Part 64, Section 64.1 of the Code of Federal Regulations (40 CFR Part 64, Section 64.1). This also can be accessed via the internet at: http://www.access.gpo.gov/nara/cfr/waisidx_99/40cfr64_99.html.

2 Only one CAM plan is required for a control device that is common to more than one emissions unit, or if an emissions unit is controlled by more than one control device similar in design and operation. If the control devices are not similar in design and operation, one plan is required for each control device.

3 List all new and existing emission units and the connected control devices either by AQMD application, permit or device number. When the emission unit is new and has not yet been assigned an application number, leave this column blank.

4 Provide a brief equipment description of the emission units and control devices by indicating equipment type, make, and model and serial numbers as appropriate.

5 Potential to Emit

GRAYSON POWER PLANT RETROFIT PROJECT

PERMIT APPLICATIONS FOR EXISTING GAS TURBINES MODIFICATIONS AND PERMIT APPLICATION TO CONSTRUCT NEW AIR POLLUTION CONTROL SYSTEMS AND AQUEOUS AMMONIA TRANSFER SYSTEM

EQUIPMENT LOCATION:

Glendale City, Glendale Water & Power
800 Air Way
Glendale, CA 91201
Facility ID 800327

FOR SUBMITTAL TO:

South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, California 91765

PREPARED BY:

MONTROSE
ENVIRONMENTAL

1631 E. Saint Andrew Place
Santa Ana, California 92705

August 2021

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SECTION 1.0

INTRODUCTION

1.1 Project Summary

Glendale Water & Power (GWP) is submitting this permit application report to retrofit its existing Gas Turbine 8A, 8B, and 8C to comply with Rule 1135 amended on November 2, 2018.

This retrofit project will include the following modification and construction:

- Refurbishing Gas Turbine 8A (Unit 8A) from combine cycle unit to simple cycle unit. The refurbishment will replace the existing heat recovery steam generator (HRSG), associated steam turbine, and emission control system with a new simple cycle emission control system. This modification would allow Unit 8A to start and achieve full load within ten minutes.

- Refurbishing the existing Gas Turbine 8B and 8C (Unit 8BC) by replacing the existing heat recovery steam generator and associated steam turbine cycle with a new once through boiler and new steam turbine cycle. This modification would allow Unit 8BC to start and achieve full load on the gas turbines within ten minutes. Additionally, the existing emission control system for Unit 8BC will be replaced with a new emission control system.

- Installing a new aqueous ammonia storage and transfer system for the new emission control systems for Unit 8a and Unit 8BC.

The Project will also include the removal of the following permitted units:

- Boiler Unit 3 (Device D2) with cyclone (Device C9)
- Boiler Unit 4 (Device D1)
- Boiler Unit 5 (Device D3)
- Rule 219 Cooling towers (Device E33)

The simple cycle gas turbine Unit 9 (Device D58) will remain in operation.

This permit application has been prepared in accordance with South Coast Air Quality Management District (SCAQMD) requirements with assistance from Montrose Environmental Solutions (Montrose).

1.2 Technical Project Contacts

For the purposes of this submittal, MAQS will be the primary contact for technical issues related to air quality.

A. Edward Krisnadi
Principal – Permitting & Compliance

Montrose Environmental Solutions
1631 E. Saint Andrew Place
Santa Ana, CA 92705

Phone: (714) 919-65577
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141 N. Glendale Ave.
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Senior Principal – Permitting & Compliance

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1631 E. Saint Andrew Place
Santa Ana, CA 92705

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SECTION 2.0

FACILITY AND EQUIPMENT INFORMATION

2.1 Facility Description

Grayson Power Plant is located in an industrial area of the City of Glendale at 800 Air Way. just northeast of the Interstate 5 and the Highway 134 interchange. The proposed power generation equipment will be constructed entirely within the existing Grayson Power Plant, which is bounded to the south by Verdugo Wash and Highway 134, to the west by the Los Angeles River and Interstate 5, to the north by commercial properties, and to the east by commercial properties. There are residential properties approximately 700 feet to northeast of the facility. The approximate latitude and longitude coordinates of the Project are 34º 09’19” N and 118º 16’42” W. Facility diagrams and an area map are included in Appendix B.

2.2 Equipment Description

2.2.1 Natural Gas-fired Combustion Turbines

GWP proposes to retrofit Unit 8A by converting the gas turbine from combine cycle to simple cycle. This retrofit includes removing Unit 8A HRSG and replacing the existing air pollution control system by a new control system. GWP is also planning to retrofit Unit 8BC by replacing the existing HRSG with a new HRSG and the existing air pollution control system with a new one as well.

When Unit 8A is converted to simple cycle, it will be upgraded using a new emissions control system utilizing a CO catalyst and an SCR catalyst with 19% aqueous ammonia. A new CEMS will also be provided as well. The specific equipment and catalyst suppliers have not yet been selected and will be made based upon a public procurement process as required by California and Glendale law. Potential emissions control system vendors include Peerless, EnergyLink, as well as others. Potential catalyst suppliers include Cormetech, Engelhard, as well as others.

When Unit 8BC is converted to a fast start combined cycle, the unit configuration will be very similar to Pasadena Water & Power’s Glenarm GT5 unit with the major difference being that Glendale will utilize the existing FT4 Twinpack. A once through boiler will be used with a CO catalyst and an SCR catalyst with 19% aqueous ammonia. A new CEMS will also be provided as well. The specific equipment and catalyst suppliers have not yet been selected. Selection will be made based upon a public procurement process as required by California and Glendale law. Potential once through boiler vendors include John Cockerill Energy, Propak Systems/Innovative Steam Technologies, and potentially others as well. Potential catalyst suppliers include Cormetech, Engelhard, as well as others.

2.2.2 Aqueous Ammonia Transfer and Storage System

The aqueous ammonia transfer and storage system is part of the SCR equipment. The ammonia storage system would be constructed above a spill containment basin and equipped with sump vapor control. A pressure relief valve and a vapor return line would be used to control ammonia emission during storage tank filing operations. Similar to turbine, GWP has not selected specific ammonia transfer and storage system. However, it is expected the system will have similar specification as the ammonia transfer and storage system currently serving Unit 9.

SECTION 3.0

CRITERIA POLLUTANTS

3.1 Natural Gas-fired Combustion Turbines (Post-Modifications)

The emission rates of criteria pollutants were calculated using the following emission factors:

- Unit 8A (Simple Cycle Turbine)
  - 2.5 ppmv at 15 percent O_2 for NO_X to comply with Rule 1135 emission limit.
  - 25 ppmv at 15 percent O_2 for CO as its currently permitted.
  - 13.91 lbs/hour for VOC emission rates and 0.2 lbs/hour PM10/2.5 emission rates based on the previous SCAQMD engineering evaluation.
  - 0.714 lbs/mmcf SO_X emission rates is based on the concentration limit of 4 ppmv of sulfur compounds calculated as H_2S in natural gas.
  - The turbine is expected to be operated no more than 250 hours per month and 1,200 hours per year at 100% operating load. The daily operating hour is estimated to be 8.6 hour based on the permitted combined daily natural gas limit of 8.6 mmcf per day for Unit 8A and 8BC.
  - *Startup and Shutdown emissions.*
    The following Table 3-1 reflects the startup and shutdown emission rates estimated by the manufacturer:

TABLE 3-1
GAS TURBINE 8A
STARTUP AND SHUTDOWN EMISSION RATES

Pollutant	Startup 60 minutes	Shutdown 15 minutes
NO_X, lbs/event	15.60	3.85
CO, lbs/event	84.39	2.49
VOC, lbs/event	13.91	3.48
PM10/2.5, lbs/event	0.20	0.05
SO_X, lbs/event	0.24	0.06

- Unit 8BC (Combined Cycle Turbines)
    - 2.0 ppmv at 15 percent O_2 for NO_X to comply with Rule 1135 emission limit.
    - 25 ppmv at 15 percent O_2 for CO as its currently permitted.
    - 13.91 lbs/hour for VOC emission rates and 0.2 lbs/hour PM10/2.5 emission rates based on the previous SCAQMD engineering evaluation.
    - 0.714 lbs/mmcf SO_X emission rates is based on the concentration limit of 4 ppmv of sulfur compounds calculated as H_2S in natural gas.
    - Each turbine is expected to be operated no more than 250 hours per month and 1,200 hours per year at 100% operating load. The daily operating hour is estimated to be 8.6 hour based on the permitted combined daily natural gas limit of 8.6 mmcf per day for Unit 8A and 8BC. Gas Turbine 8B and 8C will be operated simultaneously.
    - *Startup and Shutdown emissions.*
      Table 3-2 reflects the startup and shutdown emission rates estimated by the manufacturer:

TABLE 3-2
GAS TURBINE 8B OR 8C
STARTUP AND SHUTDOWN EMISSION RATES

Pollutant	Startup 60 minutes	Shutdown 15 minutes
NO_X, lbs/event	15.30	3.85
CO, lbs/event	84.39	2.49
VOC, lbs/event	13.91	3.48
PM10/2.5, lbs/event	0.20	0.05
SO_X, lbs/event	0.24	0.06

Based upon the emission factors described above, Tables 3-3 and 3-4 summarize the maximum hourly, maximum daily, 30-day average, and maximum annual criteria pollutant emission rates for each turbine. Emission rates during normal operations are typically much lower than the rates listed in Tables 3-3 and 3-4. A detailed emission inventory for the Project is included in Appendix C.

TABLE 3-3
CRITERIA POLLUTANT EMISSION SUMMARY
GAS TURBINE 8A

Pollutant	Max. Daily (lbs/day)	Max. Monthly (lbs/month)	30-Day Avg. (lbs/day)	Annual PTE (tons/year)
NO_X	58.85	1,202	40.08	2.92
CO	295.27	6,534	217.82	15.83
VOC	119.63	3,481	116.03	8.35
PM10/2.5	1.72	50	1.67	0.12
SO_X	2.05	60	1.99	0.14

TABLE 3-4
CRITERIA POLLUTANT EMISSION SUMMARY
GAS TURBINE 8B OR 8C

Pollutant	Max. Daily (lbs/day)	Max. Monthly (lbs/month)	30-Day Avg. (lbs/day)	Annual PTE (tons/year)
NO_X	54.28	1,290	43.00	3.16
CO	295.27	7,459	248.64	18.15
VOC	119.63	3,478	115.92	8.35
PM10/2.5	1.72	50	1.67	0.12
SO_X	2.05	60	1.98	0.14

Table 3-5 summarizes the overall potential to emit from the post modification of the turbines.

TABLE 3-5
CRITERIA POLLUTANT EMISSION SUMMARY
POST MODIFICATION

Pollutant	Max. Daily (lbs/day)	30-Day Avg. (lbs/day)	Annual PTE (tons/year)
NO_X	167	126	9.24
CO	886	715	52.13
VOC	359	348	25.04
PM10/2.5	5	5	0.36
SO_X	6	6	0.43

3.2 Natural Gas-fired Combustion Turbines (Pre-Modifications)

Table 3-6, 3-7, and 3-8 summarize the permitted emissions of Unit 8A and Unit 8BC. These emissions are based on the SCAQMD engineering evaluations dated December 12, 2000.

TABLE 3-6
CRITERIA POLLUTANT EMISSION SUMMARY
GAS TURBINE 8A

Pollutant	Max. Daily (lbs/day)	Max. Monthly (lbs/month)	30-Day Avg. (lbs/day)	Annual PTE (tons/year)
NO_X	307	9,219	307	56.08
CO	521	15,615	521	94.99
VOC	334	10,014	334	60.93
PM10/2.5	5	147	5	0.89
SO_X	5	144	5	0.88

TABLE 3-7
CRITERIA POLLUTANT EMISSION SUMMARY
GAS TURBINE 8B OR 8C

Pollutant	Max. Daily (lbs/day)	Max. Monthly (lbs/month)	30-Day Avg. (lbs/day)	Annual PTE (tons/year)
NO_X	282	8,451	282	51.41
CO	477	14,316	477	87.08
VOC	334	10,014	334	60.93
PM10/2.5	5	147	5	0.89
SO_X	5	144	5	0.88

TABLE 3-8
CRITERIA POLLUTANT EMISSION SUMMARY
PREMODIFICATION

Pollutant	Max. Daily (lbs/day)	30-Day Avg. (lbs/day)	Annual PTE (tons/year)
NO_X	871	871	158.90
CO	1,475	1,475	269.15
VOC	1,001	1,002	182.78
PM10/2.5	15	15	2.68
SO_X	14	15	2.63

3.3 Natural Gas-fired Combustion Turbines (Net Emissions)

Table 3-9 summarizes the net emission from the post-modification and pre-modification of Unit 8A and Unit 8BC.

TABLE 3-9
CRITERIA POLLUTANT EMISSION SUMMARY
NET EMISSION

Pollutant	Max. Daily (lbs/day)	30-Day Avg. (lbs/day)	Annual PTE (tons/year)
NO_X	-703	-745	-150
CO	-589	-760	-217
VOC	-643	-654	-158
PM10/2.5	-10	-10	-2
SO_X	-8	-9	-2

As shown in the above table, there is not net emission increase from these modifications.

SECTION 4.0

TOXIC AIR CONTAMINANTS

4.1 Emissions Inventory

Toxic Air Contaminants (TAC) emissions are expected from the natural gas-fired combustion turbines and the emergency engine. A TAC emission analysis is required for the combustion turbines.

TAC emissions from the gas turbines were calculated based on the default emission factors provided on SCAQMD AB2588 Quadrennial Air Toxics Emission Inventory Reporting Procedures dated June 2020 and December 2016. Ammonia emissions were calculated based on the concentration limit of 5 ppmv @ 15% O_2. Since the turbines will be equipped with oxidation catalyst, the TAC emissions, except ammonia will be controlled by 97.7% control efficiency based on Rule 1401 calculator. Table 4-1 summarizes the TAC emissions from the turbines. Detailed emission calculations for the air toxics are provided in Appendix D.

TABLE 4-1
TOXIC AIR CONTAMINANTS EMISSIONS SUMMARY

Pollutant	CAS	Post-Mod. Max. Hourly (lbs/hr)	Post-Mod Max. Annual (lbs/yr)	Pre-Mod. Max. Hourly (lbs/hr)	Pre-Mod Max. Annual (lbs/yr)	Net Emissions Max. Hourly (lbs/hr)	Net Emissions Max. Annual (lbs/yr)
Ammonia	766417	7.3	8.71E+03	7.3	6.36E+04	0.00E+00	-5.49E+04
Acetaldehyde	75070	9.38E-04	1.13E+00	9.38E-04	8.22E+00	0.00E+00	-7.09E+00
Acrolein	107028	1.50E-04	1.80E-01	1.50E-04	1.32E+00	0.00E+00	-1.14E+00
Benzene	71432	2.81E-04	3.37E-01	2.81E-04	2.46E+00	0.00E+00	-2.12E+00
Butadiene, 1,3-	106990	1.01E-05	1.21E-02	1.01E-05	8.84E-02	0.00E+00	-7.63E-02
Ethylbenzene	100414	7.50E-04	9.00E-01	7.50E-04	6.57E+00	0.00E+00	-5.67E+00
Formaldehyde	50000	1.67E-02	2.00E+01	1.67E-02	1.46E+02	0.00E+00	-1.26E+02
Naphthalene	91203	3.06E-05	3.67E-02	3.06E-05	2.68E-01	0.00E+00	-2.31E-01
PAHS (excluding naphthalene)	1151	2.11E-05	2.53E-02	2.11E-05	1.85E-01	0.00E+00	-1.60E-01
Propylene Oxide	75569	6.81E-04	8.17E-01	6.81E-04	5.96E+00	0.00E+00	-5.15E+00
Toluene	108883	3.06E-03	3.67E+00	3.06E-03	2.68E+01	0.00E+00	-2.31E+01
Xylenes	1330207	1.50E-03	1.80E+00	1.50E-03	1.32E+01	0.00E+00	-1.14E+01

4.2 Health Risk Assessment (HRA)

Pursuant to Rule 1401 requirements, health risk assessment (HRA) is required for net emission increase due to permit modifications. As shown in table 4-1, these modifications result in no net emission increase; therefore, HRA is not required to perform for this project.

SECTION 5.0

REGULATORY INFORMATION

5.1 South Coast AQMD Regulatory Analysis

Rule 212 – Standards for Approving Permits
The facility is not located within 1,000 feet from the outer boundary of K-12 school; therefore, a public notification is not required for this project.

Rule 403 – Fugitive Dust
The purpose of this rule is to reduce PM emissions from anthropogenic (man-made) fugitive dust sources by requiring actions to prevent, reduce, or mitigate fugitive dust emissions. During the construction phase of the proposed Project, control measures, such as applying sufficient amount of water on the disturbed surfaces, covering truck loads when hauling material, etc., would be taken to demonstrate compliance with Rule 403.

Rule 407 – Liquid and Gaseous Air Contaminants
This rule limits CO emissions to 2,000 ppm and SO_X emissions to 500 ppm, averaged over 15 consecutive minutes. The proposed modifications will meet the CO limit. Additionally, the proposed equipment is exempt from the SO_X limit of this rule because it complies with the sulfur content requirements of Rule 431.1 for gaseous fuels.

Rule 409 – Combustion Contaminants
This rule prohibits contaminant emissions of more than 0.1 grain per cubic foot of gas at 12 percent CO_2 at standard conditions, averaged over 15 consecutive minutes. The proposed equipment will only combust natural gas as fuel. Therefore, the proposed Project is expected to comply with Rule 409.

Rule 431.1 – Sulfur Content of Gaseous Fuels
This rule limits the sulfur content of natural gas not to exceed 16 ppmv calculated as as hydrogen sulfide (H_2S). The sulfur content of natural gas combusted in the proposed gas turbines will be less than 12.6 ppmv or 0.75 grains of sulfur per 100 scf of natural gas. Therefore, the compliance with this rule is expected.

Rule 475 – Electric Power Generating Equipment
This rule applies to power generating equipment greater than 10MW installed after May 7, 1976 and established limit for combustion contaminants or PM emissions of 11 lbs/hr or 0.01 gr/scf. According to SCAQMD engineering evaluation, the PM emissions for each gas turbines 8A, 8B, and 8C are estimated to be 0.2 lbs/hr. Therefore, compliance with this rule is expected.

Regulation IX – Standards of Performance for New Stationary Sources
This regulation incorporates Title 40 CFR, Part 60 of the Code of Federal Regulations (CFR), and is applicable to all new, modified, or reconstructed sources of air pollution. Subparts KKKK of this regulation apply to the proposed turbines. These subparts establish emission limits,

monitoring, and test method requirements. Compliance with Subpart KKKK will be achieved through the application of BACT.

Rule 1135 – Emissions of Oxides of Nitrogen from Electric Power Generating Systems
Rule 1135 applies to electric power generating systems, which are defined as boilers and their replacement unit. These gas turbines modifications are proposed to comply with the NO_X and ammonia emission limits provided in Rule 1135 Table-1 by January 1, 2024. Therefore, compliance with Rule 1135 is expected.

Regulation XIII – New Source Review (NSR)
The SCAQMD regulatory framework includes two options for implementing new source review. Certain facilities included in the Regional Clean Air Market (RECLAIM) cap and trade program for NO_X and SO_X are subject to the new source review requirements of Regulation XX. Facilities that are not part of RECLAIM are subject to the NO_X and SO_X new source review requirements of Regulation XIII. New source review for VOC, CO and PM is administered through Regulation XIII for all facilities. Glendale Water and Power opted out of RECLAIM and is therefore subject to the new source review requirements of Regulation XIII for all criteria pollutants.

Rule 1303 – NSR Requirements: Best Available Control Technology (BACT)
Rule 1303(a) requires any new or modified source which results in an emission increase of any nonattainment air contaminant, any ozone depleting compound, or ammonia to meet the BACT requirement. The proposed modifications will result in a net emission decrease because it will replace the existing air pollution control system with newer and better air pollution control system. Therefore, this project is not subject to the BACT requirements.

Rule 1303 – NSR Requirements: Air Quality Modeling
Rule 1303(b)(1) requires an analysis to demonstrate compliance with ambient air quality standards. Since there is not net emission increase on criteria pollutants, the proposed project is not subject to modeling requirements.

Rule 1303 – NSR Requirements: Emissions Offsets
Rule 1303(b)(2) requires that an emission increase of nonattainment air contaminants is to be offset by either Emission Reduction Credits (ERC) approved pursuant to Rule 1309, allocations from the Priority Reserve pursuant to Rule 1309.1, or allocations form the Offset Budget pursuant to Rule 1309.2. Since there is not net emission increase on criteria pollutants, the proposed project is not subject to emission offsets requirements.

Rule 1401 – New Source Review of Toxic Air Contaminants (TACs)
Rule 1401 establishes allowable risk thresholds for permit units that emit TACs. Depending on the pollutant, the rule specifies limits for maximum individual cancer risk (MICR), cancer burden, and/or non-cancer acute and chronic Hazard Indices (HA and HC). The proposed project will not result in net emission increase on any Toxic Air Contaminants; therefore, this project is not subject to the requirements of this rule.

Regulation XVII – Prevention of Significant Deterioration (PSD)
Regulation XVII sets forth requirements for when a significant increase of attainment air contaminants occurs at an existing major stationary source of criteria pollutants. PSD applies when the region is in attainment with ambient air quality standards. In the South Coast Basin, attainment with federal air quality standards have been reached for NO_2, SO_2, CO, and PM10.

GWP Grayson Power Plant is currently considered to be a major source; and a PSD analysis must be conducted if the facility has an emission increase of greater than 40 tons per year for the NO_2 and SO_2, 15 tons per year for PM10, and 100 tons per year for CO. The proposed project will not result in any emission increase of the criteria pollutants; therefore, PSD analysis is not applicable for this project.

5.2 Federal Regulatory Analysis

Title 40 CFR, Part 52, Subpart A, Section 52.21 – Prevention of Significant Deterioration (PSD) of Air Quality

As discussed in the above section 5.1 of Regulation XVII, PSD permitting for this Project is not required because no net emission increase on attainment pollutants will result from the project.

Title 40 CFR, Part 60, Subpart KKKK – Standards of Performance of Stationary Combustion Turbines

New Source Performance Standards (NSPS) subpart KKKK sets emission standards and compliance schedules for NO_X and SO_X from stationary gas turbines. SCAQMD has been delegated the authority to implement and enforce these federal regulations. Under SCAQMD Regulation IX, this subpart was adopted and made part of the Rules and Regulations of the SCAQMD.

Based on this subpart, the emission standards for NO_X and SO_X are 42 ppmv @ 15%O2 and 0.06 lb/MMBtu respectively. The proposed gas turbines will meet these emission standards by complying with SCAQMD Best Available Retrofit Control Technology (BARCT) emission standards of 2.5 or 2.0 ppmv @ 15%O2 for NO_X and 0.0007 lb/MMBtu for SO_X.

Title 40 CFR, Part 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Combustion Gas Turbines

NESHAP Subpart YYYY establishes national emission and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines. NESHAP Subpart YYYY is typically less stringent than the policies and rules enforced by SCAQMD to manager emissions of organic and hazardous air pollutants. As a result, the proposed Project is expected to comply with federal emission standards by complying with SCAMQD regulations.

APPENDIX A

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
APPLICATION FORMS (COPIES)

COPY

South Coast Air Quality Management District

Form 400 - XPP

Express Permit Processing Request

Form 400-A, Form 400-CEQA and one or more 400-E-xx form(s) must accompany all submittals.

South Coast AQMD

Mail To:
SCAQMD
P.O Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator To Appear On The Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Section B - Equipment Location Address

3. (◉) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

Street Address: 800 AIR WAY
City: GLENDALE, State: CA, Zip: 91201
Contact Name: MARK YOUNG, Title: GENERAL MANAGER
Phone #: 8185482107, Ext.: , Fax #:
E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

4. Permit and Correspondence Information:
☐ Check here if same as equipment location address

Address: 141 N. GLENDALE AVENUE
City: GLENDALE, State: CA, Zip: 91206
Contact Name: MARK YOUNG, Title: GENERAL MANAGER
Phone #: 8185482107, Ext.: , Fax #:
E-Mail: myoung@glendaleca.gov

Section D - Authorization/Signature

I understand that the Expedited Permit Processing fees must be submitted at the time of application submittal, and that the application may be subject to additional fees per Rule 301. I understand that requests for Express Permit Processing neither guarantees action by any specific date nor does it guarantee permit approval; that Express Permit Processing is subject to availability of qualified staff; and that once Express Permit Processing has commenced, the expedited fees will not be refunded. I hereby certify that all information contained herein and information submitted with the application are true and correct.

5. Signature of Responsible Official: Mark Young	**6. Title of Responsible Official:** GENERAL MANAGER
7. Print Name of Responsible Official: MARK YOUNG	**8. Date:** 08-09-2021
9. Phone #: 8185482107	**10. Fax #:**

AQMD USE ONLY	APPLICATION TRACKING #	TYPE B C	EQUIPMENT CATEGORY CODE	FEE SCHEDULE $		VALIDATION
ENG. A R DATE	ENG. A R DATE	CLASS I III	ASSIGNMENT Unit Engineer	CHECK/MONEY ORDER #	AMOUNT $	TRACKING #

COPY

South Coast AQMD

South Coast Air Quality Management District
Form 400-CEQA
California Environmental Quality Act (CEQA) Applicability

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

The SCAQMD is required by state law, the California Environmental Quality Act (CEQA), to review discretionary permit project applications for potential air quality and other environmental impacts. This form is a screening tool to assist the SCAQMD in clarifying whether or not the project [1] has the potential to generate significant adverse environmental impacts that might require preparation of a CEQA document [CEQA Guidelines § 15060(a)]. Form 400-CEQA and the instructions for guidance on completing this form are available at http://www.aqmd.gov/home/regulations/ceqa/ceqa-permit-forms or http://www.aqmd.gov/home/permits/permit-application-forms. For each Form 400-A application, also complete and submit one Form 400-CEQA. If submitting multiple Form 400-A applications for the same project at the same time, only one Form 400-CEQA is necessary for the entire project. If you need assistance completing this form, contact Permit Services at (909) 396-3385.

Section A – Facility Information

1. Facility Name (Business Name of Operator to Appear on the Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. SCAQMD Facility ID: 800327

3. Project Description: TURBINE 8A, 8B, AND 8C MODIFICATIONS, INCLUDING ITS AIR POLLUTION CONTROL SYSTEMS.

Section B – Review For Exemption From Further CEQA Action

Check "Yes" or "No" as applicable. If "Yes" is checked for any question in Section B, skip Section C and proceed to page 2 and complete Section D - Signatures.

	Yes	No	Is this application for:
1.	( )	(•)	A request for a change of operator only (without equipment or process change modifications)?
2.	( )	(•)	A functionally identical permit unit replacement with no increase in equipment unit rating or emissions?
3.	( )	(•)	A change of daily VOC permit limit to a monthly VOC permit limit?
4.	( )	(•)	Equipment damaged as a result of a disaster during state of emergency?
5.	( )	(•)	A Title V (e.g., SCAQMD Regulation XXX) permit renewal without equipment or process change modifications?
6.	( )	(•)	A Title V administrative permit revision?
7.	( )	(•)	The conversion of an existing permit into an initial Title V permit?

Section C – Review of Impacts Which May Trigger Further CEQA Review

Check "Yes" or "No" as applicable. To avoid delays in processing your application(s), explain all "Yes" responses on a separate sheet and attach it to this form.

	Yes	No	
1.	(•)	( )	**Is this project specifically evaluated in a previously certified or adopted CEQA document?** If "Yes" is checked, attach a copy of the signed Notice of Determination to this form.
2.	( )	(•)	**Is this project specifically exempted from CEQA by another entity (e.g., city or agency)?** If "Yes" is checked, attach a copy of the signed Notice of Exemption or other documentation from the entity to this form.
3.	( )	(•)	**Is this project part of a larger project?** If "Yes" is checked, attach a separate sheet to briefly describe the larger project.
4.	( )	(•)	**Will the project increase the QUANTITY of hazardous materials stored aboveground onsite or transported by mobile vehicle to or from the site by greater than or equal to the amounts associated with each compound listed on Form 400-CEQA, Table 1 - Regulated Substances List and Threshold Quantities for Accidental Release Prevention [http://www.aqmd.gov/home/regulations/ceqa/ceqa-permit-forms]?** If "Yes" is checked, attach a separate sheet to identify each hazardous material and corresponding quantity to be transported, stored, or used.
5.	( )	(•)	**Will the project emit any air toxic listed on Form 400-CEQA, Table 2 - Other Air Toxics and Their Screening Levels [http://www.aqmd.gov/home/regulations/ceqa/ceqa-permit-forms] [2]?** If "Yes" is checked, attach a separate sheet to identify each air toxic and corresponding quantity to be emitted.
6.	( )	(•)	**Will the project require any demolition, excavation, and/or grading construction activities that encompass an area exceeding 20,000 square feet?**

[1] A "project" means the whole of an action which has a potential for resulting in physical change to the environment, including construction activities, clearing or grading of land, improvements to existing structures, and activities or equipment involving the issuance of a permit. For example, a project might include installation of a new, or modification of an existing internal combustion engine, dry cleaning facility, boiler, gas turbine, spray coating booth, solvent cleaning tank, etc

[2] Form 400-CEQA, Table 2 – Other Air Toxics and Their Screening Levels, contains a list of air toxics that either do not have a cancer potency (CP) or reference exposure level (REL) approved by the Office of Environmental Health Hazards Assessment (OEHHA) or have a combination of OEHHA-approved and non-approved CPs or RELs.

COPY

Section C – Review of Impacts Which May Trigger Further CEQA (concluded)

	Yes	No	
7.	⊙	O	**Will the project utilize a boiler, engine, or other combustion equipment that uses fuel (e.g., gasoline, diesel, natural gas, liquefied petroleum gas (LPG), or landfill gas)?** If "Yes" is checked, then the applicant will need to calculate the amount of GHGs from fuel use via on the Greenhouse Gas (GHG) online estimator [http://www.aqmd.gov/home/regulations/ceqa/ceqa-permit-forms], and attaching the printout or by conducting hand calculations and providing the documentation. Refer to the Instructions for Form 400-CEQA for guidance.
8.	O	⊙	**Will the project utilize other types of equipment not addressed in Question 7 that require the use of, or will generate, any chemicals listed on Form 400-CEQA, Table 3 - Greenhouse Gases [http://www.aqmd.gov/home/regulations/ceqa/ceqa-permit-forms]?** If "Yes" is checked, attach a separate sheet to identify each equipment unit, the chemical name(s), and the quantity of each chemical identified.
9.	O	⊙	**Will the project include the open outdoor storage of dry bulk solid materials that could generate dust?** If "Yes" is checked, include a plot plan with the application package.
10.	O	⊙	**Will the project result in or make worse noticeable off-site odors from activities that may not be subject to SCAQMD permit requirements?** For example, landfills, materials recovery/recycling facilities (MRF), and compost materials or other types of greenwaste (e.g., lawn clippings, tree trimmings, etc.) have the potential to generate odor complaints subject to SCAQMD Rule 402 – Nuisance.
11.	O	⊙	**Will the project cause an increase of emissions from marine vessels, trains and/or airplanes?**
12.	O	⊙	**Will the project increase demand for potable water at the facility by more than 262,820 gallons per day?** The following examples identify some, but not all, types of projects that may result in a "Yes" answer to this question: 1) a project that generates steam; 2) a project that uses water as part of operating air pollution control equipment; 3) a project that requires water as part of the production process; 4) a project that requires a new, or the expansion of an existing, sewage treatment facility, new water lines, sewage lines, sewage hook-ups etc.; 5) a project where the water demand exceeds the capacity of the local water purveyor to supply sufficient water for the project; 6) a project that requires new or the expansion of existing, water supply and conveyance facilities; and, 7) a project that requires water to hydrotest pipelines, storage tanks etc. for structural integrity.
13.	O	⊙	**Will the project create an increase in the mass inflow of effluents to a public wastewater treatment facility that would require a new, or revision to an existing, National Pollutant Discharge Elimination System (NPDES) or other related permit at the facility?**
14.	O	⊙	**Will the project result in the need for more than 350 new employees?**
15.	O	⊙	**Will the project result in an increase in heavy-duty transport truck traffic to and/or from the facility by more than 350 truck round-trips per day?**
16.	O	⊙	**Will the project result in an increase in customer traffic by more than 700 visits per day?**
17.	O	⊙	**Will the project result in temporary or permanent noise or vibration in excess of what is allowed by the applicable local noise ordinance?**
18.	O	⊙	**Will the project create a permanent need for new or additional solid waste disposal?** Check "No" if the projected potential amount of solid waste to be generated by the project is less than five tons per day.
19.	O	⊙	**Will the project create a permanent need for new or additional hazardous waste disposal?** Check "No" if the projected potential amount of hazardous wastes to be generated by the project is less than 42 cubic yards per day (or equivalent in pounds).
20.	O	⊙	**Will the project include equipment that after installation or modification will change the visual character of the site and its surroundings or block views?**
21.	O	⊙	**Will the project have equipment that will create a new source of external lighting that will be visible at the property line?**

Section D – SIGNATURES

I HEREBY CERTIFY THAT ALL INFORMATION CONTAINED HEREIN AND INFORMATION SUBMITTED WITH THIS APPLICATION IS TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE. I UNDERSTAND THAT THIS FORM IS A SCREENING TOOL AND THAT THE SCAQMD RESERVES THE RIGHT TO CONSIDER OTHER PERTINENT INFORMATION IN DETERMINING CEQA APPLICABILITY.

1. Signature of Responsible Official of Firm: [signature]		2. Title of Responsible Official of Firm: GENERAL MANAGER
3. Print Name of Responsible Official of Firm: MARK YOUNG		4. Date Signed: 08-09-2021
5. Phone # of Responsible Official of Firm: 8185482107	6. Fax # of Responsible Official of Firm:	7. Email of Responsible Official of Firm: myoung@glendaleca.gov
8. Signature of Preparer, (If prepared by person other than responsible official of firm): [signature]		9. Title of Preparer: PRINCIPAL (CONSULTANT)
10. Print Name of Preparer: A. EDWARD KRISNADI		11. Date Signed: 08-10-2021
12. Phone # of Preparer: (909) 261-2927	13. Fax # of Preparer:	14. Email of Preparer: ekrisnadi@montrose-env.com

THIS CONCLUDES FORM 400-CEQA. INCLUDE THIS FORM AND ANY ATTACHMENTS WITH FORM 400-A.

COPY

South Coast Air Quality Management District

Form 400-A

Application Form for Permit or Plan Approval

List only one piece of equipment or process per form.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. Owner's Business Name (If different from Business Name of Operator):

Section B - Equipment Location Address

4. Equipment Location Is: (●) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

800 AIR WAY
Street Address

GLENDALE, CA 91201
City, Zip

MARK YOUNG — GENERAL MANAGER
Contact Name, Title

8185482107
Phone # Ext. Fax #

E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

141 N. GLENDALE AVENUE
Address

GLENDALE, CA 91206
City, State, Zip

MARK YOUNG — GENERAL MANAGER
Contact Name, Title

8185482107
Phone # Ext. Fax #

E-Mail: myoung@glendaleca.gov

Section D - Application Type

6. The Facility Is: ( ) Not In RECLAIM or Title V ( ) In RECLAIM (●) In Title V ( ) In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:
- (●) New Construction (Permit to Construct)
- ( ) Equipment On-Site But Not Constructed or Operational
- ( ) Equipment Operating Without A Permit *
- ( ) Compliance Plan
- ( ) Registration/Certification
- ( ) Streamlined Standard Permit

7b. Facility Permits:
- ( ) Title V Application or Amendment (Refer to Title V Matrix)
- ( ) RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:
- ( ) Administrative Change
- ( ) Alteration/Modification
- ( ) Alteration/Modification without Prior Approval *
- ( ) Change of Condition
- ( ) Change of Condition without Prior Approval *
- ( ) Change of Location
- ( ) Change of Location without Prior Approval *
- ( ) Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number:

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy):
8b. Estimated End Date of Construction (mm/dd/yyyy):
8c. Estimated Start Date of Operation (mm/dd/yyyy):

9. Description of Equipment or Reason for Compliance Plan (list applicable rule): NEW AMMONIA STORAGE TANK

10. For identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / process) 0

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-for-profit training center) (●) No ( ) Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? (●) No ( ) Yes
If Yes, provide NOV/NC#:

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location? ELECTRICAL POWER GENERATION

14. What is your business primary NAICS Code? (North American Industrial Classification System) 221112

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator? ( ) No (●) Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line? (●) No ( ) Yes

Section F - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application are true and correct.

17. Signature of Responsible Official: Mark Young

18. Title of Responsible Official: GENERAL MANAGER

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.) ( ) No (●) Yes

20. Print Name: MARK YOUNG

21. Date: 08-09-2021

22. Do you claim confidentiality of data? (If Yes, see instructions.) (●) No ( ) Yes

23. Check List: ☒ Authorized Signature/Date ☒ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TRACKING #	CHECK #	AMOUNT RECEIVED $	PAYMENT TRACKING #	VALIDATION

DATE	APP REJ	DATE	APP REJ	CLASS I III	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN

COPY

South Coast Air Quality Management District

Form 400-A

Application Form for Permit or Plan Approval

List only one piece of equipment or process per form.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. Owner's Business Name (If different from Business Name of Operator):

Section B - Equipment Location Address

4. Equipment Location Is: (●) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

800 AIR WAY
Street Address

GLENDALE, CA 91201
City, Zip

MARK YOUNG — GENERAL MANAGER
Contact Name, Title

8185482107
Phone #, Ext., Fax #

E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

141 N. GLENDALE AVENUE
Address

GLENDALE, CA 91206
City, State, Zip

MARK YOUNG — GENERAL MANAGER
Contact Name, Title

8185482107
Phone #, Ext., Fax #

E-Mail: myoung@glendaleca.gov

Section D - Application Type

6. The Facility Is: ( ) Not In RECLAIM or Title V ( ) In RECLAIM (●) In Title V ( ) In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:
- ( ) New Construction (Permit to Construct)
- ( ) Equipment On-Site But Not Constructed or Operational
- ( ) Equipment Operating Without A Permit *
- ( ) Compliance Plan
- ( ) Registration/Certification
- ( ) Streamlined Standard Permit

7b. Facility Permits:
- ( ) Title V Application or Amendment (Refer to Title V Matrix)
- ( ) RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:
- ( ) Administrative Change
- (●) Alteration/Modification
- ( ) Alteration/Modification without Prior Approval *
- ( ) Change of Condition
- ( ) Change of Condition without Prior Approval *
- ( ) Change of Location
- ( ) Change of Location without Prior Approval *
- ( ) Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number: 370621

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy):
8b. Estimated End Date of Construction (mm/dd/yyyy):
8c. Estimated Start Date of Operation (mm/dd/yyyy):

9. Description of Equipment or Reason for Compliance Plan (list applicable rule): GAS TURBINE 8A (D4) MODIFICATION; CONVERT TO SIMPLE CYCLE OPERATION; CONTROL TECH. MODIFICATIONS

10. For identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / process) 0

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-for-profit training center) (●) No ( ) Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? (●) No ( ) Yes
If Yes, provide NOV/NC#:

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location? ELECTRICAL POWER GENERATION

14. What is your business primary NAICS Code? (North American Industrial Classification System) 221112

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator? ( ) No (●) Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line? (●) No ( ) Yes

Section F - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application are true and correct.

17. Signature of Responsible Official: [signature]

18. Title of Responsible Official: GENERAL MANAGER

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.) ( ) No (●) Yes

20. Print Name: MARK YOUNG

21. Date: 08-09-2021

22. Do you claim confidentiality of data? (If Yes, see instructions.) (●) No ( ) Yes

23. Check List: ☒ Authorized Signature/Date ☒ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TRACKING #	CHECK #	AMOUNT RECEIVED	PAYMENT TRACKING #	VALIDATION
			$		

DATE	APP REJ	DATE	APP REJ	CLASS I III	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN

COPY

South Coast Air Quality Management District

Form 400-A

Application Form for Permit or Plan Approval

List only one piece of equipment or process per form.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. Owner's Business Name (If different from Business Name of Operator):

Section B - Equipment Location Address

4. Equipment Location Is: (●) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

800 AIR WAY
Street Address

GLENDALE, CA 91201
City, Zip

MARK YOUNG — GENERAL MANAGER
Contact Name, Title

8185482107
Phone #, Ext., Fax #

E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

141 N. GLENDALE AVENUE
Address

GLENDALE, CA 91206
City, State, Zip

MARK YOUNG — GENERAL MANAGER
Contact Name, Title

8185482107
Phone #, Ext., Fax #

E-Mail: myoung@glendaleca.gov

Section D - Application Type

6. The Facility Is: ( ) Not In RECLAIM or Title V ( ) In RECLAIM (●) In Title V ( ) In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:
- ( ) New Construction (Permit to Construct)
- ( ) Equipment On-Site But Not Constructed or Operational
- ( ) Equipment Operating Without A Permit *
- ( ) Compliance Plan
- ( ) Registration/Certification
- ( ) Streamlined Standard Permit

7b. Facility Permits:
- ( ) Title V Application or Amendment (Refer to Title V Matrix)
- ( ) RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:
- ( ) Administrative Change
- (●) Alteration/Modification
- ( ) Alteration/Modification without Prior Approval *
- ( ) Change of Condition
- ( ) Change of Condition without Prior Approval *
- ( ) Change of Location
- ( ) Change of Location without Prior Approval *
- ( ) Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number: 344955

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy):

8b. Estimated End Date of Construction (mm/dd/yyyy):

8c. Estimated Start Date of Operation (mm/dd/yyyy):

9. Description of Equipment or Reason for Compliance Plan (list applicable rule):
GAS TURBINE 8B (D5) MODIFICATION; REPLACING STEAM TURBINE; CONTROL TECH. MODIFICATIONS

10. For identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / process): 1

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-for-profit training center) (●) No ( ) Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? (●) No ( ) Yes
If Yes, provide NOV/NC#:

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location?
ELECTRICAL POWER GENERATION

14. What is your business primary NAICS Code? (North American Industrial Classification System): 221112

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator? ( ) No (●) Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line? (●) No ( ) Yes

Section F - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application are true and correct.

17. Signature of Responsible Official: [signature]

18. Title of Responsible Official: GENERAL MANAGER

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.) ( ) No (●) Yes

20. Print Name: MARK YOUNG

21. Date: 08-09-2021

22. Do you claim confidentiality of data? (If Yes, see instructions.) (●) No ( ) Yes

23. Check List: ☒ Authorized Signature/Date ☒ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TRACKING #	CHECK #	AMOUNT RECEIVED $	PAYMENT TRACKING #	VALIDATION

DATE	APP REJ	DATE	APP REJ	CLASS I III	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN

COPY

South Coast Air Quality Management District

Form 400-A

Application Form for Permit or Plan Approval

List only one piece of equipment or process per form.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944
Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. Owner's Business Name (If different from Business Name of Operator):

Section B - Equipment Location Address

4. Equipment Location Is: (●) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

800 AIR WAY
Street Address
GLENDALE, CA 91201
City, Zip
MARK YOUNG — Contact Name
GENERAL MANAGER — Title
8185482107 — Phone # — Ext. — Fax #
E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

141 N. GLENDALE AVENUE
Address
GLENDALE, CA 91206
City, State, Zip
MARK YOUNG — Contact Name
GENERAL MANAGER — Title
8185482107 — Phone # — Ext. — Fax #
E-Mail: myoung@glendaleca.gov

Section D - Application Type

6. The Facility Is: ( ) Not In RECLAIM or Title V ( ) In RECLAIM (●) In Title V ( ) In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:
- ( ) New Construction (Permit to Construct)
- ( ) Equipment On-Site But Not Constructed or Operational
- ( ) Equipment Operating Without A Permit *
- ( ) Compliance Plan
- ( ) Registration/Certification
- ( ) Streamlined Standard Permit

7b. Facility Permits:
- ( ) Title V Application or Amendment (Refer to Title V Matrix)
- ( ) RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:
- ( ) Administrative Change
- (●) Alteration/Modification
- ( ) Alteration/Modification without Prior Approval *
- ( ) Change of Condition
- ( ) Change of Condition without Prior Approval *
- ( ) Change of Location
- ( ) Change of Location without Prior Approval *
- ( ) Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number: 344956

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy):
8b. Estimated End Date of Construction (mm/dd/yyyy):
8c. Estimated Start Date of Operation (mm/dd/yyyy):

9. Description of Equipment or Reason for Compliance Plan (list applicable rule):
GAS TURBINE 8C (D6) MODIFICATION; REPLACING STEAM TURBINE; CONTROL TECH. MODIFICATIONS

10. For identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / process) 1

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-for-profit training center) (●) No ( ) Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? (●) No ( ) Yes
If Yes, provide NOV/NC#:

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location? ELECTRICAL POWER GENERATION

14. What is your business primary NAICS Code? (North American Industrial Classification System) 221112

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator? ( ) No (●) Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line? (●) No ( ) Yes

Section F - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application are true and correct.

17. Signature of Responsible Official: Mark Young

18. Title of Responsible Official: GENERAL MANAGER

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.) ( ) No (●) Yes

20. Print Name: MARK YOUNG

21. Date: 08-09-2021

22. Do you claim confidentiality of data? (If Yes, see instructions.) (●) No ( ) Yes

23. Check List: ☒ Authorized Signature/Date ☒ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TRACKING #	CHECK #	AMOUNT RECEIVED	PAYMENT TRACKING #	VALIDATION
			$		

DATE	APP REJ	DATE	APP REJ	CLASS I III	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN

COPY

South Coast Air Quality Management District

Form 400-A

Application Form for Permit or Plan Approval

List only one piece of equipment or process per form.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944
Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. Owner's Business Name (If different from Business Name of Operator):

Section B - Equipment Location Address

4. Equipment Location Is: (●) Fixed Location ( ) Various Location
(For equipment operated at various locations, provide address of initial site.)

800 AIR WAY
Street Address

GLENDALE, CA 91201
City, Zip

MARK YOUNG — GENERAL MANAGER
Contact Name, Title

8185482107
Phone #, Ext., Fax #

E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

141 N. GLENDALE AVENUE
Address

GLENDALE, CA 91206
City, State, Zip

MARK YOUNG — GENERAL MANAGER
Contact Name, Title

8185482107
Phone #, Ext., Fax #

E-Mail: myoung@glendaleca.gov

Section D - Application Type

6. The Facility Is: ( ) Not In RECLAIM or Title V ( ) In RECLAIM (●) In Title V ( ) In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:

- (●) New Construction (Permit to Construct)
- ( ) Equipment On-Site But Not Constructed or Operational
- ( ) Equipment Operating Without A Permit *
- ( ) Compliance Plan
- ( ) Registration/Certification
- ( ) Streamlined Standard Permit

7b. Facility Permits:

- ( ) Title V Application or Amendment (Refer to Title V Matrix)
- ( ) RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:

- ( ) Administrative Change
- ( ) Alteration/Modification
- ( ) Alteration/Modification without Prior Approval *
- ( ) Change of Condition
- ( ) Change of Condition without Prior Approval *
- ( ) Change of Location
- ( ) Change of Location without Prior Approval *
- ( ) Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number: ______

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy):
8b. Estimated End Date of Construction (mm/dd/yyyy):
8c. Estimated Start Date of Operation (mm/dd/yyyy):

9. Description of Equipment or Reason for Compliance Plan (list applicable rule):
REPLACING EXISTING CONTROL TECHNOLOGY (C51,C52) WITH NEW SCR&CATOX UNIT

10. For identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / process) 0

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-for-profit training center) (●) No ( ) Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? (●) No ( ) Yes
If Yes, provide NOV/NC#:

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location? ELECTRICAL POWER GENERATION

14. What is your business primary NAICS Code? (North American Industrial Classification System) 221112

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator? ( ) No (●) Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line? (●) No ( ) Yes

Section F - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application are true and correct.

17. Signature of Responsible Official: Mark Young

18. Title of Responsible Official: GENERAL MANAGER

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.) ( ) No (●) Yes

20. Print Name: MARK YOUNG

21. Date: 08-09-2021

22. Do you claim confidentiality of data? (If Yes, see instructions.) (●) No ( ) Yes

23. Check List: ☒ Authorized Signature/Date ☒ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TRACKING #	CHECK #	AMOUNT RECEIVED $	PAYMENT TRACKING #	VALIDATION

DATE	APP REJ	DATE	APP REJ	CLASS I III	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN

COPY

South Coast Air Quality Management District

Form 400-A

Application Form for Permit or Plan Approval

List only one piece of equipment or process per form.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944
Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. Owner's Business Name (If different from Business Name of Operator):

Section B - Equipment Location Address

4. Equipment Location Is: ◉ Fixed Location ○ Various Location
(For equipment operated at various locations, provide address of initial site.)

800 AIR WAY
Street Address
GLENDALE, CA 91201
City, Zip
MARK YOUNG — GENERAL MANAGER
Contact Name, Title
8185482107
Phone #, Ext, Fax #
E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

141 N. GLENDALE AVENUE
Address
GLENDALE, CA 91206
City, State, Zip
MARK YOUNG — GENERAL MANAGER
Contact Name, Title
8185482107
Phone #, Ext, Fax #
E-Mail: myoung@glendale.ca.gov

Section D - Application Type

6. The Facility Is: ○ Not In RECLAIM or Title V ○ In RECLAIM ◉ In Title V ○ In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:
- ◉ New Construction (Permit to Construct)
- ○ Equipment On-Site But Not Constructed or Operational
- ○ Equipment Operating Without A Permit *
- ○ Compliance Plan
- ○ Registration/Certification
- ○ Streamlined Standard Permit

7b. Facility Permits:
- ○ Title V Application or Amendment (Refer to Title V Matrix)
- ○ RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:
- ○ Administrative Change
- ○ Alteration/Modification
- ○ Alteration/Modification without Prior Approval *
- ○ Change of Condition
- ○ Change of Condition without Prior Approval *
- ○ Change of Location
- ○ Change of Location without Prior Approval *
- ○ Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number:

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy):
8b. Estimated End Date of Construction (mm/dd/yyyy):
8c. Estimated Start Date of Operation (mm/dd/yyyy):

9. Description of Equipment or Reason for Compliance Plan (list applicable rule):
REPLACING EXISTING CONTROL TECHNOLOGY (C53,C54) WITH NEW SCR&CATOX UNIT

10. For identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / process) 0

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-for-profit training center) ◉ No ○ Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? ◉ No ○ Yes
If Yes, provide NOV/NC#:

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location? ELECTRICAL POWER GENERATION

14. What is your business primary NAICS Code? (North American Industrial Classification System) 221112

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator? ○ No ◉ Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line? ◉ No ○ Yes

Section F - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application are true and correct.

17. Signature of Responsible Official: Mark Y

18. Title of Responsible Official: GENERAL MANAGER

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.) ○ No ◉ Yes

20. Print Name: MARK YOUNG

21. Date: 08-09-2021

22. Do you claim confidentiality of data? (If Yes, see instructions.) ◉ No ○ Yes

23. Check List: ☒ Authorized Signature/Date ☒ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TRACKING #	CHECK #	AMOUNT RECEIVED $	PAYMENT TRACKING #	VALIDATION

DATE	APP REJ	DATE	APP REJ	CLASS I III	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN

COPY

South Coast Air Quality Management District

Form 400-A

Application Form for Permit or Plan Approval

List only one piece of equipment or process per form.

South Coast AQMD

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

1. Facility Name (Business Name of Operator to Appear on the Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. Owner's Business Name (If different from Business Name of Operator):

Section B - Equipment Location Address

4. Equipment Location Is: ◉ Fixed Location ○ Various Location
(For equipment operated at various locations, provide address of initial site.)

Street Address: 800 AIR WAY
City: GLENDALE, CA Zip: 91201
Contact Name: MARK YOUNG Title: GENERAL MANAGER
Phone #: 8185482107 Ext. Fax #:
E-Mail: myoung@glendaleca.gov

Section C - Permit Mailing Address

5. Permit and Correspondence Information:
☐ Check here if same as equipment location address

Address: 141 N. GLENDALE AVENUE
City: GLENDALE, State: CA Zip: 91206
Contact Name: MARK YOUNG Title: GENERAL MANAGER
Phone #: 8185482107 Ext. Fax #:
E-Mail: myoung@glendaleca.gov

Section D - Application Type

6. The Facility Is: ○ Not In RECLAIM or Title V ○ In RECLAIM ◉ In Title V ○ In RECLAIM & Title V Programs

7. Reason for Submitting Application (Select only ONE):

7a. New Equipment or Process Application:
- ○ New Construction (Permit to Construct)
- ○ Equipment On-Site But Not Constructed or Operational
- ○ Equipment Operating Without A Permit *
- ○ Compliance Plan
- ○ Registration/Certification
- ○ Streamlined Standard Permit

7b. Facility Permits:
- ◉ Title V Application or Amendment (Refer to Title V Matrix)
- ○ RECLAIM Facility Permit Amendment

7c. Equipment or Process with an Existing/Previous Application or Permit:
- ○ Administrative Change
- ○ Alteration/Modification
- ○ Alteration/Modification without Prior Approval *
- ○ Change of Condition
- ○ Change of Condition without Prior Approval *
- ○ Change of Location
- ○ Change of Location without Prior Approval *
- ○ Equipment Operating with an Expired/Inactive Permit *

Existing or Previous Permit/Application
If you checked any of the items in 7c., you MUST provide an existing Permit or Application Number:

* A Higher Permit Processing Fee and additional Annual Operating Fees (up to 3 full years) may apply (Rule 301(c)(1)(D)(i)).

8a. Estimated Start Date of Construction (mm/dd/yyyy):

8b. Estimated End Date of Construction (mm/dd/yyyy):

8c. Estimated Start Date of Operation (mm/dd/yyyy):

9. Description of Equipment or Reason for Compliance Plan (list applicable rule): TITLE V FACILITY AMENDMENT

10. For Identical equipment, how many additional applications are being submitted with this application? (Form 400-A required for each equipment / process) 0

11. Are you a Small Business as per AQMD's Rule 102 definition? (10 employees or less and total gross receipts are $500,000 or less OR a not-for-profit training center) ◉ No ○ Yes

12. Has a Notice of Violation (NOV) or a Notice to Comply (NC) been issued for this equipment? ◉ No ○ Yes
If Yes, provide NOV/NC#:

Section E - Facility Business Information

13. What type of business is being conducted at this equipment location? ELECTRICAL POWER GENERATION

14. What is your business primary NAICS Code? (North American Industrial Classification System) 221112

15. Are there other facilities in the SCAQMD jurisdiction operated by the same operator? ○ No ◉ Yes

16. Are there any schools (K-12) within 1000 feet of the facility property line? ◉ No ○ Yes

Section F - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application are true and correct.

17. Signature of Responsible Official: [signature]

18. Title of Responsible Official: GENERAL MANAGER

19. I wish to review the permit prior to issuance. (This may cause a delay in the application process.) ○ No ◉ Yes

20. Print Name: MARK YOUNG

21. Date: 08-09-2021

22. Do you claim confidentiality of data? (If Yes, see instructions.) ◉ No ○ Yes

23. Check List: ☒ Authorized Signature/Date ☒ Form 400-CEQA ☒ Supplemental Form(s) (ie., Form 400-E-xx) ☒ Fees Enclosed

AQMD USE ONLY	APPLICATION TRACKING #	CHECK #	AMOUNT RECEIVED $	PAYMENT TRACKING #	VALIDATION

DATE	APP REJ	DATE	APP REJ	CLASS I III	BASIC CONTROL	EQUIPMENT CATEGORY CODE	TEAM	ENGINEER	REASON/ACTION TAKEN

COPY

South Coast Air Quality Management District

Form 500-A2
Title V Application Certification

South Coast AQMD

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section I - Operator Information

1. Facility Name (Business Name of Operator That Appears On Permit):
GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD):
800327

3. This Certification is submitted with a (Check one):
a. ◉ Title V Application (Initial, Revision or Renewal)
b. ○ Supplement/Correction to a Title V Application
c. ○ MACT Part 1

4. Is Form 500-C2 included with this Certification? ○ Yes ◉ No

Section II - Responsible Official Certification Statement

*Read each statement carefully and check each that applies – **You must check 3a or 3b.***

1. For Initial, Permit Renewal, and Administrative Application Certifications:

a. ○ The facility, including equipment that are exempt from written permit per Rule 219, is currently operating and will continue to operate in compliance with all applicable requirement(s) identified in Section II and Section III of Form 500-C1,

i. ☐ except for those requirements that do not specifically pertain to such devices or equipment and that have been identified as "Remove" on Section III of Form 500-C1.

ii. ☐ except for those devices or equipment that have been identified on the completed and attached Form 500-C2 that will not be operating in compliance with the specified applicable requirement(s).

b. ○ The facility, including equipment that are exempt from written permit per Rule 219, will meet in a timely manner, all applicable requirements with future effective dates.

2. For Permit Revision Application Certifications:

a. ☑ The equipment or devices to which this permit revision applies, will in a timely manner comply with all applicable requirements identified in Section II and Section III of Form 500-C1.

3. For MACT Hammer Certifications:

a. ○ The facility is subject to Section 112(j) of the Clean Air Act (Subpart B of 40 CFR part 63), also known as the MACT "hammer." The following information is submitted with a Title V application to comply with the Part 1 requirements of Section 112(j).

b. ◉ The facility is not subject to Section 112(j) of the Clean Air Act (Subpart B of 40 CFR part 63).

Section III - Authorization/Signature

I certify under penalty of law that I am the responsible official for this facility as defined in AQMD Regulation XXX and that based on information and belief formed after reasonable inquiry, the statement and information in this document and in all attached application forms and other materials are true, accurate, and complete.

1. Signature of Responsible Official: Mark Young	2. Title of Responsible Official: GENERAL MANAGER
3. Print Name: MARK YOUNG	4. Date: 08-09-2021
5. Phone #: (818) 548-2107	6. Fax #:

7. Address of Responsible Official:

Street #	City	State	Zip
141 N. GLENDALE AVE	GLENDALE	CA	91206

Acid Rain Facilities Only: Please Complete Section IV

COPY

Acid Rain facilities must certify their compliance status of the devices subject to applicable requirements under Title IV by an individual who meets the definition of Designated (or Alternate) Representative in 40 CFR Part 72.

Section IV - Designated Representative Certification Statement	
***For Acid Rain Facilities Only*: I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.**	
1. Signature of Designated Representative or Alternate: Mark Y	**2. Title of Designated Representative or Alternate:** GENERAL MANAGER
3. Print Name of Designated Representative or Alternate: MARK YOUNG	**4. Date:** 08-09-2021
5. Phone #: (818) 548-2107	**6. Fax #:**
7. Address of Designated Representative or Alternate: 141 N. GLENDALE AVE (Street #), GLENDALE (City), CA (State), 91206 (Zip)	

COPY

South Coast Air Quality Management District

Form 400-E-5
Selective Catalytic Reduction (SCR) System, Oxidation Catalyst, and Ammonia Catalyst

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Address where the equipment will be operated (for equipment which will be moved to various location in AQMD's jurisdiction, please list the initial location site): 800 AIR WAY, GLENDALE, CA 91201

(•) Fixed Location ( ) Various Locations

Section B - Equipment Description

Selective Catalytic Reduction (SCR)

SCR Catalyst	Manufacturer: TO BE DETERMINED Catalyst Active Material: ____ Model Number: ____ Type: ____ Size of Each Layer or Module: L: ____ ft. ____ in. W: ____ ft. ____ in. H: ____ ft. ____ in. No. of Layers or Modules: ____ Total Volume: ____ cu. ft. Total Weight: ____ lbs.
Reducing Agent	( ) Urea ( ) Anhydrous Ammonia (•) Aqueous Ammonia 19.00 % Injection Rate: ____ lb/hr
Reducing Agent Storage*	Diameter: ____ ft. ____ in. Height: ____ ft. ____ in. Capacity: 15000 gal Pressure Setting: 40 psia * A separate permit may be needed for the storage equipment.
Space Velocity	Gas Flow Rate/Catalyst Volume: ____ per hour
Area Velocity	Gas Flow Rate/Wetted Catalyst Surface Area: ____ ft/hr
Manufacturer's Guarantee	NOx: 2.5 ppm %O_2: 15.00 NOx: ____ gm/bhp-hr Ammonia Slip: 5 ppm @ 15.00 %O_2
Catalyst Life	5 years (expected)
Cost	Capital Cost: ____ Installation Cost: ____ Catalyst Replacement Cost: ____

Oxidation Catalyst

Oxidation Catalyst	Manufacturer: ____ Catalyst Active Material: ____ Model Number: TO BE DETERMINED Type: ____ Size of Each Layer or Module: L: ____ ft. ____ in. W: ____ ft. ____ in. H: ____ ft. ____ in. No. of Layers or Modules: ____ Total Volume: ____ cu. ft. Total Weight: ____ lbs.
Space Velocity	Gas Flow Rate/Catalyst Volume: ____ per hour
Manufacturer's Guarantee	VOC: ____ ppm VOC: ____ gm/bhp-hr %O_2: ____ CO: 25 ppm CO: ____ gm/bhp-hr %O_2: 15.00
Catalyst Life	5 years (expected)
Cost	Capital Cost: ____ Installation Cost: ____ Catalyst Replacement Cost: ____

COPY

Form 400-E-5
Selective Catalytic Reduction (SCR) System, Oxidation Catalyst, and Ammonia Catalyst

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section B - Equipment Description (cont.)

Ammonia Catalyst

Ammonia Catalyst	**Manufacturer:** ____ **Catalyst Active Material:** ____ **Model Number:** ____ **Type:** ____ **Size of Each Layer or Module: L:** ____ ft. ____ in. **W:** ____ ft. ____ in. **H:** ____ ft. ____ in. **No. of Layers or Modules:** ____ **Total Volume:** ____ cu. ft. **Total Weight:** ____ lbs.
Space Velocity	**Gas Flow Rate/Catalyst Volume:** ____ per hour
Manufacturer's Guarantee	**NH_3:** ____ ppm **$\%O_2$:** ____
Catalyst Life	____ years (expected)
Cost	**Capital Cost:** ____ **Installation Cost:** ____ **Catalyst Replacement Cost:** ____

Section C - Operation Information

Operating Temperature	**Minimum Inlet Temperature:** ____ °F (from cold start) **Maximum Temperature:** ____ °F **Warm-up Time:** 1 hr. ____ min. (maximum)
Operating Schedule	**Normal:** ____ hours/day ____ days/week ____ weeks/yr **Maximum:** 9 hours/day 7 days/week 52 weeks/yr

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info	**Signature:** ____ **Date:** ____ **Title:** CONSULTANT **Company Name:** MONTROSE	**Name:** A. EDWARD KRISNADI **Phone #:** (909) 261-2927 **Fax #:** ____ **Email:** ekrisnadi@montrose-env.com
Contact Info	**Name:** A. EDWARD KRISNADI **Title:** CONSULTANT **Company Name:** MONTROSE	**Phone #:** (909) 261-9297 **Fax #:** ____ **Email:** ekrisnadi@montrose-env.com

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South Coast Air Quality Management District

Form 400-E-5
Selective Catalytic Reduction (SCR) System, Oxidation Catalyst, and Ammonia Catalyst

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Address where the equipment will be operated (for equipment which will be moved to various location in AQMD's jurisdiction, please list the initial location site): 800 AIR WAY, GLENDALE, CA 91201

(●) Fixed Location ( ) Various Locations

Section B - Equipment Description

Selective Catalytic Reduction (SCR)	
SCR Catalyst	Manufacturer: TO BE DETERMINED Catalyst Active Material: ____ Model Number: ____ Type: ____ Size of Each Layer or Module: L: ____ ft. ____ in. W: ____ ft. ____ in. H: ____ ft. ____ in. No. of Layers or Modules: ____ Total Volume: ____ cu. ft. Total Weight: ____ lbs.
Reducing Agent	( ) Urea ( ) Anhydrous Ammonia (●) Aqueous Ammonia 19.00 % Injection Rate: ____ lb/hr
Reducing Agent Storage*	Diameter: ____ ft. ____ in. Height: ____ ft. ____ in. Capacity: 15000 gal Pressure Setting: 40 psia * A separate permit may be needed for the storage equipment.
Space Velocity	Gas Flow Rate/Catalyst Volume: ____ per hour
Area Velocity	Gas Flow Rate/Wetted Catalyst Surface Area: ____ ft/hr
Manufacturer's Guarantee	NOx: 2.0 ppm %O_2: 15.00 NOx: ____ gm/bhp-hr Ammonia Slip: 5 ppm @ 15.00 %O_2
Catalyst Life	5 years (expected)
Cost	Capital Cost: ____ Installation Cost: ____ Catalyst Replacement Cost: ____
Oxidation Catalyst	
Oxidation Catalyst	Manufacturer: TO BE DETERMINED Catalyst Active Material: ____ Model Number: ____ Type: ____ Size of Each Layer or Module: L: ____ ft. ____ in. W: ____ ft. ____ in. H: ____ ft. ____ in. No. of Layers or Modules: ____ Total Volume: ____ cu. ft. Total Weight: ____ lbs.
Space Velocity	Gas Flow Rate/Catalyst Volume: ____ per hour
Manufacturer's Guarantee	VOC: ____ ppm VOC: ____ gm/bhp-hr %O_2: ____ CO: 25 ppm CO: ____ gm/bhp-hr %O_2: 15.00
Catalyst Life	5 years (expected)
Cost	Capital Cost: ____ Installation Cost: ____ Catalyst Replacement Cost: ____

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South Coast Air Quality Management District

Form 400-E-5
Selective Catalytic Reduction (SCR) System, Oxidation Catalyst, and Ammonia Catalyst

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section B - Equipment Description (cont.)

Ammonia Catalyst

Ammonia Catalyst	**Manufacturer:** ____ **Catalyst Active Material:** ____ **Model Number:** ____ **Type:** ____ **Size of Each Layer or Module:** **L:** ____ ft. ____ in. **W:** ____ ft. ____ in. **H:** ____ ft. ____ in. **No. of Layers or Modules:** ____ **Total Volume:** ____ cu. ft. **Total Weight:** ____ lbs.
Space Velocity	**Gas Flow Rate/Catalyst Volume:** ____ per hour
Manufacturer's Guarantee	**NH_3:** ____ ppm **%O_2:** ____
Catalyst Life	____ years (expected)
Cost	**Capital Cost:** ____ **Installation Cost:** ____ **Catalyst Replacement Cost:** ____

Section C - Operation Information

Operating Temperature	**Minimum Inlet Temperature:** ____ °F (from cold start) **Maximum Temperature:** ____ °F **Warm-up Time:** 1 hr. ____ min. (maximum)
Operating Schedule	**Normal:** ____ hours/day ____ days/week ____ weeks/yr **Maximum:** 9 hours/day 7 days/week 52 weeks/yr

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info	**Signature:** ____ **Date:** ____ **Title:** CONSULTANT **Company Name:** MONTROSE	**Name:** A. EDWARD KRISNADI **Phone #:** (909) 261-2927 **Fax #:** ____ **Email:** ekrisnadi@montrose-env.com
Contact Info	**Name:** A. EDWARD KRISNADI **Title:** CONSULTANT **Company Name:** MONTROSE	**Phone #:** (909) 261-9297 **Fax #:** ____ **Email:** ekrisnadi@montrose-env.com

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South Coast Air Quality Management District

Form 400-E-12
Gas Turbine

South Coast AQMD

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Address where the equipment will be operated (for equipment which will be moved to various location in AQMD's jurisdiction, please list the initial location site): 800 AIR WAY, GLENDALE, CA 91201

(•) Fixed Location ( ) Various Locations

Section B - Equipment Description

Turbine	**Manufacturer:** TURBO POWER & MARINE **Model:** FT4C3FLF **Serial No.:** TURBINE 8A (D4) Size (based on Higher Heating Value - HHV): **Manufacturer Maximum Input Rating:** 350.00 MMBTU/hr ______ kWh **Manufacturer Maximum Output Rating:** ______ MMBTU/hr 30,000.00 kWh
Function (Check all that apply)	[X] Electrical Generation [ ] Driving Pump/Compressor [ ] Emergency Peaking Unit [ ] Steam Generation [ ] Exhaust Gas Recovery [ ] Other (specify): ______
Cycle Type	(•) Simply Cycle ( ) Regenerative Cycle ( ) Combined Cycle ( ) Other (specify): ______
Combustion Type	( ) Tubular ( ) Can-Annular (•) Annular
Fuel (Turbine)	[X] Natural Gas [ ] LPG [ ] Digester Gas* [ ] Landfill Gas* [ ] Propane [ ] Refinery Gas* [ ] Other*: ______ * (If Digester Gas, Landfill Gas, Refinery Gas, and/or Other are checked, attach fuel analysis indicating higher heating value and sulfur content).
Heat Recovery Steam Generator (HRSG)	**Steam Turbine Capacity:** ______ MW **Low Pressure Steam Output Capacity:** ______ lb/hr @ ______ °F **High Pressure Steam Output Capacity:** ______ lb/hr @ ______ °F **Superheated Steam Output Capacity:** ______ lb/hr @ ______ °F
Duct Burner	**Manufacturer:** NOT APPLICABLE (NO DUCT BURNER) **Model:** ______ **Number of burners:** ______ **Rating of each burner** (HHV): ______ **Type:** (•) **Low NOx** (please attach manufacturer's specifications) ( ) **Other:** ______ Show all heat transfer surface locations with the HRSG and temperature profile
Fuel (Duct Burner)	( ) Natural Gas ( ) LPG ( ) Digester Gas* ( ) Landfill Gas* ( ) Propane ( ) Refinery Gas* (•) Other*: NONE * (If Digester Gas, Landfill Gas, Refinery Gas, and/or Other are checked, attach fuel analysis indicating higher heating value and sulfur content).

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South Coast Air Quality Management District

Form 400-E-12
Gas Turbine

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section B - Equipment Description (Cont.)

Air Pollution Control

- ○ Selective Catalytic Reduction (SCR)*
- ○ Selective Non-Catalytic Reduction (SNCR)*
- ○ Oxidation Catalyst*
- ◉ Other (specify)*: SCR AND OXIDATION CAT IN SERIES
- ○ Steam/Water Injection: Injection Rate:________ lbs. water/lbs. fuel, or________ mole water/mole fuel

* Separate application is required.

Capital Cost:________ Installation Cost:________ Annual Operating Cost:________

Oxidation Catalyst Data (If Applicable)

Manufacturer: TBD

Model: TBD

Catalyst Dimensions: Length:____ ft.____ in. Width:____ ft.____ in. Height:____ ft.____ in.

Catalyst Cell Density:________ cells/sq.in. Pressure Drop Across Catalyst:________

Manufacturer's Guarantee: CO Control Efficiency: 50.00 % Catalyst Life: 5 yrs

VOC Control Efficiency: 30.00 % Operating Temp. Range:________ °F

Space Velocity (gas flow rate/catalyst volume):________ Area Velocity (gas flow/wetted catalyst surface area):________

VOC Concentration into Catalyst:________ PPMVD@ 15%O_2 CO Concentration inot Catalyst:________ PPMVD@ 15%O_2

Section C - Operation Information

On-line Emissions Data

Pollutants	Maximum Emissions Before Control*		Maximum Emissions After Control	
	PPM@15% O_2, dry	lb/hour	PPM@15% O_2, dry	lb/hour
ROG				13.91
NOx			2.5	3.27
CO			25	19.92
PM_{10}				1.05
SOx				0.24
NH_3			5	

* Based on temperature, fuel consumption, and MW output.

Reference (attach data):

☒ Manufacturer Emission Data ☐ EPA Emission Factors ☒ AQMD Emission Factors ☐ Source Test

Stack or Vent Data

Stack Height: 115 ft.________ in. Stack Diameter: 10 ft. 0 in.

Exhaust Temperature: 857 °F Exhaust Pressure: 0.2 inches water column

Exhaust Flow Rate: 558240 CFM Oxygen Level:________ %

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South Coast Air Quality Management District

Form 400-E-12
Gas Turbine

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section C - Operation Information (cont.)

Startup Data: No. of Startups per day: 2 No. of Startups per year: 125 Duration of each startup: 1 hrs.

Shutdown Data: No. of Shutdowns per day: 2 No. of Shutdowns per year: 125 Duration of each Shutdown: 0.25 hrs.

Startup and Shutdown Emissions Data

Pollutants	Startup Emissions		Shutdown Emissions	
	PPM@15% O_2, dry	lb/hour	PPM@15% O_2, dry	lb/hour
ROG		13.91		13.91
NOx		15.60		15.40
CO		84.39		9.96
PM_{10}		0.20		0.20
SOx		0.24		0.24
NH_3				

Monitoring and Reporting

Continuous Emission Monitoring System (CEMS): CEMS Make: TBD

CEMS Model: TBD

Will the CEMS be used to measure both on-line and startup/shutdown emissions? (•) Yes ( ) No

The following parameters will be continuously monitored:

- [x] NOx
- [x] CO
- [x] O_2
- [x] Fuel Flow Rate
- [x] Ammonia Injection Rate
- [ ] Other (specify): ____
- [ ] Ammonia Stack Concentration: Ammonia CEMS Make: ____

Ammonia CEMS Model: ____

Operating Schedule

	hours/day	days/week	weeks/yr
Normal:			
Maximum:	9	7	52

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info

Signature: ____ Date: ____

Name: A. EDWARD KRISNADI

Title: CONSULTANT

Company Name: MONTROSE

Phone #: (909) 261-2927 Fax #: ____

Email: ekrisnadi@montrose-env.com

Contact Info

Name: A. EDWARD KRISNADI

Title: CONSULTANT

Company Name: MONTROSE

Phone #: (909) 261-2927 Fax #: ____

Email: ekrisnadi@montrose-env.com

THIS IS A PUBLIC DOCUMENT

Pursuant to the California Public Records Act, your permit application and any supplemental documentation are public records and may be disclosed to a third party. If you wish to claim certain limited information as exempt from disclosure because it qualifies as a trade secret, as defined in the District's Guidelines for Implementing the California Public Records Act, you must make such claim at the time of submittal to the District.

Check here if you claim that this form or its attachments contain confidential trade secret information. [x]

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South Coast Air Quality Management District
Form 400-E-12
Gas Turbine

South Coast AQMD

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Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Address where the equipment will be operated (for equipment which will be moved to various location in AQMD's jurisdiction, please list the initial location site): 800 AIR WAY, GLENDALE, CA 91201

(•) Fixed Location ( ) Various Locations

Section B - Equipment Description

Turbine	**Manufacturer:** TURBO POWER & MARINE **Model:** FT4C3FLF **Serial No.:** TURBINE 8B (D5) **Size** (based on Higher Heating Value - HHV): **Manufacturer Maximum Input Rating:** 350.00 MMBTU/hr ____ kWh **Manufacturer Maximum Output Rating:** ____ MMBTU/hr 30,000.00 kWh
Function (Check all that apply)	☒ Electrical Generation ☐ Driving Pump/Compressor ☐ Emergency Peaking Unit ☒ Steam Generation ☐ Exhaust Gas Recovery ☐ Other (specify): ____
Cycle Type	( ) Simply Cycle ( ) Regenerative Cycle (•) Combined Cycle ( ) Other (specify): ____
Combustion Type	( ) Tubular ( ) Can-Annular (•) Annular
Fuel (Turbine)	☒ Natural Gas ☐ LPG ☐ Digester Gas* ☐ Landfill Gas* ☐ Propane ☐ Refinery Gas* ☐ Other*: ____ * (If Digester Gas, Landfill Gas, Refinery Gas, and/or Other are checked, attach fuel analysis indicating higher heating value and sulfur content).
Heat Recovery Steam Generator (HRSG)	**Steam Turbine Capacity:** ____ MW **Low Pressure Steam Output Capacity:** ____ lb/hr @ ____ °F **High Pressure Steam Output Capacity:** ____ lb/hr @ ____ °F **Superheated Steam Output Capacity:** ____ lb/hr @ ____ °F
Duct Burner	**Manufacturer:** NOT APPLICABLE (NO DUCT BURNER) **Model:** ____ **Number of burners:** ____ **Rating of each burner** (HHV): ____ **Type:** (•) **Low NOx** (please attach manufacturer's specifications) ( ) **Other:** ____ Show all heat transfer surface locations with the HRSG and temperature profile
Fuel (Duct Burner)	( ) Natural Gas ( ) LPG ( ) Digester Gas* ( ) Landfill Gas* ( ) Propane ( ) Refinery Gas* (•) Other*: NONE * (If Digester Gas, Landfill Gas, Refinery Gas, and/or Other are checked, attach fuel analysis indicating higher heating value and sulfur content).

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South Coast Air Quality Management District

Form 400-E-12
Gas Turbine

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section B - Equipment Description (Cont.)

Air Pollution Control

○ Selective Catalytic Reduction (SCR)* ○ Selective Non-Catalytic Reduction (SNCR)*

○ Oxidation Catalyst* ◉ Other (specify)*: SCR AND OXIDATION CAT IN SERIES

○ Steam/Water Injection: Injection Rate:________ lbs. water/lbs. fuel, or________ mole water/mole fuel

* Separate application is required.

Capital Cost:________ Installation Cost:________ Annual Operating Cost:________

Oxidation Catalyst Data (If Applicable)

Manufacturer: TBD Model: TBD

Catalyst Dimensions: Length:____ ft.____ in. Width:____ ft.____ in. Height:____ ft.____ in.

Catalyst Cell Density:________ cells/sq.in. Pressure Drop Across Catalyst:________

Manufacturer's Guarantee: CO Control Efficiency: 50.00 % Catalyst Life: 5 yrs

VOC Control Efficiency: 30.00 % Operating Temp. Range:________ °F

Space Velocity (gas flow rate/catalyst volume):________ Area Velocity (gas flow/wetted catalyst surface area):________

VOC Concentration into Catalyst:________ PPMVD@ 15%O_2 CO Concentration inot Catalyst:________ PPMVD@ 15%O_2

Section C - Operation Information

On-line Emissions Data

Pollutants	Maximum Emissions Before Control *		Maximum Emissions After Control	
	PPM@15% O_2, dry	lb/hour	PPM@15% O_2, dry	lb/hour
ROG				13.91
NOx			2	2.62
CO			25	19.92
PM_{10}				0.20
SOx				0.24
NH_3			5	

* Based on temperature, fuel consumption, and MW output.

Reference (attach data):

☒ Manufacturer Emission Data ☐ EPA Emission Factors ☒ AQMD Emission Factors ☐ Source Test

Stack or Vent Data

Stack Height: 115 ft.________ in. Stack Diameter: 10 ft. 0 in.

Exhaust Temperature: 378 °F Exhaust Pressure: 0.2 inches water column

Exhaust Flow Rate: 738000 CFM Oxygen Level:________ %

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South Coast Air Quality Management District

Form 400-E-12
Gas Turbine

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section C - Operation Information (cont.)

Startup Data: No. of Startups per day: 2 No. of Startups per year: 250 Duration of each startup: 1 hrs.

Shutdown Data: No. of Shutdowns per day: 2 No. of Shutdowns per year: 250 Duration of each Shutdown: 0.25 hrs.

Startup and Shutdown Emissions Data

Pollutants	Startup Emissions		Shutdown Emissions	
	PPM@15% O_2, dry	lb/hour	PPM@15% O_2, dry	lb/hour
ROG		13.91		13.91
NOx		15.30		15.40
CO		84.39		9.96
PM_{10}		0.20		0.20
SOx		0.24		0.24
NH_3				

Monitoring and Reporting

Continuous Emission Monitoring System (CEMS): CEMS Make: TBD

CEMS Model: TBD

Will the CEMS be used to measure both on-line and startup/shutdown emissions? ◉ Yes ○ No

The following parameters will be continuously monitored:

☒ NOx ☒ CO ☒ O_2

☒ Fuel Flow Rate ☒ Ammonia Injection Rate ☐ Other (specify): ____

☐ Ammonia Stack Concentration: Ammonia CEMS Make: ____

Ammonia CEMS Model: ____

Operating Schedule

Normal: ____ hours/day ____ days/week ____ weeks/yr

Maximum: 9 hours/day 7 days/week 52 weeks/yr

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info

Signature: ____ Date: ____

Title: CONSULTANT Company Name: MONTROSE

Name: A. EDWARD KRISNADI

Phone #: (909) 261-2927 Fax #: ____

Email: ekrisnadi@montrose-env.com

Contact Info

Name: A. EDWARD KRISNADI

Title: CONSULTANT Company Name: MONTROSE

Phone #: (909) 261-2927 Fax #: ____

Email: ekrisnadi@montrose-env.com

THIS IS A PUBLIC DOCUMENT

Pursuant to the California Public Records Act, your permit application and any supplemental documentation are public records and may be disclosed to a third party. If you wish to claim certain limited information as exempt from disclosure because it qualifies as a trade secret, as defined in the District's Guidelines for Implementing the California Public Records Act, you must make such claim at the time of submittal to the District.

Check here if you claim that this form or its attachments contain confidential trade secret information. ☒

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South Coast Air Quality Management District

Form 400-E-12
Gas Turbine

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944
Tel: (909) 396-3385
www.aqmd.gov

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Address where the equipment will be operated (for equipment which will be moved to various location in AQMD's jurisdiction, please list the initial location site): 800 AIR WAY, GLENDALE, CA 91201

(●) Fixed Location ( ) Various Locations

Section B - Equipment Description

Turbine	**Manufacturer:** TURBO POWER & MARINE **Model:** FT4C3FLF **Serial No.:** TURBINE 8C (D6) Size (based on Higher Heating Value - HHV): **Manufacturer Maximum Input Rating:** 350.00 MMBTU/hr ______ kWh **Manufacturer Maximum Output Rating:** ______ MMBTU/hr 30,000.00 kWh
Function (Check all that apply)	[X] Electrical Generation [ ] Driving Pump/Compressor [ ] Emergency Peaking Unit [X] Steam Generation [ ] Exhaust Gas Recovery [ ] Other (specify): ______
Cycle Type	( ) Simply Cycle ( ) Regenerative Cycle (●) Combined Cycle ( ) Other (specify): ______
Combustion Type	( ) Tubular ( ) Can-Annular (●) Annular
Fuel (Turbine)	[X] Natural Gas [ ] LPG [ ] Digester Gas* [ ] Landfill Gas* [ ] Propane [ ] Refinery Gas* [ ] Other*: ______ * (If Digester Gas, Landfill Gas, Refinery Gas, and/or Other are checked, attach fuel analysis indicating higher heating value and sulfur content).
Heat Recovery Steam Generator (HRSG)	Steam Turbine Capacity: ______ MW Low Pressure Steam Output Capacity: ______ lb/hr @ ______ °F High Pressure Steam Output Capacity: ______ lb/hr @ ______ °F Superheated Steam Output Capacity: ______ lb/hr @ ______ °F
Duct Burner	Manufacturer: NOT APPLICABLE (NO DUCT BURNER) Model: ______ Number of burners: ______ Rating of each burner (HHV): ______ Type: (●) Low NOx (please attach manufacturer's specifications) ( ) Other: ______ Show all heat transfer surface locations with the HRSG and temperature profile
Fuel (Duct Burner)	( ) Natural Gas ( ) LPG ( ) Digester Gas* ( ) Landfill Gas* ( ) Propane ( ) Refinery Gas* (●) Other*: NONE * (If Digester Gas, Landfill Gas, Refinery Gas, and/or Other are checked, attach fuel analysis indicating higher heating value and sulfur content).

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South Coast Air Quality Management District

Form 400-E-12
Gas Turbine

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section B - Equipment Description (Cont.)

Air Pollution Control

○ Selective Catalytic Reduction (SCR)* ○ Selective Non-Catalytic Reduction (SNCR)*

○ Oxidation Catalyst* ◉ Other (specify)*: SCR AND OXIDATION CAT IN SERIES

○ Steam/Water Injection: Injection Rate:__________ lbs. water/lbs. fuel, or__________ mole water/mole fuel

* Separate application is required.

Capital Cost:__________ Installation Cost:__________ Annual Operating Cost:__________

Oxidation Catalyst Data (If Applicable)

Manufacturer: TBD Model: TBD

Catalyst Dimensions: Length:_____ ft._____ in. Width:_____ ft._____ in. Height:_____ ft._____ in.

Catalyst Cell Density:__________ cells/sq.in. Pressure Drop Across Catalyst:__________

Manufacturer's Guarantee: CO Control Efficiency: 50.00 % Catalyst Life: 5 yrs

VOC Control Efficiency: 30.00 % Operating Temp. Range:__________ °F

Space Velocity (gas flow rate/catalyst volume):__________ Area Velocity (gas flow/wetted catalyst surface area):__________

VOC Concentration into Catalyst:__________ PPMVD@ 15%O_2 CO Concentration inot Catalyst:__________ PPMVD@ 15%O_2

Section C - Operation Information

On-line Emissions Data

Pollutants	Maximum Emissions Before Control *		Maximum Emissions After Control	
	PPM@15% O_2, dry	lb/hour	PPM@15% O_2, dry	lb/hour
ROG				13.91
NOx			2	2.62
CO			25	19.92
PM_{10}				0.20
SOx				0.24
NH_3			5	

* Based on temperature, fuel consumption, and MW output.

Reference (attach data):

☒ Manufacturer Emission Data ☐ EPA Emission Factors ☒ AQMD Emission Factors ☐ Source Test

Stack or Vent Data

Stack Height: 115 ft.__________ in. Stack Diameter: 10 ft. 0 in.

Exhaust Temperature: 378 °F Exhaust Pressure: 0.2 inches water column

Exhaust Flow Rate: 738000 CFM Oxygen Level:__________ %

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South Coast Air Quality Management District

Form 400-E-12
Gas Turbine

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section C - Operation Information (cont.)

Startup Data — No. of Startups per day: 2 — No. of Startups per year: 250 — Duration of each startup: 1 hrs.

Shutdown Data — No. of Shutdowns per day: 2 — No. of Shutdowns per year: 250 — Duration of each Shutdown: 0.25 hrs.

Startup and Shutdown Emissions Data

Pollutants	Startup Emissions		Shutdown Emissions	
	PPM@15% O_2, dry	lb/hour	PPM@15% O_2, dry	lb/hour
ROG		13.91		13.91
NOx		15.30		15.40
CO		84.39		9.96
PM_{10}		0.20		0.20
SOx		0.24		0.24
NH_3				

Monitoring and Reporting

Continuous Emission Monitoring System (CEMS): CEMS Make: TBD

CEMS Model: TBD

Will the CEMS be used to measure both on-line and startup/shutdown emissions? ◉ Yes ○ No

The following parameters will be continuously monitored:

☒ NOx ☒ CO ☒ O_2

☒ Fuel Flow Rate ☒ Ammonia Injection Rate ☐ Other (specify): ____

☐ Ammonia Stack Concentration: Ammonia CEMS Make: ____

Ammonia CEMS Model: ____

Operating Schedule

	hours/day	days/week	weeks/yr
Normal:			
Maximum:	9	7	52

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info

Signature: ____ Date: ____

Name: A. EDWARD KRISNADI

Title: CONSULTANT

Company Name: MONTROSE

Phone #: (909) 261-2927 Fax #:

Email: ekrisnadi@montrose-env.com

Contact Info

Name: A. EDWARD KRISNADI

Title: CONSULTANT

Company Name: MONTROSE

Phone #: (909) 261-2927 Fax #:

Email: ekrisnadi@montrose-env.com

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Pursuant to the California Public Records Act, your permit application and any supplemental documentation are public records and may be disclosed to a third party. If you wish to claim certain limited information as exempt from disclosure because it qualifies as a trade secret, as defined in the District's Guidelines for Implementing the California Public Records Act, you must make such claim at the time of submittal to the District.

Check here if you claim that this form or its attachments contain confidential trade secret information. ☒

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South Coast Air Quality Management District
Form 400-E-18
Storage Tank

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Section A - Operator Information

Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Address where the equipment will be operated (for equipment which will be moved to various locations in AQMD's jurisdiction, please list the initial location site): 800 AIR WAY, GLENDALE, CA 91201

(●) Fixed Location ( ) Various Locations

Tank Type (Select ONE)	( ) External Floating Roof Tank (EFRT) ( ) Internal Floating Roof Tank (IFRT) (●) Horizontal Tank (HT) ( ) Vertical Fixed Roof Tank (VFRT) ( ) Domed External Roof Tank (DEFRT)
Identification	**Tank Identification Number:** TBD **Tank Contents/Product (include MSDS):** 19% AQUEOUS AMMONIA

Section B - Tank Information

Tank Characteristics	**Shell Diameter (ft.):** ____ **Shell Length (ft.):** ____ **Shell Height (ft.):** ____ **Turnovers Per Year:** ____ **Is Tank Heated?** ( ) Yes (●) No **Is Tank Underground?** ( ) Yes ( ) No **Net Throughput (gal/year):** ____ **Self Support Roof:** ( ) Yes ( ) No **Number of Columns?** ____ **Effective Column Diameter:** ( ) 9" by 7" Built Up Column - 1.1 ( ) 8" Diameter Pipe - 0.7 ( ) Unknown - 1 **External Shell Condition:** (●) Good ( ) Poor **Internal Shell Color:** ( ) Light Rust ( ) Dense Rust ( ) Gunite Lining **External Shell Color:** (●) White/White ( ) Aluminum/Specular ( ) Aluminum/Diffuse ( ) Gray/Light ( ) Gray/Medium ( ) Red/Primer **Average Liquid Height (ft.) (Vertical Only):** ____ **Maximum Liquid Height (ft.) (Vertical Only):** ____ **Working Volume (gal.) (Vertical Only):** ____ **Actual Volume (gal.) (Vertical Only):** ____ **Paint Condition:** ( ) Good ( ) Poor **Paint Color/Shade:** (●) White/White ( ) Aluminum/Diffuse ( ) Gray/Light ( ) Aluminum/Specular ( ) Gray/Medium ( ) Red/Primer
Roof Characteristics (Floating Roof Tank)	**Roof Type:** ( ) Pontoon ( ) Double Deck ( ) Dome Roof (Height____ft.) ( ) Cone Roof (Height____ft.) **Roof Fitting Category:** ( ) Typical ( ) Detail **Roof Height (ft.):** ____ **Roof Paint Condition:** ( ) Good ( ) Poor **Roof Color/Shade:** ( ) White/White ( ) Aluminum/Diffuse ( ) Gray/Light ( ) Aluminum/Specular ( ) Gray/Medium ( ) Red/Primer
Deck Characteristics (Floating Roof Tank)	**Deck Type:** ( ) Welded ( ) Bolted **Deck Fitting Characteristics:** ( ) Typical ( ) Detailed (Complete Deck Seam) **Construction:** ( ) Sheet ( ) Panel **Deck Seam Length (ft.):** ____ ____ **Deck Seam:** ( ) 5 ft. wide ( ) 6 ft. wide ( ) 7 ft. wide ( ) 5 x 7.5 ft. ( ) 5 x 12 ft.
Tank Construction and Rim -Seal System (Floating Roof Tank)	**Tank Construction:** ( ) Welded ( ) Riveted **Primary Seal:** ( ) Mechanical Shoe ( ) Liquid Mounted ( ) Vapor Mounted **Secondary Seal:** ( ) Rim Mounted ( ) None ( ) Shoe Mounted
Breather Vent Setting	**Vacuum Setting (psig):** -1.25 **Pressure Setting (psig):** 25

* Section D of the application MUST be completed.

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SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944
Tel: (909) 396-3385
www.aqmd.gov

South Coast AQMD

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section B - Tank Information (cont.)

Site Selection

Nearest Major City: GLENDALE

Daily Average Ambient Temperature (°F): 65 — Annual Average Minimum Temperature (°F): 50

Annual Average Maximum Temperature (°F): 85 — Average Wind Speed (mph): ______

Annual Average Solar Insulation Factor (Btu / (ft^3 * ft * day)): ______

Tank Contents

Chemical Category: ◯ Organic Liquids ◯ Crude Oil ◯ Petroleum Distillates

Liquid: ◉ Single ◯ Multiple

If Multiple, Select Speciation Option: ◯ Full Speciation ◯ Partial Speciation ◯ Various Weight Speciation ◯ None

Section C - Operation Information

Vapor Control

Vapor Control During Loading or Unloading: ☐ Sparger ☒ Vapor Balance System ☐ Vapor Return Line ☐ Vented to Air Pollution Control Equipment [1]

[1] A separate permit is required. If APC equipment is already permitted, provide Permit or Device Number: ______

Vent Valve Data

Indicate Type of Setting and Vapor Disposal

	Number	Pressure Setting	Vaccum Setting	Discharging to (Check Appropriate Box): Atmosphere	Vapor Control	Flare
Combination				☐	☐	☐
Pressure	1	25	-1.25	☒	☐	☐
Vaccum				☐	☐	☐
Open				☐	☐	☐

Materials

Name all liquids, vapors, gases, or mixtures of such material to be stored in this tank:
19% AQUEOUS AMMONIA

If material is stored in a solution, supply the following information:

Name of Solvent: WATER — Name of Materials Dissolved: AMMONIA

Concentration of Materials Dissolved: 19.00 % by Weight OR ______ % by Volume OR ______ lbs/gal

Section D - Roof/Deck Fitting

Section D is required for the following tanks: External Floating Roof Tank, Internal Floating Roof Tanks, or Domed External Floating Roof Tanks.

Select the number of fittings for each applicable question. Examples: __3__ Unbolted Cover, Ungasketed
______ Unbolted Cover, Gasketed

Roof/Deck Fitting Details

1. Access Hatch (24" diameter well)
   - ______ Bolted Cover, Gasketed
   - ______ Unbolted Cover, UnGasketed
   - ______ Unbolted Cover, Gasketed

2. Automatic Gauge Float Well (20" diameter well)
   - ______ Bolted Cover, Gasketed
   - ______ Unbolted Cover, Ungasketed
   - ______ Unbolted Cover, Gasketed

3. Column Well (24" diameter well)
   - ______ Built-Up Col - Sliding Cover, Gasketed
   - ______ Built-Up Col - Sliding Cover, Ungasketed
   - ______ Pipe Col - Flex, Fabric Sleeve Seal
   - ______ Pipe Col - Sliding Cover, Gasketed
   - ______ Pipe Col - Sliding Cover, Ungasketed

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South Coast Air Quality Management District

Form 400-E-18
Storage Tank

This form must be accompanied by a completed Application for a Permit to Construct/Operate - Forms 400-A, Form 400-CEQA, and Form 400-PS.

Section D - Roof/Deck Fitting (cont.)

Roof/Deck Fitting Details (cont.)

4. Gauge Hatch/Sample Well (8" diameter well)

____________ Weighted Mechanical Actuation, Gasketed

____________ Weighted Mechanical Actuation, Ungasketed

5. Ladder Well (36" diameter)

____________ Sliding Cover, Gasketed

____________ Sliding Cover, Ungasketed

6. Rim Vent (6" diameter)

____________ Weighted Mechanical Actuation, Gasketed

____________ Weighted Mechanical Actuation, Ungasketed

7. Roof Drain (3" diameter)

____________ Open

____________ 90% Close

8. Roof Leg (3" diameter leg)

____________ Adjustable, Pontoon Area, Ungasketed

____________ Adjustable, Center Area, Ungasketed

____________ Adjustable, Double-Deck Roofs

____________ Fixed

____________ Adjustable, Pontoon Area, Gasketed

____________ Adjustable, Pontoon Area, Sock

____________ Adjustable, Center Area, Gasketed

____________ Adjustable, Center Area, Sock

9. Roof Leg or Hang Well

____________ Adjustable

____________ Fixed

10. Sample Pipe (24" diameter)

____________ Slotted Pipe – Sliding Cover, Gasketed

____________ Slotted Pipe – Sliding Cover, Ungasketed

____________ Slit Fabric Seal, 10% Open

11. Guided Pole/Sample Well

____________ Ungasketed, Sliding Cover, Without Float

____________ Ungasketed Sliding Cover, With Float

____________ Gasketed Sliding Cover, Without Float

____________ Gasketed Sliding Cover, With Float

____________ Gasketed Sliding Cover, With Pole Sleeve

____________ Gasketed Sliding Cover, With Pole Wiper

____________ Gasketed Sliding Cover, With Float, Wiper

____________ Gasketed Sliding Cover, With Float, Sleeve, Wiper

____________ Gasketed Sliding Cover, With Pole Sleeve, Wiper

12. ____________ **Stub Drain (1" diameter)**

13. Unslotted Guide – Pole Well

____________ Ungasketed, Sliding Cover

____________ Gasketed Sliding Cover

____________ Ungasketed Sliding Cover with Sleeve

____________ Gasketed Sliding Cover with Sleeve

____________ Gasketed Sliding Cover with Wiper

14. Vacuum Breaker (10" diameter well)

____________ Weighted Mechanical Actuation, Gasketed

____________ Weighted Mechanical Actuation, Ungasketed

Section D - Authorization/Signature

I hereby certify that all information contained herein and information submitted with this application is true and correct.

Preparer Info	**Signature:**	**Date:**	**Name:** A. EDWARD KRISNADI	
			Phone #: (909) 261-2927	**Fax #:**
	Title: CONSULTANT	**Company Name:** MONTROSE	**Email:** ekrisnadi@montrose-env.com	
Contact Info	**Name:** A. EDWARD KRISNADI		**Phone #:** (909) 261-9297	**Fax #:**
	Title: CONSULTANT	**Company Name:** MONTROSE	**Email:** ekrisnadi@montrose-env.com	

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South Coast Air Quality Management District

Form 500-B
Title V List of Exempt Equipment

South Coast AQMD

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

Use this form for all application submittals requesting an initial Title V permit or permit renewal. If you are applying for a permit revision, you may also use this form to have your exempt equipment listing updated prior to renewing your permit.

This form is designed to summarize all of the equipment at a facility that is exempt per SCAQMD Rule 219 from SCAQMD permit requirements (e.g., I.C. Engines ≤ 50 BHP, Boilers < 2 MM BTU/hr etc.). This equipment can be listed according to category. However, if there is a specific device that is vented to control equipment, then the equipment must be listed separately. Trivial activities listed on the back of this form or the Technical Guidance Document do not have to be listed on this form. Note: If your facility is in the RECLAIM program, it is not necessary to repeat any equipment currently listed in Appendix A of the RECLAIM permit.

Section I - Operator Information

1. Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. Check box if facility is in RECLAIM program: ☐

4. Provide Current Permit Issue Date: 12/03/2019

5. Permit Revision No.: 10

Section II - Summary of Equipment Exempt from Permit Requirements (Including Portable)

Exempt Equipment Description [e.g., Small Boilers (75,000 BTU/hr-2,000,000 BTU/hr)]	Venting to Control (Device# or Application#)	Control Device Description	Basis for Exemption [e.g., Rule 219 (b)(2), 05/19/00]	Source Specific Rule [e.g., Rule 1146.2]
Blasting Cabinet < 53 ft3 w/ Filter	N/A	N/A	Rule 219(f)(2)	
Portable Coating Equipment	N/A	N/A	Rule 219(l)(9)	
Air Conditioning Unit	N/A	N/A	Rule 219(d)(1)	
Refrigerant Recycling & Recovery	N/A	N/A	Rule 219(d)(11)	
Cleaning Equipment	N/A	N/A	Rule219(o)	

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South Coast Air Quality Management District

Form 500-F1 (Title V)

Title IV - Acid Rain Phase II Facility Information Summary

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944
Tel: (909) 396-3385
www.aqmd.gov

This form shall be completed by Acid Rain facilities ONLY and shall accompany all requests for Phase II permit actions unique to Acid Rain facilities. Also attach a completed Form 500-A2. In addition, if an initial Title V permit, permit renewal, or permit revision is requested, attach Form 500-A1 and any supplemental Acid Rain forms (Forms 500-F2, 500-F3, and 500-F4), as appropriate.

Section I - General Information

1. Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER & POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

3. ORIS Code (5-Digit): ______

4. This is an application for a (Check all that apply to the facility):

a. ☑ Phase II Acid Rain Permit or Revision (Complete Section II of this form)

b. ☐ Repowering Extension Plan or Revision (Complete Form 500-F2)

c. ☐ New Unit Exemption or Revision (Complete Form 500-F3)

d. ☐ Retired Unit Exemption or Revision (Complete Form 500-F4)

5. The requested permit action involves a(n) (Check one):

a. ○ Administrative Permit Revision

b. ◉ Significant Permit Revision

c. ○ Fast Track Permit Revision

d. ○ Automatic Permit Revision

e. ○ Other (specify): ______

6. For all applications requesting a permit revision, provide a general description of the proposed changes (Attach additional sheets as necessary):

Section II - Phase II Acid Rain Device Summary

1. The following information is (Check one): a. ○ New b. ○ Revised

AQMD Device #	EPA Unit #	Will device need a Repowering Extension Plan?	Has device started operations on or after 11/15/90?	Device Operations Start Date (mo/day/yr)	For devices starting-up after 11/15/90, provide date when Monitoring Certification will begin (mo/day/yr)
TBD	TBD	○ Yes ○ No	○ Yes ○ No		
		○ Yes ○ No	○ Yes ○ No		
		○ Yes ○ No	○ Yes ○ No		
		○ Yes ○ No	○ Yes ○ No		
		○ Yes ○ No	○ Yes ○ No		

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South Coast Air Quality Management District

Form 500-H
Title V - Compliance Assurance Monitoring (CAM) Applicability Determination for Initial, Renewal, & Significant Permit Revision

Mail To:
SCAQMD
P.O. Box 4944
Diamond Bar, CA 91765-0944

Tel: (909) 396-3385
www.aqmd.gov

This form is required as part of an initial, significant permit revision, or renewal Title V application. If your Title V facility has control devices in use, the CAM rule may apply. Follow the instructions on the reverse side of this form to determine whether your facility is subject to CAM requirements.

Section I - Operator Information

1. Facility Name (Business Name of Operator That Appears On Permit): GLENDALE CITY, GLENDALE WATER AND POWER

2. Valid AQMD Facility ID (Available On Permit Or Invoice Issued By AQMD): 800327

Section II - CAM Status Summary for Emission Units

3. Based on the criteria in the instructions (check one and attach additional pages as necessary):

a. ☐ The emission units identified below are subject to the CAM rule[1] and a CAM plan[2] is attached for each affected emissions unit:

b. ☑ There are no emission units with control devices at this Title V facility that are subject to the CAM rule.

Emission Unit[3] (Application, Permit or Device No.)	Equipment Description[4]	Uncontrolled Emissions		Connected to Control Unit[3] (Application, Permit or Device No.)	Equipment Description[4]	Controlled Emissions	
		Pollutant	PTE[5] (tons/year)			Pollutant	PTE[5] (tons/year)

1 For more detailed information regarding the CAM rule applicability, refer to Title 40, Chapter I, Part 64, Section 64.1 of the Code of Federal Regulations (40 CFR Part 64, Section 64.1). This also can be accessed via the internet at: http://www.access.gpo.gov/nara/cfr/waisidx_99/40cfr64_99.html.

2 Only one CAM plan is required for a control device that is common to more than one emissions unit, or if an emissions unit is controlled by more than one control device similar in design and operation. If the control devices are not similar in design and operation, one plan is required for each control device.

3 List all new and existing emission units and the connected control devices either by AQMD application, permit or device number. When the emission unit is new and has not yet been assigned an application number, leave this column blank.

4 Provide a brief equipment description of the emission units and control devices by indicating equipment type, make, and model and serial numbers as appropriate.

5 Potential to Emit

APPENDIX B

FACILITY MAPS AND DIAGRAMS

GLENDALE CITY, GLENDALE WATER & POWER
GRAYSON POWER PLANT REPOWERING PROJECT
800 AIR WAY, GLENDALE, CA 91201

AREA MAP

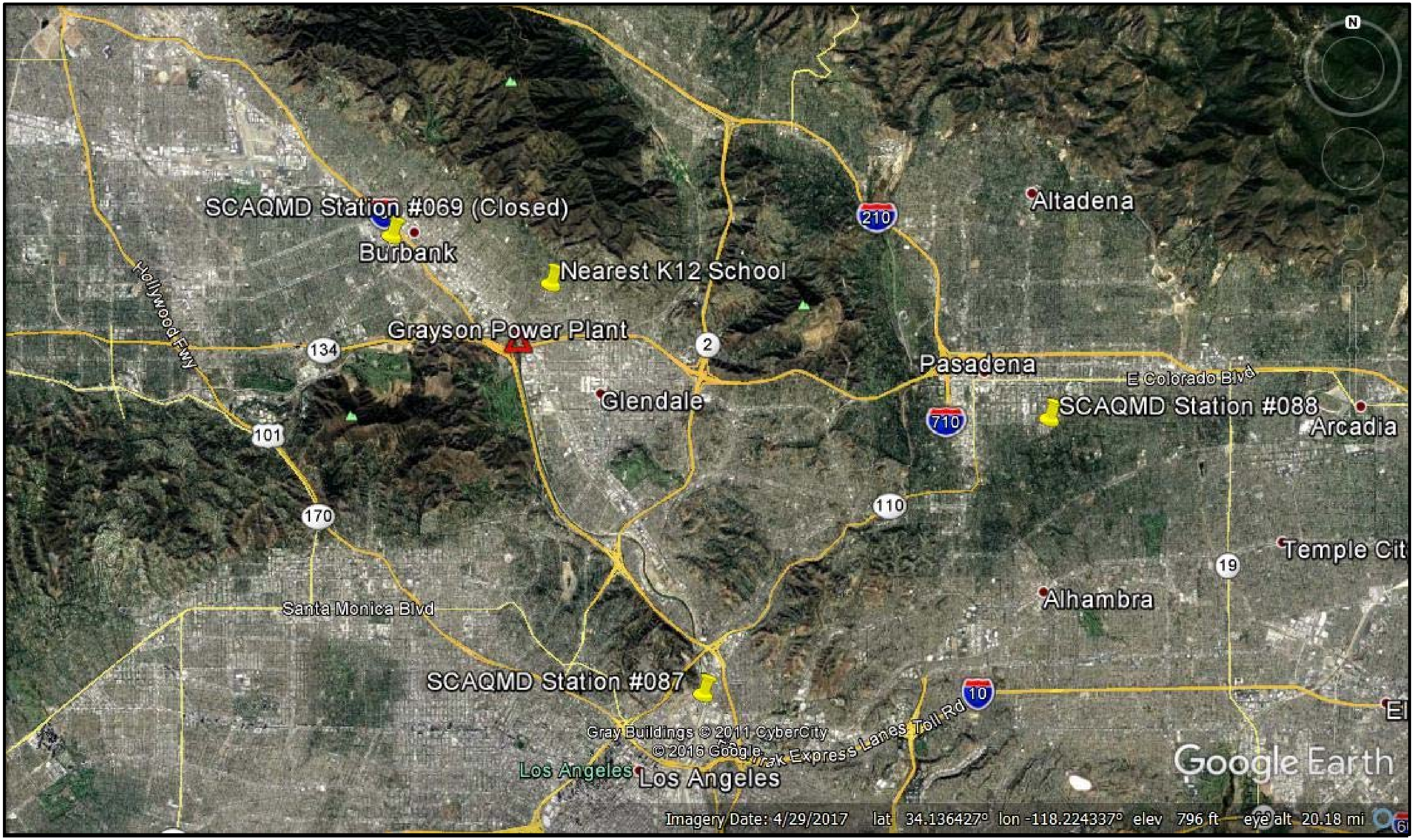
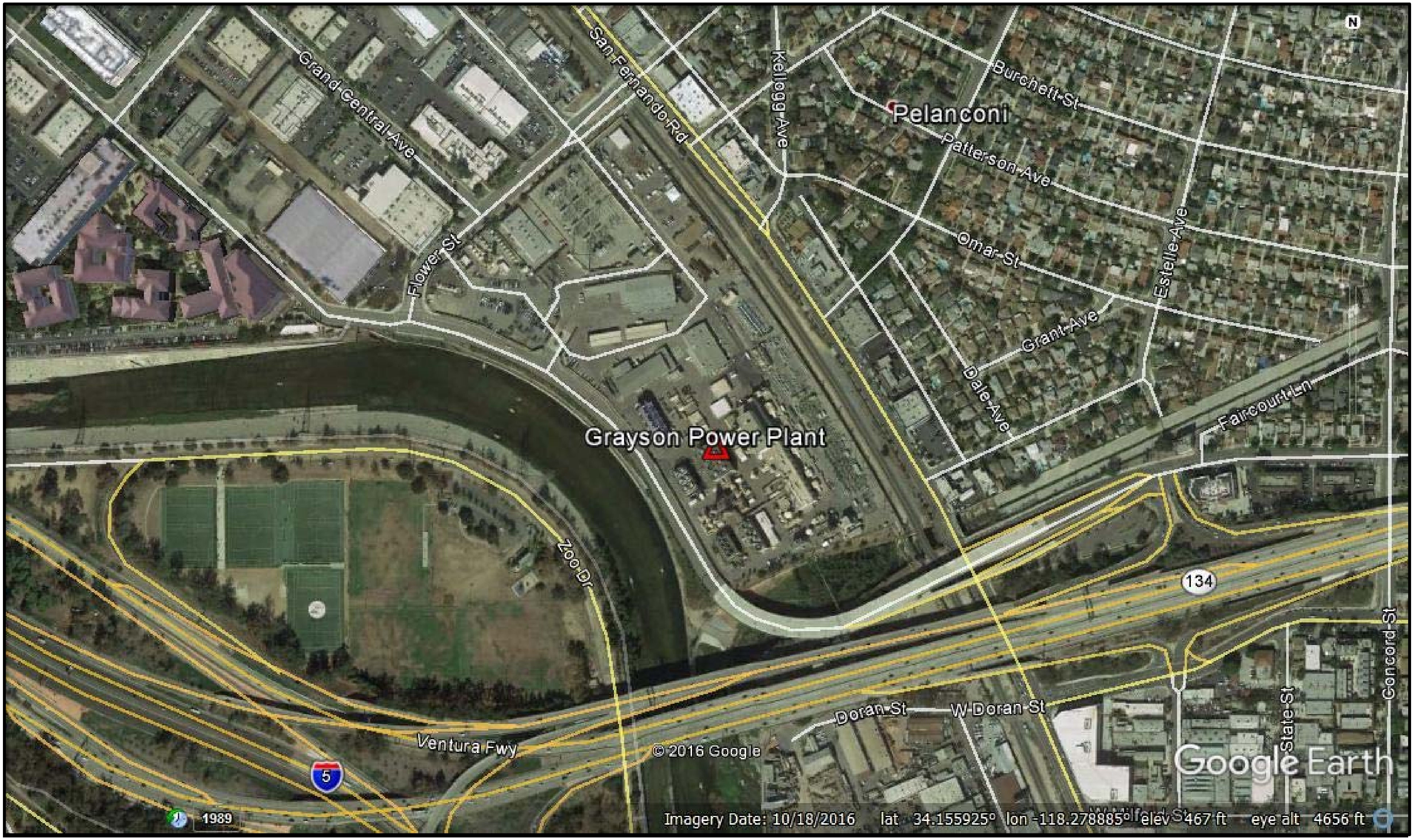


Image courtesy of Google ©2017 (www.google.com)

GLENDALE CITY, GLENDALE WATER & POWER
GRAYSON POWER PLANT REPOWERING PROJECT
800 AIR WAY, GLENDALE, CA 91201

SITE MAP



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APPENDIX C

CRITERIA POLLUTANT EMISSION INVENTORY

Simple Cycle Turbine 8A

Pollutant	No. of Normal Operating Hours per Day	Normal Operating Hour Emission Rate	No. of Startups Per Day	lb / Startup	No. of shutdowns per Day	Lb / Shutdown	Number of Normal Operating Hours Per Month	Number of Normal Operating Hours Per Year	Daily Maximum Emissions (Lbs)	Monthly Maximum Emissions (Lbs)	30-Day Average Emissions (lbs)	Annual PTE (Lbs)	Annual PTE (Tons)
NOx	6.10	3.27	2	15.60	2	3.85	219	1044	58.85	1,202	40.08	5,845	2.92
CO	6.10	19.92	2	84.39	2	2.49	219	1044	295.27	6,534	217.82	31,656	15.83
VOC	6.10	13.91	2	13.91	2	3.48	219	1044	119.63	3,481	116.03	16,695	8.35
PM10/2.5	6.10	0.20	2	0.20	2	0.05	219	1044	1.72	50	1.67	240	0.12
SOx	6.10	0.24	2	0.24	2	0.06	219	1044	2.05	60	1.99	286	0.14

Monthly Op. hours:	250
Annual Op. hours:	1,200
Monthly Operating Load	100%
Annual Operating Load	100%

Max. number of Startups/Shutdown per Day:	2
Max. hours of Startups/Shutdown per Day:	2.50
Max. number of Startups/Shutdowns per Month:	25
Max. hours of Startups/Shutdowns per Month:	31
Number of Startups/Shutdowns per Year:	125
Hours of Startups/Shutdowns per Year:	156

Combined Cycle Turbine 8B or 8C

Pollutant	No. of Normal Operating Hours per Day	Normal Operating Hour Emission Rate	No. of Startups Per Day	lb / Startup	No. of shutdowns per Day	Lb / Shutdown	Number of Normal Operating Hours Per Month	Number of Normal Operating Hours Per Year	Daily Maximum Emissions (Lbs)	Monthly Maximum Emissions (Lbs)	30-Day Average Emissions (lbs)	Annual PTE (Lbs)	Annual PTE (Tons)
NOx	6.10	2.62	2	15.30	2	3.85	200	950	54.28	1,290	43.00	6,319	3.16
CO	6.10	19.92	2	84.39	2	2.49	200	950	295.27	7,459	248.64	36,300	18.15
VOC	6.10	13.91	2	13.91	2	3.48	200	950	119.63	3,478	115.92	16,692	8.35
PM10/2.5	6.10	0.20	2	0.20	2	0.05	200	950	1.72	50	1.67	240	0.12
SOx	6.10	0.24	2	0.24	2	0.06	200	950	2.05	60	1.98	286	0.14

Monthly Op. hours:	250
Annual Op. hours:	1,200
Monthly Operating Load	100%
Annual Operating Load	100%

Max. number of Startups/Shutdown per Day:	2
Max. hours of Startups/Shutdown per Day:	2.50
Number of Startups/Shutdowns per Month:	40
Hours of Startups/Shutdowns per Month:	50
Number of Startups/Shutdowns per Year:	200
Hours of Startups/Shutdowns per Year:	250

Combined daily limit (8ABC)	8.6	MMCF/DAY	Natural Gas HHV:	1050	Btu/scf
Each turbine (8ABC)	2.86667	MMCF/DAY	Dry fuel factor (Fd)	8710	dscf/mmbtu
Each turbine rating:	350	MMBTU/HR			
	0.33333	MMCF/HR			

	POLLUTANT CONCENTRATION (CONTROLLED)										POLLUTANT EMISSION FACTOR (CONTROLLED)				
Equipment Type	NO_X		CO		VOC		PM10/2.5		SO_X		NO_X, LBS/HR	CO, LBS/HR	VOC, LBS/HR	PM10/2.5, LBS/HR	SO_X, LBS/HR
Turbine 8A (Simple cycle)	2.5	PPMV	25	PPMV	13.91	LBS/HR	3.15	LBS/MMCF	0.714	LBS/MMCF	3.27	19.92	13.91	0.20	0.24
Turbine 8B or 8C (Combined Cycle)	2	PPMV	25	PPMV	13.91	LBS/HR	3.15	LBS/MMCF	0.714	LBS/MMCF	2.62	19.92	13.91	0.20	0.24

	STARTUP EMISSION RATE (LBS/EVENT)					SHUTDOWN EMISSION RATE (LBS/EVENT)				
STARTUP/SHUTDOWN RATE	NO_X	CO	VOC	PM10/2.5	SO_X	NO_X	CO	VOC	PM10/2.5	SO_X
Turbine 8A (Simple cycle) Startup: 60 minutes; Shutdown 15 minutes	15.60	84.39	13.91	0.20	0.24	3.85	2.49	3.48	0.05	0.06
Turbine 8B or 8C (Combined Cycle) Startup: 60 minutes; Shutdown 15 minutes	15.30	84.39	13.91	0.20	0.24	3.85	2.49	3.48	0.05	0.06

Startup/Shutdown Schedule	Daily Event	Monthly Event	Annual Event
Turbine 8A (Simple cycle)	2	25	125
Turbine 8B or 8C (Combined Cycle)	2	40	200

Startup schedule (Turbine 8A)	1	hours/event	60	minutes/event
Startup schedule (Turbine 8B or 8C)	1	hours/event	60	minutes/event
Shutdown schedule (Turbine 8A)	0.25	hours/event	15	minutes/event
Shutdown schedule (Turbine 8B or 8C)	0.25	hours/event	15	minutes/event

Operating Schedule	Daily	Monthly	Annual
Turbine 8A (Simple cycle)	8.60	250	1,200
Turbine 8B or 8C (Combined Cycle)	8.60	250	1,200

APPENDIX D

TOXIC AIR CONTAMINANTS EMISSION INVENTORY

TOXIC EMISSION INVENTORY

POST-MODIFICATIONS

Turbine Model	Heat Input, MMBtu/hr	Heat Input, MMCF/hr	Max Annual Hours, hrs/yr
Gas Turbine 8A (Simple Cycle)	350	0.333	1200
Gas Turbine 8B (Combined Cycle)	350	0.333	1200
Gas Turbine 8C (Combined Cycle)	350	0.333	1200
Operating Load	100%		

			Gas Turbine 8A (Simple Cycle)		Gas Turbine 8B (Combined Cycle)		Gas Turbine 8C (Combined Cycle)	
Compound	CAS	Emission Factor[2], lbs/MMCF	Maximum Hourly Emissions, lbs/hr[4]	Maximum Annual, lbs/yr[4]	Maximum Hourly Emissions, lbs/hr[4]	Maximum Annual, lbs/yr[4]	Maximum Hourly Emissions, lbs/hr[4]	Maximum Annual, lbs/yr[4]
Ammonia[1]	766417	7.26	2.42E+00	2.90E+03	2.42E+00	2.90E+03	2.42E+00	2.90E+03
Acetaldehyde	75070	4.08E-02	3.13E-04	3.75E-01	3.13E-04	3.75E-01	3.13E-04	3.75E-01
Acrolein	107028	6.53E-03	5.01E-05	6.01E-02	5.01E-05	6.01E-02	5.01E-05	6.01E-02
Benzene	71432	1.22E-02	9.35E-05	1.12E-01	9.35E-05	1.12E-01	9.35E-05	1.12E-01
Butadiene, 1,3-	106990	4.39E-04	3.37E-06	4.04E-03	3.37E-06	4.04E-03	3.37E-06	4.04E-03
Ethylbenzene	100414	3.26E-02	2.50E-04	3.00E-01	2.50E-04	3.00E-01	2.50E-04	3.00E-01
Formaldehyde	50000	7.24E-01	5.55E-03	6.66E+00	5.55E-03	6.66E+00	5.55E-03	6.66E+00
Naphthalene	91203	1.33E-03	1.02E-05	1.22E-02	1.02E-05	1.22E-02	1.02E-05	1.22E-02
PAHS (excluding naphthalene)[3]	1151	9.18E-04	7.04E-06	8.45E-03	7.04E-06	8.45E-03	7.04E-06	8.45E-03
Propylene Oxide	75569	2.96E-02	2.27E-04	2.72E-01	2.27E-04	2.72E-01	2.27E-04	2.72E-01
Toluene	108883	1.33E-01	1.02E-03	1.22E+00	1.02E-03	1.22E+00	1.02E-03	1.22E+00
Xylenes	1330207	6.53E-02	5.01E-04	6.01E-01	5.01E-04	6.01E-01	5.01E-04	6.01E-01

Note:

[1] Ammonia hourly emission factor is estimated based on concentration limit of 5 ppmv at 15%O2.
[2] Emission factors are based on the SCAQMD Supplemental Instruction for AB2588 Facilities for Reporting Quadrennial Air Toxics Emission Inventory, dated June 2020.
[3] Emission factors for PAHS excluding naphthalene are based on the SCAQMD Supplemental Instruction for AB2588 Facilities for Reporting Quadrennial Air Toxics Emission Inventory, dated December 2016.
[4] Turbine 8A, 8B, and 8C will be equipped with oxidation catalyst. The control efficinecy of oxidation catalyst for organic TACs is 97.7% based on Rule 1401 calculator. Therefore, this control efficiency is applied to all TACs, except ammonia.

PRE-MODIFICATIONS

Turbine Model	Heat Input, MMBtu/hr	Heat Input, MMCF/hr	Max Annual Hours, hrs/yr
Gas Turbine 8A (Simple Cycle)	350	0.333	8760
Gas Turbine 8B (Combined Cycle)	350	0.333	8760
Gas Turbine 8C (Combined Cycle)	350	0.333	8760
Operating Load	100%		

			Gas Turbine 8A (Simple Cycle)		Gas Turbine 8B (Combined Cycle)		Gas Turbine 8C (Combined Cycle)	
Compound	CAS	Emission Factor[2], lbs/MMCF	Maximum Hourly Emissions, lbs/hr	Maximum Annual, lbs/yr	Maximum Hourly Emissions, lbs/hr	Maximum Annual, lbs/yr	Maximum Hourly Emissions, lbs/hr	Maximum Annual, lbs/yr
Ammonia[1]	766417	7.26	2.42E+00	2.12E+04	2.42E+00	2.12E+04	2.42E+00	2.12E+04
Acetaldehyde	75070	4.08E-02	3.13E-04	2.74E+00	3.13E-04	2.74E+00	3.13E-04	2.74E+00
Acrolein	107028	6.53E-03	5.01E-05	4.39E-01	5.01E-05	4.39E-01	5.01E-05	4.39E-01
Benzene	71432	1.22E-02	9.35E-05	8.19E-01	9.35E-05	8.19E-01	9.35E-05	8.19E-01
Butadiene, 1,3-	106990	4.39E-04	3.37E-06	2.95E-02	3.37E-06	2.95E-02	3.37E-06	2.95E-02
Ethylbenzene	100414	3.26E-02	2.50E-04	2.19E+00	2.50E-04	2.19E+00	2.50E-04	2.19E+00
Formaldehyde	50000	7.24E-01	5.55E-03	4.86E+01	5.55E-03	4.86E+01	5.55E-03	4.86E+01
Naphthalene	91203	1.33E-03	1.02E-05	8.93E-02	1.02E-05	8.93E-02	1.02E-05	8.93E-02
PAHS (excluding naphthalene)[3]	1151	9.18E-04	7.04E-06	6.17E-02	7.04E-06	6.17E-02	7.04E-06	6.17E-02
Propylene Oxide	75569	2.96E-02	2.27E-04	1.99E+00	2.27E-04	1.99E+00	2.27E-04	1.99E+00
Toluene	108883	1.33E-01	1.02E-03	8.93E+00	1.02E-03	8.93E+00	1.02E-03	8.93E+00
Xylenes	1330207	6.53E-02	5.01E-04	4.39E+00	5.01E-04	4.39E+00	5.01E-04	4.39E+00

NET EMISSIONS

			Post Modifications		Pre-Modifications		Net Emissions	
Compound	CAS	Emission Factor, lbs/MMBtu	Maximum Hourly Emissions, lbs/hr	Maximum Annual, lbs/yr	Maximum Hourly Emissions, lbs/hr	Maximum Annual, lbs/yr	Maximum Hourly Emissions, lbs/hr	Maximum Annual, lbs/yr
Ammonia	766417	5 ppm	7.3	8.71E+03	7.3	6.36E+04	0.00E+00	-5.49E+04
Acetaldehyde	75070	1.76E-04	9.38E-04	1.13E+00	9.38E-04	8.22E+00	0.00E+00	-7.09E+00
Acrolein	107028	3.62E-06	1.50E-04	1.80E-01	1.50E-04	1.32E+00	0.00E+00	-1.14E+00
Benzene	71432	3.26E-06	2.81E-04	3.37E-01	2.81E-04	2.46E+00	0.00E+00	-2.12E+00
Butadiene, 1,3-	106990	4.30E-07	1.01E-05	1.21E-02	1.01E-05	8.84E-02	0.00E+00	-7.63E-02
Ethylbenzene	100414	3.20E-05	7.50E-04	9.00E-01	7.50E-04	6.57E+00	0.00E+00	-5.67E+00
Formaldehyde	50000	3.60E-04	1.67E-02	2.00E+01	1.67E-02	1.46E+02	0.00E+00	-1.26E+02
Naphthalene	91203	1.30E-06	3.06E-05	3.67E-02	3.06E-05	2.68E-01	0.00E+00	-2.31E-01
PAHS (excluding naphthalene)	1151	4.50E-07	2.11E-05	2.53E-02	2.11E-05	1.85E-01	0.00E+00	-1.60E-01
Propylene Oxide	75569	2.90E-05	6.81E-04	8.17E-01	6.81E-04	5.96E+00	0.00E+00	-5.15E+00
Toluene	108883	1.30E-04	3.06E-03	3.67E+00	3.06E-03	2.68E+01	0.00E+00	-2.31E+01
Xylenes	1330207	6.40E-05	1.50E-03	1.80E+00	1.50E-03	1.32E+01	0.00E+00	-1.14E+01

ATTACHMENT H RESPONSE TO COUNCILMEMBER BROTMAN DATED DECEMBER 15, 2021

December 15, 2021, Response to Councilmember Brotman

Glossary of Terms

B&V	Black & Veatch
BESS	Battery Energy Storage System
CO	Carbon Monoxide
CO2	Carbon Dioxide
COSA	Cost of Service Analysis
DER	Distributed Energy Resources
DR	Demand Response
EE	Energy Efficiency
EPA	Environmental Protection Agency
FIT	Feed-In-Tariff
GWP	Glendale Water and Power
IRP	Integrated Resource Plan
LNTP	Limited Notice to Proceed
MW	Megawatt(s)
MWH	Megawatt-Hour(s)
NEM	Net Energy Metering
SCAQMD	South Coast Air Quality Management District
SCR	Selective Catalytic Reduction
STS	Southern Transmission System
TOU	Time of Use
VPP	Virtual Power Plant

On the need for 5 RICE units

- **The big question is why GWP is still recommending the same/similar mix of thermal, BESS and DERs as it did in 2019 [IRP] even though there have been some important developments that were not part of the original modeling? These include (i) 25MW of solar/storage from Eland in 2024 coming with new, albeit limited, transmission rights, (ii) 73MW of new transmission on the STS line starting in 2027, (iii) an increase in the Sunrun VPP from 13MW to 25MW.**

  Response

  Post-2027 GWP needs ~570 MW to serve load and meet contingency requirements. Even with inclusion of solar power from Eland, the additional transmission capacity that becomes available, and local virtual power plant and demand response/energy efficiency, GWP still will not have enough resources.

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The table below illustrates whether GWP will be able to meet reliability criteria based upon GWP's historic and forecasted peak power demand (peak load) with and without repowering the Grayson Power Plant.

- The "Presumed Non-Thermal Resources" are the expected power from clean resources that will be available both via transmission lines and from local renewable energy, energy storage, energy efficiency, and demand response. Transmission assets are included in the "Presumed Non-Thermal Resources" because, even though today the resources which are imported over the transmission system are a mix of thermal and carbon-free resources, imported generation resources will transition to 100% carbon-free over time.
- Existing local solar/energy efficiency/demand response resources whose development GWP has supported over the past 20 years are not explicitly shown as they are already in use and past peak loads reflect their contribution.
- New local solar/energy efficiency/demand response resources are treated as a generation resource. Behind the meter solar, energy efficiency, and demand response all reduce load; however the effect is the same whether it is added on the generation side or subtracted on the load side.

The calculation shows that without repowering the Grayson Power Plant (but still relying on 50 MW of local new DER/VPP, 75 MW of BESS, Magnolia and Unit 9), GWP cannot meet peak load until 2027 when an additional 72 MW of transmission becomes available. After 2027, GWP can meet the City's peak load, but will not be able to meet all contingency reserve requirements without repowering Grayson. Note that while the table indicates Alternative 7 and 8 are only operating for contingency events, they could also run in place of Unit 9 or Magnolia which are relied upon to meet peak load in the following table. Similarly, if the Tesla batteries are discharged or not available, the thermal generation from Alternative 7 or 8 would operate in their place.

Item	All values are in MW	2024	2027
Presumed Non-Thermal Resources			
1A	Existing Transmission (100 MW Pacific DC, 112 MW Southwest Transmission System)	212	212
1B	Post-2027 Transmission Addition on Southwest Transmission System	0	72
1C	Reduction due to transmission losses on Southwest Transmission System (losses are 5.6%)	-12	-16
1D	Eland I Solar and Storage Project (the full 25 MW capacity was assumed for this analysis, actual performance may be less)	0	25
1E	Local new DER/VPP (Franklin, Willdan, and Sunrun from the Clean Energy RFP, plus future additional programs). There are limits as to time of day and/or number of times these resources can be called upon.	0	50

1F	BESS contribution for peak load. This is a 4-hour resource and some energy capacity must be reserved to provide sufficient spinning reserve. This table assumes that the full 75 MW/300 MWH of BESS capacity will be installed earlier than the IRP contemplated, as the IRP contemplated that the 93 MW of Wartsila engines would be available.	0	75
1G	Scholl Canyon BioGas	0	11
1T	**Total of Presumed Non-Thermal Resources**	**200**	**429**
Remaining Thermal Resources (Assumes Units 1-8 Retired)			
2A	Magnolia (summer net)	35	35
2B	Unit 9	48	48
2T	**Total of Thermal Resources**	**83**	**83**
3	Alternative 7 Repower	0	93
4	Alternative 8 Repower	0	101
	Grayson Generation to be Retired	214	0
Available Resources Summary			
Line 1T, above (transmission imports plus local green)		200	429
Lines 1T + 2T (adds remaining thermal)		283	512
Lines 1T + 2T + 3 (adds Alternative 7)		283	605
Lines 1T + 2T + 4 (adds Alternative 8)		283	613

How Much Generating Capacity Must be Provided?			
5	**Historical Peak Load and Forecasted Peak Load from IRP (the value of 346 MW is a historical peak; the value of 398 MW was interpolated from the values published in the IRP[1])**	**346**	**398**
Contingency Requirements N-1 = based on the capacity of the largest resource N-1-1 = based on the capacity of second largest resource			
6A	N-1 (loss of 100 MW of transmission)	100	100
6B	N-1-1 (No Repower)	48	64
6C	N-1-1 (Alternative 7) • loss of 48 MW from Unit 9 through 2026 • loss of 64 MW of Southwest Transmission System post-2027	48	64

[1] Note that the IRP did not include a forecast for building electrification load. With that inclusion, the predicted load of 398 MW may be higher.

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How Much Generating Capacity Must be Provided?			
	• Due to the modular design and redundancies within the control system, the 75 MW BESS creates contingencies that are smaller than the ones shown here		
6D	N-1-1 (Alternative 8) • loss of 48 MW from Unit 9 through 2026 • loss of 75 MW from Unit 8BC post-2027	48	75
Required Resources Summary			
Lines 5 + 6A (peak plus N-1 contingency with no repower)		446	498
Lines 5 + 6A + 6B (peak plus contingencies with no repower)		494	562
Lines 5 + 6A + 6C (peak plus contingencies with Alternative 7)		494	562
Lines 5 + 6A + 6C (peak plus contingencies with Alternative 8)		494	573

Are Reliability Criteria Met (Are Available Resources > Required Resources)?		
Grayson Units 1-8 Shut Down, Existing and Forecast Resources with Peak Load and No Contingencies		
Are Presumed Non-Thermal Resources greater than Peak Load? [Is 1T > 5?] [Is 200>346?] [Is 429>398?]	No	Yes
Are Presumed Non-Thermal + Remaining Thermal Resources greater than Peak Load? [Is (1T+2T) > 5?] [Is 283>346?] [Is 512>398?]	No	Yes
Grayson Units 1-8 Shut Down, Existing and Forecast Resources with Peak Load and Contingencies		
Are Presumed Non-Thermal + Remaining Thermal Resources greater than Peak Load + N-1 Contingency Requirements? [Is (1T+2T)>(5+6A)?] [Is 283>446?] [Is 512>498?]	No	Yes[2]
Are Presumed Non-Thermal + Remaining Thermal Resources greater than Peak Load + (N-1) + (N-1-1) Contingency Requirements? [Is (1T+2T)>(5+6A+6B)?] [Is 283>494?] [Is 512>562?]	No	No
Alternative 7 or 8, Existing and Forecast Resources		

[2] Note that there is a 14 MW margin which does not include a forecast for building electrification and is relying on the full output of Eland (the solar peak and load peak are not coincident), the full 50 MW of DER/VPP (that 100% is available and fully responds), and the full 75 MW from the BESS is available. Thus, the 14 MW margin (3%) may not be as large as indicated.

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Are Reliability Criteria Met (Are Available Resources > Required Resources)?		
with Peak Load and Contingencies		
Are Presumed Non-Thermal + Remaining Thermal Resources + Alternative 7 greater than Peak Load + (N-1) Contingency Requirements? [Is (1T+2T+3)>(5+6A)?] [Is 605>498?]	N/A	Yes
Are Presumed Non-Thermal + Remaining Thermal Resources + Alternative 7 greater than Peak Load + (N-1) + (N-1-1) Contingency Requirements? [Is (1T+2T+3)>(5+6A+6C)?] [Is 605>562?]	N/A	Yes
Are Presumed Non-Thermal + Remaining Thermal Resources + Alternative 8 greater than Peak Load + (N-1) + (N-1-1) Contingency Requirements? [Is (1T+2T+4)>(5+6A)?] [Is 613>498?]	N/A	Yes
Are Presumed Non-Thermal + Remaining Thermal Resources + Alternative 8 greater than Peak Load + (N-1) + (N-1-1) Contingency Requirements? [Is (1T+2T+4)>(5+6A+6D)?] [Is 613>573?]	N/A	Yes

- **What's the potential for commercial solar/storage through a Commercial VPP or FiT program? Ascend plugged 20MW into the 2030 Plan, but if we did something along the lines of LADWP's FiT we would be looking at closer to 25MW. Why isn't this factored into the model for determining the thermal-BESS-DER mix?**

  Increasing 20MW to 25MW will decrease the number of MWHs generated from the thermal units but wouldn't reduce the required capacity. Contingency requirement is based on the PDCI and STS lines.

- **The 2019 IRP assumed 10MW of solar/storage on City sites. What's the current expectation based on projects we're working on today and any other available sites?**

  GWP is working on getting at least 10 MW of solar on City sites as planned. Glendale engaged with Black and Veatch (B&V) to conduct a study to identify potential sites. The study deliverables include technical specifications, solar capacities, and cost estimates for the sites that are deemed viable for solar. This "master list" of specifications will then be used to bid each site for the construction of solar. GWP anticipates having the master list available by Q1 2022. B&V started with an initial list of 101 sites which has been reduced to 77 potential sites. These sites are still being vetted.

- **The 2019 IRP assumed 28MW of residential/commercial EE and DR. What's the current expectation based on the programs with Willdan and Franklin? How much more could we do in EE**

and DR if we went at this harder (e.g., DR programs for other appliances, including EV charging, EE and DR for our largest customers, etc.)?

GWP requested that each of the Clean Energy vendors provide "stretch" numbers for the maximum amount of clean energy capacity they could offer. The maximum energy efficiency capacity that Willdan is able to guarantee is 8.32MW by the 7th year of the program implementation. The maximum amount of demand response capacity that Franklin is able to guarantee is 10MW of DR by the 4th year of the program. If the 10 MW are achieved there is an option for GWP to purchase an additional 1 MW of demand response capacity from Franklin during the four-year contract term. Largest customers are eligible for both of these programs (as well as other GWP programs) and are already taken into account. GWP will continue to develop and implement more EE and DR programs, and will continue to explore new and innovative ways to reduce demand and increase energy efficiency. We will always aim higher. However, 28 MW of EE/DR is an extremely aggressive plan that puts GWP at the forefront among other utilities. For planning and reliability purposes, it would not be prudent to count on more than 28 MW of projected EE/ DR growth.

- **Are we doing anything for people who already have solar that want batteries and are willing to allow GWP to control them? I thought I remember Craig talking about this.**

  The City has executed a contract with Shpigler Consulting to assist GWP in three phases (assessment, requirements and procurement) to move towards the implementation of not only residential energy storage program but commercial solar + energy storage program as well. The scope of work includes preparation of RFP, vendor selection and coming up with incentive programs for customers. The project is expected to commence in Q1 2022.

Costs of Alternatives 7 and 8

- **I'd like to see estimated costs for the two alternatives asap, disaggregated as much as possible to break out equipment costs, site prep and engineering costs; etc.; it's fine if they are rough figures now—I won't hold you to them.**

  Response

  - Due to ongoing pricing and contract negotiations with proposed vendors, pricing information is not included in the public version of this report. The bulk of the Alternative 7 project cost is associated with the Tesla and Wartsila power islands, and for Alternative 8, the refurbishment costs. The current estimate for Alternative 7 is $390 million and for Alternative 8, the current estimate is $330 million. These estimates do not include the cost of the Glendale Switching Station.

- **I'd also like to know the assumptions we're making for cost of carbon, gas prices, and equipment depreciation.**

  On the cost of carbon, we have assumed a carbon cost of $96/ton of CO_2. This includes the EPA's social cost of carbon at $58/ton. For natural gas prices, GWP used a forward looking price of approximately $3.68/MMBTU for the COSA modeling in November 2021. It's expected that both Alternatives 7 and 8 will be depreciated over 25 years.

Permitting & Run Time Protocols

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- **If you have any thoughts on how to lay out operating protocols for our thermal assets that make them a last resort resource, only used if we cannot otherwise meet load with imports, stored energy or DERs, I'd love to see that.**

  Response

  GWP's dispatch strategy already utilizes the following dispatch order which dispatches thermal generation only when needed. Energy efficiency is presumed to always be engaged and to have already somewhat reduced the load.

  GWP would rely first upon transmission imports and local renewable (rooftop solar) generation.

  In the event that transmission imports and local renewable generation were not sufficient, then demand response would then be considered with recognition that demand response can only be called upon a limited number of times per year. Additionally, frequent calls for demand response could lead participants to opt out as they are allowed to do.

  Energy from the BESS could be called upon subject to maintaining sufficient spinning reserve to meet reliability requirements and consideration of the forecasted power/energy demand for the remainder of the day. The alternative of fully committing the BESS to serve load would necessitate starting a thermal unit to provide spinning reserve.

  If the above was not sufficient, then GWP would need to call upon local thermal resources (currently thermal resources are sometimes run in anticipation of their need due to lengthy startup times. With either alternative and their ten minute start capability, thermal resources will only be started when required).

COSA

- **We didn't talk about this but I'd like to know when I will get to weigh in, formally or informally, on elements of the COSA, such as a FiT program, changes to NEM (which make me very nervous!), TOU rates, etc.**

  GWP's consultant is finalizing the cost of service analysis. GWP plans to agendize a City Council meeting or study session to present the cost of service results and seek City Council direction regarding rate development in early 2022. As part of GWP's presentation of the COSA to the City Council, the City Council may provide direction regarding Feed-In-Tariff, Net Energy Metering, and Time of Use rates.

AQMD Rule 1135

- **My notes on this weren't the best. Can you explain again why the permit application we put in doesn't satisfy the July 1, 2022 requirements?**

  Response

  The air permit application for Alternative 7 was only to add the new Wartsila units and removal of the existing Units 1-8.

  The air permit application for Alternative 8 was to: convert Unit 8A to simple cycle and while keeping Unit 8BC a combined cycle unit and replace the heat recovery steam generator with a once through boiler (to allow 10 minute starts on the gas turbine as well as simple cycle operation if the steam plant is not needed or unavailable); and remove Units 1-5.

  If neither Alternative is approved and the City desires to keep any/all of the Units, a new permit application would be needed to identify: 1) which Units are being retained, and 2) what modifications would be made to bring the Units into compliance with Rule 1135 by end of 2023. Additionally, based upon the current regulation, the application to address reducing Unit 9's permitted emissions to the Rule 1135 levels still needs to be prepared and submitted by June 30, 2022. However, the SCAQMD recently informed Glendale that the SCAQMD staff will be proposing an amendment to the regulation allowing Glendale until January 1, 2023 to submit its application. The proposed change in the application deadline will be considered by the SCAQMD Board in early January 2022. It should be noted that if that change is adopted, the change would only shift the deadline for Glendale to file its permit application with the SCAQMD. The December 31, 2023 deadline to bring the units into compliance would not change.

Bringing Units 8ABC into compliance with Rule 1135 is expected to require:

1. Replacing the SCR and SCR/CO catalyst in both heat recovery steam generators;
2. Changing out the Continuous Emissions Monitoring Systems analyzers to analyzers that can measure lower levels of emissions;
3. Adding electric boilers for steam turbines 1 and 2. The electric boilers are needed to provide steam to maintain the steam turbine steam seals and condenser vacuum for startup purposes. The electric boilers would also keep the steam turbines warm so Unit 8A and/or 8BC could startup within 2 hours. The electric auxiliary boiler is required since the existing boilers, which currently provide the necessary steam for startup of the combined cycle units, would not meet Rule 1135 requirements starting January 1, 2024.
4. Adding a condenser steam bypass system to support startup of the units during the time that the heat recovery steam generator steam outlet conditions are not up to pressure and temperature for the steam turbines.

In conjunction with these modifications, it would also be desirable to replace the control system and portions of the electrical system due to their age.

The above recommendations for Units 8A and 8BC modifications are subject to further study, discussions with vendors on their willingness to offer performance guarantees, and analysis of SCAQMD rules.

1. **What exactly is required to satisfy the deadline, what have we already done, and what do we still need to do?**

   <u>Response</u>

   As discussed above, we need to determine what the plan is for Units 1-5 and 8A and 8BC. If the City Council does not proceed with the project or a project alternative, GWP presumes Units 1-5 would be retired and Units 8A and 8BC retained. No engineering work has been performed to date to study this option. Some engineering work would be needed to scope the required upgrades, work with vendors, and support development of the application to SCAQMD for Units 8A, 8BC, and 9.

   Alternative 8 contemplates converting Unit 8A to simple cycle and keeping Unit 8BC as a combined cycle unit but replacing the existing heat recovery steam generator with a once-through boiler. If those changes are not made and the existing heat recovery steam generator is retained, the stack exit location, height, and mass flow would be different from Alternative 8, and thus new air modeling and health risk assessment may be needed.

   Note that if the decision is to still convert Unit 8A to simple cycle and replace the Unit 8BC heat recovery steam generator with a once-through boiler, that may also necessitate replacing the steam turbine due to the differences in outlet steam pressure and temperature conditions.

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2. **How long do you need to prepare and submit the parts of the application that aren't already complete once you get the Council's direction on the project?**

   Response

   If City Council elects to proceed with the project or either Alternative 7 or Alternative 8, GWP will only need to submit an application to address reducing Unit 9's permitted emissions to the Rule 1135 levels. It is expected that it will take GWP 1-2 months to prepare the application and SCAQMD 6-9 months to process the application.

   If the City Council does not approve the project or Alternative 7 or Alternative 8, GWP would need to submit an application not only for Unit 9, but also to modify Units 8A and 8BC to comply with Rule 1135.

   At this time, we expect it would take six months to: 1) work with potential vendors and confirm the feasibility of upgrading the existing Units 8A and 8BC heat recovery steam generator emissions control systems, and their willingness to guarantee the required emissions performance, 2) develop project work scope and cost estimates, 3) perform required air modeling and prepare the application, 4) obtain City approvals, and 5) submit the application to SCAQMD.

   For Unit 9 the work to prepare the application can proceed more quickly as all that should be required are tuning changes within the emissions control system to increase ammonia injection rates as well as possible changes to the water injection flows.

3. **Can the application be modified after July 1 (e.g., if there are changes to the number of gas-burning units) without being out of compliance with the deadline?**

   Response

   Yes, any of the applications could be modified after the application deadline but doing so will delay permit issuance and subsequent activities. While demolition could begin without an air permit, construction (beginning with excavation for foundations) or modification to existing equipment cannot begin without an issued air permit.

   If Alternative 7 is selected by the City, and the City subsequently choses to build fewer units, that could be done without a permit change as long as the starts and operating hours for the remaining units are not changed (e.g., the starts and operating hours associated with the units not being built cannot be transferred to the units being built without a modification to the air permit). The total number of starts and operating hours planned for all five units could not be preserved with fewer units without a modification to the air permit.

   If Alternative 8 is selected by the City, and the City subsequently chooses not to permit Unit 8A or Unit 8BC, the process would be similar to that outlined immediately above for Alternative 7.

   If the Proposed Project or any alternative were not selected, the existing air permits would still remain in effect but only until December 31, 2023.