BUREAU OF LAND MANAGEMENT
CENTRAL COAST FIELD OFFICE
RESOURCE MANAGEMENT PLAN AMENDMENT

TECHNICAL SUPPORT DOCUMENT

AIR QUALITY

January 2019

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SECTION 1: BLM PLANNING EFFORT AND DESCRIPTION OF ALTERNATIVES

For the Central Coast Field Office (CCFO)[1], the California State Office initiated the California Oil and Gas Resource Management Plan[2] Amendment (RMPA) in August 2013. In the *Federal Register* notice initiating this planning process, the BLM indicated that it may also use this process to consider amending RMPs for four other field offices in California with oil and gas leasing and development (Bakersfield, Palm Springs–South Coast, Mother Lode, and Ukiah Field Offices).

Planning Area Description

The Planning Area lies within the geographical boundaries of the CCFO. This includes 6.8 million acres of Federal, State, local government, and private lands across all or portions of the following 12 counties in western-central California:

- Alameda
- Contra Costa
- Fresno
- Merced
- Monterey
- San Benito
- San Francisco
- San Joaquin
- San Mateo
- Santa Clara
- Santa Cruz
- Stanislaus

The CCFO manages public land in 11 of these counties; there are currently no BLM-managed public lands within San Francisco County (see Fig. 1-1). Public land parcels vary in size from less than 40 acres to more than 50,000 acres. The most notable holdings are located on the Central Coast at the former Fort Ord military base and in the western San Joaquin Valley.

The BLM considered public comments from scoping, the reports by the California Council on Science and Technology, and an internal evaluation of the RMPs for the five BLM field offices to determine the proper geographic scope of this RMPA. The Mother Lode and Ukiah field offices were not included in this RMPA because their resources are primarily natural gas with an affected environment and environmental effects that differ substantially from the CCFO. At the time the Court remanded the 2007 Hollister Field Office RMP, the Bakersfield and South Coast RMPs were already under revision. The BLM determined that it was more appropriate to continue with the revised RMPs rather than initiate a new single amendment for all five plans during the active revision process. Because CCFO does have oil development potential, and was not revising its RMP, the BLM determined that the Hollister Field Office (now CCFO) would be the appropriate geographic scope for this particular RMPA.

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[1] Formerly Hollister Field Office (HFO)

[2] Resource Management Plans (RMPs) are land use plans that establish goals and objectives for resource management and guide land management actions, which are based on the principles of multiple use and sustained yield. Over time, decisions on how the land is managed need to be revised or amended to respond to new, intensified, or changed uses on public land, prompting an RMP revision or amendment.

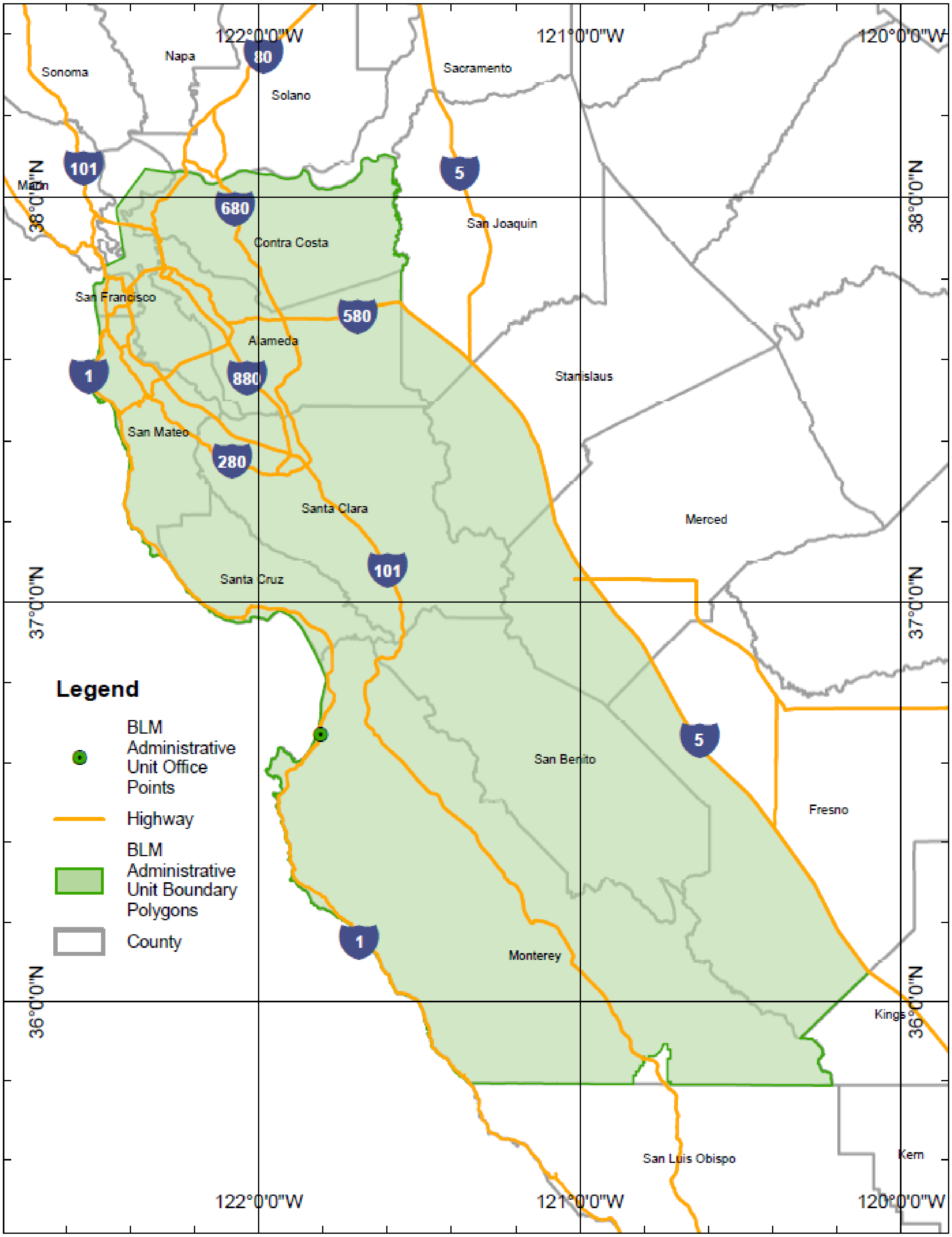

Figure 1-1 Central Coast Field Office boundary, showing counties and major roadways.

Planning Approach

The land use planning process is the key tool used by the BLM to manage resources and to designate and allocate uses on public lands, in coordination with state and local governments, tribal governments, public land users, and interested public. The planning process under which this RMPA is being developed complies with the Federal Land Policy and Management Act of 1976 (FLPMA), the National Environmental Policy Act of 1969 (NEPA), and BLM policies, manuals, and handbooks. Fluid mineral leasing, inclusive of oil and gas, is a resource use for which the RMP makes decisions regarding areas open to leasing, areas open with stipulations (e.g., controlled surface use restrictions, no surface occupancy) or areas that are closed to leasing. In addition, the associated Environmental Impact Statement (EIS; BLM, 2017) completed for the RMPA includes an analysis of a Reasonable Foreseeable Development Scenario (RFDS; Appendix B of BLM, 2017) for oil and gas leasing. The RFDS describes the anticipated level of oil and gas exploration and development from leasing over the next 15-20 years.

Area Profile of Oil and Gas Development Potential

Overall, five major sedimentary basins in California have reservoirs of known economically viable oil and gas resources: the Los Angeles, Ventura, Santa Maria, Salinas, and San Joaquin Basins. Since 2002, well drilling activity in California has largely occurred outside of the CCFO Planning Area. Within the CCFO area, oil and gas activity occurs or has occurred across 35 active oil and gas fields, with a total administrative area of 195,300 acres. Twelve of the 35 active fields intersect the federal mineral estate. The most-productive fields in the area (in order of cumulative past production) are:

Coalinga Oil and Gas Field with Coalinga East Extension Oil and Gas Field; San Ardo Oil and Gas Field; Lynch Canyon Oil and Gas Field; Jacalitos Oil and Gas Field; Kettleman North Dome Oil and Gas Field; and Hollister-Sargent Oil and Gas Field. Nearly all well development since 2002 has occurred in the Coalinga, San Ardo, Lynch Canyon, and Jacalitos fields.

Based on the introduction of hydraulic fracturing technology and other enhanced well stimulation techniques, the BLM amended its 2005 Reasonably Foreseeable Development Scenario. Since 2005, zero (0) new wells have been drilled on public lands in the Central Coast Field Office. As of mid-2014, 65 authorized oil and gas leases on Federal mineral estate lie within the CCFO Decision Area, covering approximately 41,200 acres. Eighty (80) active producing oil and gas and service wells and 66 idle wells are located on Federal mineral estate within the CCFO Planning Area. For reference, see Fig. 1-3 from the Draft RMPA/DEIS (2017), included below. Over 99 percent of the wells in the CCFO Planning Area are located within oil and gas field boundaries, with less than one percent being classified as wildcats (outside administrative field boundaries[3]).

[3] An oil and gas field is a geographical area under which an oil or gas reservoir lies. Oil and gas field boundaries are defined by the California Division of Oil, Gas and Geothermal Resources (DOGGR). Administrative field boundaries are drawn on section or quarter-section lines and incorporate all producing wells within a field.

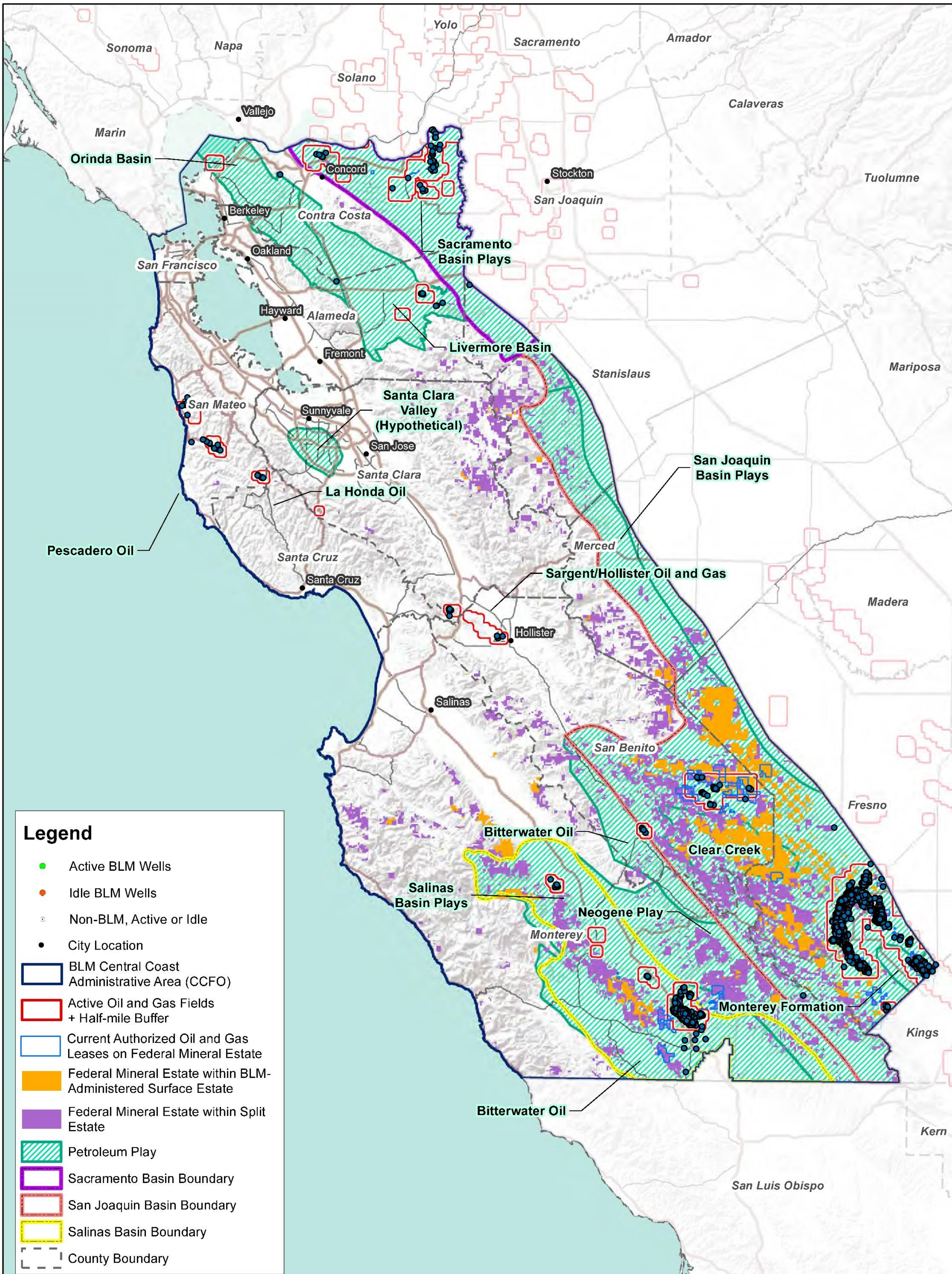

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Figure 1-3

Plays and Active Oil and Gas Wells within the BLM Central Coast Field Office Administrative Area

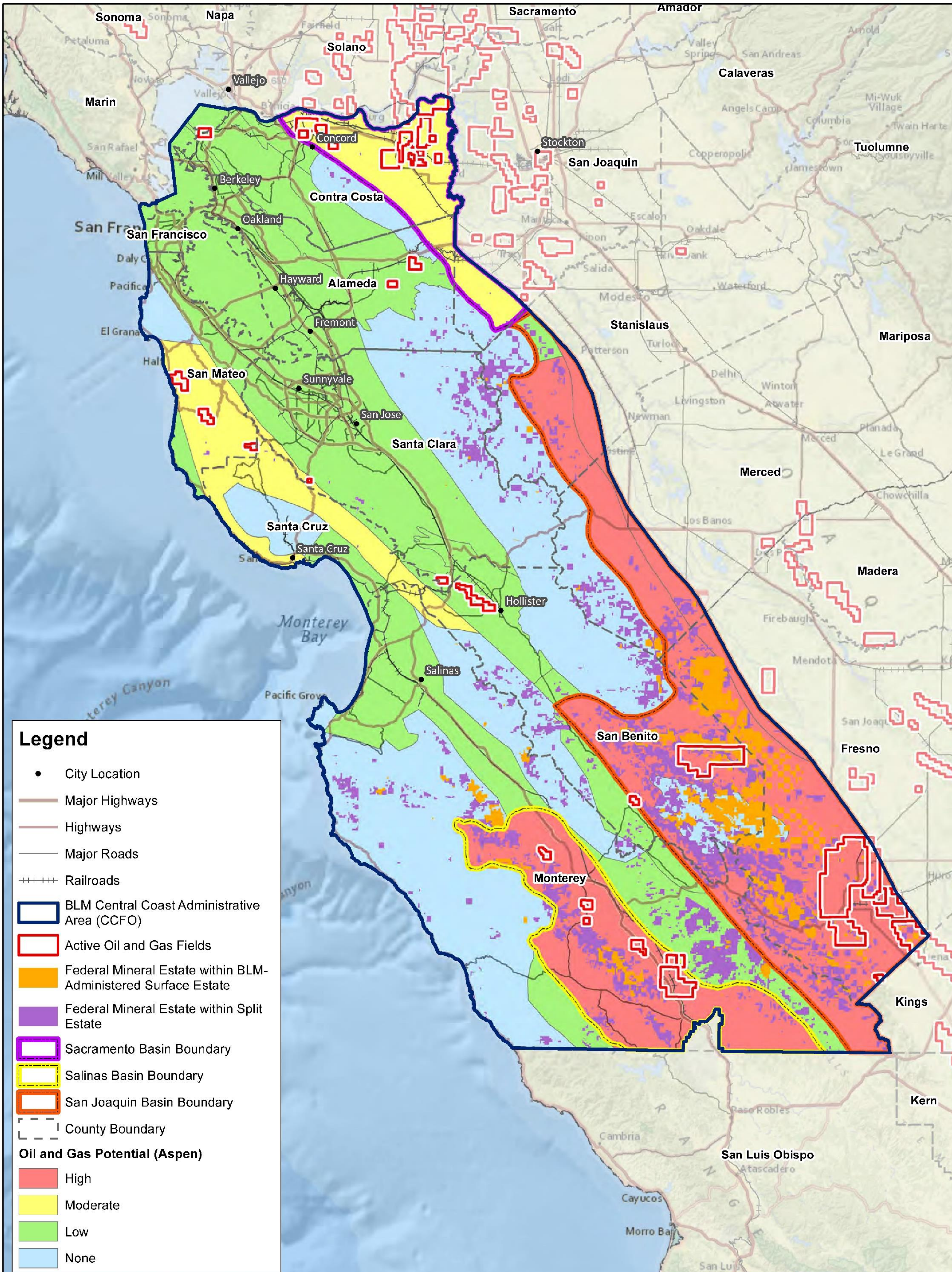
Date: December 2016

While very little new geologic information has been released, based on the activity described above, the BLM now estimates that a total of up to 37 wells would be drilled, and no more than zero to two (0-2) new fields would be developed on federal minerals in the Planning Area, over the life of the RMPA, resulting in temporary or long-term (i.e., greater than 2-3 years, up to several decades or longer) disturbance of up to approximately 206 acres. Roughly half that acreage would be reclaimed on an interim basis, as once the well is drilled and put into production, a large drill pad and access road are no longer needed.

The Decision Area for the RMPA includes approximately 793,000 acres of BLM-administered subsurface mineral estate underlying public lands or split estate lands within the CCFO Planning Area. Split estate refers to lands where an entity or person other than the BLM owns the surface land but the BLM manages the Federal subsurface mineral estate.

Of the total 4,292 producing wells within the CCFO, the 146 wells that occur on Federal authorized leases amount to BLM involvement with 3.4 percent of all current oil and gas activity within the Planning Area.

Oil and gas occurrence potential is presented in the BLM Draft RMPA/DEIS (2017) on Fig. 5-1, as presented below.



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Source: BLM, 2015

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Figure 5-1

Reasonably Foreseeable Oil and Gas Development Potential

Date: December 2016

Description of Alternatives
For this planning effort, six alternatives have been developed based upon public comments and issues identified by the planning team. Each alternative, briefly summarized below, is a separate and distinct resource management plan, and the impacts of management direction for resource and resource uses are analyzed in an accompanying EIS.

The level of oil and gas development described in the RFDS would apply to all six alternatives. Although it would be expected that alternatives with fewer acres open for development would likely have fewer wells, a large majority of the wells expected to be drilled are in areas that remain open in all cases. Trying to differentiate between the various alternatives by projecting 1-3 fewer or more wells in each case would infer a greater degree of certainty than actually exists.

The RFDS estimates that during the life of this plan, between zero and 32 development wells could be expected on Federal mineral estate within existing fields in the CCFO Decision Area and three to five exploratory wildcat wells (wells outside of the administrative boundary of existing oil and gas fields) would be drilled on Federal mineral estate in the CCFO Decision Area. Therefore, given the limited extent of area of Federal mineral estate within the entire Planning Area (approximately 793,000 acres of Federal mineral estate out of 6.8 million acres in the Planning Area), it is unlikely that more than a total of 37 exploratory and development wells will be drilled on existing and/or new Federal oil and gas leases over the next 15 to 20 years. If trends in Hollister are similar to those in the rest of the state where most of the drilling occurs, by far most of the drilling occurs on existing leases, not on new leases. Accordingly, since all leases that currently exist will remain open to new development as long as they have economic production, it's reasonable to expect most of the new development in the CCFO to occur on existing leases, and those wells can be drilled regardless of which alternative is chosen.

Alternative A: No Action Alternative

Council on Environmental Quality (CEQ) regulations at 40 CFR 1502.14(d) (CEQ, 2005) require an EIS to analyze the "No Action" alternative. The No Action is defined as a "no change" from current management direction and will be referred to as "current management" in this document. The existing designations, allowable uses, and management actions contained in the RMP for the Southern Diablo Mountain Range and Central Coast of California (BLM, 2007) would continue to be implemented in their respective areas, unless changed by laws, regulations or policies. Alternative A serves as the baseline when comparing the range of alternatives.

Oil and gas leasing decisions (and restrictions) under Alternative A are depicted in the Draft RMPA/DEIS (2017) on Fig. 2-1, as illustrated below.

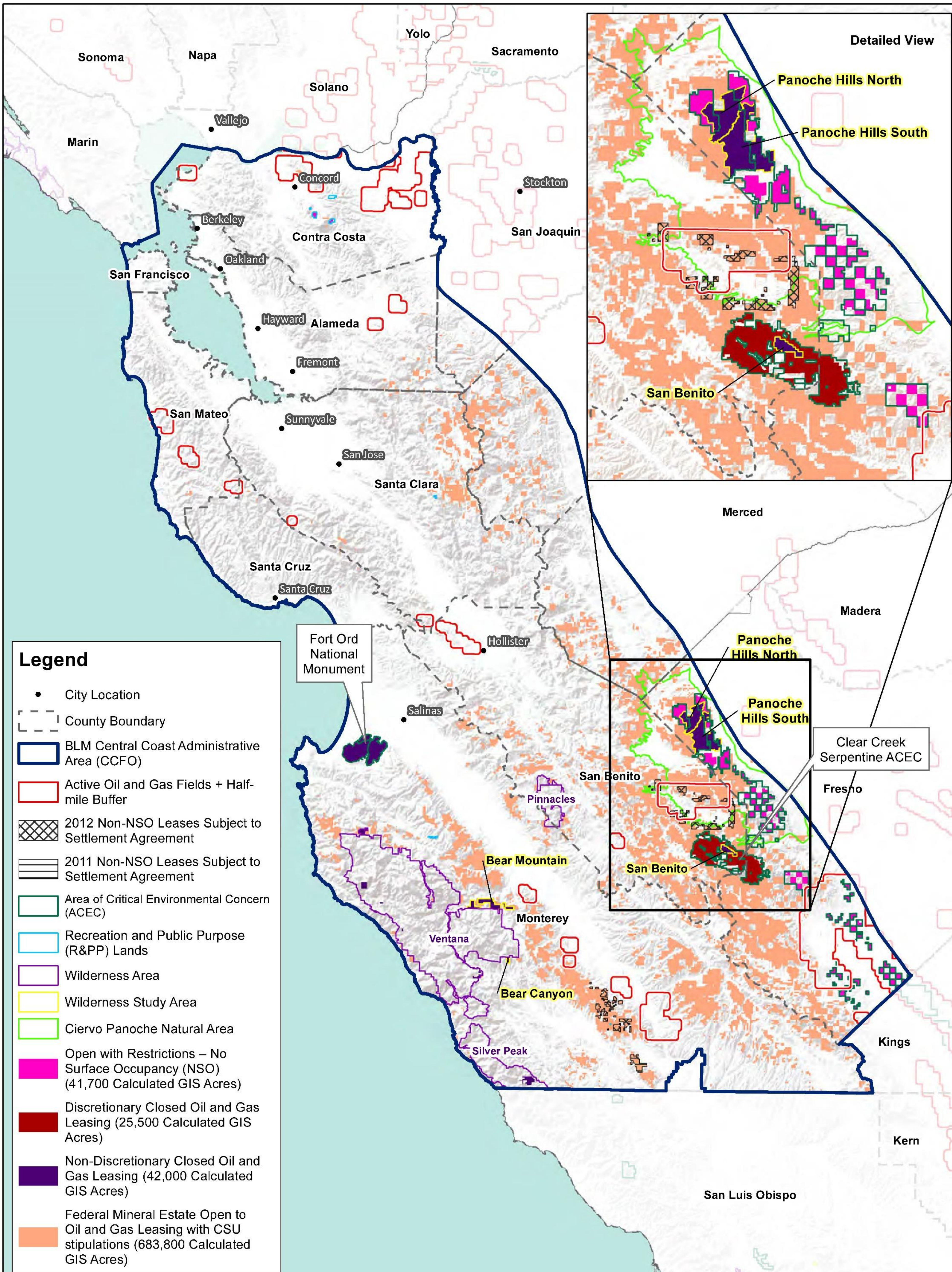

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Figure 2-1

Alternative A
(No Action Alternative)

Date: December 2016

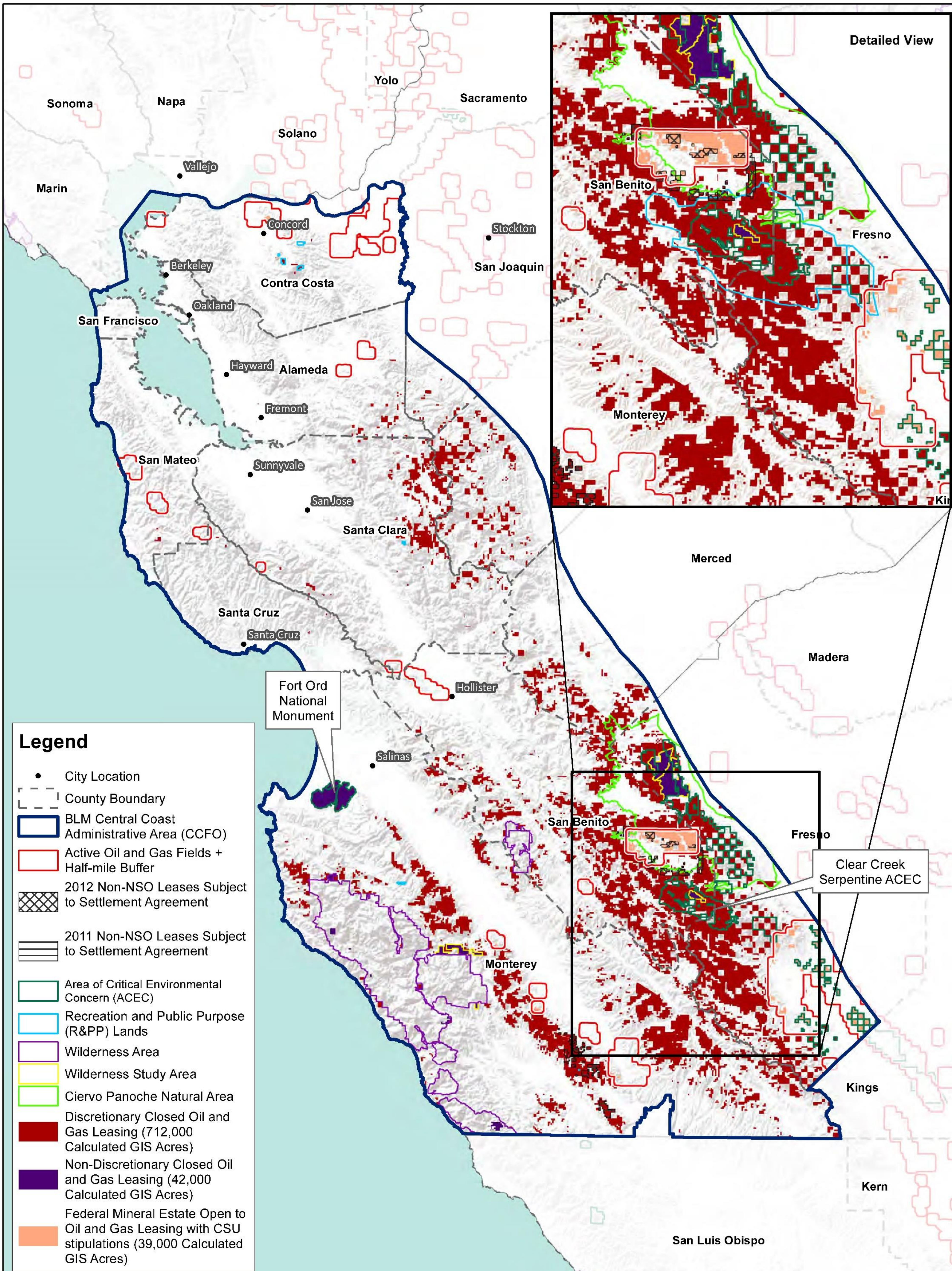
Alternative B

Under Alternative B, Federal mineral estate within the boundaries of oil and gas fields plus a 0.5-mile buffer defined by DOGGR would be available for leasing. Other areas would be closed to oil and gas leasing. For the 15-20 year planning horizon, a total of 0-32 development wells is contemplated for this alternative, mostly on existing leases.

Controlled Surface Use (CSU) stipulations would apply to all lands open to leasing. Under Alternative B, approximately 39,000 acres of BLM oil and gas Federal mineral estate are identified as open to oil and gas leasing with CSU stipulation(s) and 754,000 acres would be closed to leasing.

For additional details on Alternative B, see subsection 2.7.1 of BLM (2017).

Oil and gas leasing decisions (and restrictions) under Alternative B are depicted in the Draft RMPA/DEIS (2017) on Fig. 2-2, as presented below.



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Source: BLM, 2015

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Figure 2-2

Alternative B

Date: December 2016

Alternative C

Under Alternative C, unless currently closed under the 2007 Hollister Field Office RMP, Federal mineral estate would be open to leasing within high oil and gas occurrence potential areas or within the boundaries of oil and gas fields plus a 0.5-mile buffer currently identified by DOGGR, with the exception of core population areas of the giant kangaroo rat in the vicinity of Panoche, Griswold, Tumey, and Ciervo Hills, which are closed to leasing.

CSU stipulations would apply to all lands open to leasing. No Surface Occupancy (NSO) stipulations would apply to some lands open to leasing, including: (1) threatened and endangered species critical habitat; (2) BLM developed recreation and administrative sites; and (3) special status split estate lands (e.g., state parks, county parks, conservation easements, land trusts, and scenic designations).

Under Alternative C, approximately 368,800 acres of BLM oil and gas Federal mineral estate are identified as open to oil and gas leasing with CSU stipulation(s), 394,400 acres would be closed to leasing, and 29,800 acres would be subject to NSO stipulations. Of the approximately 394,400 acres closed to leasing, approximately 35,400 acres are located within or in the vicinity of Panoche, Griswold, Tumey, and Ciervo Hills.

A total of 0-32 wells are expected under this alternative, mostly on existing leases.

For additional details on Alternative C, see subsection 2.8.1 of BLM (2017).

Oil and gas leasing decisions (and restrictions) under Alternative C are depicted in the Draft RMPA/DEIS (2017) on Fig. 2-3, as shown below.

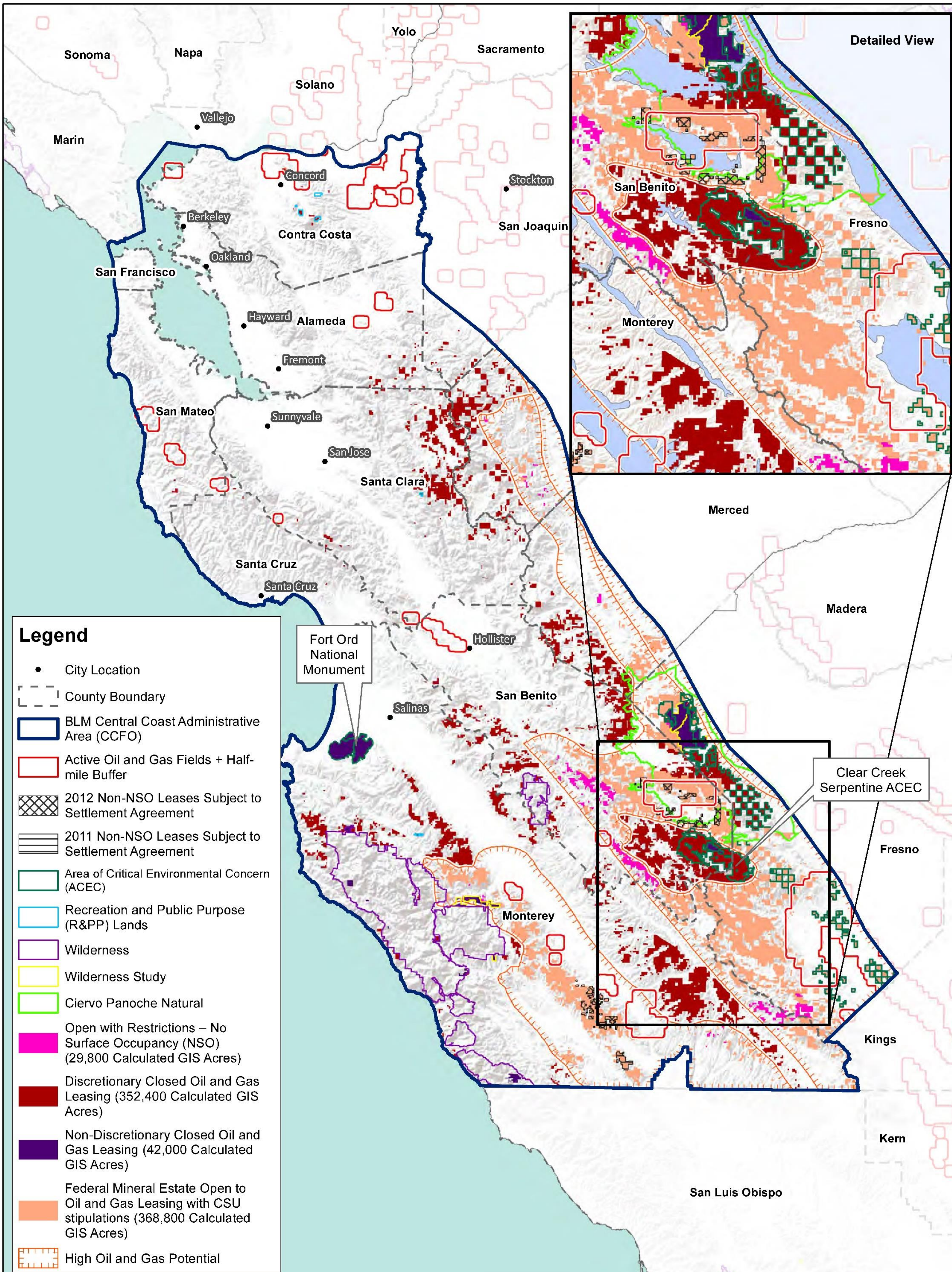

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Figure 2-3

Alternative C

Date: December 2016

Alternative D

Under Alternative D, unless currently closed under the 2007 Hollister Field Office RMP, Federal mineral estate underlying BLM surface estate would be available for leasing. All BLM split estate lands and the Ciervo Panoche Natural Area (both BLM surface and split estate lands) would be closed to leasing.

CSU stipulations would apply to all lands open to leasing. NSO stipulations would be applied in ACECs and R&PP leases.

Under Alternative D, approximately 121,200 acres of BLM oil and gas Federal mineral estate are identified as open to oil and gas leasing with CSU stipulation(s), 655,400 acres would be closed to leasing, and 16,400 acres would be subject to NSO stipulations.

A total of 0-32 wells are expected under this alternative, mostly on existing leases.

For additional details on Alternative D, see subsection 2.9.1 of BLM (2017).

Oil and gas leasing decisions (and restrictions) under Alternative D are depicted in the Draft RMPA/DEIS on Fig. 2-4, included below for reference.

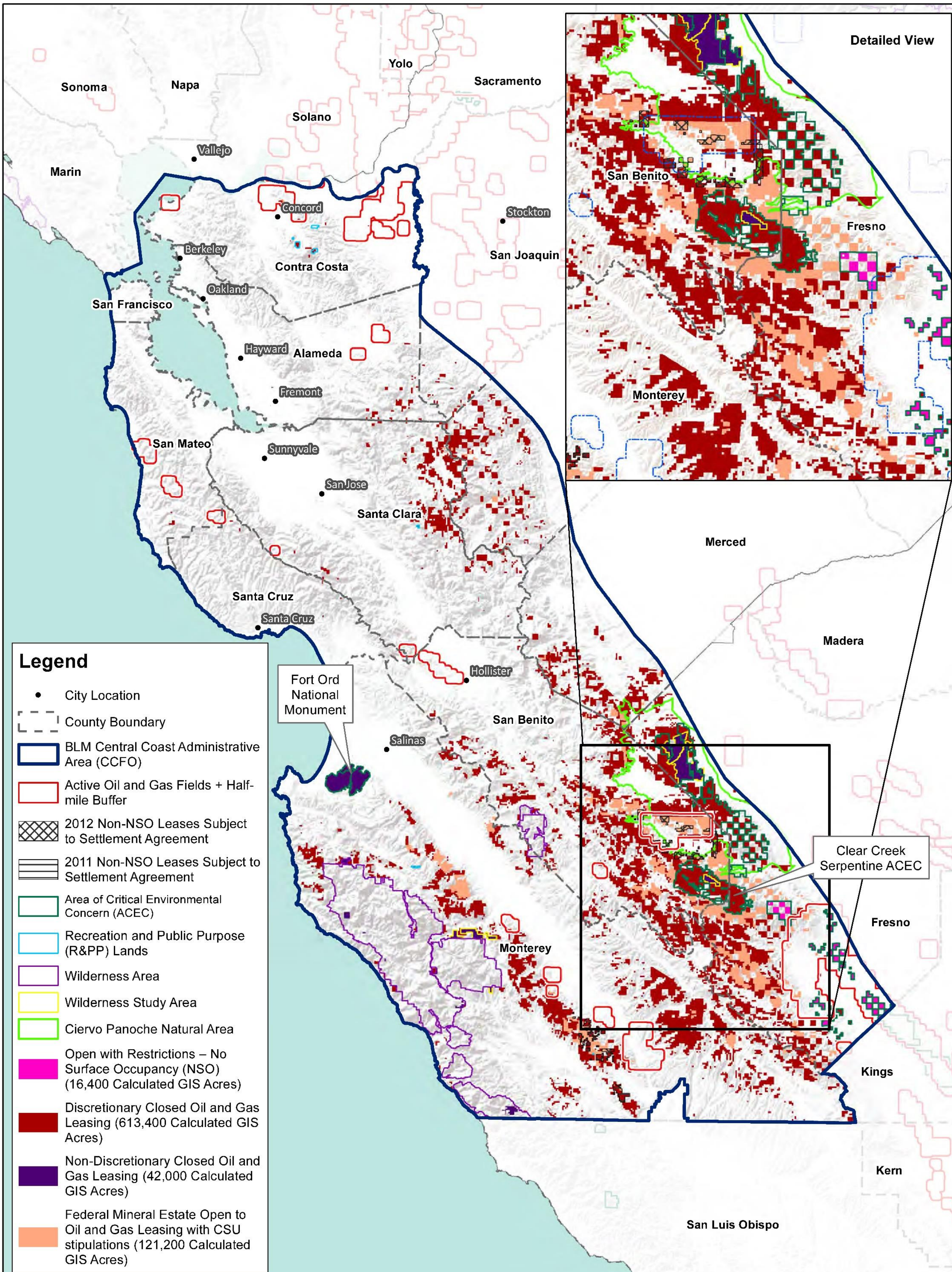

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Figure 2-4

Alternative D

Date: December 2016

Alternative E

Under Alternative E, unless currently closed under the 2007 Hollister Field Office RMP, Federal mineral estate outside of a California Department of Water Resources (DWR) Bulletin 118, Groundwater Basin or Sub-basin, would be available for leasing.

CSU stipulations would apply to all lands open to leasing. NSO stipulations would apply to some lands open to leasing, including: (1) 12-digit Hydrologic Unit Codes (HUCs) intersecting EPA impaired, perennial surface waters (BLM surface and split estate); (2) 12-digit HUCs intersecting non-impaired, perennial surface waters that intersect split estate; (3) 12-digit HUC subwatersheds with the highest aquatic intactness score; (4) 0.25 miles from non-impaired, perennial surface waters; and (5) 0.25 miles from eligible Wild and Scenic Rivers.

Under Alternative E, approximately 487,200 acres of BLM oil and gas Federal mineral estate are identified as open to oil and gas leasing with CSU stipulation(s), 99,400 acres would be closed to leasing, and 206,400 acres would be subject to NSO stipulations.

A total of 0-32 wells are expected under this alternative, mostly on existing leases.

For additional details on Alternative E, see subsection 2.10.1 of BLM (2017).

Oil and gas leasing decisions (and restrictions) under Alternative E are depicted in the Draft RMPA/DEIS (2017) on Fig. 2-5, as shown below.

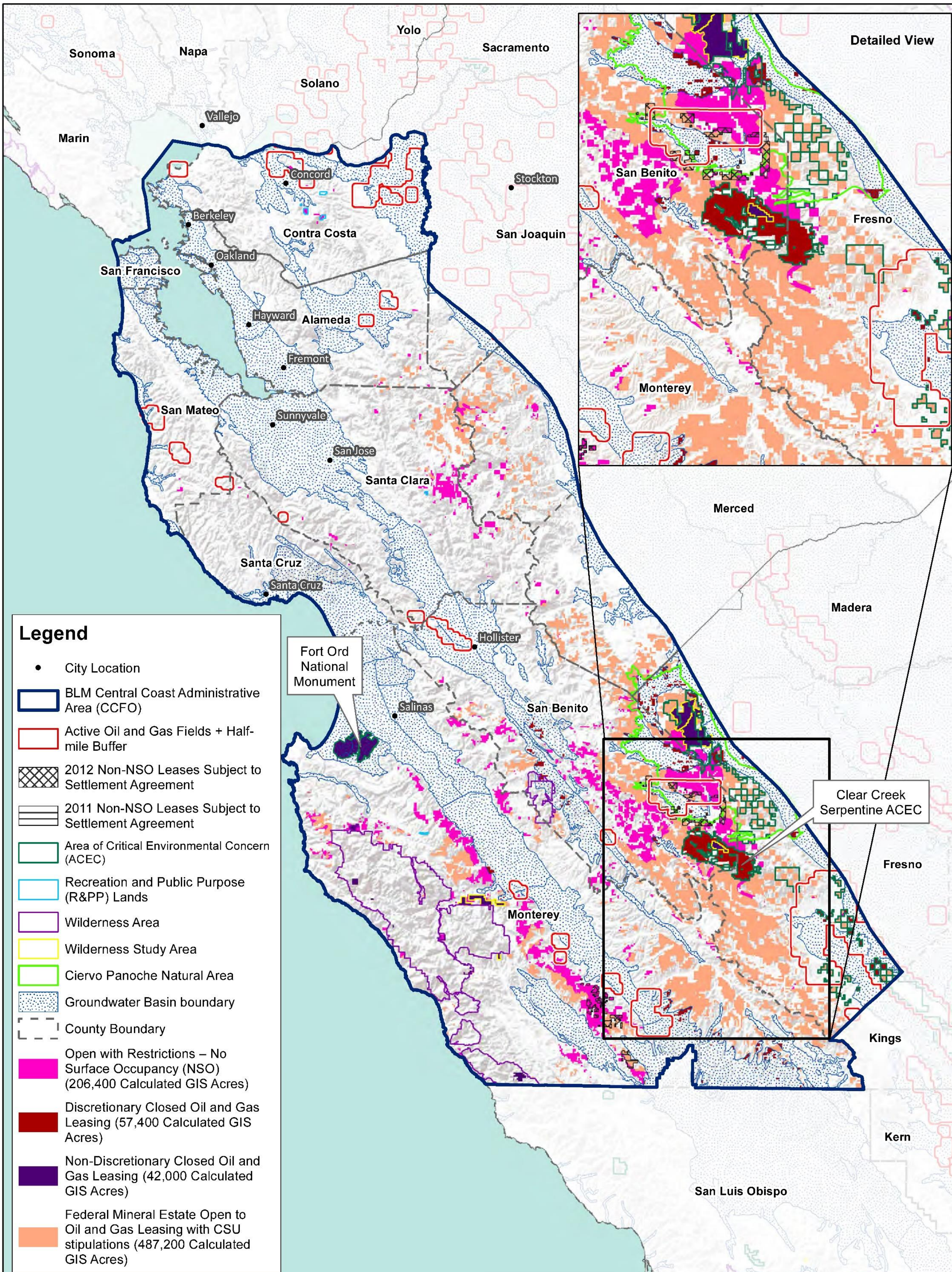

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Figure 2-5

Alternative E

Date: December 2016

Alternative F

Under Alternative F, unless currently closed under the 2007 Hollister Field Office RMP, Federal mineral estate would be open with CSU stipulations and/or subject to NSO.

CSU stipulations would apply to all lands open to leasing (see Appendix C). NSO stipulations would apply to some lands open to leasing, including: (1) Joaquin Rocks ACEC; (2) ACECs within Ciervo-Panoche Natural Area; and (3) giant kangaroo rat core population areas. Under Alternative F, approximately 683,100 acres of BLM oil and gas Federal mineral estate are identified as open to oil and gas leasing with CSU stipulation(s), 67,500 acres would be closed to leasing, and 42,400 acres would be subject to NSO stipulations.

The BLM's policy is to apply the least restrictive stipulation necessary to adequately protect the identified resource value(s), thus CSU stipulations are being considered in addition to closures and NSO stipulations within the range of alternatives. As with all alternatives, the CSU-Protected Species stipulation provides that presence of habitat or species may result in the proposed action being moved, modified, or delayed to mitigate project effects.

Under Alternative F, approximately 17,600 acres of the BLM-managed areas that contain the 14 non-NSO leases, as identified in Hollister I and II, would be open to leasing with CSU stipulations. Therefore, the implementation decision would be to issue all 14 non-NSO leases with CSU stipulations. Alternative F would not change the current management goals, objectives, and direction of the 14 leases, and no NSO stipulations would apply to the lease areas.

A total of 0-37 wells are expected under this alternative, mostly on existing leases.

For additional details on Alternative F, see subsection 2.11 of the CCFO Proposed RMP Amendment and Final EIS (BLM 2019).

Oil and gas leasing decisions (and restrictions) under Alternative F are depicted on Fig. 2-6. Refer to Table 1 and Table 2 (below) for additional details on Alternative F, including a comparison with the previous preferred alternative and other management alternatives identified in the Draft EIS (BLM 2017).

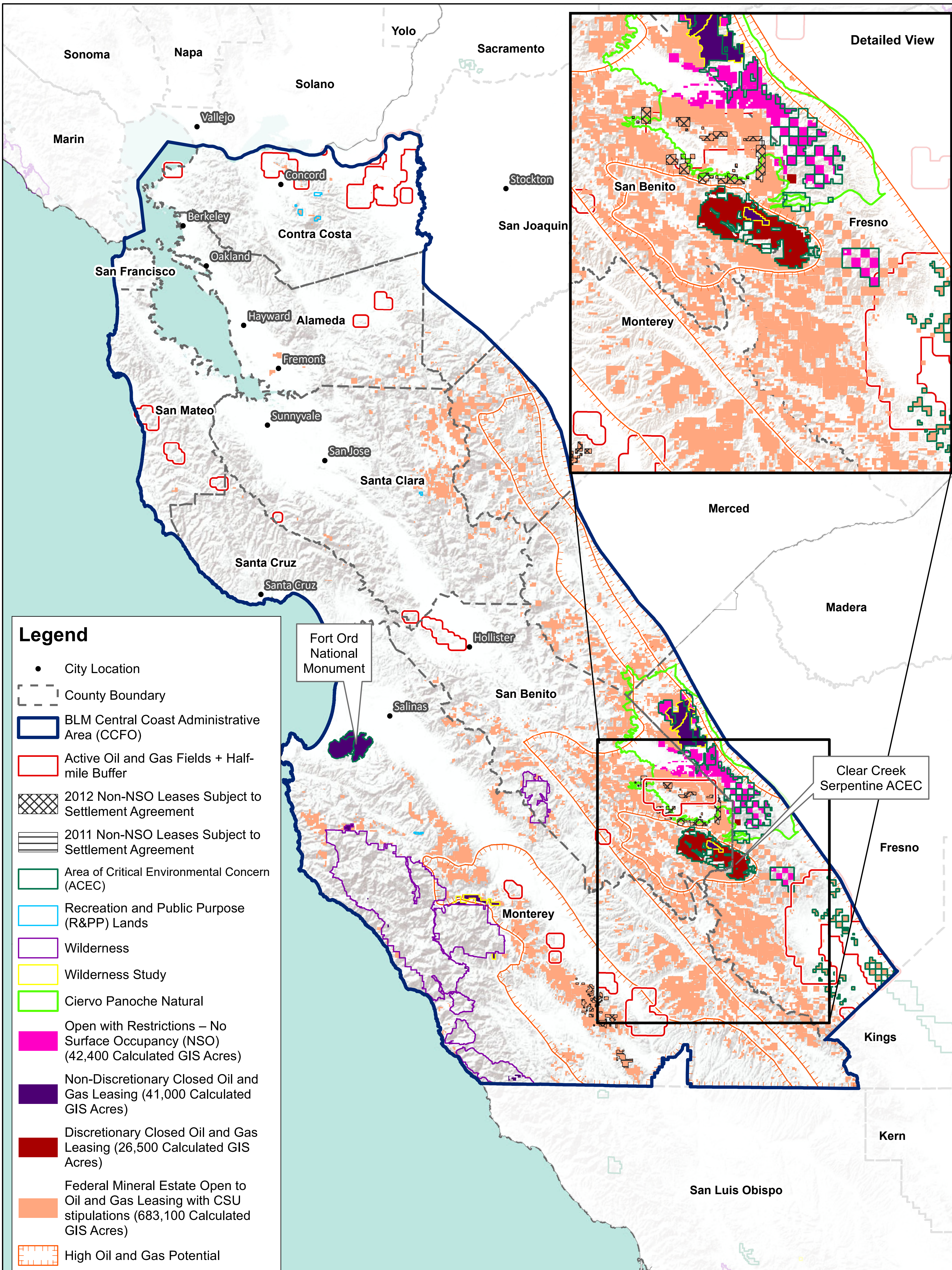

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Figure 2-6

Alternative F

Date: February 2019

Table 1 - Comparison of Alternative C and Alternative F

	Oil and Gas Potential	**Threatened and Endangered Species Management**	**Special Management Areas**
Alternative C (preferred alternative in Draft RMPA/EIS)	Close all areas with no, low or moderate oil and gas potential to leasing (unless closed under current management Alt. A),	Core population area of the San Joaquin giant kangaroo rat would be closed to leasing*; FWS designated critical habitat subject to NSO.	Following areas would be closed to leasing: ● Clear Creek Serpentine ACEC ● Wilderness and WSAs ● Fort Ord National Monument Special status split estate (e.g. state and county parks) would be subject to NSO.
Alternative F (preferred alternative in Proposed RMPA/ FINAL EIS)	All areas open to leasing (unless closed under current management Alt. A).	Joaquin Rocks ACEC; plus designated ACEC (and core population area of the San Joaquin giant kangaroo rat) within the Ciervo Panoche Natural Area would stipulate no surface occupancy for oil and gas leases*.	Same as above.

*The core population area of the San Joaquin giant kangaroo rat is tied to the recovery plan for this species and based on monitoring data from the BLM and US Fish and Wildlife Service (FWS).

Table 2 - Comparison of Alternatives

Alternative	Open with CSU	Closed	Open with NSO
A	683,800	87,500	41,700
B	39,000	754,000	0
C	368,800	394,400	29,800
D	121,200	655,400	16,400
E	487,200	99,400	206,400
F*	683,100	67,500	42,400

*In the Proposed RMPA/Final EIS, Alternative F would be identified as a sixth alternative and labelled as the preferred alternative.

SECTION 2: CURRENT AIR QUALITY CONDITIONS

Criteria air pollutants[4] are those for which national health-based concentration standards have been established. Measured pollutant concentrations greater than these standards represent a risk to human health or welfare. Criteria air pollutant concentrations are compared to National Ambient Air Quality Standards[5] (NAAQS) which are different than the standards adopted by the State of California, California AAQS (Appendix A).

Attainment/Non-Attainment/Maintenance Areas
EPA, California Air Resources Board (CARB) and local air districts work together to classify each area within the state as *attainment*, *unclassified*, or *nonattainment* depending on the historical levels of contaminants measured in the ambient air and the history of pollutants occurring at levels that do not attain the standards.

Three air basins overlap the Central Coast Field Office Planning Area. The San Francisco Air Basin is not shown in this TSD because there are no anticipated emissions that would result from BLM authorizations. The two air basins most likely to experience oil and gas leasing activity are isolated and presented by county, here.

4 https://www.epa.gov/criteria-air-pollutants
5 https://www.epa.gov/criteria-air-pollutants/naaqs-table

Table 2-1 summarizes the attainment designations for both the Federal and State standards for the criteria pollutants within the three air basins - North Central Coast, San Joaquin Valley, and San Francisco Bay Area air basins, respectively.

Table 2-1 Attainment status within the Central Coast Field Office[6]

Pollutant	Federal Designation	California Designation
North Central Coast Air Basin		
Ozone	Attainment	Nonattainment
PM10	Attainment	Nonattainment
PM2.5	Attainment	Attainment
CO	Attainment	Attainment
NO2	Attainment	Attainment
SO2	Attainment	Attainment
San Joaquin Valley Air Basin		
Ozone	Nonattainment (Extreme)	Nonattainment
PM10	Attainment (Maintenance)	Nonattainment
PM2.5	Nonattainment	Nonattainment
CO	Attainment (Maintenance)	Attainment
NO2	Attainment	Attainment
SO2	Attainment	Attainment
San Francisco Bay Area Air Basin		
Ozone	Nonattainment (Marginal)	Nonattainment
PM10	Attainment	Nonattainment
PM2.5	Nonattainment	Nonattainment
CO	Attainment (Maintenance)	Attainment
NO2	Attainment	Attainment
SO2	Attainment	Attainment

As stated in Section 1, there are currently no BLM-managed public lands within San Francisco County, which occupies a very small part of the San Francisco Bay air basin. Most of the oil and gas activity (existing and planned future development) is expected to occur within Monterey County and San Benito County in the North Central Coast air basin, and within western Fresno County in the San Joaquin Valley air basin.

The Federal nonattainment areas within the CCFO Planning Area for ozone and PM2.5 include the Coalinga Field (Fresno County), whereas the San Ardo Field is in an area that attains all Federal standards (Monterey County). Further discussion of current air quality and trends by air basin may be found in Subsection 3.5.4 of BLM's Draft RMPA/DEIS (2017). Current conditions and trends for climate and greenhouse gases are in section 3.6.4.

[6] Adapted from Table 3.1-1, 3.5-2 and 3.5-3 of BLM, 2017.

SECTION 3: AIR EMISSIONS INVENTORY FOR OIL WELLS LOCATED WITHIN THE CENTRAL COAST FIELD OFFICE PLANNING AREA AND PROJECTED EMISSIONS

As stated in Subsection 4.5.1 of BLM (2017), extraction of petroleum resources generally requires preparing the site, transporting, drilling, and installing well equipment, and storing or transporting the resource off-site. These processes produce air pollution in the form of engine exhaust emissions and fugitive dust from the transport of materials and the movement of vehicles over unpaved areas. Additional air pollution may be produced at extraction sites that include a facility for treatment or processing of the extracted oil and gas or byproducts of oil and gas extraction. Also, *fugit*ive emissions[7] of hydrocarbons would include volatile organic compounds (VOC), along with methane and hydrogen sulfide (H_2S) entrained in the oil and gas, and these emissions may occur at wellheads through leaking valves or behind casing in idle oil and gas wells.

Based on data posted by CARB, current emissions for oil and gas operations are presented in Table 3-1. The table focuses on two air basins: North Central Coast (San Benito County and Monterey County) and the Fresno County portion of the San Joaquin Valley air basin.

Table 3-1 Baseline emissions for oil and gas development within the CCFO Planning Area

Baseline Emissions[8] (tons/year) from 2012						
	ROG	**NOx**	**CO**	**SOx**	**PM10**	**PM2.5**
	San Benito County (North Central Coast Air Basin)					
030 O&G Combustion	3.7	14.6	3.7	0	0	0
310 O&G Production	3.7	0	0	0	0	0
	Monterey County (North Central Coast Air Basin)					
030 O&G Combustion	3.7	135.1	7.3	7.3	3.7	3.7
310 O&G Production	784.8	0	0	3.7	0	0
	Fresno County (San Joaquin Valley Air Basin)					
030 O&G Combustion	32.9	69.4	21.9	7.3	84.0	84.0
310 O&G Production	244.6	0	3.7	3.7	0	0
Total for Fresno County (SJV Air Basin):	277.5	69.4	25.6	11.0	84.0	84.0

[7] https://en.wikipedia.org/wiki/Fugitive_emissions

[8] https://www.arb.ca.gov/ei/maps/2017statemap/abmap.htm
Annual rates shown here were derived by multiplying CARB's daily values (which were projected from a 2012 data base) by 365. Since combustion and/or production are not necessarily continuous (24/7), values shown here are conservative. ROG = Reactive Organic Gases.

The emissions presented in Table 3-1 are conservative in several ways. As explained in the footnote, the values were taken from CARB data which present rates in terms of tons/day. Since the operations are not necessarily continuous (24/7), generating annual rates by applying a factor of 365 is conservative. Also, because only the western half of Fresno County is included within the CCFO Planning Area, Fresno County values over represent the portion of emissions that occur within the CCFO Planning Area.

To project emissions for future potential development, information and data in Table 3-1 are applied to Table 3-2. Table 3-2 presents construction-phase emissions for the development of three wells (annually) based on the RFD scenario (up to 37 wells over 15 years). Table 3-2 also presents projected emissions for oil and gas production – operation & maintenance –if all 37 wells forecast under the RFD scenario were developed.

RFD scenario emissions would most likely occur within the jurisdiction of either the Monterey Bay Unified Air Pollution Control District (MBUAPCD) or San Joaquin Valley Air Pollution Control District (SJVAPCD), depending on the location of the leases. Because the western side of the RMPA Planning Area has no Federal nonattainment designations, no *de minimis* thresholds apply from EPA's Conformity Regulations within the North Central Coast air basin and the area governed by the MBUAPCD.

Note that conservatively projected emissions from the 37 wells represent a small fraction of the standing emissions attributed to oil and gas development/production within the CCFO Planning Area. These proportions for ozone precursors range from 3.5% for Reactive Organic Gases (ROG) to 12% for NOx in the Fresno County portion of the San Joaquin Valley air basin. The proportions for the ozone precursors are 1.2% of ROG and 6.2% for NOx in Monterey County. Emission inventories for the standing base of oil and gas sources do not include dust from surface disturbance, although Table 3-2 shows that surface disturbance the primary cause of PM10 and PM2.5 for the 2015 RFD Scenario. The added emissions represent a small part of the standing base. With emission *offsets* (Emission Reduction Credits) that would be required to permit a new stationary source within nonattainment areas, the proportion is expected to remain low.

Note that the bottom two rows present different *de minimis* thresholds for annual emissions. The first row presents Federal thresholds for EPA's Conformity Regulations (https://www.epa.gov/general-conformity), which ensure that actions taken by federal agencies do not interfere with the State Implementation Plan (SIP) to attain and maintain national standards for air quality. The second row presents thresholds established by the San Joaquin Valley Air Pollution Control District (SJVAPCD), which apply to the California Environmental Quality Act (CEQA) process (http://resources.ca.gov/ceqa/). Table 3.2 shows that the projected emissions do not exceed values for either set of thresholds. The single exception is that for PM10, in which the projected value of 29.11 tons/year exceeds the SJVAPCD threshold of 15 tons/year. However, it should be noted that the projected values contemplate a total of 37 additional wells, whereas the thresholds are typically used to evaluate a single proposed source. In this sense, the compliance with the thresholds is dramatically conservative.

Table 3-2 Projected emissions in the Planning Area

Development Phase[9] Planning Area Emissions for 2015 RFD Scenario (tons/year)						
	ROG	**NOx**	**CO**	**SOx**	**PM10**	**PM2.5**
Surface disturbance	0	0	0	0	27.2	4.1
New well development	0.09	1.46	0.42	0	0.05	0.05
Geophysical exploration	0.01	0.25	0.11	0	0.01	0.01
Well stimulation	0.15	3.10	0.49	0	0.09	0.09
TOTAL:	0.25	4.81	1.01	0.01	27.34	4.22
Production Phase[10] Planning Area Emissions for 2015 RFD Scenario (tons/year)						
Combustion sources	0.13	3.59	0.21	1.04	1.77	1.77
Vents & fugitives	9.23	0	0	0	0	0
TOTAL:	9.37	3.59	0.21	1.04	1.77	1.77
Development + Production:	9.62	8.40	1.22	1.04	29.11	5.99
Federal *de minimis* thresholds[11]:	10	10	100	100	100	100
San Joaquin Valley Air Basin CEQA Guidance significance threshold[12]:	10	10	100	27	15	15

Projected emissions are the same under the range of alternatives because the RFD is the same under all management alternatives. This Technical Support Document focuses on the criteria air pollutants and whether the alternatives would be likely to create air quality impacts to the NAAQS and AQRVs. Federal standards also exist for categories of sources that emit hazardous air pollutants (HAPs) as defined in Section 112(b) of the Federal CAA (42 USC Section 7412(b)), including HAPs from oil and gas production. Although dangerous, hydrogen sulfide (H_2S) is not a HAP. The BLM's Draft RMPA/DEIS (2017), in Section 3.4.3, Hazardous Materials and Public Safety, shows the sulfur content of crude from the most active fields in the Planning Area. Fresno County fields in the Planning Area tend to produce lower-sulfur crude (sweet or semi-sweet) than the San Ardo field in Monterey County (sour). Potential localized air quality and health impacts to sensitive receptors are addressed in Section 4.4 and Section 4.5 of the EIS (BLM, 2017).

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9 Maximum anticipated criteria pollutant emissions for wells on Federal minerals assuming 3 wells/year. Contemplates new well construction and well stimulation of **3 wells/year**. Adapted from Table 4.5-1 of BLM, 2017.

10 Criteria pollutant emissions from long-term operations and/or maintenance activities upon full buildout (**37 wells**) of the RFD Scenario within the planning horizon for wells constructed on Federal mineral estate within the CCFO PA. Adapted from Table 4.5-2 of BLM, 2017.

11 These thresholds are adopted by EPA specifically for Federal nonattainment or maintenance areas (40 CFR Part 93, in particular §93.153): https://www.epa.gov/general-conformity/de-minimis-tables
If a proposed action will cause emissions above the *de miminis* threshold in any nonattainment or maintenance area and the action is not otherwise exempt, "presumed to conform," or included in the existing emissions budget of the SIP or TIP, the agency must conduct a conformity determination before it takes the action. When the applicability analysis shows that the action must undergo a conformity determination, federal agencies must first show that the action will meet all SIP control requirements such as reasonably available control measures, and the emissions from the action will not cause a new violation of the standard, or interfere with the timely attainment of the standard, the maintenance of the standard, or the area's ability to achieve an interim emission reduction milestone. Federal agencies then must demonstrate conformity by meeting one or more of the methods specified in the regulation for determining conformity.

12 SJVAPCD establishes its own thresholds for use in the CEQA process:
http://www.valleyair.org/transportation/0714-GAMAQI-Criteria-Pollutant-Thresholds-of-Significance.pdf
If a threshold is exceeded, mitigation measures are required, as discussed in Section 7.20 and 7.21 of SJVAPCD, 2015.

BLM's emission estimates for well stimulation are based on vertical drilling. Prices for energy have been extremely volatile over the past quarter-century, but development and production in the Central Coast Field Office remains low. Therefore, BLM considers historic California averages to be representative of oil and gas activities that may occur in the planning area over the next 10-15 years.

The basis for the emission estimates in Table 3-2 are provided in [new] Appendix B of the TSD. Appendix B includes a breakout of emissions calculated for individual equipment and area sources, as well as emission estimates for transportation (e.g. related to equipment, water, waste hauling, etc.). The emission factors, horsepower, type of engines, load factors, number of units, and expected duration of equipment use presented in Appendix B are based on the same method CARB uses to calculate emissions from existing oil and gas developments in productive basins.

Federal Class I Areas

More stringent standards have been established for maintaining air quality and preserving visibility in many designated wilderness areas. Air Quality Related Values[13] (AQRVs) in such areas must also be protected. Pinnacles National Park and Ventana Wilderness (managed by U.S. Forest Service and including some BLM public lands) have been designated as Federal Class I Areas and granted special air quality protections under Section 162(a) of the Federal Clean Air Act (CAA). If BLM lands are added to a wilderness area after the wilderness area was designated as a Federal Class I Area , the BLM parcels would also become Federal Class I Areas.

All of the active oil and gas fields within the Monterey County, San Benito County, and Fresno County in portions of the CCFO Planning Area are within 100 kilometers of Class I areas, which include Pinnacles National Park and the Ventana Wilderness. These Class I areas are depicted on the maps showing the BLM's range of alternatives (ref. Figs. 2-1 to 2-6).

Leases Subject to Settlement Agreement

Under BLM's preferred alternative (Alternative F), approximately 17,600 acres of federal mineral estate would be leased [with CSU stipulations] upon the issuance of the Record of Decision and Approved RMP Amendment for the Central Coast Field Office. The 14 federal leases that would be issued are identified on Figure 2-6. The prospective BLM fluid mineral leases in southern Monterey County are within 100 m of the Ventana Wilderness managed by the US Forest Service. The (proposed) fluid mineral leases in San Benito County are within 100 km of the Pinnacles National Park. As stated in Section 5 of this TSD, any project that is anticipated to result in emissions that materially contribute to potential adverse cumulative air quality impacts would be reviewed for potential impacts to sensitive receptors, including mandatory Federal Class I Areas.

[13] https://science.nature.nps.gov/im/inventory/aqrv/index.cfm

SECTION 4: AIR QUALITY IMPACT ANALYSIS AND THE AIR QUALITY MOU

For all alternatives described in Section 1 of this Technical Support Document, oil and gas exploration and development could occur anywhere that is open to oil and gas leasing within the CCFO Planning Area, although the most likely areas of development are on Federal mineral estate either in the North Central Coast air basin or in the San Joaquin Valley air basin. All oil and gas development activities would be subject to the jurisdiction of either the MBUAPCD or SJVAPCD, depending on the location. The history of activity for oil and gas exploration and development on Federal mineral estate within the CCFO Planning Area portion of the San Francisco Bay Area air basin is limited, and for this reason little or no new oil and gas activity or emissions is anticipated in the San Francisco Bay Area Air Quality Management District (BAAQMD) portion of the CCFO Planning Area.

Oil and gas development activities could result in emissions causing air quality impacts if they:

- Exceed any air quality standard, contribute substantially to an existing or projected air quality violation, or result in a cumulatively considerable net increase of any criteria pollutant for which the geographic area is in nonattainment under an applicable Federal or State ambient air quality standard (including releasing emissions that exceed quantitative thresholds for ozone precursors);

- Exceed *de minimis* threshold values for pollutants in nonattainment or maintenance areas;

- Conflict with or obstruct implementation of an applicable air quality plan;

- Expose sensitive receptors to substantial pollutant concentrations; or

- Affect long-term air quality as a result of operation and/or maintenance activities.

For oil and gas development within BLM lands, local air pollution control districts (APCDs) are responsible for developing an air quality management plan (AQMP) or clean air plan (CAP) where necessary to attain the California Ambient Air Quality Standards (CAAQS; Appendix A). CARB develops and implements statewide air pollution control plans to achieve and maintain the NAAQS, known as the State Implementation Plan (SIP). Each local air district:

- Develops the clean air strategies and air quality plans, such as an AQMP or CAP, for the attainment of ambient air quality standards;

- Adopts and enforces rules and regulations concerning sources of air pollution; and

- Issues permits for stationary sources of air pollution.

Each air quality plan relies upon an emissions inventory and emission control measures to demonstrate how the area will attain and maintain the ambient air quality standards.

Permitting

Before initiating any type of oil and gas development, the entity proposing the development may need to apply for and obtain air permits from the APCD where the activity would be located. Each local air district issues permits that must be obtained before constructing and operating new stationary sources of air pollution. Facilities that do not include stationary sources of air pollution may not require an air permit. The permit rules provide for a rigorous evaluation of air quality impacts for the proposed activity, which might in some cases include dispersion modeling. Such modeling would include an assessment of localized impacts as well as those that may potentially affect Class I and sensitive Class II area within 100km. The proposed activity must be deemed acceptable by the administering APCD before an air permit would be approved because Section 176(c) of the Clean Air Act, as articulated in the United States Environmental Protection Agency (USEPA) General Conformity Rule (40 Code of Federal Regulations [CFR] Part 93), states that a federal agency cannot issue a permit for, or support, an activity unless the agency determines that it will conform to the most recent USEPA-approved SIP. This means that projects using federal funds or requiring federal approval must not (1) cause or contribute to any new violation of a NAAQS, (2) increase the frequency or severity of any existing violation, or (3) delay the timely attainment of any standard, interim emission reduction, or other milestone.

The BLM anticipates the low number of wells identified in the RFDS would not increase the frequency or severity of the existing non-attainment; nor delay the attainment of the standard, interim reduction or other milestone. The goal for air quality management under the RMPA is to ensure that BLM authorizations and management activities comply with local, State, and Federal air quality regulations, requirements, State Implementation Plans (SIPs), and APCDs' standards and goals.

Interagency Air Quality Memorandum of Understanding (MOU)

The Air Quality Memorandum of Understanding (MOU) for Oil and Gas Decisions on Federal Lands [14] (2011) was developed jointly by five Federal agencies. Under the MOU, BLM has an affirmative responsibility to address air quality impacts for NEPA analyses in coordination with the United States National Park Service, Fish and Wildlife Service, Forest Service, and Environmental Protection Agency. The main objective of the MOU is to standardize the approach to facilitate the completion of NEPA environmental analysis for Federal land use planning and oil and gas development decisions. The MOU describes specific conditions and circumstances that may determine when dispersion modeling analysis may be or may not be required.

Paragraph V.E.3 of the MOU states that "the Lead Agency will conduct modeling to assess impacts to air quality and/or AQRVs if a proposed actions meets at least one of the criteria in subparagraph (a) **and** at least one of the criteria in subparagraph (b)":

[14] This document is presently undergoing revision.

a. *Emissions/Impacts* – the proposed action:
• Is anticipated to cause a Substantial Increase in Emission based on the Emissions Inventory prepared pursuant to Section V.E.2; or
• Will materially contribute to potential adverse cumulative air quality impacts as determined under NEPA.

b. *Geographic Location* – the proposed action is in:
• Proximity to a Class I or sensitive Class II Area; or
• A Non—Attainment or Maintenance Area; or
• An area expected to exceed the NAAQS or PSD increment based on:
- Monitored or previously modeled values for the area;
- Proximity to designated Non-Attainment or Maintenance Areas; or
- Emissions for the proposed action based on the Emissions Inventory prepared pursuant to Section V.E.2.

With respect to subparagraph (a), comparing the lower highlighted row (RFD Scenario development for the entire Planning Area) in Table 3-2 with the upper highlighted row (Fresno County portion of the SJV air basin only), the added increase in emissions is not substantial. For example, for ROG, the increment from 37 additional wells would be 9.6 tons/year compared to the existing 277.5 tons/year, while for PM2.5 the increment would be 5.00 tons/year compared to an existing 84.0 tons/year. Emission offsets associated with APCD permitting would prevent (potential) material contributions to adverse cumulative air quality impacts.

With respect to subparagraph (b), dispersion modeling contemplated by the first bullet would occur under EPA's NSR/PSD program. As stated in Section 3 above, for Federal Class I Areas, the CAA requires special management to control emissions from ***major*** stationary sources within 100 kilometers of the area. Subjected sources must comply with the Prevention of Significant Deterioration (PSD) program to prevent violations of the ambient air quality standards and protect the natural qualities of and visibility in Federal Class I Areas. EPA regulations require, under certain circumstances to be discussed with the applicable FLM, that long-range transport modeling be performed to ensure compliance with PSD increments for the relevant Class I areas. In addition, the MOU, through its appendix, points heavily to Appendix W[15] of 40 CFR Part 51 for technical guidance on dispersion modeling. That regulation in turn points heavily to PSD regulations at 40 CFR 52.21, which further defines major stationary sources.

None of the proposed sources (oil and gas well operations) associated with the RFD Scenario is expected to be a *major* source, and therefore would not be required to perform long-range transport modeling by a reviewing (permitting) authority. As stated in Section 3 above, any project that is anticipated to result in emissions that constitute a "major source" would be subject to local APCD permitting requirements and reviewed for potential impacts to sensitive receptors, including mandatory Federal Class I Areas, and this would be completed at the site-specific NEPA stage.

[15] *Guideline on Air Quality Models*: https://www.epa.gov/scram/air-quality-dispersion-modeling

Paragraph V.E.4 of the MOU presents *exceptions* to criteria under V.E.3, stating that modeling will *not* be required in the following circumstances:

- **a.** If the Lead Agency demonstrates and the EPA, and the Agencies whose lands are affected, concur (in writing or by electronic transmission) that, due to mitigation or control measures or design features that will be implemented, the proposed action will not cause a Substantial Increase in Emissions. The demonstration will describe the proposed features or measures, the anticipated means of implementations, and the basis for the conclusion that the proposed action will not cause a Substantial Increase in Emissions.

- **b.** If the EPA and the Agencies whose lands are affected concur (in writing or by electronic transmission) that:

    - An existing modeling analysis addresses and describes the impacts to air quality and AQRVs and an area under consideration, and
    - The analysis can be used to assess the impacts of the proposed action.

With respect to V.E.4(a), three design features to protect air quality are required under the BLM's Standard Oil and Gas Stipulations:

1. Measures to Protect Air Quality
    (A) All oil and gas exploration and development activities that require off-road vehicle use or surface disturbance would be required to obtain an air quality emission permit or verification that such permits are not appropriate from the appropriate APCD.
    (B) All oil and gas exploration and development activities resulting in surface disturbance or requiring the use of motorized vehicles would be required to suppress fugitive dust emissions from paved and unpaved surfaces in accordance with local APCD regulations.

2. Additional Mitigation Measure: Air modeling studies per the requirements of the Monterey Bay Unified Air Pollution Control District Rule 207[16] would be required before any emissions are allowed on leases in the Pinnacles National Park.

3. BLM Best Management Practices/Standard Operating Procedures for air quality (Appendix D) could reduce emissions of dust and other air pollutants during oil and gas production by implementing techniques for controlling road dust and for reducing, capturing, and/or controlling vapors, leaks, fugitives, and other emissions related to energy development.

Specific mitigation measures are also detailed in Appendix J.

[16] Review of New or Modified Sources: https://www.arb.ca.gov/DRDB/MBU/CURHTML/R207.pdf

AQ-1 Control or Suppress Fugitive Dust
AQ-2 Control Off-road Vehicle Engine Exhaust
AQ-3 Offset Emissions to Reduce Residual Impacts

SECTION 5: CONCLUSIONS AND RECOMMENDATIONS

In Section 3 of this Technical Support Document, projected emissions from the proposed 37 additional oil and gas wells which may come into operation over the 15-20 year planning horizon were discussed and presented in Table 3-2. The projected emissions for the entire CCFO Planning Area are significantly less than the standing emissions for the Fresno County portion of the San Joaquin Valley air basin alone. This supports the conclusion that, based upon the best available information, the proposed addition of 37 new oil and gas wells will not "cause a Substantial Increase in Emissions" per MOU V.E.3(a).

Based on the RFD scenario [i.e. 3 new wells/year], BLM's preferred alternative will not contribute to elevated pollutant concentrations in NAAQS non-attainment areas. For assurance, BLM would develop strategies in coordination with appropriate Federal Land Managers (FLM) to analyze impacts to AQRV's, if proposed oil and gas activities are likely to exceed the estimated emissions provided in Table 3-2 of this TSD. Elements of this strategy may include an emission balance sheet (targeting as close to net zero as possible for the pollutants of concern), enhanced directed inspection and maintenance (e.g. optical gas imaging) and operator training associated with oil and gas development activities on Federal mineral estate.

Due to the surrounding nonattainment areas within the Planning Area, emission *offsets* (Emission Reduction Credits) would be required to permit a new stationary source. These Emission Reduction Credits would be part of the APCD permit conditions and would have to be purchased by the proponent.

Section 4 describes the responsibility of local APCDs to develop an air quality management plan (AQMP) or clean air plan (CAP) where necessary to attain the California Ambient Air Quality Standards. This section also includes a discussion of the permitting requirement by the appropriate reviewing authority (i.e., APCD) for any proposed source (e.g., an oil and gas well) which may trigger enhanced emission inventory reporting or possibly rigorous dispersion modeling as an analysis of air quality impacts, as determined by the reviewing authority. Such modeling analysis could entail refined near-field modeling using a model preferred and recommended by EPA, as well as long-range transport modeling for impacts within 100km of Class I areas for any *major* sources. Section 4 also provides a discussion of the Air Quality MOU and air dispersion modeling. Based on the aggregate impacts projected from 37 new oil and gas wells would not substantially increase emissions, BLM< determined that dispersion modeling is not required. .

MOU paragraph V.E.4 supports the BLM's conclusion that dispersion modeling is **not** required because paragraph (a) considers that adequate "mitigations or control measures or design features" will be implemented for any proposed source, such that the proposed actions would "not cause a Substantial Increase in Emissions". For example, Appendix D and Appendix J of the BLM's Proposed RMPA/FEIS describe the type of mitigation measures intended for implementation.

Given the suite of mitigation measures, MOU paragraph V.E.4(a) is met and thus dispersion modeling is not required.

For all the reasons set out above, BLM determined that air dispersion modeling is not required for the Proposed RMPA and Final EIS for Oil and Gas Leasing and Development in the Central Coast Field Office. This recommendation is consistent with the BLM's preliminary determination described in the Hollister RMP Amendment MOU Technical Committee Call Notes, dated September 2, 2015.

In short, the air quality analysis is not necessary or warranted based on the low anticipated level of development and the uncertainty in where subsequent development would occur. Since there would be additional environmental review completed for oil and gas activities, BLM would provide notification to FLM's to address potential issues and/or concerns.

The following recommendations from the AQTWG would also be implemented, as appropriate, under the auspices of the interagency MOU:

BLM would confer with the National Park Service and/or US Forest Service to determine the appropriate level of analysis for oil and gas leasing or development activities that may adversely affect Class I areas [and AQRVs]. FLM's may also consult with EPA regarding emission offsets when further site-specific NEPA analysis begins and/or the APD phase commences.

As feasible, FLM's would tier from existing near-field analyses in order to disclose potential impacts from well drilling, completion and operation. Analyses would take into account emission reduction strategies that are currently committed to, and identify mitigation strategies that may be necessary including, but not limited to buffers from occupied structures or sensitive receptors.

If necessary, BLM would require near-field dispersion modeling at the leasing or Application for Permit to Drill (APD) phase for oil and gas development activities that may adversely affect Class I areas [and AQRVs].

SECTION 6: REFERENCES

BLM, 2007. Resource Management Plan for the Southern Diablo Mountain Range and Central Coast of California Record of Decision. September 2007. http://www.blm.gov/ca/pdfs/hollister_pdfs/SouthernDiablo-CenCoastRMP/ROD-August2007/ROD-Complete-8-07.pdf

BLM, 2017 Draft EIS for the Amended Resource Management Plan (RMPA) for the Central Coast Field Office (CCFO). January 2017.
https://eplanning.blm.gov/epl-front-office/eplanning/planAndProjectSite.do?methodName=dispatchToPatternPage&currentPageId=96884

CEQ, 2005. Regulations for Implementing the Procedural Provisions of the National Environmental Policy Act. Council on Environmental Quality. 47pp.
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EPA. *Guideline on Air Quality Models*:
https://www.epa.gov/scram/air-quality-dispersion-modeling

MOU, 2011. Interagency Memorandum of Understanding Regarding Air Quality Analysis and Mitigation for Federal Oil and Gas Decisions through the National Environmental Policy Act Process. Joint signatories: Dept. of Agriculture, Department of Interior, and Environmental Protection Agency. 17pp. + 4pp appendix and 6pp overview & sample of a reusable modeling framework.

SJVAPCD, 2015. *Guidance for Assessing and Mitigating Air Quality Impacts*. San Joaquin Valley Air Pollution Control District. 19 March 2015. 125pp.
http://www.valleyair.org/transportation/0714-GAMAQI-Criteria-Pollutant-Thresholds-of-Significance.pdf

APPENDIX A: AMBIENT AIR QUALITY STANDARDS

Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards [1]		National Standards [2]		
		Concentration [3]	Method [4]	Primary [3,5]	Secondary [3,6]	Method [7]
Ozone (O_3)[8]	1 Hour	0.09 ppm (180 μg/m^3)	Ultraviolet Photometry	—	Same as Primary Standard	Ultraviolet Photometry
	8 Hour	0.070 ppm (137 μg/m^3)		0.070 ppm (137 μg/m^3)		
Respirable Particulate Matter (PM10)[9]	24 Hour	50 μg/m^3	Gravimetric or Beta Attenuation	150 μg/m^3	Same as Primary Standard	Inertial Separation and Gravimetric Analysis
	Annual Arithmetic Mean	20 μg/m^3		—		
Fine Particulate Matter (PM2.5)[9]	24 Hour	—	—	35 μg/m^3	Same as Primary Standard	Inertial Separation and Gravimetric Analysis
	Annual Arithmetic Mean	12 μg/m^3	Gravimetric or Beta Attenuation	12.0 μg/m^3	15 μg/m^3	
Carbon Monoxide (CO)	1 Hour	20 ppm (23 mg/m^3)	Non-Dispersive Infrared Photometry (NDIR)	35 ppm (40 mg/m^3)	—	Non-Dispersive Infrared Photometry (NDIR)
	8 Hour	9.0 ppm (10 mg/m^3)		9 ppm (10 mg/m^3)	—	
	8 Hour (Lake Tahoe)	6 ppm (7 mg/m^3)		—	—	
Nitrogen Dioxide (NO_2)[10]	1 Hour	0.18 ppm (339 μg/m^3)	Gas Phase Chemiluminescence	100 ppb (188 μg/m^3)	—	Gas Phase Chemiluminescence
	Annual Arithmetic Mean	0.030 ppm (57 μg/m^3)		0.053 ppm (100 μg/m^3)	Same as Primary Standard	
Sulfur Dioxide (SO_2)[11]	1 Hour	0.25 ppm (655 μg/m^3)	Ultraviolet Fluorescence	75 ppb (196 μg/m^3)	—	Ultraviolet Flourescence; Spectrophotometry (Pararosaniline Method)
	3 Hour	—		—	0.5 ppm (1300 μg/m^3)	
	24 Hour	0.04 ppm (105 μg/m^3)		0.14 ppm (for certain areas)[11]	—	
	Annual Arithmetic Mean	—		0.030 ppm (for certain areas)[11]	—	
Lead[12,13]	30 Day Average	1.5 μg/m^3	Atomic Absorption	—	—	High Volume Sampler and Atomic Absorption
	Calendar Quarter	—		1.5 μg/m^3 (for certain areas)[12]	Same as Primary Standard	
	Rolling 3-Month Average	—		0.15 μg/m^3		
Visibility Reducing Particles[14]	8 Hour	See footnote 14	Beta Attenuation and Transmittance through Filter Tape	No National Standards		
Sulfates	24 Hour	25 μg/m^3	Ion Chromatography			
Hydrogen Sulfide	1 Hour	0.03 ppm (42 μg/m^3)	Ultraviolet Fluorescence			
Vinyl Chloride[12]	24 Hour	0.01 ppm (26 μg/m^3)	Gas Chromatography			

From California Air Resources Board website (05/04/16):
https://www.arb.ca.gov/research/aaqs/aaqs2.pdf
See footnotes on following page.

1. California standards for ozone, carbon monoxide (except 8-hour Lake Tahoe), sulfur dioxide (1 and 24 hour), nitrogen dioxide, and particulate matter (PM10, PM2.5, and visibility reducing particles), are values that are not to be exceeded. All others are not to be equaled or exceeded. California ambient air quality standards are listed in the Table of Standards in Section 70200 of Title 17 of the California Code of Regulations.

2. National standards (other than ozone, particulate matter, and those based on annual arithmetic mean) are not to be exceeded more than once a year. The ozone standard is attained when the fourth highest 8-hour concentration measured at each site in a year, averaged over three years, is equal to or less than the standard. For PM10, the 24 hour standard is attained when the expected number of days per calendar year with a 24-hour average concentration above 150 $\mu g/m^3$ is equal to or less than one. For PM2.5, the 24 hour standard is attained when 98 percent of the daily concentrations, averaged over three years, are equal to or less than the standard. Contact the U.S. EPA for further clarification and current national policies.

3. Concentration expressed first in units in which it was promulgated. Equivalent units given in parentheses are based upon a reference temperature of 25°C and a reference pressure of 760 torr. Most measurements of air quality are to be corrected to a reference temperature of 25°C and a reference pressure of 760 torr; ppm in this table refers to ppm by volume, or micromoles of pollutant per mole of gas.

4. Any equivalent measurement method which can be shown to the satisfaction of the ARB to give equivalent results at or near the level of the air quality standard may be used.

5. National Primary Standards: The levels of air quality necessary, with an adequate margin of safety to protect the public health.

6. National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant.

7. Reference method as described by the U.S. EPA. An "equivalent method" of measurement may be used but must have a "consistent relationship to the reference method" and must be approved by the U.S. EPA.

8. On October 1, 2015, the national 8-hour ozone primary and secondary standards were lowered from 0.075 to 0.070 ppm.

9. On December 14, 2012, the national annual PM2.5 primary standard was lowered from 15 $\mu g/m^3$ to 12.0 $\mu g/m^3$. The existing national 24-hour PM2.5 standards (primary and secondary) were retained at 35 $\mu g/m^3$, as was the annual secondary standard of 15 $\mu g/m^3$. The existing 24-hour PM10 standards (primary and secondary) of 150 $\mu g/m^3$ also were retained. The form of the annual primary and secondary standards is the annual mean, averaged over 3 years.

10. To attain the 1-hour national standard, the 3-year average of the annual 98th percentile of the 1-hour daily maximum concentrations at each site must not exceed 100 ppb. Note that the national 1-hour standard is in units of parts per billion (ppb). California standards are in units of parts per million (ppm). To directly compare the national 1-hour standard to the California standards the units can be converted from ppb to ppm. In this case, the national standard of 100 ppb is identical to 0.100 ppm.

11. To attain the 1-hour national standard, the 3-year average of the annual 98th percentile of the 1-hour daily maximum concentrations at each site must not exceed 100 ppb. Note that the national 1-hour standard is in units of parts per billion (ppb). California standards are in units of parts per million (ppm). To directly compare the national 1-hour standard to the California standards the units can be converted from ppb to ppm. In this case, the national standard of 100 ppb is identical to 0.100 ppm.

Note that the 1-hour national standard is in units of parts per billion (ppb). California standards are in units of parts per million (ppm). To directly compare the 1-hour national standard to the California standard the units can be converted to ppm. In this case, the national standard of 75 ppb is identical to 0.075 ppm.

12. The ARB has identified lead and vinyl chloride as 'toxic air contaminants' with no threshold level of exposure for adverse health effects determined. These actions allow for the implementation of control measures at levels below the ambient concentrations specified for these pollutants.

13. The national standard for lead was revised on October 15, 2008 to a rolling 3-month average. The 1978 lead standard (1.5 $\mu g/m^3$ as a quarterly average) remains in effect until one year after an area is designated for the 2008 standard, except that in areas designated nonattainment for the 1978 standard, the 1978 standard remains in effect until implementation plans to attain or maintain the 2008 standard are approved.

14. In 1989, the ARB converted both the general statewide 10-mile visibility standard and the Lake Tahoe 30-mile visibility standard to instrumental equivalents, which are "extinction of 0.23 per kilometer" and "extinction of 0.07 per kilometer" for the statewide and Lake Tahoe Air Basin standards, respectively.

Appendix B: Greenhouse Gas Emissions Inventory for Oil and Gas RFDS

HFO Oil and Gas Well Development Scenario Assumptions

New/Additional Wells (exploratory)	3 to 5 wells
New/Additional Wells within Existing Fields (development)	0 to 32 wells

Subtotal Construction: Surface Disturbance

12 mo
206 acre (total disturbance over 15 to 20 year plan)
247.2 acre-months (one-tenth of disturbance occurs in single year)

	PM10 Emission Factor (ton / acre-months)		PM10 (tpy)	PM2.5 (tpy)
Ref: MRI 1996 (BACM PM10 emission factors; minimal earthmoving, average condiitons)	0.11	**Surface Disturbance : Subtotal**	**27.2**	**4.1**

0.15 : PM2.5 portion of airborne PM10 (EPA AP-42 Sec 13.2.5)

Subtotal Construciton: New Well Development and Surface Disturbance

Off-Road Equipment	Example Duty per Well		Emission Factors	ROG (lb/hr)	NOX (lb/hr)	CO (lb/hr)	SOX (lb/hr)	PM10 (lb/hr)	PM2.5 (lb/hr)	CO2e (lb/hr)
Drill Rig (Mobile)	100	hr	Drill Rig (~770 hp)	0.2567	4.6354	1.1339	0.0064	0.1358	0.1358	640.7
Workover Rig (Mobile)	100	hr	Workover Rig (~580 hp)	0.1880	2.5808	0.7231	0.0041	0.0954	0.0954	408.9
Pumping Units (Mud Pumping)	60	hr	Other (~360 hp)	0.0947	1.5409	0.5351	0.0019	0.0583	0.0583	190.8
Cranes	20	hr	Cranes (~570 hp)	0.0851	1.5533	0.5551	0.0021	0.0547	0.0547	214.9
Graders	40	hr	Graders (~290 hp)	0.0716	0.9881	0.4317	0.0020	0.0384	0.0384	181.6
Tractors/Loaders/Backhoes	40	hr	Loaders/Backhoes (~320 hp)	0.0682	1.1489	0.4552	0.0025	0.0395	0.0395	220.5

Ref: ARB Off-road Inventory 2011 (per typical equipment in 2015 fleet); CO-SOx from SCAB average

On-Road Mobile Sources			Emission Factors	ROG (lb/VMT)	NOX (lb/VMT)	CO (lb/VMT)	SOX (lb/VMT)	PM10 (lb/VMT)	PM2.5 (lb/VMT)	CO2e (lb/VMT)
Water Trucks	1200	VMT	T7	0.00076	0.01724	0.00383	3.821E-05	0.0004576	0.0003101	4.027
Control Trucks	600	VMT	T7	0.00076	0.01724	0.00383	3.821E-05	0.0004576	0.0003101	4.027
Haul Trucks	600	VMT	T7	0.00076	0.01724	0.00383	3.821E-05	0.0004576	0.0003101	4.027
Crew Trucks	600	VMT	LDT2	0.00099	0.00112	0.00806	1.059E-05	0.0001065	4.634E-05	1.047

Ref: ARB EMFAC2014 Inventory (emissions per VMT in 2015 fleet)

Development Scenario

37 wells over 15 to 20 year plan
3 wells constructed in single year

Emission Rates	ROG (tpy)	NOX (tpy)	CO (tpy)	SOX (tpy)	PM10 (tpy)	PM2.5 (tpy)	CO2e (MT/yr)
Drill Rig (Mobile)	0.039	0.695	0.170	0.001	0.020	0.020	87.2
Workover Rig (Mobile)	0.028	0.387	0.108	0.001	0.014	0.014	55.6
Pumping Units (Mud Pumping)	0.009	0.139	0.048	0.000	0.005	0.005	15.6
Cranes	0.003	0.047	0.017	0.000	0.002	0.002	5.8
Graders	0.004	0.059	0.026	0.000	0.002	0.002	9.9
Tractors/Loaders/Backhoes	0.004	0.069	0.027	0.000	0.002	0.002	12.0
Water Trucks	0.001	0.031	0.007	0.000	0.001	0.001	6.6
Control Trucks	0.001	0.016	0.003	0.000	0.000	0.000	3.3
Haul Trucks	0.001	0.016	0.003	0.000	0.000	0.000	3.3
Crew Trucks	0.001	0.001	0.007	0.000	0.000	0.000	0.9
New Well Development : Subtotal	**0.090**	**1.459**	**0.418**	**0.002**	**0.048**	**0.047**	**200.1**

Subtotal: Geophysical Exploration

Off-Road Equipment	Example Duty per Survey	Emission Factors	ROG (lb/hr)	NOX (lb/hr)	CO (lb/hr)	SOX (lb/hr)	PM10 (lb/hr)	PM2.5 (lb/hr)	CO2e (lb/hr)
Tractors/Loaders/Backhoes	40 hr	Loaders/Backhoes (~320 hp)	0.0682	1.1489	0.4552	0.0025	0.0395	0.0395	220.5
Bore/Drill Rigs	100 hr	Bore/Drill Rigs (~610 hp)	0.0922	1.6353	0.7730	0.0044	0.0558	0.0558	440.0

Ref: ARB Off-road Inventory 2011 (per typical equipment in 2015 fleet); CO-SOx from SCAB average

On-Road Mobile Sources		Emission Factors	ROG (lb/VMT)	NOX (lb/VMT)	CO (lb/VMT)	SOX (lb/VMT)	PM10 (lb/VMT)	PM2.5 (lb/VMT)	CO2e (lb/VMT)
Water Trucks	1200 VMT	T7	0.00076	0.01724	0.00383	3.821E-05	0.0004576	0.0003101	4.027
Control Trucks	600 VMT	T7	0.00076	0.01724	0.00383	3.821E-05	0.0004576	0.0003101	4.027
Haul Trucks	600 VMT	T7	0.00076	0.01724	0.00383	3.821E-05	0.0004576	0.0003101	4.027
Crew Trucks	600 VMT	LDT2	0.00099	0.00112	0.00806	1.059E-05	0.0001065	4.634E-05	1.047

Ref: ARB EMFAC2014 Inventory (emissions per VMT in 2015 fleet)

Number of Geophysical Surveys (four notices during life of plan)
2 surveys in single year

Emission Rates	ROG (tpy)	NOX (tpy)	CO (tpy)	SOX (tpy)	PM10 (tpy)	PM2.5 (tpy)	CO2e (MT/yr)
Tractors/Loaders/Backhoes	0.003	0.046	0.018	0.000	0.002	0.002	8.0
Bore/Drill Rigs	0.009	0.164	0.077	0.000	0.006	0.006	39.9
Water Trucks	0.001	0.021	0.005	0.000	0.001	0.000	4.4
Control Trucks	0.000	0.010	0.002	0.000	0.000	0.000	2.2
Haul Trucks	0.000	0.010	0.002	0.000	0.000	0.000	2.2
Crew Trucks	0.001	0.001	0.005	0.000	0.000	0.000	0.6
Geophysical Exploration : Subtotal	**0.014**	**0.252**	**0.110**	**0.001**	**0.008**	**0.008**	**57.3**

Subtotal: Well Stimulation

Off-Road Equipment	Example Duty per Well		Emission Factors	ROG (lb/hr)	NOX (lb/hr)	CO (lb/hr)	SOX (lb/hr)	PM10 (lb/hr)	PM2.5 (lb/hr)	CO2e (lb/hr)
Pumping Units (Hydraulic Fracturing)	300	hr	Other (~1130 hp)	0.2600	5.5152	0.6623	0.0040	0.1527	0.1527	541.1
Blenders	100	hr	Other (~360 hp)	0.0947	1.5409	0.5351	0.0019	0.0583	0.0583	190.8
Cranes	20	hr	Cranes (~570 hp)	0.0851	1.5533	0.5551	0.0021	0.0547	0.0547	214.9

Ref: ARB Off-road Inventory 2011 (per typical equipment in 2015 fleet); CO-SOx from SCAB average

On-Road Mobile Sources			Emission Factors	ROG (lb/VMT)	NOX (lb/VMT)	CO (lb/VMT)	SOX (lb/VMT)	PM10 (lb/VMT)	PM2.5 (lb/VMT)	CO2e (lb/VMT)
Water Trucks	6000	VMT	T7	0.00076	0.01724	0.00383	3.821E-05	0.0004576	0.0003101	4.027
Control Trucks	600	VMT	T7	0.00076	0.01724	0.00383	3.821E-05	0.0004576	0.0003101	4.027
Pump Trucks	600	VMT	T7	0.00076	0.01724	0.00383	3.821E-05	0.0004576	0.0003101	4.027
Blender Trucks	600	VMT	T7	0.00076	0.01724	0.00383	3.821E-05	0.0004576	0.0003101	4.027
Sand Trucks	3000	VMT	T7	0.00076	0.01724	0.00383	3.821E-05	0.0004576	0.0003101	4.027
Haul Trucks	2400	VMT	T7	0.00076	0.01724	0.00383	3.821E-05	0.0004576	0.0003101	4.027
Crew Trucks	600	VMT	LDT2	0.00099	0.00112	0.00806	1.059E-05	0.0001065	4.634E-05	1.047
Supplies Deliveries	600	VMT	MDV	0.00094	0.00133	0.00902	1.368E-05	0.0001052	4.515E-05	1.354

Ref: ARB EMFAC2014 Inventory (emissions per VMT in 2015 fleet)

Number of Well Stimulation Treatments

37 wells over 15 to 20 year plan

3 well stimulations in single year

Emission Rates	ROG (tpy)	NOX (tpy)	CO (tpy)	SOX (tpy)	PM10 (tpy)	PM2.5 (tpy)	CO2e (MT/yr)
Pumping Units (Hydraulic Fracturi	0.117	2.482	0.298	0.002	0.069	0.069	220.9
Blenders	0.014	0.231	0.080	0.000	0.009	0.009	26.0
Cranes	0.003	0.047	0.017	0.000	0.002	0.002	5.8
Water Trucks	0.007	0.155	0.034	0.000	0.004	0.003	32.9
Control Trucks	0.001	0.016	0.003	0.000	0.000	0.000	3.3
Pump Trucks	0.001	0.016	0.003	0.000	0.000	0.000	3.3
Blender Trucks	0.001	0.016	0.003	0.000	0.000	0.000	3.3
Sand Trucks	0.003	0.078	0.017	0.000	0.002	0.001	16.4
Haul Trucks	0.003	0.062	0.014	0.000	0.002	0.001	13.2
Crew Trucks	0.001	0.001	0.007	0.000	0.000	0.000	0.9
Supplies Deliveries	0.001	0.001	0.008	0.000	0.000	0.000	1.1
Well Stimulation : Subtotal	**0.15**	**3.10**	**0.49**	**0.00**	**0.09**	**0.09**	**327.0**

Subtotal Production: Operations and Maint, including EOR

Enhanced Oil Recovery

EOR (cyclic steam and steam flood) and secondary recovery techniques (water flood)

ARB Almanac for criteria air pollutants includes combustion and ROG separated for vents, fugitives

ARB 2007 Survey Results include inventory of GHG from vents, fugitives, and combustion (Steam Generators; CHP / Cogeneration; IC Engines)

Well Operations and Maintenance

Plugging and Abandonment

Emission Factors	ROG	NOX	CO	SOX	PM10	PM2.5	CO2e
	(lb/day-per-well)						(MT/yr-well)
Oil and Gas Production	0.01961	0.53165	0.03068	0.15340	0.26272	0.26272	500
+ ROG vents and fugitives	1.36738						

Ref: ARB 2013 Almanac for Oil and Gas Production (average emissions per active well)

Ref: ARB 2013 Report on OIl and Gas 2007 Survey Results (Table 3-4: 498,249 MTCO2e/yr for Monterey Bay Unified APCD / approx 1000 active wells)

Number of Wells in Op & Maint

all exploratory and development wells

	Emission Rates	ROG	NOX	CO	SOX	PM10	PM2.5	CO2e
37	**wells in production**	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(MT/yr)
Op & Maint : Subtotal	**Oil and Gas Production**	**0.132**	**3.590**	**0.207**	**1.036**	**1.774**	**1.774**	**18,500.0**
Op & Maint : Subtotal	**+ ROG vents and fugitives**	**9.233**						

Summary for Development Scenario

	ROG	NOX	CO	SOX	PM10	PM2.5	CO2e
Construction and Well Stim	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(MT/yr)
Surface Disturbance : Subtotal	---	---	---	---	27.2	4.1	---
New Well Development : Subtotal	0.09	1.46	0.42	0.00	0.05	0.05	200.1
Geophysical Exploration : Subtotal	0.01	0.25	0.11	0.00	0.01	0.01	57.3
Well Stimulation : Subtotal	0.15	3.10	0.49	0.00	0.09	0.09	327.0
Total, Development	**0.25**	**4.81**	**1.01**	**0.01**	**27.34**	**4.22**	**584.4**

	ROG	NOX	CO	SOX	PM10	PM2.5	CO2e
Operations & Maint	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(MT/yr)
Oil and Gas Production	0.13	3.59	0.21	1.04	1.77	1.77	18,500.0
+ ROG vents and fugitives	9.23	---	---	---	---	---	---
Total, Production	**9.37**	**3.59**	**0.21**	**1.04**	**1.77**	**1.77**	**18,500.0**
Total	**9.62**	**8.40**	**1.22**	**1.04**	**29.11**	**5.99**	**19,084.4**

GHG Indirect Emissions Calculation for Oil and Gas RFDS

Production Baseline

Carbon Intensity (CI) data developed by ARB per Section 95486(b)(2)(A)3 of the Low Carbon Fuel Standard (LCFS) Regulation

Historic Production from: ARB Crude Average Carbon Intensity Calculations

(typical of regional fields only)

CI: (gCO2e/MJ) attributed to production and transport of crude oil supply as a feedstock to CA refineries

Ref: ARB Calculation of 2012 Crude Average CI Value, (a) March 17, 2014; (b) July 14, 2014; (c) June 23, 2016

http://www.arb.ca.gov/fuels/lcfs/crude-oil/2012-crude-ave-ci.pdf

	(b)	(c)	(b)	(a)		(c)	(c)			
Crude Name	Est 2013-2014 CI (g/MJ)	Est 2015 CI (g/MJ)	2012 and 2013 Volume (bbl)	**2012 Volume (bbl)**	**2013 Volume (bbl)**	**2014 Volume (bbl)**	**2015 Volume (bbl)**	**2013 CI * Vol**	**2014 CI * Vol**	**2015 CI * Vol**
San Ardo	28.82	27.26	14,501,933	7,262,337	7,239,596	7,682,477	7,795,661	2.09E+08	2.21E+08	2.13E+08
Coalinga	25.36	27.85	11,068,127	5,544,989	5,523,138	6,105,373	6,780,338	1.40E+08	1.55E+08	1.89E+08
Lynch Canyon	7.73	12.00	305,429	144,944	160,485	291,504	268,814	1.24E+06	2.25E+06	3.23E+06
Jacalitos	2.22	2.40	264,450	139,061	125,389	124,479	113,835	2.78E+05	2.76E+05	2.73E+05
Sargent	4.77	3.98	75,516	40,006	35,510	32,284	26,784	1.69E+05	1.54E+05	1.07E+05
Kettleman North Dome	4.70	5.14	59,195	27,351	31,844	75,584	171,640	1.50E+05	3.55E+05	8.82E+05

	2013 Volume (bbl)	**2014 Volume (bbl)**	**2015 Volume (bbl)**	3-yr Regional CI Est'd (g/MJ)
*Regional Average CI Est'd = [sum (CI * Vol) / sum (Vol)]*	13,115,962	14,311,701	15,157,072	26.67

Baseline Average Crude Oil Production per Well

See also: EIS APPENDIX B. REASONABLY FORESEEABLE DEVELOPMENT SCENARIO FOR OIL AND GAS

Field Name	**Well Counts**		**Production Baseline per Well Count**			
	EIS RFD # 2014 "A"+"N"	*DOC # 2016 Status "A"*	2012 Avg Prod'cd Vol (bbl/well)	2013 Avg Prod'cd Vol (bbl/well)	2014 Avg Prod'cd Vol (bbl/well)	2015 Avg Prod'cd Vol (bbl/well)
San Ardo	918	905	7,911	7,886	8,369	8,614
Coalinga	2934	3136	1,890	1,882	2,081	2,162
Lynch Canyon	38	39	3,814	4,223	7,671	6,893
Jacalitos	88	89	1,580	1,425	1,415	1,279
Sargent	19	15	2,106	1,869	1,699	1,786
Kettleman North Dome	20	21	1,368	1,592	3,779	8,173
		Historic Highest of Avg (bbl/well):	7,911	7,886	8,369	8,614

Ref: EIS RFD Scenario (Table 3) survey of well counts (active and new) from: DOGGR GIS (2014) appended by Appendix M, CCST, 2015.

Ref: DOC well counts (active) from: DOC Division of Oil, Gas, and Geothermal Resources - Well Search (Oct 12, 2016)

RFDS Crude Oil Production Potential (total full buildout)

Historic Highest of Avg Production in Established Fields x RFDS Number of Wells in Production

8,614 bbl/well (peak per year)

37 wells in production

Crude Oil Heating Value (LHV), from OPGEE v1.1e Fuel Specs Table 1.1

6,324 MJ/bbl (API 12)

RFDS Crude Production:

By volume (barrels)	318,718 bbl per year	By heat content (mega-Joules)	2.016E+09 MJ per year
By volume (million barrels)	0.319 MMbbl per year	By heat content (tera-Joules)	2.016E+03 TJ per year
By volume (gallons)	13,386,141 gal per year		

Crude Oil (Default High Heat Value, HHV), from 40 CFR Part 98, Subpart C Table C-1

0.138 MMBtu/gallon

By heat content (million Btu)	1,847,287 MMBtu per year
By heat content (tera-Joules)	1.949E+03 TJ per year

RFDS GHG Emitted via Production & Transport (ARB CI basis)

GHG via Production & Transport

(Source: ARB Carbon Intensity (CI) data for typical fields in this region.)

Baseline 3-yr Regional CI Est'd (g/MJ) x RFDS Crude Production (MJ per year)

26.67 CI (gCO2e/MJ)

Result (Production & Transport)

118,504,993 CO2e (lb/yr)

53,754 CO2e (MT/yr)

RFDS GHG Emitted via End Use of Crude Oil

GHG Indirect Emissions due to End Use

CO2 Emission Factor x RFDS Crude Production (by volume or by heat content)

CO2 Emission Factor Source 1 - IPCC, 2006

73,300 kg CO2/TJ (IPCC, 2006)

73.30 MTCO2/TJ

Result Source 1 (End Use)

325,723,502 CO2 (lb/yr)

147,747 CO2 (MT/yr)

CO2 Emission Factor Source 2 - EIA, 2011

10.29 kg CO2/gallon (EIA, 2011)

Result Source 2 (End Use)

303,669,069 CO2 (lb/yr)

137,743 CO2 (MT/yr)

CO2 Emission Factor Source 3 - EPA, 2016

74.54 kg CO2/MMBtu (EPA, 2016)

70.65 MTCO2/TJ

Result Source 3 (End Use)

303,566,371 CO2 (lb/yr)

137,697 CO2 (MT/yr)

Average of above CO2 results >>>>>>>>>>

Result (End Use)

141,062 CO2 (MT/yr)

Include CH4 & N2O Source 3 - EPA, 2016

25 GWP CH4 — 3.00E-03 kg CH4/MMBtu (EPA, 2016)

5.54 CH4 (MT/yr)

139 CO2e (MT/yr)

298 GWP N2O — 6.00E-04 kg N2O/MMBtu (EPA, 2016)

1.11 N2O (MT/yr)

330 CO2e (MT/yr)

Result (End Use)

141,531 CO2e (MT/yr)

Ref (1): IPCC, 2006. TABLE 2.2 DEFAULT EMISSION FACTORS FOR STATIONARY COMBUSTION IN THE ENERGY INDUSTRIES (kg of greenhouse gas per TJ on a Net Calorific Basis)
2006 IPCC Guidelines for National Greenhouse Gas Inventories
http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_2_Ch2_Stationary_Combustion.pdf

Ref (2): U.S. EIA, 2011. Voluntary Reporting of Greenhouse Gases Program. Fuel Emission Coefficients Table 1 (CO2 for Stationary Combustion)
http://www.eia.gov/oiaf/1605/coefficients.html#tbl2

Ref (3): U.S. EPA, 2016. Mandatory Greenhouse Gas Reporting Regulation. 40 CFR Part 98, Subpart C, Table C-1. (Default HHV, CO2 factors)
40 CFR Part 98, Subpart C, Table C-2. (Default CH4, N2O); Subpart A, Table A-1 (GWPs)
http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=&SID=fbd64b2188110b00aaa829eed7718d5d&mc=true&n=sp40.23.98.c&r=SUBPART&ty=HTML#ap40.23.98_138.1