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July 2015

CCST
CALIFORNIA COUNCIL ON SCIENCE & TECHNOLOGY

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Lawrence Berkeley National Laboratory

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An Independent Scientific Assessment of Well Stimulation in California

Volume III

Case Studies of Hydraulic Fracturing and Acid Stimulations in Select Regions: Offshore, Monterey Formation, Los Angeles Basin and San Joaquin Basin

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About CCST

CCST is a non-profit organization established in 1988 at the request of the California State Government and sponsored by the major public and private postsecondary institutions of California and affiliate federal laboratories in conjunction with leading private-sector firms. CCST's mission is to improve science and technology policy and application in California by proposing programs, conducting analyses, and recommending public policies and initiatives that will maintain California's technological leadership and a vigorous economy.

Note

Any opinions, findings, conclusions, or recommendations expressed in this publication are those of the author(s) and do not necessarily reflect the views of the organizations or agencies that provided support for the project.

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Acronyms and Abbreviations

ALA	American Lung Association
APCHH	American Petrofina Central Core Hole
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
ATSDR	Agency for Toxic Substances and Disease Registry
BAT	Best Available Treatment Economically Achievable
bbl	Oil Barrel
bble	Oil Barrel Equivalent Energy
BBO	Billion Barrels of Oil
BCT	Best Conventional Pollutant Control Technology
BLS	(U.S.) Bureau of Labor Statistics
BOE	Barrels of Oil Equivalent
BOEM	Bureau of Ocean Energy Management
BSEE	Bureau of Safety and Environmental Enforcement
BTEX	Benzene, Toluene, Ethylbenzene, and Xylene
CARB	California Air Resources Board
CCC	California Coastal Commission
CCST	California Council on Science and Technology
CDC	Centers for Disease Control and Prevention
CER	Categorical Exclusion Reviews
CI	Confidence Interval
CI	Carbon Intensity
CMIT	Biocide 5-Chloro-2-methyl-3(2H)-isothiazolone
CSLC	California State Land Commission
CT	Cristobalite and Tridymite
CVRWQCB	Central Valley Regional Water Quality Control Board
DG	Distributed Petroleum-Powered Generation
DMR	Discharge Monitoring Report
DOE	U.S. Department of Energy
DOGGR	(California) Division of Oil, Gas, and Geothermal Resources
DPH	Department of Public Health
DWR	Department of Water Resources
EOR	Enhanced Oil Recovery
FM	Fractured Monterey
FOIA	Freedom of Information Act
FR	Federal Register
ft	Feet
GAMA	Groundwater Ambient Monitoring & Assessment
GHG	Greenhouse Gases
GHS	Globally Harmonized System

GIS	Geographic Information Systems
GOR	Gas-Oil Ratio
GSM	Gaviota-Sacate-Matilija
HAP	Hazardous Air Pollutant
HBACVs	Health-Based Air Concentration Values
HCl	Hydrochloric Acid
HF	Hydraulically Fractured
HLTHFAC	California Health Care Facility Dataset
HRGP	High-Rate Gravel Packs
ICIS/PCS	Integrated Compliance Information System and Permit Compliance System (database)
iF	Intake Fraction
IRIS	Integrated Risk Information System
kg	Kilogram
L	Liter
LBNL	Lawrence Berkeley National Laboratory
m^3	Cubic Meter
m^3e	Cubic Meter of Oil Equivalent Energy
mi.	Mile
MMS	Minerals Management Service
MRLs	Minimal Risk Levels
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
OCS	(Federal) Outer Continental Shelf
OEHHA	Office of Environmental Health Hazard Assessment
OOIP	Original Oil In Place
OR	Odds Ratio
OSHA	Occupational Safety and Health Administration
OSPAR	Oslo and Paris Convention
PAH	Polycyclic Aromatic Hydrocarbons
PLSS	Public Land Survey System
PM	Particulate Matter
PM_{10}	Particulates Smaller than 10 Microns
$PM_{2.5}$	Particulates Smaller than 2.5 Microns
PPB	Parts Per Billion
PPM	Parts Per Million
PR	Pico-Repetto
REL	Reference Exposure Levels
RfC	Reference Concentrations
RfDs	Reference Doses
RMT-SAV	Rincon-Monterey-Topanga-Sespe-Alegria-Vaqueros
RO	Reverse Osmosis
ROG	Reactive Organic Gases
SB 1281	Senate Bill 1281

SB 4	Senate Bill 4
SCAQMD	South Coast Air Quality Management District
SCEDC	Southern California Earthquake Data Center
SIC	Standard Industry Classification code
SJVAB	San Joaquin Valley Air Basin
SJVUAPCD	San Joaquin Valley Unified Air Pollution Control District
SoCAB	South Coast Air Basin
SO_x	Sulfur Oxides
SWRCB	(California) State Water Resources Control Board
TAC	Toxic Air Contaminant
TCW	Treatment, Completion, and Workover
TDS	Total Dissolved Solids
THUMS	Texaco, Humble, Union, Mobil, and Shell (a set of artificial islands)
TOC	Total Organic Carbon
TOG	Total Organic Gases
TR	Transformation Ratio
TRRC	Texas Railroad Commission
TVD	True Vertical Depth
U.S. EIA	U.S. Energy Information Administration
U.S. EPA	U.S. Environmental Protection Agency
UIC	Underground Injection Control
USC	United States Code
USDW	Underground Source of Drinking Water
USGS	United States Geological Survey
USQFF	U.S. Quaternary Fault and Fold Database
VCAPCD	Ventura County Air Pollution Control District
VOC	Volatile Organic Compound
WDR	Waste Discharge Requirements
WET	Whole Effluent Toxicity
$\mu g/m^3$	Micrograms per Cubic Meter

Chapter One

Introduction

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1.1. Background

In 2013, the California Legislature passed Senate Bill 4 (SB 4), setting the framework for regulation of well stimulation technologies in California, including hydraulic fracturing. SB 4 also requires the California Natural Resources Agency to conduct an independent scientific study of well stimulation technologies in California. SB 4 stipulates that the independent study assess current and potential future well stimulation practices, including the likelihood that these technologies could enable extensive new petroleum production in the state; evaluate the impacts of well stimulation technologies and the gaps in data that preclude this understanding; identify potential risks associated with current practices; and identify alternative practices that might limit these risks. This scientific assessment addresses well stimulation used in oil and gas production both on land and offshore in California.

Well stimulation enhances oil and gas production by making the reservoir rocks more permeable, thus allowing more oil or gas to flow to the well. The reports discuss three types of well stimulation as defined in SB 4 (Table 1.1-1 and Volume I, Chapter 2). The first type is "hydraulic fracturing." To create a hydraulic fracture, an operator increases the pressure of an injected fluid in an isolated section of a well until the surrounding rock breaks, or "fractures." Sand injected into these fractures props them open after the pressure is released. The second type is "acid fracturing," in which a high-pressure acidic fluid fractures the rock and etches the walls of the fractures, so they remain permeable after the pressure is released. The third type, "matrix acidizing," does not fracture the rock; instead, acid pumped into the well at relatively low pressure dissolves some of the rock and makes it more permeable. See Box 1.1-1 for a short history of oil and gas production in California.

This study is issued in three volumes. Volume I, issued in January 2015, describes how well stimulation technologies work, how and where operators deploy these technologies for oil and gas production in California, and where they might enable production in the future. Volume II, issued in July 2015, discusses how well stimulation could affect water, atmosphere, seismic activity, wildlife and vegetation, and human health. Volume II reviews available data, and identifies knowledge gaps and alternative practices that could avoid or mitigate these possible impacts. Volume III, this volume, presents case studies that assess environmental issues and qualitative risks for specific geographic regions. The Summary Report summarizes key findings, conclusions and recommendations of all three volumes.

Table 1.1-1. Well stimulation technologies included in Senate Bill 4 (SB 4).

<table>
<tr><td colspan="3">Hydraulic Fracturing Stimulation
Common feature: All treatments create sufficient pressure in the well to induce fractures in the reservoir.</td></tr>
<tr><td colspan="2">Proppant Fracturing:
Uses proppant to retain fracture permeability</td><td>Acid Fracturing:
Uses acid instead of proppant</td></tr>
<tr><td>Traditional Fracturing: Creates long, narrower hydraulic fractures deep into the formation for stimulating flow through lower-permeability reservoirs; proppant injected into fractures to retain fracture permeability</td><td>Frac-Pack: Creates short, wider hydraulic fractures near wells within higher-permeability reservoirs; objectives are bypassing regions near-the wellbore damaged by drilling and preventing sand from the reservoir entering the well</td><td>Similar to traditional fracturing, but uses acid instead of proppant to retain fracture permeability by etching, or “roughening” the fracture walls; only used in carbonate reservoirs</td></tr>
</table>

<table>
<tr><td colspan="2">Acidizing Stimulation
Common feature: All treatments use acid to dissolve materials impeding flow</td></tr>
<tr><td colspan="2">Matrix Acidizing: Dissolves material in the near-well region to make the reservoir rocks more permeable; typically only used for reservoirs that are already permeable enough to not require traditional or acid fracturing</td></tr>
<tr><td>Sandstone Acidizing: Uses hydrofluoric acid in combination with other acids to dissolve minerals (silicates) that plug the pores of the reservoir; only used in reservoirs composed of sandstone or other siliceous rocks</td><td>Carbonate Acidizing: Uses hydrochloric acid (or acetic or formic acids) to dissolve carbonate minerals, such as those comprising limestone, and bypass rock near the wellbore damaged by drilling; only used in carbonate reservoirs</td></tr>
</table>

Volumes I, II and III of this report address issues that have very different amounts of available information and cover a wide range of topics and associated disciplines, which have well established but differing protocols for inquiry. In Volume I, available data and methods of statistics, engineering and geology allow the authors to present the factual basis of well stimulation in California. With a few exceptions, the existing data was sufficient to accurately identify the technologies used, analyze where and how often they are used, and evaluate where they are likely to be used in the future (see Volume I, Chapter 3).

The authors of Volume II faced the challenge of assessing and presenting the impacts of well stimulation. Since many impacts have never been thoroughly investigated, the authors drew on literature describing conditions and outcomes in other places, circumstantial evidence and expert judgment to catalog a complete list of potential impacts that may or may not occur in California. Volume II also identifies a set of concerning situations – “risk factors” (summarized in Appendix D of the Summary Report and Table 6.2-1 of Volume II) – that warrant a closer look and perhaps regulatory attention.

Box 1.1-1. History of Oil and Gas Production in California

California has some highest concentrations of oil in the world and oil and gas production remains a major California industry. Commercial production started in the middle of the 19th century from hand-dug pits and shallow wells. In 1929, at the peak of oil development in the Los Angeles Basin, California accounted for more than 22% of total world oil production (American Petroleum Institute, Basic Petroleum Data Book, Volume XIII, Number 2, 1993). California's oil production reached an all-time high of almost 64 million m^3 (400 million barrels) in 1985 and has generally declined since then. Today California is the third highest producing state, with about 6% of US production but less than 1% of global production. In 1960, almost as much oil was produced in California as was consumed, but by 2012 Californians produced only 32% of the oil they used (31.5 million m^3 or198 million barrels produced in the state out of a total of about 98.7 million m^3 or 621 million barrels consumed). Californian's mainly made up the shortfall of about 67.3 million m^3 (423 million barrels) mainly with oil delivered by tanker from Alaska, Saudi Arabia, Ecuador, Iraq, Colombia, and other countries.

Over the years, water flooding, gas injection, thermal recovery, hydraulic fracturing, and other techniques have been used to enhance oil and gas production as California fields mature. The diatomite reservoirs in the western San Joaquin Valley contain billions of barrels of oil in rocks that are not very permeable, and can only be produced with hydraulic fracturing—now accounting for about 20% of California oil and gas production (see Volume I, Chapter 3). Most of the natural gas produced in the state is a co-product of oil production, which is known as "associated" gas production. Most of this production occurs in the San Joaquin Valley, including reservoirs that use hydraulic fracturing.

Volume III largely extends the method of inquiry used in Volume II to location-specific issues for offshore, the Monterey Formation Case Study, the Los Angeles Basin, and the San Joaquin Basin. The Offshore Case Study evaluates what we know and do not know about the use of stimulation technologies in that environment. The Monterey Case Study identifies the geographic locations (or "footprint") of the parts of the Monterey Formation that could contain producible oil and gas in "source rock," (see the Summary Report, Appendix E for a definition of source rock) and examines the implications if new production were to begin in those regions. Likewise, the San Joaquin Basin Case study evaluates likely future production with hydraulic fracturing and examines the implications of that production.

The first part of the Los Angeles Basin Case Study describes the geologic basis of oil production and its implications for future oil and gas production using technology such as hydraulic fracturing. The second part evaluates sparse information about public health implications of oil and gas development in a densely populated mega-city. This study compensates for the lack of data documenting adverse health outcomes by investigating information that suggests, but does not confirm with certainty, the risks to human health. The precepts of the field of public health include an emphasis on the anticipation of potential problems even though specific problems have not been observed or proven to create risk. In this way, the public health chapter of Volume II and the public health analysis for the Los Angeles Basin Case Study differ from other parts of this report. A major goal of public health research is to anticipate and avoid harm rather than to observe and allocate cause for harm.

The authors of this report hope this flexible and appropriate use of different (but well established) methods of inquiry under highly variable conditions of data availability and potential impacts serves useful to California.

1.2. CCST Committee Process

The California Council on Science and Technology (CCST) organized and led the study reported on here. Members of the CCST steering committee were appointed based on technical expertise and a balance of technical viewpoints. (Appendix B provides information about CCST's steering committee.) Under the guidance of the steering committee, Lawrence Berkeley National Laboratory (LBNL) and subcontractors (the science team) developed the findings based on the literature review and original technical data analyses. Appendix C provides information about the LBNL science team and subcontractors who authored Volumes I, II, and III of this report. The science team reviewed relevant literature and conducted original technical data analyses.

The science team studied each of the issues required by SB 4, and the science team and the steering committee collaborated to develop a series of conclusions and recommendations that are provided in this summary report. Both science team and steering committee members proposed draft conclusions and recommendations. These were modified based on discussion within the steering committee along with continued consultation with the science team. Final responsibility for the conclusions and recommendations in this report lies with the steering committee. All steering committee members have agreed with these conclusions and recommendations. Any steering committee member could have written a dissenting opinion, but no one requested to do so.

SB 4 also required the participation of the California Environmental Protection Agency's Office of Environmental Health Hazard Assessment (OEHHA) in this study. OEHHA provided toxicity and other risk assessment information on many of the chemicals used in hydraulic fracturing, offered informal technical advice during the course of the study, and provided comments on drafts of Volumes II and III. OEHHA also organized a February 3, 2015 public workshop in Bakersfield in which representatives of CCST, LBNL, and subcontractors heard comments from attendees on the topics covered in the report.

This report has undergone extensive peer review. (Peer reviewers are listed in Appendix F, "California Council on Science and Technology Study Process"). Seventeen reviewers were chosen for their relevant technical expertise. More than 1,500 anonymous review comments were provided to the authors. The authors revised the report in response to peer review comments. In cases where the authors disagreed with the reviewer, the response to review included their reasons for disagreement. Report monitors then reviewed the response to review and when satisfied, approved the report.

1.3. The Four Case Studies

The case studies in this volume examine the impacts and issues that arise in four locations in California that are affected by well stimulation. Focus on a specific geography allows a more detailed examination of practices, impacts and potential risks specific to that region.

Offshore Case Study: Offshore production became controversial with the Santa Barbara oil spill in the 1970s, and subsequent policies severely limited development of the vast reserves that lie off the California coast. Concerns about hydraulic fracturing have exacerbated concerns about ocean contamination. The Offshore Case Study assembles available data describing stimulation practices offshore, the possible impacts on the ocean environment, and describes data gaps. The case study focuses on production in state and federal waters (those that are more than 5.6 km, or three nautical miles offshore). (Volume III, Chapter 2, Offshore Case Study).

Monterey Formation Case Study: The Energy Information Agency produced an estimate of shale-oil production potential in the source rocks of the Monterey Formation that caused concern about an imminent oil boom in California. A subsequent estimate downgraded the first by 96%; however, neither of these estimates have a strong basis in data (see Volume I). The Monterey Formation Case Study attempts to map the geographic locations where there is some possibility of deep, underlying source-rock shale oil that could possibly be produced with stimulation technology and how these locations compare to current land use. In these locations, we also map the specific environmental and ecological issues that might cause concern if oil and gas development did occur and we provide some guidance about what it would take to get a more reliable estimate of the production potential for these rocks (Volume III, Chapter 3, Monterey Formation Case Study)

Los Angeles Basin Case Study: Los Angeles, a megacity with challenging air pollution problems, has giant, world-class oil fields within the city boundary. The development of these fields, contemporaneous with the growth of the city, has caused conflict for nearly a hundred years. Though oil production has been declining for years, there have been reports recently suggesting the possibility of additional large-scale oil production enabled by hydraulic fracturing. The Los Angeles Basin Case Study has two parts: The first part investigates the resource potential in the region in particular with regards to possible future production from deep source rocks. The second part examines air pollution in the valley caused by oil and gas development and the contribution to that air pollution made by stimulated wells. Although the oil and gas sector contributes a minor percentage of the total air pollution burden in the valley, the concentration of these air contaminants can be much larger near the wells that are a source of emissions. Exposure to toxic pollutants from production wells depends on how close people are to the wells. We look at the current proximity of population including vulnerable portions of the population to oil and gas development in general and to stimulated wells in particular. The future of oil production in the urban environment, including that enabled by well stimulation, has potential implications for human health. (Volume III, Chapter 4, Los Angeles Basin Case Study).

San Joaquin Basin Case Study: The San Joaquin Basin produces most of the oil and gas in California and is home to 96% of the stimulation treatments. The valley is also a major center of industrial agriculture and suffers from chronic air pollution and water shortage. The San Joaquin Basin Case Study examines the likely future of well stimulation and the potential risks posed by this practice to water, air and human health (Volume III, Chapter 5, San Joaquin Basin Case Study).

One other case study was initially considered but not developed. Most of our focus has been on oil production and gas production associated with oil production. However, northern California does have “un-associated” or “dry” gas production. We found very little evidence to support a new major dry gas play that would require well stimulation or any evidence supporting extensive use of well stimulation in current dry gas production, so there seemed little point in pursuing a northern California gas case study.

These case studies integrate what we learned about stimulation practices in Volume I with generalized potential impacts evaluated in Volume II and focus on more detailed locally specific issues. Each case study is different and depends entirely on apparent issues for each location. Each might well be revisited in the future as more data is collected and as the practice in industry changes.

1.4. Data and Literature Used in the Report

This assessment reviews and analyzes both existing data and scientific literature, with preference given to findings presented in the peer-reviewed scientific literature. The study included both voluntary and mandatory reporting of stimulation data, as well as non-peer reviewed reports and documents if they were topically relevant and determined to be scientifically credible by the authors and reviewers of this volume. Finally, the California Council on Science and Technology solicited and reviewed nominations of literature from the public, employing specific criteria for material as described in Appendix E, “Review of Information Sources.” The science team did not collect any new data, but did do original analysis of available data.

1.4.1. Data on Well Stimulation Statistics and Stimulation Chemistry

A comprehensive understanding of well stimulation in the state requires complete and accurate reporting, as directed by SB 4, and sufficient time for a representative number and type of operations to be reported. The analyses summarized in this report assess less than one year of well stimulation data reported under mandatory reporting starting on January 1, 2014. Mandatory reporting under SB 4 includes data submittals to FracFocus, a website created by petroleum industry groups to disclose information about drilling and chemical use in hydraulic fracturing, as well as submission of this and additional information to the California Division of Oil, Gas and Geothermal Resources (DOGGR), which provides access through its website. Other sources of data collected under mandatory reporting include data from the South Coast Air Quality Management District (SCAQMD) since June 2013 and from the Central Valley Regional Water Quality Control Board (CVRWQCB) for 2012 and 2013. The SCAQMD and CVRWQCB data are limited to the Los Angeles Air Basin and the Central Valley Region, respectively. Voluntary data on hydraulic fracturing operations have been available for longer time periods going back several years, but remain incomplete and are not fully verifiable. Voluntary sources include information submitted to FracFocus, between 2011 and 2013, and well construction histories provided to and available from DOGGR going back many years. We estimate more than half of hydraulic fracturing operations in California are recorded in these histories. The content of each record varies from as little as just an indication a hydraulic fracturing operation occurred to as much as the times, flow rates, stages, fluid type, injection pressures, and proppant loading schedule for the operation. In all cases, analyses summarized in this report only assess data available prior to 2015, and prior to July 2014 for many of the data sets considered starting in Volume I.

The conclusions about hydraulic fracturing onshore derived in this report are supported by information from voluntary and mandatory reported data, scientific literature, government reports, and other sources such as patents and industrial literature which give largely consistent results, indicating that we can have reasonable confidence in the quality and consistency of the data collected before and since mandatory reporting began despite the limitations in the data. Consequently, the authors think the report conclusions about hydraulic fracturing are generally accurate and representative of well stimulation activities in the state. Additional data in the future might change some of the quantitative findings in the report, but it is unlikely these will fundamentally alter the report findings about the current and likely future use of well stimulation in California.

We consider the available information on the geology of conventional resources in California and the potential for future use of well stimulation in reservoirs of the state to be of high quality. In contrast, current estimates on the recoverable shale-oil resources in the deep Monterey source rock are highly uncertain.

1.4.2. Information and Data on Well Stimulation Impacts

The SB 4 completion reports contain reliable data on stimulation statistics and provide a basis for assessment of certain potential environmental and health impacts, such as the quantity of fresh water for hydraulic fracturing or the fracturing depth in the vicinity of groundwater resources. For many other impacts, however, only incomplete information and data exist, and questions remain that require additional research and data collection. For example, few scientific studies of health and environmental impacts of well stimulation have been done to date, and the ones that have been done address other parts of the country, where practices differ significantly from present-day practices in California. Generally, environmental baseline data has not been collected in the vicinity of stimulation sites before stimulation. The lack of baseline data makes it difficult to know if the process of stimulation has changed groundwater chemistry or habitat, or how likely any potential impacts might be. No records of contamination of protected water by hydraulic fracturing fluids in California exist, but few if any targeted studies have been conducted to look for such contamination. Data describing the quality of groundwater near hydraulic fracturing sites are not universally available. The requirement for groundwater monitoring in SB 4 addresses this issue by requiring groundwater monitoring when protected water is present. Applications for hydraulic fracturing operations that have no nearby protected groundwater have been exempted from groundwater monitoring. Thus, the requirements and exemptions provide some information about the quality of water near proposed hydraulic fracturing sites.

A complete analysis of the risks posed by well stimulation (primarily hydraulic fracturing) to water contamination, air pollution, earthquakes, wildlife, plants, and human health requires much more data than that available. However, the study authors were able to draw on their technical knowledge, data from other places, and consideration of the specific conditions in California to identify conditions in California that deserve more attention and make recommendations for additional data collection, increased regulation, or other mitigating measures. These conditions, or “risk factors” have become the subjects of the conclusions and recommendations under the heading of “Impacts.” Appendix D of the Summary Report also provides a summary of risk issues in a tabular form.

1.4.3. Data for Case Studies

The data sources used to construct the case studies is largely the same as the sources above with the same limitations on the length and accuracy of records and data gaps. We describe the limitations of the data throughout the volume in order to transparently qualify the accuracy of the conclusions.

1.5. Conclusions and Recommendations of Volume III

The following conclusions and recommendations are numbered to correspond to the full set of conclusions and recommendations as given in the Summary Report, but only those conclusions and recommendations that derive from this volume are given below. This is the reason that the conclusions and recommendations are not numbered sequentially starting with number 1. However, for the sake of consistency, some conclusions include information from other volumes as noted.

Offshore Case Study:

Conclusion 1.5. Record keeping for hydraulic fracturing and acid stimulation in federal waters does not meet state standards.

Current record-keeping practice on stimulations in federal waters (from platforms more than 5.6 km, or three nautical miles offshore) does not meet the standards set by the pending SB 4 well treatment regulations and does not allow an assessment of the level of activity or composition of hydraulic fracturing chemicals being discharged in the ocean. The U.S. Environmental Protection Agency's (U.S. EPA) National Pollutant Discharge Elimination System (NPDES) permits that regulate discharge from offshore platforms do not effectively address hydraulic fracturing fluids. The limited publicly available records disclose only a few stimulations per year.

The federal government does not maintain a website or other public portal with data on the use of hydraulic fracturing from platforms in federal waters (federal waters are more than 5.6 km or three nautical miles, from the coast) except for data that has been requested through the Federal Freedom of Information Act (FOIA). The FOIA records include about one hydraulic fracturing operation per year out of the 200 wells installed from 1992 through 2013, all but one of these operations were in the Santa Barbara-Ventura Basin (Volume I, Chapter 3). Through NPDES, EPA permits offshore facilities in federal waters to discharge recovered hydraulic fracturing fluids mixed with produced water to the ocean, subject to constraints on contaminant concentrations. However, the constraints do not include limits on hydraulic fracturing chemicals. EPA requires sampling of produced water discharge and testing these samples through a "whole effluent toxicity" or "WET" test that provides an integrated assessment of the toxicity of the effluent. However, these tests do not occur in coordination with any hydraulic fracturing operation, so they are likely to miss any impacts that hydraulic fracturing chemicals might cause.

Recommendation 1.2. Improve reporting of hydraulic fracturing and acid stimulation data in federal waters.

The State of California should request that the federal government improve data collection and record keeping concerning well stimulation conducted in federal waters to at least match the requirements of SB 4. The U.S. EPA should conduct an assessment of ocean discharge and, based on these results, consider if alternatives to ocean disposal for well stimulation fluid returns are necessary (Volume III, Chapter 2 [Offshore Case Study]).

Monterey Formation Case Study:

Conclusion 2.2. Oil resource assessment and future use of hydraulic fracturing and acid stimulation in the Monterey Formation[1] of California remain uncertain.

In 2011, the U.S. Energy Information Administration (EIA) estimated that 2.4 billion m^3 (15 billion barrels) of recoverable shale-oil resources existed in Monterey source rock. This caused concern about the potential environmental impacts of widespread shale-oil development in California using hydraulic fracturing. In 2014 the EIA downgraded the 2011 estimate by 96%. This study reviewed both EIA estimates and concluded that neither one can be considered reliable. Any potential for production in the Monterey Formation would be confined to those parts of the formation in the "oil window," that is, where Monterey Formation rocks have experienced the temperatures and pressures required to form oil. The surface footprint of this subset of the Monterey Formation expands existing regions of oil and gas production rather than opening up entirely new oil and gas producing regions. Significant unconventional gas resources (such as those of the Appalachian Basin Marcellus Shale or the Fort Worth Basin Barnett Formation which have been produced with large-scale hydraulic fracturing operations) probably do not exist in California.

In 2011, the EIA reported that more than 2.4 billion m^3 (15 billion barrels) of oil could be recovered from the "Monterey/Santos[2] (source rock) Play" across the state, presumably by means of hydraulic fracturing or acid stimulation. At the time, this estimate exceeded the estimated recoverable oil volume from source rock for the entire rest of the country. The EIA's projection, combined with widespread production using hydraulic fracturing of petroleum source rocks in North Dakota, Texas, and elsewhere, led to speculation and concern that similar development might be in the offing for California. Many Californians became concerned that California could experience a "boom-town" surge

1. The Summary Report, Appendix G provides an explanation of the terms Monterey Formation and Monterey Source Rock.
2. The 2011 and 2014 EIA assessments both use the term "Monterey/Santos" in describing the shale oil play in California. The "Santos" appears to be an erroneous reference to the Saltos shale of the Cuyama basin. Geochemical studies have not identified the Saltos shale as a significant source of hydrocarbons, so it is likely that the Monterey is the dominant source rock considered in the EIA evaluation.

in oil production, i.e., activity in regions of the state that have not yet experienced oil production, unacceptable water use in a water-short state, water contamination, and health impacts. While no significant source-rock production has yet occurred in the state, future technical innovations might facilitate such development. A second EIA report, released in 2014, reduced the estimate of recoverable oil in Monterey source rocks to 0.1 billion m^3 (0.6 billion barrels). Figure 1.5-1 shows both these estimates. However, EIA provided little documentation to support either estimate. Consequently, neither of these estimates can be scientifically evaluated, and they do little to constrain the range of possible source rock oil resources in the Monterey Formation.

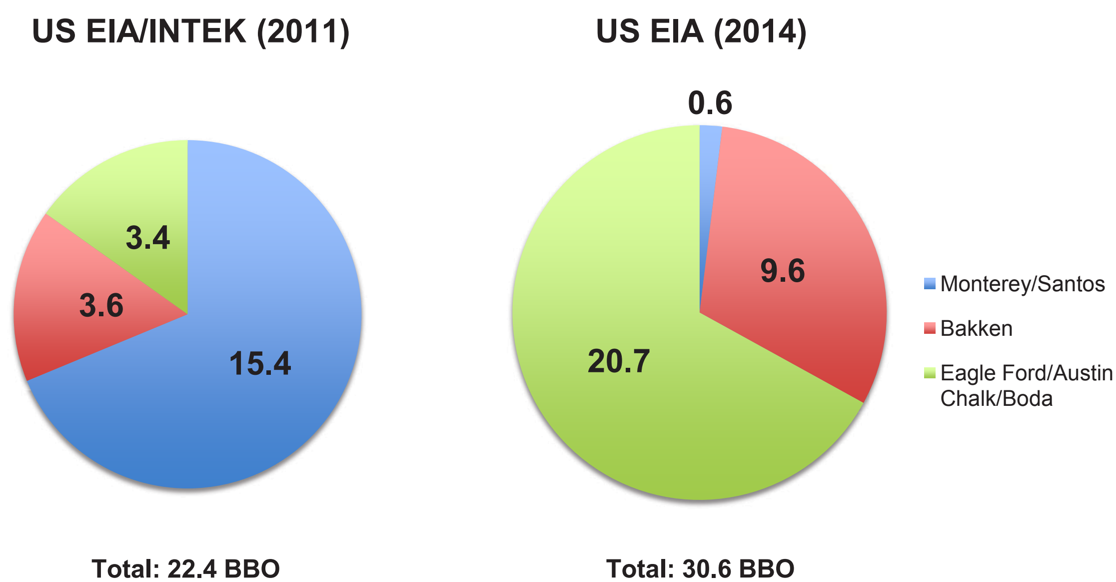

Figure 1.5-1. The Energy Information Administration 2011 and 2014 estimates of the potential of recoverable oil in source rock in the United States. The 2011 estimate for the Monterey/ Santos is more than 2.4 billion m^3 (15 billion barrels), whereas the 2014 estimate decreases the Monterey estimate to about 4 % of the earlier estimate while increasing the total U.S. estimate by 30% (figure modified from Volume III, Chapter 1).

The footprint of the oil and gas window of the Monterey Formation primarily expands the regions that currently produce oil and gas. No part of this footprint is more than ~20 km (12 miles) from existing production. Any potential future development of Monterey Formation source rocks would likely involve hydraulic fracturing or acid stimulation and would occur in the vicinity of current oil and gas producing regions with their existing infrastructure and economy (Figure 1.5-2) (Volume III, Chapter 3 [Monterey Formation Case Study]).

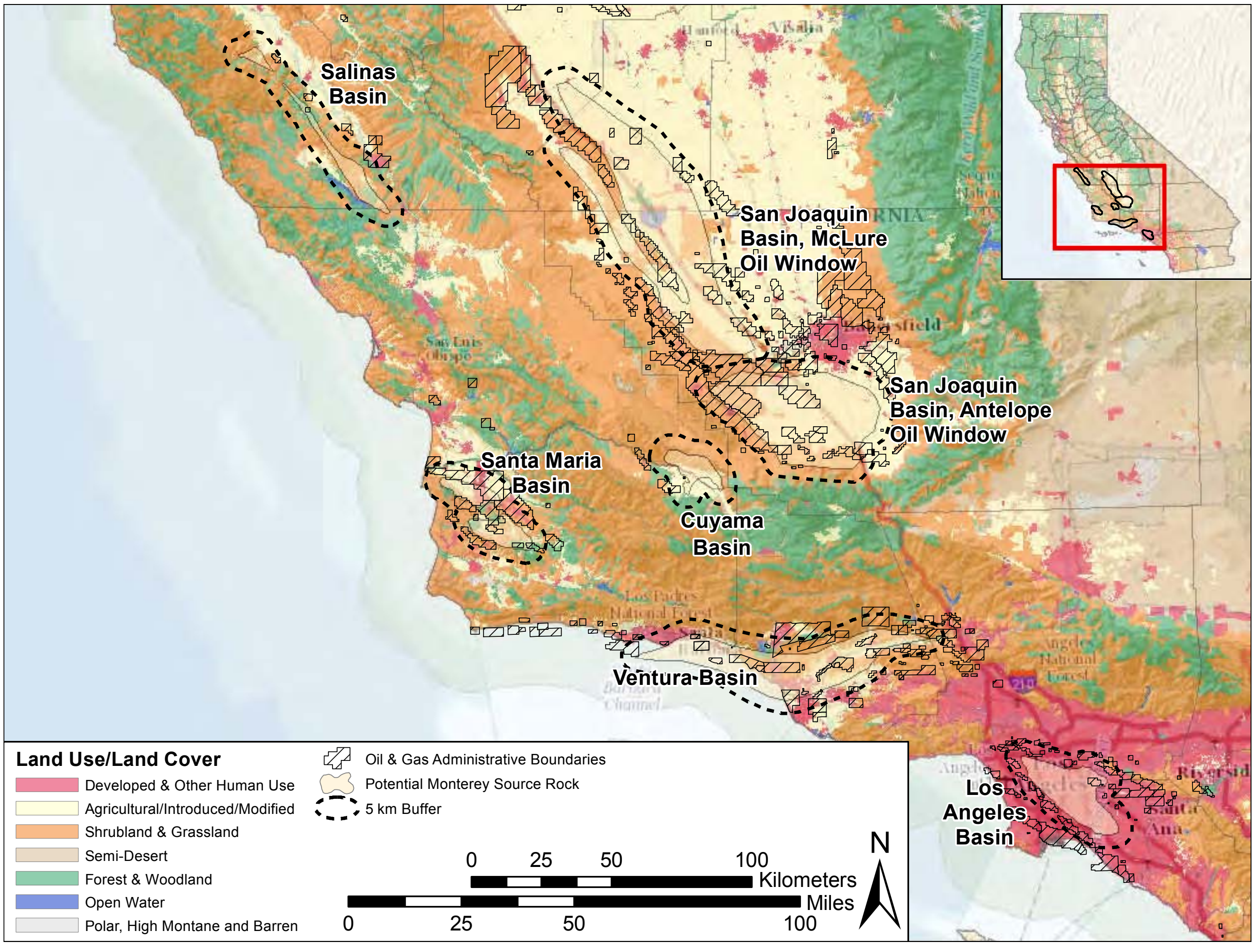

Figure 1.5-2. The approximate geographic footprint of those parts of the Monterey Formation in the oil and gas window (i.e. those parts that might be actively generating oil and gas) mapped along with current land use. Black hatching indicates the locations of existing oil fields. Thin black lines mark the footprint of the Monterey source rock oil window and dashed black lines mark a ~5 km (three-mile) buffer to include uncertainty in the actual extent. Note that the boundaries of the Monterey source rock window are in the vicinity of existing oil and gas fields, but cover a larger area (Figure modified from Volume III, Chapter 3 [Monterey Formation Case Study]).

The geological conditions in California do not likely include basin-wide gas accumulations. The Sacramento Basin, which contains the majority of dry gas reservoirs, does not exhibit the geological features of the Marcellus or Barnett Formations, or the Uinta-Piceance Basin, that would result in significant gas accumulations—at least at the depths that have been explored so far (Volume I, Chapter 4).

Recommendation 2.1. Assess the oil resource potential of the Monterey Formation.

The state should request a comprehensive, science-based and peer-reviewed assessment of source-rock ("shale") oil resources in California and the technologies that might be used to produce them. The state could request such an assessment from the U.S. Geological Survey (USGS), for example.

Recommendation 2.2. Keep track of exploration in the Monterey Formation.

As expansive production in the Monterey Formation remains possible, DOGGR should track well permits for future drilling in the "oil window" of the Monterey source rocks (and other extensive source rocks, such as the Kreyenhagen) and be able to report increased activity (Volume I, Chapter 4; Volume III, Chapter 3 [Monterey Formation Case Study]).

Los Angeles Basin Case Study:

Conclusion 6.3. Emissions concentrated near all oil and gas production could present health hazards to nearby communities in California.

Many of the constituents used in and emitted by oil and gas development can damage health, and place disproportionate risks on sensitive populations, including children, pregnant women, the elderly, and those with pre-existing respiratory and cardiovascular conditions. Health risks near oil and gas wells may be independent of whether wells in production have undergone hydraulic fracturing or not. Consequently, a full understanding of health risks caused by proximity to production wells will require studying all types of productions wells, not just those that have undergone hydraulic fracturing. Oil and gas development poses more elevated health risks when conducted in areas of high population density, such as the Los Angeles Basin, because it results in larger population exposures to toxic air contaminants.

California has large developed oil reserves located in densely populated areas. For example, the Los Angeles Basin reservoirs, which have the highest concentrations of oil in the world, exist within the global megacity of Los Angeles. Approximately half a million people live, and large numbers of schools, elderly facilities, and daycare facilities exist, within one mile of a stimulated well, and many more live near oil and gas development of all types (Figure 1.5-3). The closer citizens are to these industrial facilities, the higher their potential exposure to toxic air emissions and higher risk of associated health effects. Production enabled by well stimulation accounts for a fraction of these emissions.

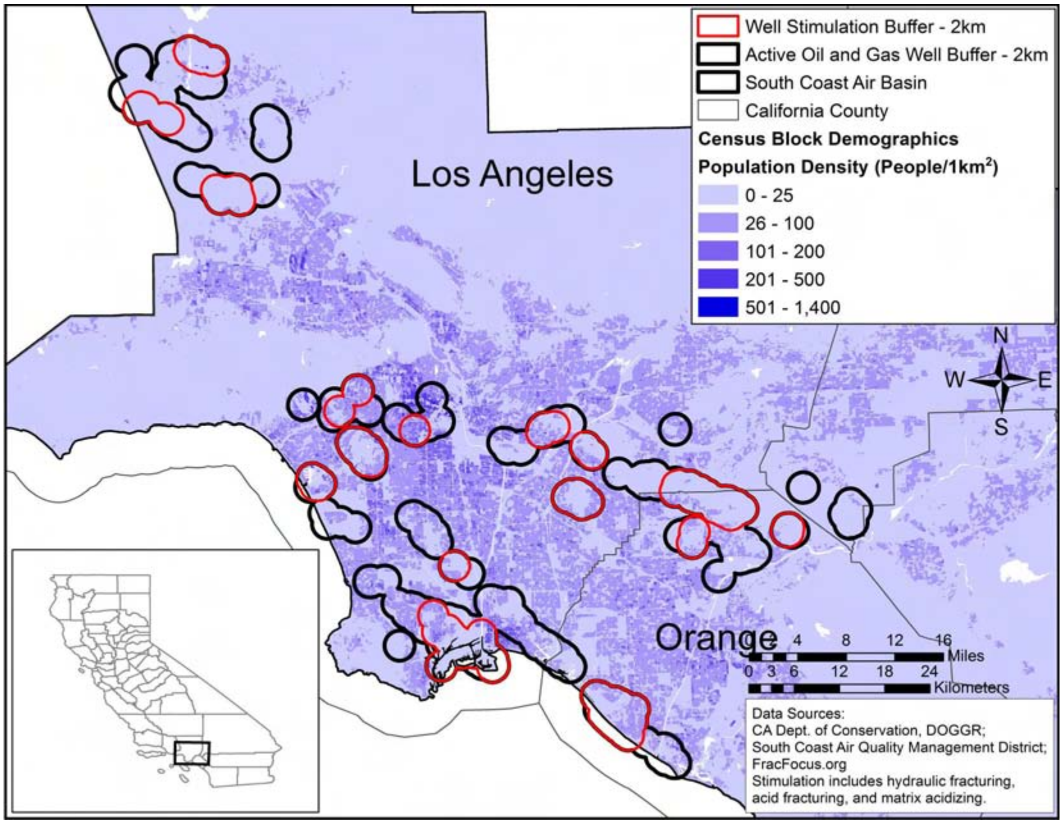

Figure 1.5-3. Population density within 2,000 m (6,562 ft) of currently active oil production wells and currently active wells that have been stimulated (figure from Volume III, Chapter 4 [Los Angeles Basin Case Study]).

Studies from outside of California indicate that, from a public health perspective, the most significant exposures to toxic air contaminants such as benzene, aliphatic hydrocarbons and hydrogen sulfide occur within 800 m (one-half mile) from active oil and gas development. These risks depend on local conditions and the type of petroleum being produced. California impacts may be significantly different, but have not been measured.

Recommendation 6.3. Assess public health near oil and gas production.

Conduct studies in California to assess public health as a function of proximity to all oil and gas development, not just stimulated wells, and develop policies such as science-based surface setbacks, to limit exposures (Volume II, Chapter 6; Volume III, Chapters 4 and 5 [Los Angeles Basin and San Joaquin Basin Case Studies]).

San Joaquin Basin Case Study:

Conclusion 2.1. Future use of hydraulic fracturing in California will likely resemble current use.

Future use of hydraulic fracturing will most likely expand production in and near existing oil fields in the San Joaquin Basin that currently require hydraulic fracturing.

The vast majority of hydraulic fracturing in the state takes place in the San Joaquin Basin in reservoirs that require this technology for economic production. A significant amount of oil remains in these reservoirs. Future additional development in these reservoirs would likely continue to use hydraulic fracturing (Volume I, Chapter 4; Volume III, Chapter 5 [San Joaquin Basin Case Study]). Figure 1.5-4 shows an example of how hydraulic-fracture-enabled production has expanded in the Cahn pool of the Lost Hills field in the San Joaquin Basin over time.

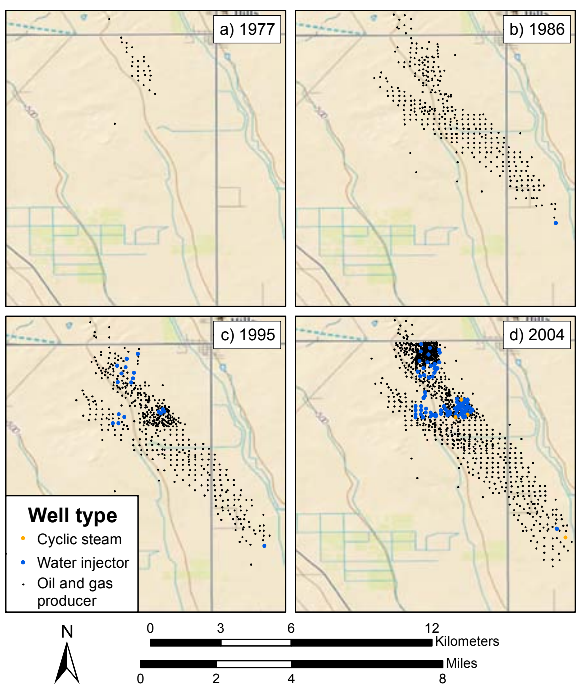

Figure 1.5-4. Growth in the number of wells operating over time in the Cahn pool in the Lost Hills field, one of the two pools in the field where hydraulic fracturing enables production. Data indicate that operators use hydraulic fracturing in almost all to all production wells in this field. Future growth in production would likely follow a similar pattern. The digital data on this field extends back to 1977. The primary well pattern reached nearly its full extent in 1986. By 1995, operators started infill drilling and by 2004, they were deploying water flooding (from Volume III, Chapter 5 [San Joaquin Basin Case Study]).

Conclusion 4.1. Produced water disposed of in percolation pits could contain hydraulic fracturing chemicals.

Based on publicly available data, operators disposed of some produced water from stimulated wells in Kern County in percolation pits. The effluent has not been tested to determine if there is a measureable concentration of hydraulic fracturing chemical constituents. If these chemicals were present, the potential impacts to groundwater, human health, wildlife, and vegetation would be extremely difficult to predict, because there are so many possible chemicals, and the environmental profiles of many of them are unmeasured.

A commonly reported disposal method for produced water from stimulated wells in California is by evaporation and percolation in percolation surface impoundments, also referred to as percolation pits, as shown in Figure 1.5-5. Information from 2011 to 2014 indicates that operators dispose of some 40-60% of the produced water from hydraulically fractured wells in percolation pits during the first full month of production after stimulation. The range in estimated proportion stems from uncertainties about which wells were stimulated prior to mandatory reporting. Produced water from these wells may contain hazardous chemicals from hydraulic fracturing treatments, as well as reaction byproducts of those chemicals. We do not know how long hydraulic fracturing chemicals persist in produced water or at what concentrations or how these change in time, which means that hazardous levels of contaminants in produced water disposed into pits cannot be ruled out.

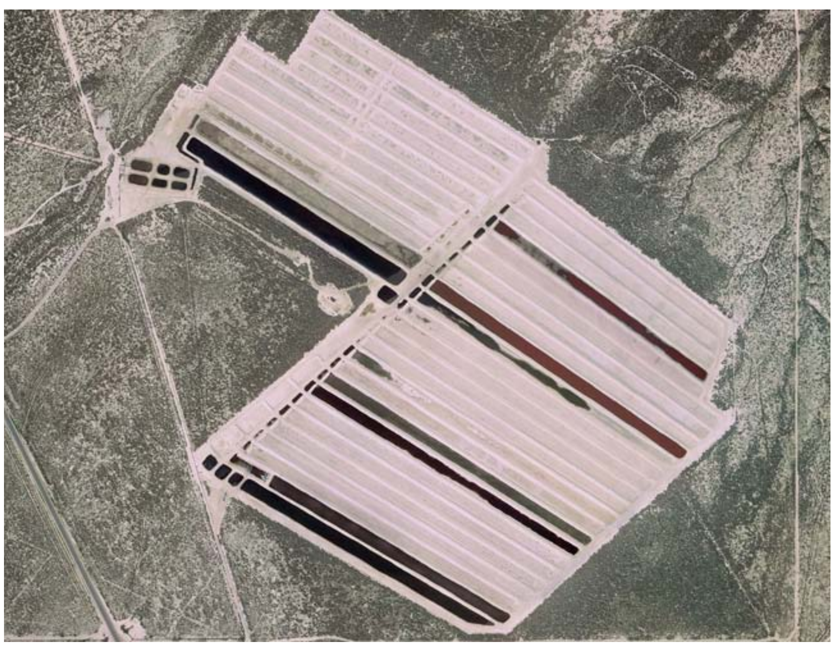

Figure 1.5-5. Percolation pits in Kern County used for produced water disposal (figure modified from Volume II, Chapter 1). Image courtesy of Google Earth.

The primary intent of percolation pits is to percolate water into the ground. This practice provides a potential direct pathway to transport produced water constituents, including returned hydraulic fracturing fluids, into groundwater aquifers. Groundwater contaminated in this way could subsequently intercept rivers, streams, and surface water resources. Contaminated water used by plants (including food crops), humans, fish, and wildlife could introduce contaminants into the food chain. Some states, including Kentucky, Texas and Ohio, have phased out the use of percolation pits for produced water disposal, because their use has demonstrably contaminated groundwater.

Operators have reported disposal of produced water in percolation pits in several California counties (e.g., Fresno, Monterey, and Tulare counties). However, records from 2011 to mid-2014 show that percolation pits received produced water from hydraulically fractured wells only in Kern County. Specifically, wells in the Elk Hills, South Belridge, North Belridge, Lost Hills, and Buena Vista fields were hydraulically fractured, and these fields disposed of produced water to percolation pits in the region under the jurisdiction of the CVRWQCB. An estimated 36% of percolation pits in the Central Valley operate without necessary permits from the CVRWQCB.

The data reported to DOGGR may contain errors on disposition of produced water. For example, DOGGR's production database shows that, during the past few years, one operator discharged produced water to percolation pits at Lost Hills, yet CVRWQCB ordered the closure of percolation pits at Lost Hills in 2009.[3]

Data collected pursuant to the recent Senate Bill 1281 (SB 1281) will shed light on the disposition of produced water and locations of percolation pits statewide. With the data available as of the writing of this report, we cannot rule out that some produced water from hydraulically fractured wells at other fields went to percolation pits and that this water might have contained chemicals used in hydraulic fracturing. Figure 1.5-6 shows that many of these pits overlie protected groundwater. The pending well stimulation regulations, effective July 1, 2015, disallow fluid produced from a stimulated well from being placed in percolation pits.[4]

3. Order R5-2013-0056, Waste Discharge Requirements for Chevron USA, Inc., Central Valley Regional Water Quality Control Board.

4. Title 14 California Code of Regulations, Section 1786(a)(4)

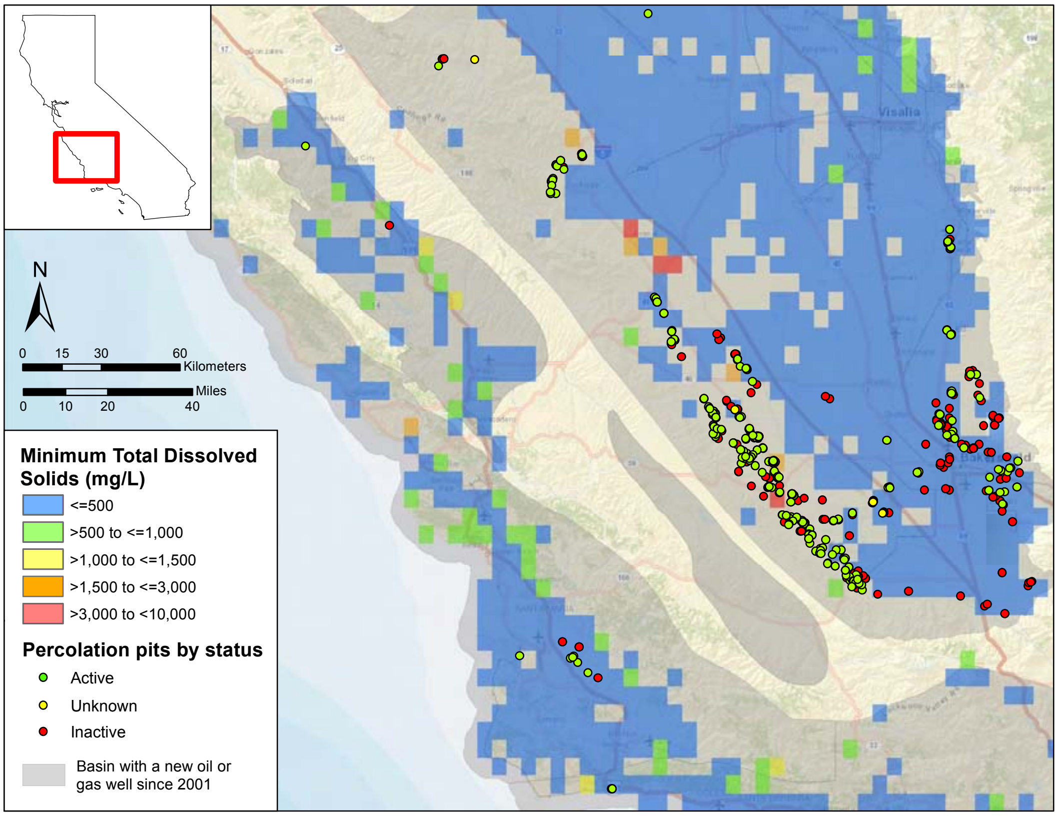

Figure 1.5-6. Location of percolation pits in the Central Valley and Central Coast used for produced water disposal and the location of groundwater of varying quality showing that many percolation pits are located in regions that have potentially protected groundwater shown in color (figure from Volume II, Chapter 2).

Recommendation 4.1. Ensure safe disposal of produced water in percolation pits with appropriate testing and treatment or phase out this practice.

Agencies with jurisdiction should promptly ensure through appropriate testing that the water discharged into percolation pits does not contain hazardous amounts of chemicals related to hydraulic fracturing as well as other phases of oil and gas development. If the presence of hazardous concentrations of chemicals cannot be ruled out, they should phase out the practice of discharging produced water into percolation pits. Agencies should investigate any legacy effects of discharging produced waters into percolation pits including the potential effects of stimulation fluids (Volume II, Chapter 2; Volume III, Chapters 4 and 5 [Los Angeles Basin and San Joaquin Basin Case Studies]).

Conclusion 4.3. Required testing and treatment of produced water destined for reuse may not detect or remove chemicals associated with hydraulic fracturing and acid stimulation.

Produced water from oil and gas production has potential for beneficial reuse, such as for irrigation or for groundwater recharge. In fields that have applied hydraulic fracturing or acid stimulations, produced water may contain hazardous chemicals and chemical byproducts from well stimulation fluids. Practice in California does not always rule out the beneficial reuse of produced water from wells that have been hydraulically fractured or stimulated with acid. The required testing may not detect these chemicals, and the treatment required prior to reuse necessarily may not remove hydraulic fracturing chemicals.

Growing pressure on water resources in the state means more interest in using produced water for a range of beneficial purposes, such as groundwater recharge, wildlife habitat, surface waterways, irrigation, etc. Produced water could become a significant resource for California.

However, produced water from wells that have been hydraulically fractured may contain hazardous chemicals and chemical by-products. Our study found only one oil field where both hydraulic fracturing occurs and farmers use the produced water for irrigation. In the Kern River field in the San Joaquin Basin, hydraulic fracturing operations occasionally occur, and a fraction of the produced water goes to irrigation (for example, Figure 1.5-7). But we did not find policies or procedures that would necessarily exclude produced water from hydraulically fractured wells from use in irrigation.

Figure 1.5-7. Produced water used for irrigation in Cawelo water district. Photo credit: Lauren Sommer/KQED (figure from Volume II, Chapter 1).

The regional water quality control boards require testing and treatment of produced water prior to use for irrigation, but the testing does not include hydraulic fracturing chemicals, and required treatment would not necessarily remove hazardous stimulation fluid constituents if they were present. Regional water-quality control boards have also established monitoring requirements for each instance where produced water is applied to irrigated lands; however, these requirements do not include monitoring for constituents specific to, or indicative of, hydraulic fracturing.

Safe reuse of produced water that may contain stimulation chemicals requires appropriate testing and treatment protocols. These protocols should match the level of testing and treatment to the water-quality objectives of the beneficial reuse. However, designing the appropriate testing and treatment protocols to ensure safe reuse of waters contaminated with stimulation chemicals presents significant challenges, because so many different chemicals could be present, and the safe concentration limits for many of them have not been established. Hydraulic fracturing chemicals may be present in extremely small concentrations that present negligible risk, but this has not been confirmed.

Limiting hazardous chemical use as described in Recommendation 3.2 would also help to limit issues with reuse. Disallowing the reuse of produced water from hydraulically fractured wells would also solve this problem, especially in the first years of production. This water could be tested over time to determine if hazardous levels of hydraulic fracturing chemicals remain before transitioning this waste stream to beneficial use.

> **Recommendation 4.3. Protect irrigation water from contamination by hydraulic fracturing chemicals and stimulation reaction products.**
>
> *Agencies of jurisdiction should clarify that produced water from hydraulically fractured wells cannot be reused for purposes such as irrigation that could negatively impact the environment, human health, wildlife and vegetation. This ban should continue until or unless testing the produced water specifically for hydraulic fracturing chemicals and breakdown products shows non-hazardous concentrations, or required water treatment reduces concentrations to non-hazardous levels (Volume II, Chapter 2; Volume III, Chapter 5 [San Joaquin Basin Case Study]).*

Conclusion 4.4. Injection wells currently under review for inappropriate disposal into protected aquifers may have received water containing chemicals from hydraulic fracturing.

DOGGR is currently reviewing injection wells in the San Joaquin Valley for inappropriate disposal of oil and gas wastewaters into protected groundwater. The wastewaters injected into some of these wells likely included stimulation chemicals because hydraulic fracturing occurs nearby.

In 2014, DOGGR began to evaluate injection wells in California used to dispose of oil field wastewater. DOGGR found that some wells inappropriately allowed injection of wastewater into protected groundwater and subsequently shut them down. DOGGR's ongoing investigation will review many more wells to determine if they are injecting into aquifers that should be protected.

Figure 1.5-8 is a map of the Elks Hills field in the San Joaquin Basin showing one example where hydraulically fractured wells exist near active water disposal wells. The DOGGR review includes almost every disposal well in this field for possible inappropriate injection into protected water. Some of the produced water likely came from nearby production wells that were hydraulically fractured. Consequently, the injected wastewater possibly contained stimulation chemicals at some unknown concentration.

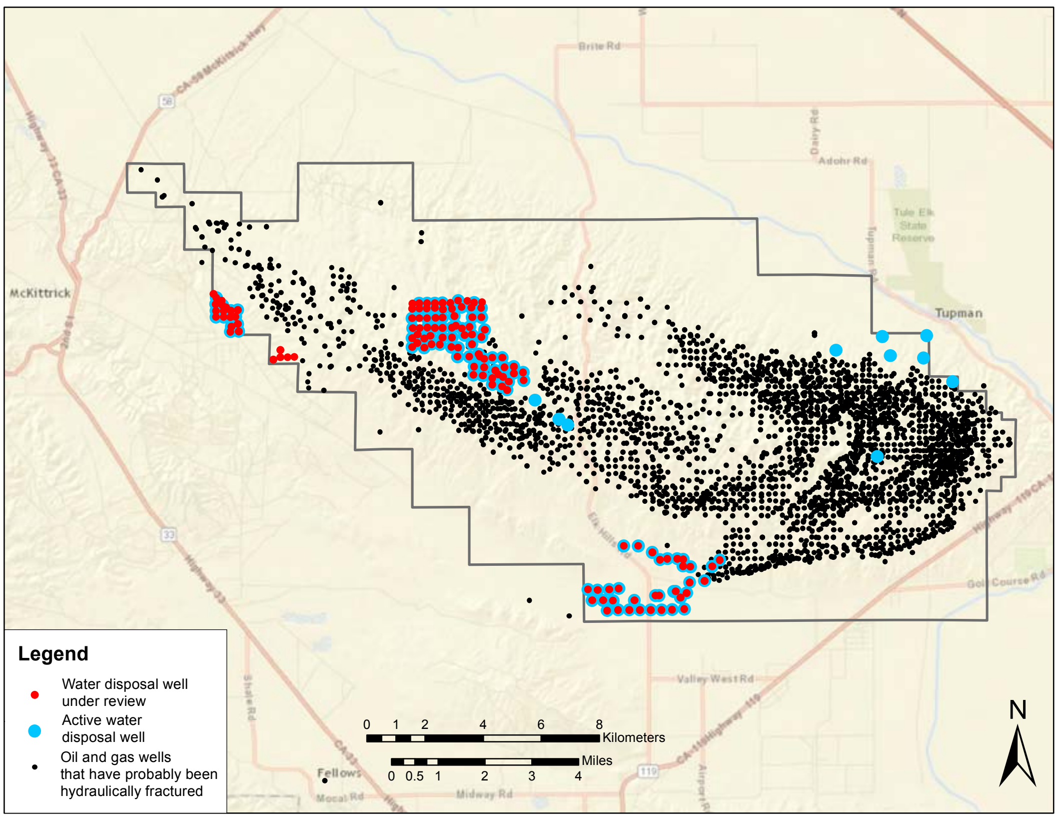

Figure 1.5-8. A map of the Elk Hills field in the San Joaquin Basin showing the location of wells that have probably been hydraulically fractured (black dots). Blue dots are the location of active water disposal wells, and blue dots with a red center are the location of disposal wells under review for possibly injecting into groundwater that should be protected (figure from Volume II, Chapter 1).

Recommendation 4.4. In the ongoing investigation of inappropriate disposal of wastewater into protected aquifers, recognize that hydraulic fracturing chemicals may have been present in the wastewater.

In the ongoing process of reviewing, analyzing, and remediating the potential impacts of wastewater injection into protected groundwater, agencies of jurisdiction should include the possibility that hydraulic fracturing chemicals may have been present in these wastewaters (Volume II, Chapter 2; Volume III, Chapter 5 [San Joaquin Basin Case Study]).

Conclusion 5.1. Shallow fracturing raises concerns about potential groundwater contamination.

In California, about three quarters of all hydraulic fracturing operations take place in shallow wells less than 600 m (2,000 ft) deep. In a few places, protected aquifers exist above such shallow fracturing operations, and this presents an inherent risk that hydraulic fractures could accidentally connect to the drinking water aquifers and contaminate them or provide a pathway for water to enter the oil reservoir. Groundwater monitoring alone may not necessarily detect groundwater contamination from hydraulic fractures. Shallow hydraulic fracturing conducted near protected groundwater resources warrants special requirements and plans for design control, monitoring, reporting, and corrective action.

Hydraulic fractures produced in deep formations far beneath protected groundwater are very unlikely to propagate far enough upwards to intersect an aquifer. Studies performed for high-volume hydraulic fracturing elsewhere in the country have shown that hydraulic fractures have propagated no further than 600 m (2,000 ft) vertically, so hydraulic fracturing conducted many thousands of feet below an aquifer is not expected to reach a protected aquifer far above. In California, however, and particularly in the San Joaquin Basin, most hydraulic fracturing occurs in relatively shallow reservoirs, where protected groundwater might be found within a few hundred meters (Figure 1.5-9). A few instances of shallow fracturing have also been reported in the Los Angeles Basin (Figure 1.5-10), but overall much less than the San Joaquin Basin. No cases of contamination have yet been reported, but there has been little to no systematic monitoring of aquifers in the vicinity of oil production sites.

Shallow hydraulic fracturing presents a higher risk of groundwater contamination, which groundwater monitoring may not detect. This situation warrants additional scrutiny. Operations with shallow fracturing near protected groundwater could be disallowed or be subject to additional requirements regarding design, control, monitoring, reporting, and corrective action, including: (1) pre-project monitoring to establish a base-line of chemical concentrations, (2) detailed prediction of expected fracturing characteristics prior to starting the operation, (3) definition of isolation between expected fractures and protected groundwater, providing a sufficient safety margin with proper weighting of subsurface uncertainties, (4) targeted monitoring of the fracturing operation to watch for and react to evidence (e.g., anomalous pressure transients, microseismic signals) indicative of fractures growing beyond their designed extent, (5) monitoring groundwater to detect leaks, (6) timely reporting of the measured or inferred fracture characteristics confirming whether or not the fractures have actually intersected or come close to intersecting groundwater, (7) preparing corrective action and mitigation plans in case anomalous behavior is observed or contamination is detected, and (8) adaption of groundwater monitoring plans to improve the monitoring system and specifically look for contamination in close proximity to possible fracture extensions into groundwater.

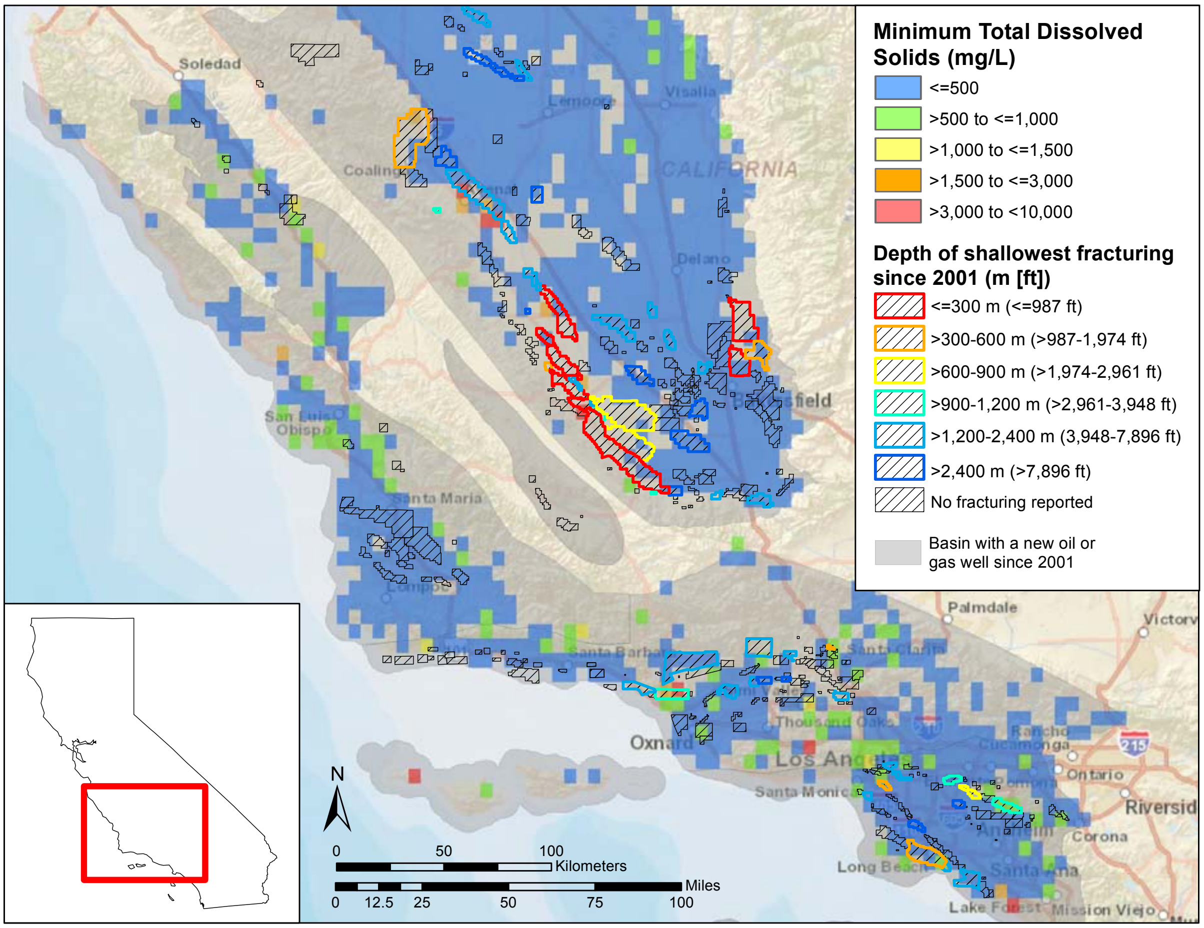

Figure 1.5-9. Shallow fracturing locations and groundwater quality in the San Joaquin and Los Angeles Basins. Some high quality water exists in fields that have shallow fractured wells (figure from Volume II, Chapter 2).

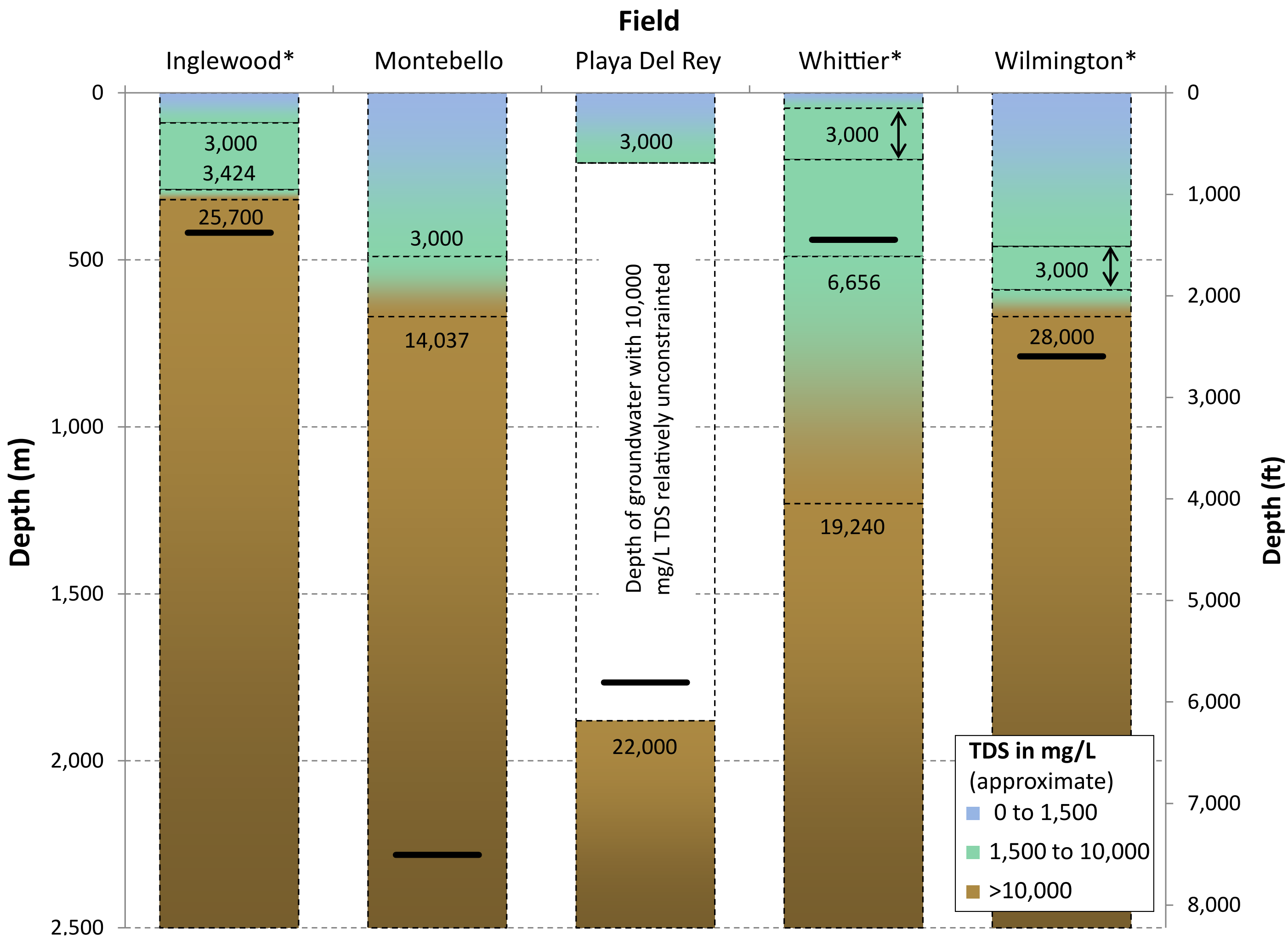

Figure 1.5-10. Depths of groundwater total dissolved solids (TDS) in mg/L in five oil fields in the Los Angeles Basin. The numbers indicate specific TDS data and the colors represent approximate interpolation. The depth of 3,000 mg/L TDS is labeled on all five fields. Blue (<3,000 mg/L) and aqua (between 3,000 mg/L and 10,000 mg/L) colors represent protected groundwater. Depth of 10,000 mg/L TDS is uncertain, but it is estimated to fall in the range where aqua transitions to brown. The heavy black horizontal line indicates the shallowest hydraulically fractured well interval in each field. (Asterisks denote the fields of most concern for the proximity of hydraulic fracturing to groundwater with less than 10,000 mg/L TDS.) (figure from Volume III, Chapter 4 [Los Angeles Basin Case Study]).

The potential for shallow hydraulic fractures to intercept protected groundwater requires both knowing the location and quality of nearby groundwater and accurate information about the extent of the hydraulic fractures. Maps of the vertical depth of protected groundwater with less than 10,000 mg/L TDS for California oil producing regions do not yet exist. Analysis and field verification could identify typical hydraulic fracture geometries; this would help determine the probability of fractures extending into groundwater aquifers. Finally, detection of potential contamination and planning of mitigation measures requires integrated site-specific and regional groundwater monitoring programs.

The pending SB 4 well stimulation regulations, effective July 1, 2015, require operators to design fracturing operations so that the fractures avoid protected water, and to implement appropriate characterization and groundwater monitoring near hydraulic fracturing operations. However, groundwater monitoring alone does not ensure protection of water, nor will it necessarily detect contamination should it occur. The path followed by contamination underground can be hard to predict, and may bypass a monitoring well. Groundwater monitoring can give false negative results in these cases,5 and does nothing to stop contamination from occurring in any case.

> **Recommendation 5.1. Protect groundwater from shallow hydraulic fracturing operations.**
>
> *Agencies with jurisdiction should act promptly to locate and catalog the quality of groundwater throughout the oil-producing regions. Operators proposing to use hydraulic fracturing operation near protected groundwater resources should be required to provide adequate assurance that the expected fractures will not extend into these aquifers and cause contamination. If the operator cannot demonstrate the safety of the operation with reasonable assurance, agencies with jurisdiction should either deny the permit, or develop protocols for increased monitoring, operational control, reporting, and preparedness (Volume I, Chapter 3; Volume II, Chapter 2; Volume III, Chapter 5 [San Joaquin Basin Case Study]).*

Conclusion 5.2. Leakage of hydraulic fracturing chemicals could occur through existing wells.

California operators use hydraulic fracturing mainly in reservoirs that have been in production for a long time. Consequently, these reservoirs have a high density of existing wells that could form leakage paths away from the fracture zone to protected groundwater or the ground surface. The pending SB 4 regulations going into effect July 1, 2015 do address

5. Chemical tracers (non-reactive chemicals that can be detected in small concentrations) can be added to hydraulic fracturing fluids and, if groundwater samples contain these tracers, it is evidence that the stimulation fluid has migrated out of the designed zone. However, the use of tracers does not guarantee that leaks to groundwater will be detected. Groundwater flow can be highly channelized and it can be difficult to place a monitoring well in the right place to intersect a possible plume of contaminant. The use of tracers is good practice, but does not “solve” the problem of detecting contamination.

concerns about existing wells in the vicinity of well stimulation operations; however, it remains to demonstrate the effectiveness of these regulations in protecting groundwater.

In California, most hydraulic fracturing occurs in old reservoirs where oil and gas has been produced for a long time. Usually this means many other wells (called "offset wells") have previously been drilled in the vicinity of the operation. Wells constructed to less stringent regulations in the past or degraded since installation may not withstand the high pressures used in hydraulic fracturing. Thus, in California, as well as in other parts of the country, existing oil and gas wells can provide subsurface conduits for oil-field contamination to reach protected groundwater. Old wells present a risk for any oil and gas development, but the high pressures involved in hydraulic fracturing can increase this risk significantly. California has no recorded incidents of groundwater contamination due to stimulation. But neither have there been attempts to detect such contamination with targeted monitoring, nor studies to determine the extent of compromised wellbore integrity.

Historically, California has required placement of well casings and cement seals to protect groundwater with a salinity less than 3,000 mg/L total dissolved solids (TDS). Now, SB 4 requires more stringent monitoring and protection from degradation of non-exempt groundwater with less than 10,000 mg/L TDS. Consequently, existing wells may not have been built to protect groundwater between 3,000 mg/L and 10,000 mg/L TDS. For instance, there may be no cement seal in place to isolate the zones containing water that is between 3,000 and 10,000 mg/L TDS from deeper zones with water that is higher than 10,000 mg/L TDS.

The new well stimulation regulations going into effect in July 1, 2015 require operators to locate and review any existing well within a zone that is twice as large as the expected fractures. Operators need to design the planned hydraulic fracturing operation to confine hydraulic fracturing fluids and hydrocarbons within the hydrocarbon formation. The pressure buildup at offset wells caused by neighboring hydraulic fracturing operations must remain below a threshold value defined by the regulations.

The new regulations for existing wells are appropriate in concept, but the effectiveness of these requirements will depend on implementation practice. For example: How will operators estimate the extent of the fractures, and how will regulators ensure the reliability of these calculations? Is the safety factor provided by limiting concern to an area equal to twice the extent of the designed fractures adequate? How will regulators assess the integrity of existing wells when information about these wells is incomplete? How will regulators determine the maximum allowed pressure experienced at existing wells? Will the regulators validate the theoretical calculations to predict fracture extent and maximum pressure with field observations?

Recommendation 5.2. Evaluate the effectiveness of hydraulic fracturing regulations designed to protect groundwater from leakage along existing wells.

Within a few years of the new regulations going into effect, DOGGR should conduct or commission an assessment of the regulatory requirements for existing wells near stimulation operations and their effectiveness in protecting groundwater with less than 10,000 TDS from well leakage. This assessment should include comparisons of field observations from hydraulic fracturing sites with the theoretical calculations for stimulation area or well pressure required in the regulations (Volume II, Chapter 2; Volume III, Chapters 4 and 5 [Los Angeles Basin and San Joaquin Basin Case Study]).

Chapter Two

A Case Study of California Offshore Petroleum Production, Well Stimulation, and Associated Environmental Impacts

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2.1. Abstract

This case study summarizes current practices concerning the use of well stimulation and associated potential environmental impacts for California offshore petroleum-production operations. It includes an assessment of the discharges and emissions of contaminants and their potential environmental impacts. Well stimulation includes hydraulic fracturing (with proppant or acid) and matrix acidizing as presented in Volume I, Chapter 2. The case study describes current offshore oil and gas production facilities, including the geologic and petrophysical characteristics of the oil and gas reservoirs under production, and the available information on fluid handling and ultimate disposition of stimulation flowback fluids as ocean discharge or injection into the producing or waste disposal zones. This case study also provides an explanation of the current regulatory limits on ocean discharge of stimulation flowback fluid and comingled produced water under the National Pollutant Discharge Elimination System, as well as a review of existing information on discharge volumes and characteristics. In addition, an assessment of offshore air emissions, including criteria pollutants, toxic pollutants, and greenhouse gases, is included.

Volume I presents the level of well stimulation activity for offshore California. Of the 109 wells per month on average undergoing hydraulic fracturing in California, about 1.5 per month were in state waters. Hydraulic fracturing in federal waters occurs even less frequently, at about 1 per year (Volume I, Chapter 3). Offshore acid treatments appear to be used more frequently than hydraulic fracturing in state and federal waters, but the levels of activity are difficult to quantify from the available records. There are no records of acid fracturing conducted offshore.

Studies of produced water discharge into the marine environment have shown that there may be adverse impacts, particularly for reproductive behavior and larval development of some species. However, site-specific studies of fish populations around offshore facilities indicate that rockfish species reached high densities around offshore oil and gas facilities. While some level of adverse impacts are likely as a result of wastewater discharge in general (including well stimulation fluids), the available data on fish species inhabiting platforms indicates that any negative impacts of discharge are relatively minor given that population growth rates in the vicinity are very high.

Criteria pollutants emitted by offshore oil and gas production facilities represent a small fraction of total emissions in the associated air basins. Only a small fraction of these offshore oil production emissions can be attributed to well stimulation. Toxic air emissions from the facilities in federal waters should have minor-to-negligible public health effects, but may be of more concern for worker safety. Facilities in state waters may have somewhat greater health impacts because they are closer to human population. Greenhouse gas (GHG) emissions for offshore operations on a unit oil and gas production basis are about the same as for average California operations. The associated GHG impact relative to benefits of usable energy produced from these operations is not exceptional. GHG emissions linked to well stimulation and well-stimulation-enabled production are expected to contribute only a small fraction of the total emissions.

Water associated with well-stimulation-enabled production in state waters is primarily injected back into producing oil reservoirs and a small fraction into water disposal wells. The volumes requiring disposal are small compared to the volume of water requiring disposal for onshore oil and gas production in counties adjacent to these offshore operations. Therefore, offshore produced-water disposal linked with well-stimulation-enabled production adds little to the hazard of induced seismicity.

Significant data gaps include data concerning the occurrence of well stimulation treatments, information on stimulation-fluid composition, treatment intervals and depths, flowback quantities and compositions, and ultimate disposition of flowback. Data relevant to these issues are insufficient and inadequate for quantitative impact assessments. In some cases, such as flowback quantities and compositions, the information is completely absent. In addition, no studies have been conducted on the toxicity and impacts of well stimulation fluids discharged in federal waters to the marine environment.

In addition to the collection of more data on offshore well stimulation, a recommendation is made to investigate alternatives to ocean disposal of stimulation flowback fluids for facilities in federal waters.

2.2. Introduction

This case study summarizes current practices concerning the use of well stimulation and associated potential environmental impacts for California offshore petroleum-production operations. Operators use hydraulic fracturing (including acid fracturing) and matrix acidizing to improve the flow of oil or gas into a production well, by increasing the effective permeability of the reservoir rock (making flow through the rock easier), removing or bypassing near-wellbore permeability damage from the drilling and well completion process, and reducing the tendency for reservoir rock fines migration that reduces permeability. Hydraulic fracturing can be used to address all three of these problems, whereas matrix acidizing is used primarily to resolve formation damage. Chapter 2 of Volume I provides a more in-depth discussion of well stimulation.

The majority of offshore production takes place without hydraulic fracturing (Volume I, Chapter 3). Ninety percent of the limited hydraulic fracturing activity in California is waters conducted on man-made islands close to the Los Angeles coastline in the Wilmington field; little hydraulic fracturing activity is documented on platforms. Operations on close-to-shore, man-made islands resemble onshore oil production activities. On these islands, operators conduct about 1–2 hydraulic fracturing treatments in the 4–9 wells completed per month. The only available survey of stimulation in federal waters records that 22 fracturing stimulations occurred or were planned from 1992 through 2013. About 10–40% of fracturing operations in wells in California waters and half of operations in U.S. waters were frac-packs (Volume I, Chapter 3). No instances of acid fracturing were recorded for state or federal offshore facilities.

Offshore production extracts petroleum fluids (oil and/or gas) from a petroleum reservoir situated beneath the ocean. While offshore production mainly takes place through wells that are drilled from offshore platforms or artificial islands, in a few cases, onshore wells are directionally drilled to enable petroleum production from offshore reservoirs.

Offshore petroleum production operations in California occur under either state or federal jurisdiction. State authority extends out to three geographic miles from the coastline; operations conducted further than three geographic miles from the coastline fall under federal authority. Currently, state waters host four offshore platforms and five artificial islands used for petroleum production in state waters, along with offshore production from onshore wells. Federal waters off the coast of California host 23 offshore platforms.

The currently operating facilities in state waters are located between 0.2 and 3.2 km (0.1–2 mi) from shore in water depths ranging from 6.7 to 64 m (22 to 211 ft). The platforms in federal waters are located between 6 and 16.9 km (3.7 and 10.5 mi) from shore in water depths ranging from 29 to 365 m (95 to 1,198 ft). Figure 2.2-1 shows the facility locations in and near the Santa Barbara channel and south of Los Angeles in or near San Pedro Bay. Most of the current petroleum production platforms (19 of 23) in federal waters are in or near the Santa Barbara Channel, and most of the petroleum production platforms (3 of 4) and artificial islands (4 of 5) in state waters are south of Los Angeles, in or near San Pedro Bay. Note that some reservoirs in state waters are produced from both onshore and offshore wells.

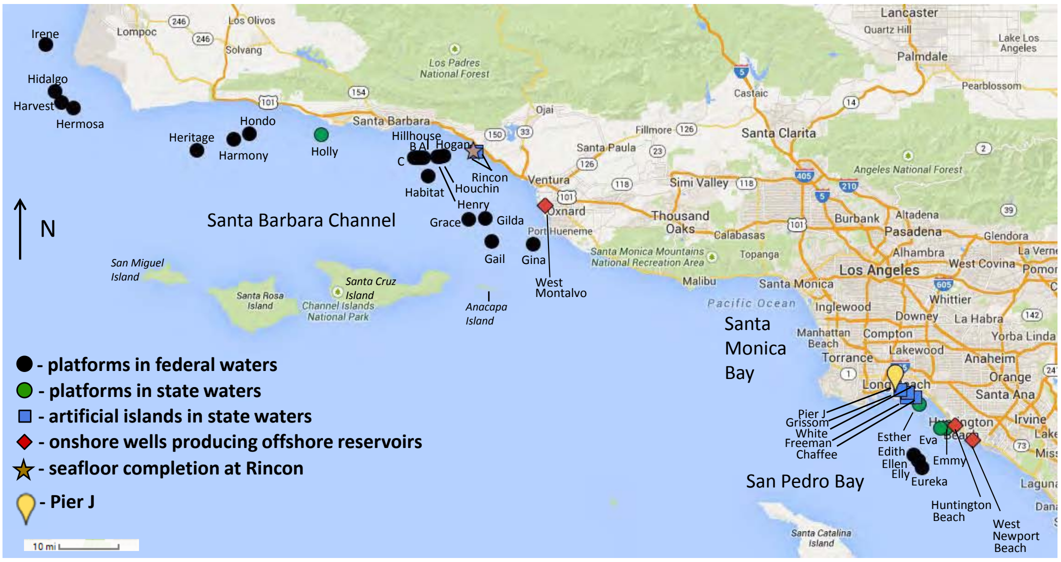

Figure 2.2-1. Map of current California offshore petroleum production facilities. All facility names are shown; onshore wells are labeled using the associated petroleum field.

Figure 2.2-2. Map of abandoned offshore production facilities. All facility names are shown; onshore wells and seafloor completions are labeled using the associated petroleum field.

Eight platforms in state waters in the Santa Barbara Channel and one artificial island in San Pedro Bay have been abandoned and removed (Figure 2.2-2). Four piers used for petroleum production and four seafloor completions[1] in the Santa Barbara Channel have been abandoned. Four onshore sites in the Santa Barbara Channel and two onshore sites in Santa Monica Bay have also been abandoned. The locations of abandoned (and generally older) facilities in Figure 2.2-2 show, by comparison with Figure 2.2-1, the trend in offshore development over time, from locations along the shoreline and near-shore to locations further from the shoreline.

Following this introduction, Section 2.3 discusses the historical development of offshore oil production. Section 2.4 covers offshore reservoir petroleum geology and reservoir characteristics for currently operating offshore reservoirs, along with historical oil and gas production data. Section 2.5 provides a detailed description of the offshore production facilities in terms of location, facility type, water depth, fluids handling, and past use of well stimulation. Section 2.6 presents information on wastewater discharge to the ocean. One important operational difference between the offshore facilities in state and federal waters is that those in state waters are not permitted to discharge wastewater into the ocean, but those in federal waters are allowed to discharge wastewater into the ocean (subject to certain restrictions). The National Pollutant Discharge Elimination System (NPDES) permits for ocean disposal from platforms in federal waters are described. Air emissions from offshore oil and gas operations are also summarized. The impacts of ocean wastewater discharge and air emissions are discussed in Section 2.7. The potential effect of wastewater injection on induced seismicity is also addressed. Section 2.8 presents the findings, conclusions, and recommendations based on this case study.

2.3. Historical Development of Offshore Oil and Gas Production in California

2.3.1. Initial Oil Development

The initial development of oil production offshore followed observations of oil and gas seeps. Active seeps offshore have been observed from Point Conception to Huntington Beach south of Los Angeles. Figure 2.3-1 shows offshore seeps cataloged by Wilkinson (1972). The pattern of these natural oil seeps roughly correlate with the pattern of offshore oil production in Figures 2.2-1 and 2.2-2.

The first offshore development in California occurred at Summerland near Santa Barbara in 1898 (Figure 2.3-2), based on observations of oil and gas seeps in the area (Love et al., 2003). By 1902, oil drilling and production was conducted from as many as 11 wooden piers extending into the ocean up to 375 m (1,250 ft), as well as from the shoreline (Love et al., 2003; Schempf, 2004). Operators drilled more than 400 sea wells between 1898

1. A seafloor (or subsea) completion is one in which the producing well does not include a vertical conduit from the wellhead back to a fixed access structure. A subsea well typically has a production tree sitting on the ocean floor to which a flow line is connected allowing production to another structure, a floating production vessel, or occasionally back to a shore-based facility (NPC, 2011).

and 1902 (Grosbard, 2002). A strong storm in 1903 severely damaged this early phase of the Summerland oil field, and high tides and storms finally destroyed the last pier and oil production in 1939 (Grosbard, 2002).

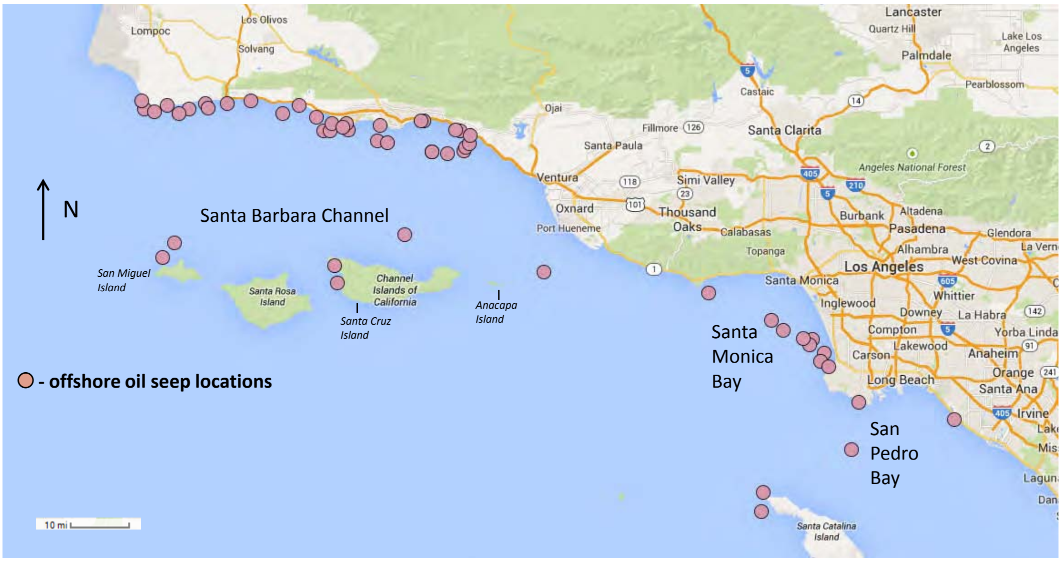

Figure 2.3-1. Offshore oil seep locations (based on data from Wilkinson, 1972).

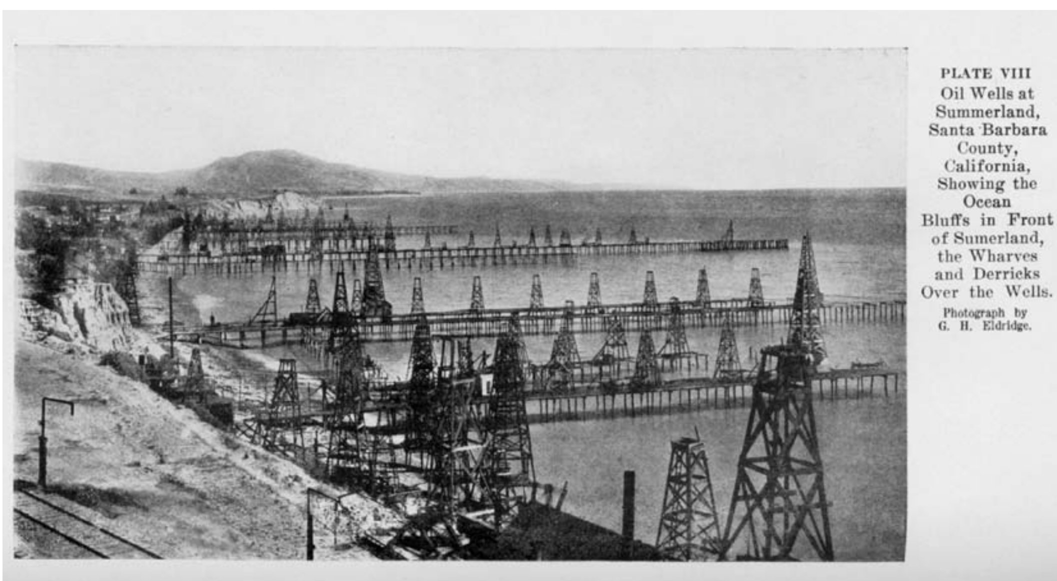

Figure 2.3-2. Summerland offshore oil development circa 1900. (NOAA, 2015).

By 1944, operators constructed several piers as far as 700 m (2,300 ft) offshore into 35 ft of water at Elwood, also near Santa Barbara (Frame, 1960). However, subsequent production from Elwood favored the use of directionally drilled wells from the tidelands. The Rincon field near Ventura also used piers for offshore development (Frame, 1960).

From 1930 to 1960, operators drilled “directional” wells from onshore into near-shore reservoirs at Huntington Beach, Redondo Beach, and West Newport Beach near Los Angeles; and at Gaviota and West Montalvo in the Santa Barbara Channel (Frame, 1960). These reports include one of the earliest successes in directional drilling in 1932 for wells drilled onshore from Huntington Beach to access oil resources under the ocean (Weaver, 1937) (Figure 2.3-3). Also during this period, the first offshore platform was installed offshore California at Rincon in 1932. This platform, called the “Steel Island,” stood in 12 m (38 ft) of water about 0.8 km (0.5 mi) offshore (Figure 2.3-3). Steel Island was destroyed by storms in 1940, and for the first time divers were used to remove well casing and set abandonment plugs (Silcox et al., 1987).

a)

b)

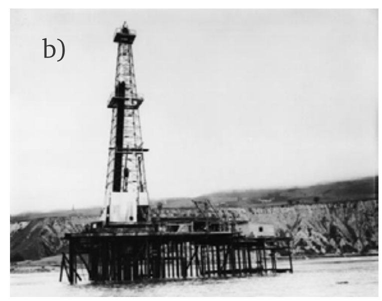

Figure 2.3-3. (a) Huntington Beach (1932) - first directional drilling from onshore under the ocean. (Wentworth, 1998); (b) Steel Island (1932) – first offshore platform. (Love, 2003).

2.3.2 Initial Post World War II Development

The development of modern offshore platforms started in the latter part of the 1950s. The first post-World War II free-standing platform to be used offshore California was Platform Hazel (Figure 2.3-4), installed in 1958 in 30 m (100 ft) of water about 2.4 km (1.5 mi) offshore to produce from the Summerland offshore oil field (Frame, 1960; Santa Barbara, 2015a). Platform Hazel was abandoned and removed in 1996.

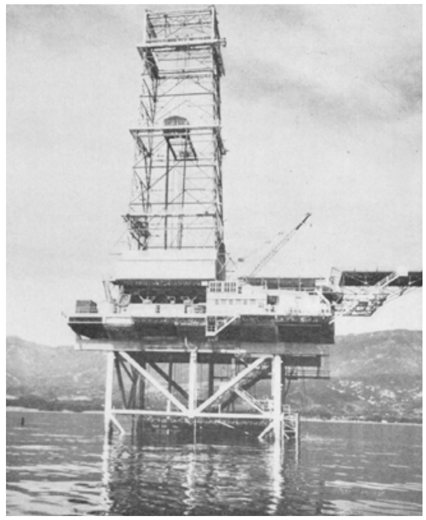

Figure 2.3-4. Platform Hazel (1958). (Carlisle et al., 1964).

In addition to offshore platforms, operators began to build artificial islands for offshore petroleum production. The first artificial island, Belmont Island, constructed near Long Beach Harbor in 1954 to produce the Belmont field (Figure 2.3-5), stood about 2.4 km (1.5 mi) offshore in about 13 m (42 ft) of water (Ahuja et al., 2003) and was decommissioned and removed in 2002. Rincon Island was constructed northwest of Ventura to produce the Rincon field offshore. The island stands about 853 m (2,800 ft) offshore in about 14 m (45 ft) of water and is the only artificial island connected to the mainland by a causeway (Yerkes et al., 1969) (Figure 2.3-5).

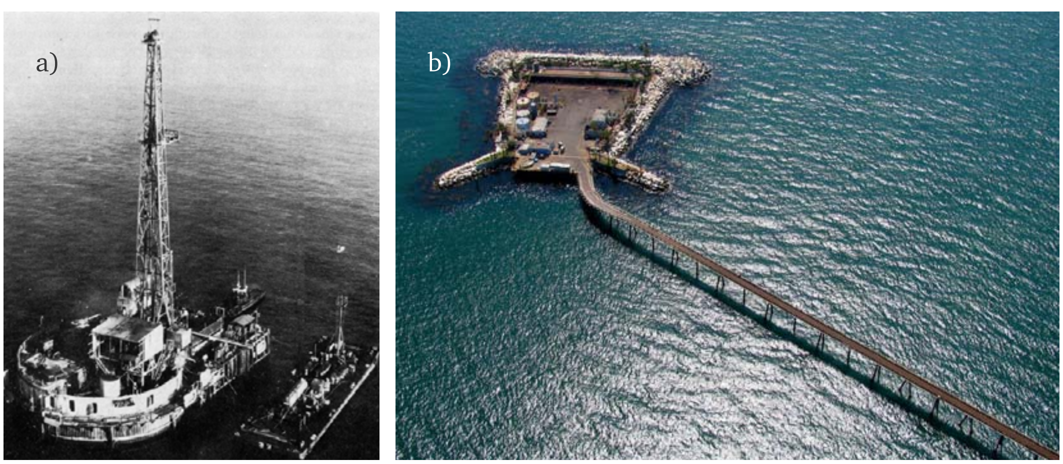

Figure 2.3-5. Offshore Artificial Islands. (a) Belmont Island (1954) - first offshore island. (McGuffee, 2002); (b) Rincon Island and causeway (1958). (Wikimedia Commons, 2015).

Offshore development accelerated in the 1960s, emphasizing the use of offshore platforms but also utilizing artificial islands. In the offshore Los Angeles area, Island Esther was installed near Huntington Beach in 1964. Islands Grissom (Figure 2.3-6), White, Chaffee, and Freeman, known collectively as “THUMS” (for the Texaco, Humble, Union, Mobil, and Shell oil companies that initially developed these islands), were all installed in 1967 offshore of Long Beach.

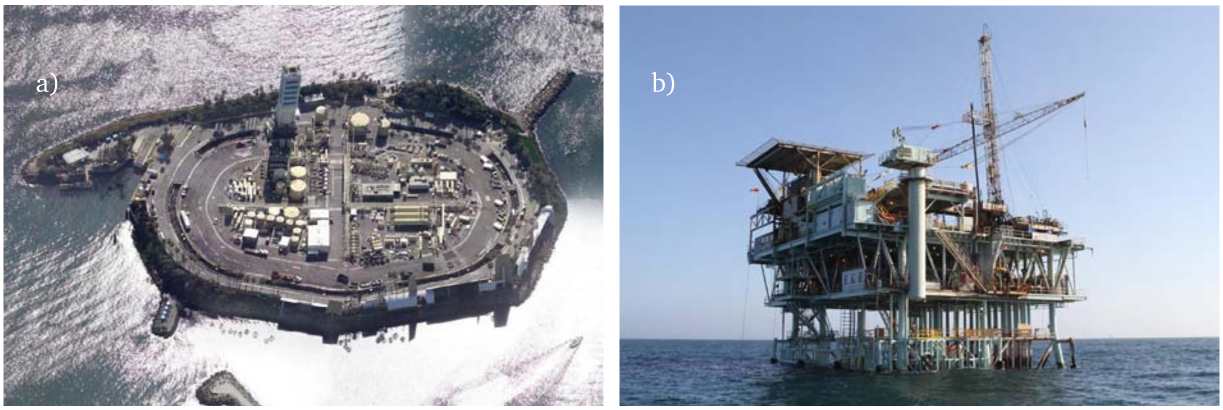

Figure 2.3-6. (a) Grissom Island (1967) – one of the THUMS islands. (The Atlantic Photo, 2014); (b) Platform Hogan (1967) – first platform installed in federal waters. (Carpenter, 2011).

The THUMS islands continue to operate; however, Esther was later converted to a platform after storms damaged the island in the winter of 1982–83. Platforms Emmy (1963) and Eva (1964) installed off of Huntington Beach still operate. In the 1960s, operators constructed platforms in the state waters of the Santa Barbara Channel, including Hilda (1960), Helen (1960), Harry (1961), Herman (1963), Hope (1965), Heidi (1966), and Holly (1966) (see Figures 2.2-1 and 2.2-2); all except Holly have since been abandoned and removed. Platforms Hogan (1967) (Figure 2.3-6), Houchin (1968), A (1968), B (1968), and Hillhouse (1969) in federal waters of the Santa Barbara Channel area continue to operate (California State Lands Commission, 1999). In addition to these facilities, offshore wells were also installed as “seafloor completions” in the Santa Barbara Channel area. In some cases (shown on Figure 2.2-2), these completions were not associated with a platform and connected directly to shore; in other cases, seafloor completions were linked to a platform, e.g., platform Herman (Adams, 1972).

2.3.3. 1969 Santa Barbara Oil Spill

The rapid-pace offshore oil production facility development slowed markedly following the Santa Barbara oil spill in 1969. The blowout and oil spill occurred at platform A, operated by Union Oil, about 11 km (7 mi) southeast of Santa Barbara (Figure 2.2-1). The disaster was a result of operator errors during drilling operations (not well stimulation) that led to a loss of well control and an insufficient casing length in the upper part of the well (see Box 2.3-1). In total, more than 12,700 m^3 (80,000 barrels or 3,360,000 gallons) of oil leaked into the ocean. The spill spread over 2070 km^2 (800 mi^2) of ocean around platform A, and 35 miles of mainland coastline were coated with an oil layer up to 0.15 m (0.5 ft) thick (Engle, 2006). The spill surrounded Anacapa Island, and parts of Santa Cruz and Santa Rosa Islands (Figure 2.3-7). The environmental cost of the spill included killing over 3,600 sea birds and a large number of seals and dolphins.

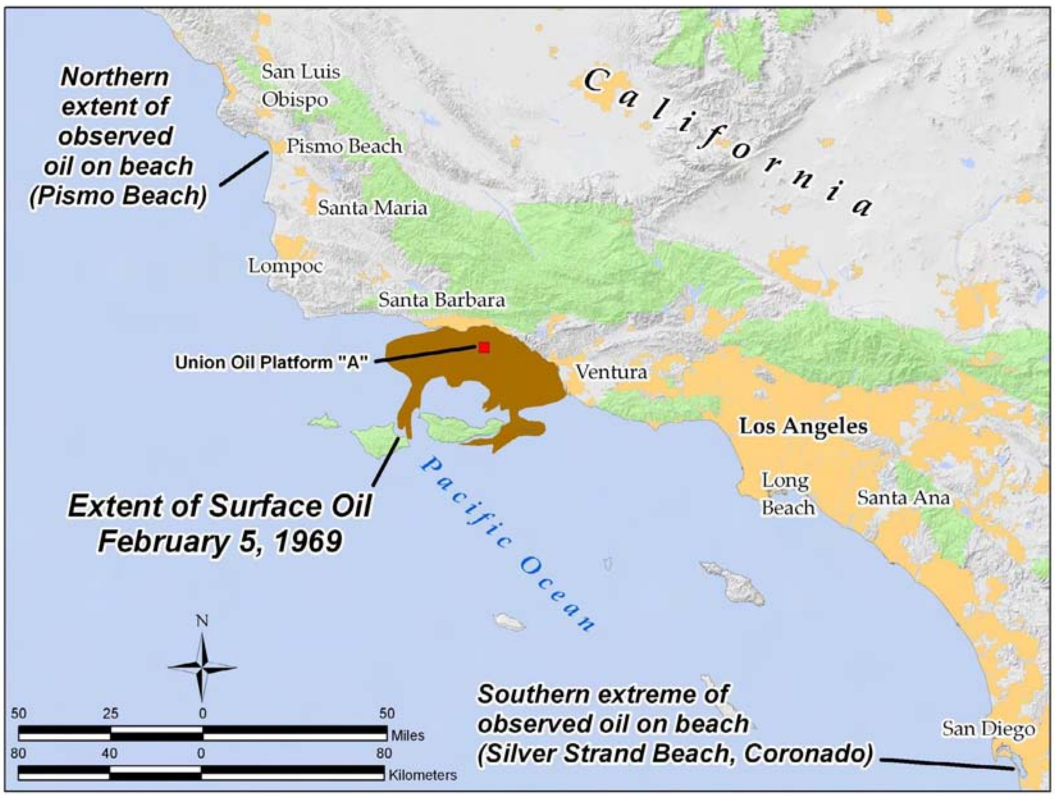

Figure 2.3-7. A view of Santa Barbara Channel with the location of platform "A" during the 1969 well blowout including the extent of the oil spill. (University of California, Santa Barbara, 2011).

Box 2.3-1 – What Caused the Platform A Blowout?

Platform A was installed in September 1968 in federal waters about 8.9 km (5.5 mi) from the coast in 57.3 m (188 ft) of water. The blowout began on January 28, 1969, during drilling of the 5th development well, 402-A-21 (The Resources Agency of California, 1971). The first stage of the blowout started while pulling the drill pipe from the directionally drilled well at a measured depth of 976 m (3,203 ft). The drill pipe was pulled faster than the drilling mud could replace the pipe volume, leading to a pressure drop in the well. The pressure drop resulted in petroleum reservoir fluids rising up the well. The rising pressure caused drilling mud to flow up through the drill pipe onto the platform, followed by an oil condensate mist from the reservoir (McCulloh, 1969). The remaining drill pipe still in the hole was dropped to the bottom of the hole, and the blowout preventer blind rams were closed to halt the gas flow about 15 minutes after the blowout began (Adams, 1969). While this stopped the flow up the well, pressure from the reservoir began to build up inside the well. The well only had 73 m (238 ft) of conductor casing and no surface casing, instead of the usual 91 m (300 ft) of conductor casing and 265 m (870 ft) of surface casing normally required (Santa Barbara, 2015b). The use of a shorter casing had been requested by Union Oil and approved by the U.S. Geological Survey. The pressure released from the reservoir blew out around the shoe of the conductor casing and fractured the surrounding seafloor as far away as 244 m (800 ft) from the platform, creating an underground blowout (Hauser and Guerard, 1993; The Resources Agency of California, 1971). Gas and oil leaked into the ocean from five locations on the seafloor around the well. The blowout continued for eleven days until the well was killed by pumping mud down the well. While this stopped most of the leakage, lower-rate leakage continued for months (NOAA, 1992).

2.3.4. Development in the 1970s and 1980s

During the 1970s, development of offshore California slowed. Only platforms Hondo (1976), C (1977), Henry (1979), and Grace (1979) were installed during this decade, all in federal waters. The development pace accelerated again during the 1980s with the installation of platforms Gina (1980), Elly (1980), Ellen (1980), Gilda (1981), Habitat (1981), Edith (1983), Eureka (1984), Hermosa (1985), Harvest (1985), Irene (1985), Hidalgo (1986), Gail (1987), Harmony (1989), and Heritage (1989) (Figure 2.3-8), all in federal waters (CSLC, 1999). In 1990, island Esther in San Pedro Bay (state waters) was converted to platform Esther.

Figure 2.3-8. Platform Heritage (1989) – the most recent platform installed in federal waters. (MMS, 2007).

The development of additional offshore production facilities stopped after 1990. This drop-off in activity was directly related to the moratoriums on offshore oil and gas leasing for both federal waters since 1982 and state waters since 1969 (Sutherland Asbill & Brennan LLP, 2008; Chiang, 2009). The moratorium for state waters became part of California law in 1994 (California Coastal Sanctuary Act, 1994). Although the moratorium in federal waters was lifted in 2008, no new offshore leases were sold (Sutherland Asbill and Brennan LLP, 2008; BOEM, 2015a). In November 2011, the Obama Administration imposed a five-year moratorium starting in 2012 that closed all offshore California to new oil and gas drilling (U.S. House of Representatives, 2011).

2.4. Petroleum Geology and Characteristics of California Offshore Oil and Gas Reservoirs

This section draws upon the petroleum geology of offshore California presented in Chapter 4 of Volume I and provides additional information about reservoir rock characteristics and petroleum production.

Petroleum source rocks and reservoir rocks all occur in sedimentary basins. Sedimentary basins are created where tectonic and other geologic processes (such as geothermal contraction and erosion) create depressions at the surface. Sediments created by erosion of rock, such as through fluvial (water driven) and aeolian (wind driven) processes, lead to the movement of sediments driven by gravitational forces into these depressions. Over millions of years, these depressions fill up with sediments to become sedimentary basins. Figure 2.4-1 shows the offshore sedimentary basins for California, Oregon, and Washington states.

Most of the oil and gas fields in California are located in structural basins (DOGGR, 1982; 1992; 1998) formed over the past 23 million years. These basins are filled with mainly marine sedimentary rocks, originally including both biogenic (produced by marine organisms) and clastic (derived by erosion of existing rocks) sediments. In each basin, geologists have identified distinct packages of sedimentary rocks as formations, which share similar time-depositional sequences and have distinctive characteristics that can be mapped.

Oil and gas accumulations (also known as reservoirs or pools) are found within oil and gas fields. The reservoirs are organized into groups called plays that have common factors associated with hydrocarbon generation, accumulation, and entrapment (BOEM, 2014a). In the BOEM (2014a) assessment of offshore oil and gas resources for the Pacific Outer Continental Shelf Region, plays were organized according to source rock, reservoir rock, and trap characteristics of stratigraphic units.

Current offshore oil production comes from the Santa Barbara, Santa Maria, and offshore Los Angeles Basins. Geologic and petrophysical characterization of these basins will be presented first, including both currently operating petroleum reservoirs and other reservoirs within these basins. This will be followed by a discussion of potential future petroleum resources from undeveloped offshore basins.

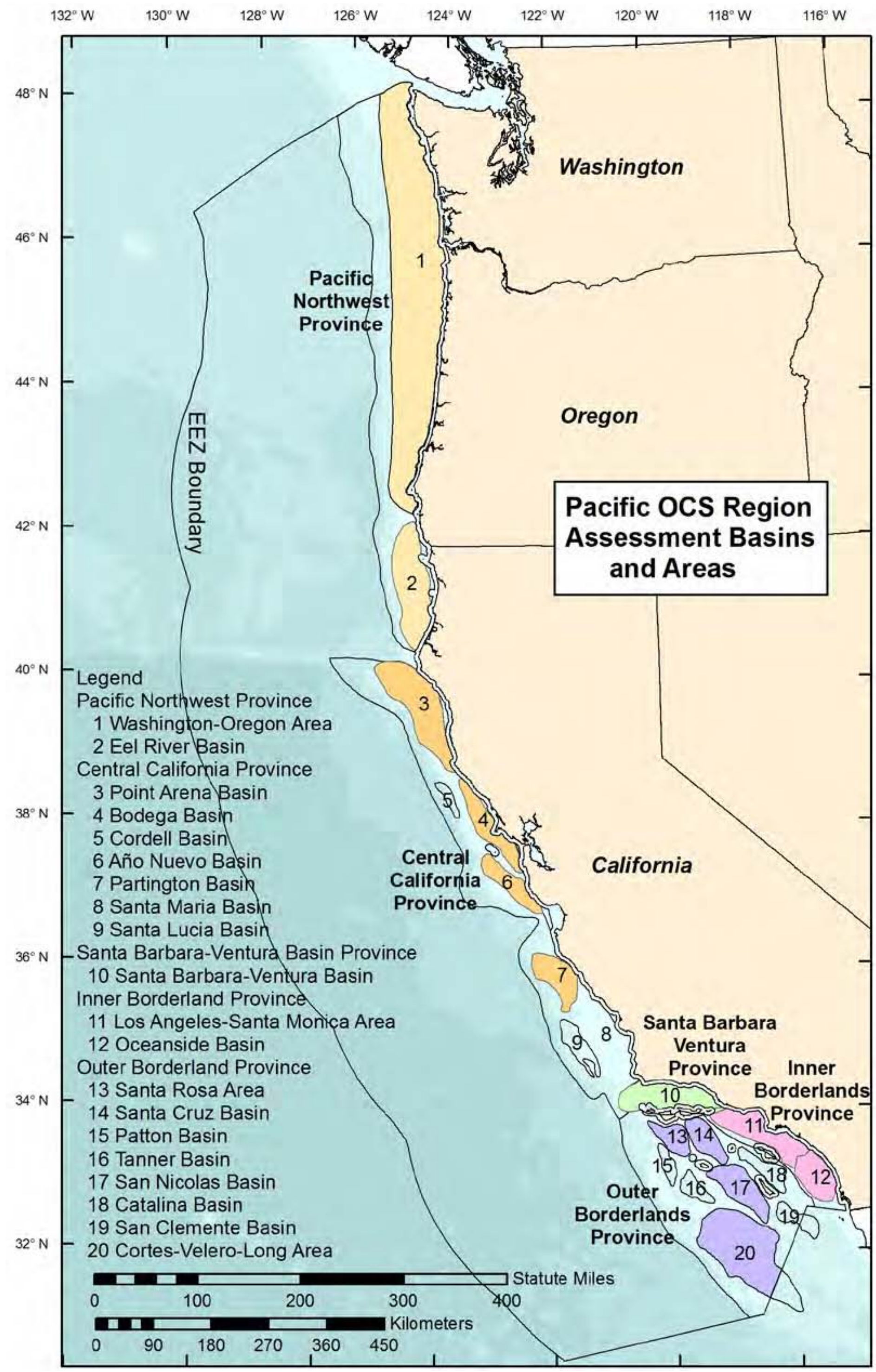

Figure 2.4-1. Provinces and sedimentary basins in and along the Pacific Coast (BOEM, 2014a).

Well stimulation is conducted offshore for the same reasons as onshore – to facilitate production from low permeability reservoirs and to counter the effects of formation damage near the well. The production of oil and gas from a reservoir depends on reservoir permeability, but it is also a function of reservoir thickness, the viscosity of the produced fluids, and other factors (Volume I, Chapter 2). Because of the complexity of the problem, an exact permeability threshold for the use of well stimulation technologies does not exist (Holditch, 2006). However, the likelihood that well stimulation is needed to economically produce oil and gas increases as the reservoir permeability falls below about 10^{-15} square meters (m^2; about 1 millidarcy, md) (e.g., King, 2012). Hydraulic fracturing for low permeability conditions is intended to open permeable fracture pathways to enable oil or gas production. However, hydraulic fracturing technology has been expanded to deal with other oil production issues that occur in moderate-to higher-permeability conventional reservoirs. These other issues are formation damage around the well and sand production into the well. The hydraulic fracturing technology used for these purposes is called "frac and pack" or just "frac-pack" (Sanchez and Tibbles, 2007) and may also be referred to as a "high-rate gravel pack" (Cardno ENTRIX, 2012). The American Petroleum Institute (API) notes that frac-packs are a common well stimulation method used for offshore oil and gas production sites that often have moderate to high permeability and sand control problems (API, 2013). Therefore, hydraulic fracturing may be used under any condition of reservoir permeability, but is not essential (i.e., not used in all cases) when permeabilities exceed about 10 md (about 10^{-14} m^2). California oil and gas reservoirs are predominantly rich in silicate rocks, which means that the form of matrix acidizing used is called "sandstone acidizing" (Volume I, Chapter 2). This type of acidizing is normally used only when formation damage near the well is impeding flow into the well. This is because penetration of a sandstone acidizing treatment into the formation is generally only about 0.3 m (1 ft). However, there is much less known about sandstone acidizing in siliceous reservoirs with permeable natural fractures, such as in some parts of the Monterey Formation (Kalfayan, 2008). In these circumstances, sandstone acidizing may be able to penetrate and remove natural or drilling-induced blockage in fractures deeper into the formation (Rowe et al., 2004; Patton et al., 2003; Kalfayan, 2008).

2.4.1. Santa Barbara Basin

The Santa Barbara/Ventura Basin is a structurally complex east-west trending synclinal trough, bounded on the north and northeast by the Santa Ynez and San Gabriel faults, and on the south by the Santa Monica Mountains and Channel Islands. The onshore and offshore parts are a single continuous structure. The onshore part is referred to as the Ventura Basin, while the offshore part is known as the Santa Barbara Basin. The basin has been structurally deformed by the active tectonic processes associated with the Pacific/North American plate margin. The stratigraphic column in Figure 2.4-2 shows that the sequence of formations has resulted in oil reservoirs that consist mainly of sandstones and the Monterey, which is a fractured siliceous shale.

The Santa Barbara/Ventura Basin exhibits as much as 7,000 m (23,000 ft) of structural relief on the base of the Miocene section (Tennyson and Isaacs, 2001) and a succession of Upper Cretaceous to Quaternary sedimentary rocks as much as 11,000 m (36,000 ft) thick. In the primary depocenter, the Plio-Pleistocene strata are more than 6,100 m (20,000 ft) thick (Dibblee, 1988; Nagle and Parker, 1971).

There are twelve petroleum fields under production in the Santa Barbara Basin shown in Figure 2.4-3, which also shows the three currently producing oil fields in the Santa Maria Basin. There are four plays identified in this basin in federal waters (BOEM, 2014a). The Pico-Repetto (PR) play consists of Pliocene and early Pleistocene turbidite sandstones. The Fractured Monterey (FM) play consists of middle to late Miocene siliceous fractured shale reservoirs of the Monterey Formation. The Rincon-Monterey-Topanga-Sespe-Alegria-Vaqueros (RMT-SAV) sandstone play consists of late Eocene to middle Miocene reservoirs. The Gaviota-Sacate-Matilija (GSM) play consists of Eocene to early Oligocene sandstones of various origins deposited as turbidites, fans, channels, and near-shore bars. The plays in state waters that are currently producing are the Neogene and Paleogene plays (Keller, 1995).

Production statistics for the Santa Barbara Basin are given in Table 2.4-1. Annual production in 2013 for all of offshore California shows about 64% of the oil and 75% of the gas is produced in the Santa Barbara Basin. About 90% of oil and gas production from the Santa Barbara Basin comes from six fields—Hondo, Pescado, Sacate, South Elwood, Carpinteria, and Dos Cuadras—that lie along the Rincon trend and its continuation along the five-mile trend and splay (Figure 2.4-3). The Hondo, Pescado, Sacate, and South Elwood fields produce mainly from fractured, siliceous, Miocene reservoir rock in the Fractured Monterey play. The Carpinteria and Dos Cuadras fields produce mainly from Pliocene turbidite sandstones in the Pico and “Repetto” (lower Pico) play. The Rincon field itself also lies along this trend but has only minor amounts of oil and gas production. The production levels for the Santa Barbara Basin in 2013 are about 8.6% of the state onshore oil production and about 15% of the gas production.

Other undeveloped reservoirs are shown in Figure 2.4-3. These are expected to be similar to the existing reservoirs, in that most of the remaining oil is likely to be in the identified plays, with current oil production in the Santa Barbara Basin today.

The source rocks for reservoirs in the Pico, “Repetto,” and Monterey Formations are likely to be in the Miocene Monterey Formation (Monterey Formation reservoir rocks lie in the same formation as the source rock). Other older source rocks include Cretaceous to Eocene organic shales. Sources for high gravity oil include Cretaceous, Eocene, and Miocene shales. Sources for low gravity, high sulfur oil are most likely Miocene formations.

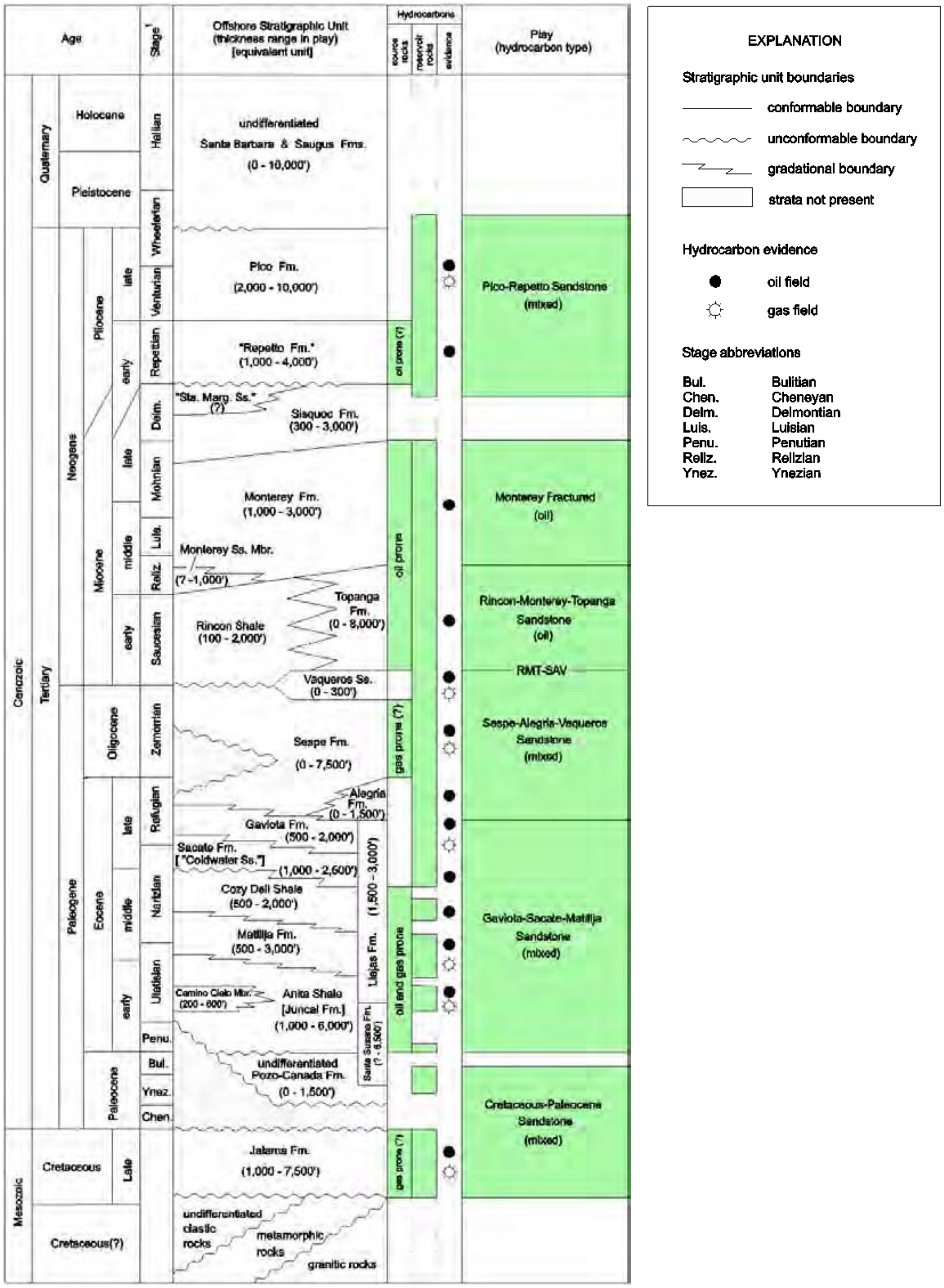

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Figure 2.4-2. Stratigraphic column of the Santa Barbara-Ventura Basin showing formation thickness ranges (ft) and source rock and reservoir rock hydrocarbon classifications (BOEM, 2014a).

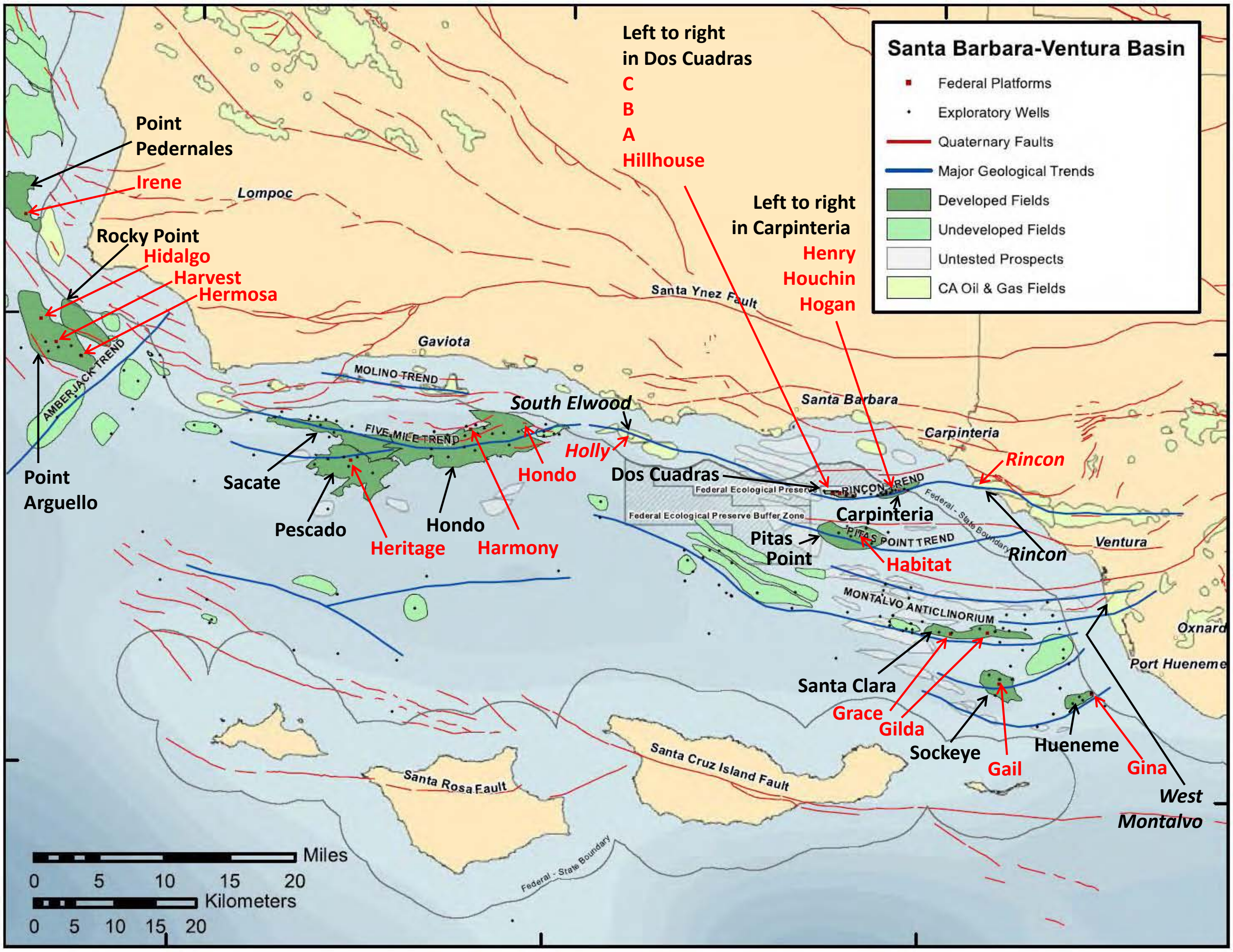


Figure 2.4-3. Operating oil fields and production facilities in the Santa Barbara and Santa Maria Basins showing faults and geologic trends. Modified from BOEM (2014a). Fields Point Pedernales, Point Arguello, and Rocky Point are in the Santa Maria Basin. All other fields are in the Santa Barbara Basin. Black font labels with black arrows denote oil fields. Red font labels with red arrows denote offshore production facilities. Note that offshore production from the West Montalvo field is performed using wells spud onshore. Facilities and field names in state waters are italicized.

Properties of the main reservoirs currently under production are given in Table 2.4-2. Notably, reservoir depths are mainly in excess of 1000 m below the ocean floor, and reservoir permeabilities are in the millidarcy to darcy range (where 1 millidarcy approximately equals 10^{15} m^2 and 1 darcy approximately equals 10^{-12} m^2).

The API gravities show that the crude oils produced are mostly heavy to medium, with a few that are at the low end of the light crude category.[2] Only the lower end of the permeability ranges are below 10 md (about 10^{-14} m^2); therefore, hydraulic fracturing is not likely to be essential for petroleum production.

Table 2.4-1. Production and resource estimates for currently producing fields in the Santa Barbara Basin in 2013 (BOEM, 2013; DOGGR, 2010, 2011, 2012, 2013, 2014a).

Field**	**Original Recoverable Reserves**		**Cumulative Production**		**Annual Production**		**Remaining Reserves**	
	Oil, (m^3) x10^6 (bbl[#]) x10^6	Gas, (m^3) x10^6 (Mcf[##]) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6
Carpinteria	11.8 (74.1)	1770 (62.5)	11.4 (71.5)	1,690 (59.8)	0.0592 (0.373)	11.4 (0.402)	0.414 (2.61)	77.5 (2.74)
Dos Cuadras	44.5 (280)	4,980 (176)	42.5 (267)	4,470 (158)	0.157 (0.988)	46.6 (1.65)	2.04 (12.8)	508 (17.9)
Hondo	62.4 (393)	22,400 (793)	48.7 (306)	19,000 (670)	0.814 (5.12)	319 (11.3)	13.8 (86.8)	8,970 (317)
Hueneme	1.92 (12.1)	347 (12.3)	1.87 (11.8)	290 (10.3)	0.0171 (0.108)	14.1 (0.499)	0.0513 (0.323)	56.4 (1.99)
Pescado	29.0 (182)	4,750 (168)	22.7 (143)	6,220 (220)	0.369 (2.32)	97.8 (3.45)	6.29 (39.6)	2,350 (82.9)
Pitas Point	0.0334 (0.211)	6,770 (239)	0.0333 (0.209)	6,590 (233)	2.19x10^{-5} (1.38x10^{-4})	4.70 (0.166)	1.60x10^{-4} (1.01x10^{-3})	186 (6.56)
Sacate	19.5 (123)	3,120 (110)	7.00 (44.0)	1,210 (42.7)	0.566 (3.56)	131 (4.64)	12.5 (78.6)	1,910 (67.6)
Santa Clara	7.67 (48.3)	2,040 (71.9)	7.28 (45.8)	1,970 (69.6)	0.0604 (0.380)	9.78 (0.345)	0.390 (2.45)	65.9 (2.33)
Sockeye	8.38 (52.7)	3,050 (108)	7.24 (45.5)	2,760 (97.5)	0.156 (0.984)	32.8(1.16)	1.14 (7.20)	291 (10.3)
South Elwood	NA	NA	12.1 (75.9)	1,780 (62.7)	0.276 (1.73)	27.0 (0.954)	NA	NA
Rincon	NA	NA	0.0101 (0.0636)	1.47 (0.0518)	0.00108 (0.00680)	0.0489 (0.00172)	NA	NA
West Montalvo	1.66 (10.4)	194 (6.84)	1.53 (9.65)	167 (5.91)	0.0574 (0.361)	1.87 (0.0660)	0.128 (0.803)	26.2 (0.927)

**Volumes of gas that have been injected into the reservoir are added to remaining reserves (Hondo and Pescado)*
*NA – not available; # bbl = oil barrel (one bbl = 42 gallons); ## Mcf = one thousand cubic feet (one Mcf = 7481 gallons)** The South Elwood, Rincon, and West Montalvo fields are in state waters. All other fields are in federal waters.*

2. The API gravity is a measure of the oil density at a standard temperature of 60° F (American Society for Testing and Materials (ASTM) D287-12b, 2012). A crude oil with API gravity greater than 10° will float on pure water. Crude oil density correlates with viscosity, and both density and viscosity increase with decreasing API gravity (Saniere, 2011; Sattarin et al., 2007). Crude oil is classified as light if the API gravity is greater than 31.1° and as heavy if it is less than 22.3° but greater than 10°. Crude oils with API gravity between 22.3° and 31.1° are classified as medium. Crude oils with API gravity less than 10° are called extra-heavy or bitumen (Saniere, 2011).

Table 2.4-2. Santa Barbara Basin Reservoir characteristics for some currently producing reservoirs (MMS, 1993; 1994; DOGGR, 1992; Keller, 1995).

Field	Formation	Epoch	Play	Average Depth (m) (ft)	Net Thickness (m) (ft)	Permeability (m^2) x 10^{15}	Porosity	API Gravity (o)
Carpinteria	P	P	PR	1,010 (3,300)	305 – 351 (1,000-1,150)	1 - 2171	15 - 39	25.5
Dos Cuadras	P(R)	P	PR	488 (1,600)	305 – 319 (1,000-1,050)	49 - 987	15 - 40	25
Hondo	M	M	FM	2,590 (8,500)	10 – 223 (32.8-732)	0.1 - 1678	9 - 23	17
Hondo	V/S	M/O	RMT-SAV	3,050 (10,000)	137 – 223 (449-732)	10 - 1480	10 - 35	35.1
Hueneme	H/S	M/O	RMT-SAV	1,560 (5,100)	46 – 76 (151-249)	1 - 1480	12 - 40	14.5
Pescado	M	M	FM	2,050 (6,710)	366 (1,200)	0.1 - 1678	2 - 30	17
Pitas Point	P(R)	P	PR	3,380 (11,100)	91 (299)	1 - 20	15 - 18	Gas
Santa Clara	P	P	PR	2,150 (7,050)	53 (174)	1 - 197	12 - 40	23
Santa Clara	M	M	FM	2,290 (7,500)	366 (1200)	1 - 1283	3 - 30	28
Sockeye	M	M	FM	1,370 (4,500)	61 – 76 (200-249)	0.1- 987	2 - 30	16.5
Sockeye	US	M/O	RMT-SAV	1,740 (5,700)	259 (850)	1 - 7106	20 - 30	29.5
South Elwood	M	M	N	1,020 (3,350)	152 (499)	NA	NA	25-34
Rincon	P	P	N	1,080 (3,560)	116 (381)	39	22	32
West Montalvo	S	O	P	3,510 (11,500)	762 (2,500)	NA	NA	13-32

Formation: M – Monterey; P – Pico; P(R) – Pico (Repetto); V – Vaqueros; S – Sespe; US – Upper Sespe; H – Hueneme

Epoch: P – Pliocene; M – Miocene; O – Oligocene

Play: PR – Pico-Repetto; FM – Fractured Monterey; RMT-SAV – Rincon-Monterey-Topanga-Sespe-Alegria-Vaqueros; N – Neogene; P – Paleogene; NA – not available

2.4.2. Santa Maria Basin

The Santa Maria Offshore Basin is a complexly faulted extensional structure, separated from the Santa Maria Onshore Basin by the Hosgri Fault Zone. Sub-basins bounded by normally faulted basement blocks were rapidly filled by volcanic, biogenic, and siliciclastic rocks of the Lospe, Point Sal, Monterey, Sisquoc, Foxen, and Careaga Formations (Figure 2.4-4). These formations, which directly overlie basement rocks, are more than 3,050 m (10,000 ft) thick. In most areas, Paleogene strata are entirely absent. Near Point Piedras Blancas (Figure 2.4-5), the Neogene stratigraphic section thins to less than 305 m (1,000 ft). In many areas, the Neogene section consists of only the Sisquoc Formation (BOEM, 2014a).

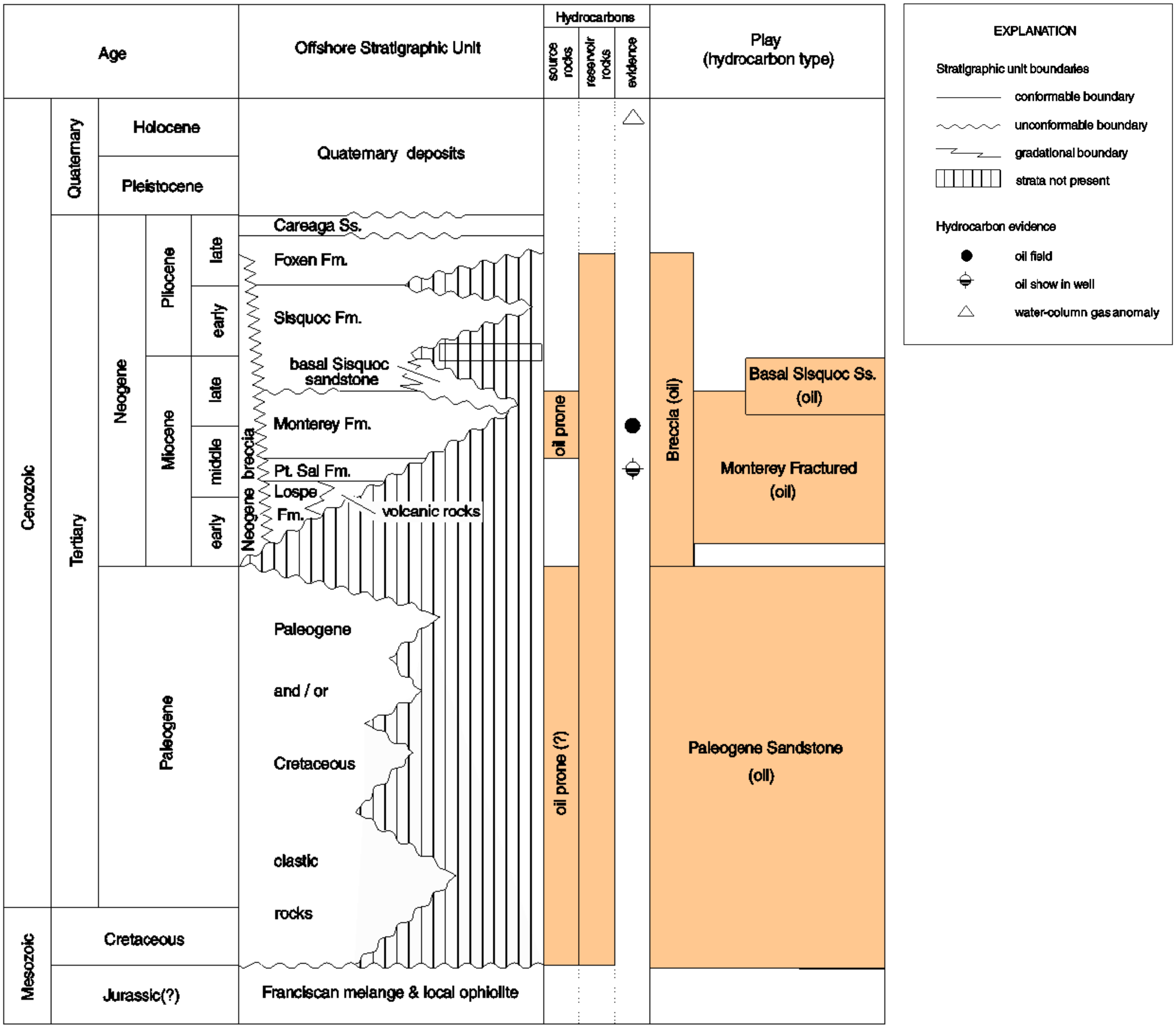


Figure 2.4-4. Stratigraphic column of the Santa Maria Basin showing source rock and reservoir rock hydrocarbon classifications (BOEM, 2014a).

The stratigraphic column in Figure 2.4-4 shows that the sequence of formations contains reservoirs in sandstones and the Monterey, which is a fractured siliceous shale. However, current offshore oil production in the Santa Maria Basin is limited to the fractured Monterey reservoir rock. Three petroleum fields are under production in the Santa Maria Basin, as shown in Figure 2.4-3.

Four petroleum geologic plays have been identified for the Santa Maria—Partington Basin. The Fractured Monterey Play in the Monterey Formation is the only one that has been established offshore. In this play, petroleum reservoirs have been found in fractured Miocene siliceous and dolomitic rocks. The Basal Sisquoc Sandstone play has only been established for the Santa Maria basin onshore. The other two plays, the Breccia play and the Paleogene Sandstone play, remain conceptual. The Monterey Formation is the likely host of source rocks for all of these plays except for some zones in the Paleogene Sandstone play, which may require a source rock in older (Paleogene) strata.

Production statistics for the Santa Barbara Basin are given in Table 2.4-3. Annual production in 2013 for all of offshore California shows about 13% of the oil and 11% of the gas is produced in the Santa Maria Basin. Production from Point Pedernales and Point Arguello were similar in 2013, with production from Rocky Point a distant third place. The production levels for the Santa Maria Basin in 2013 are about 1.7% of the state onshore oil production and about 2.2% of the gas production.

Table 2.4-3. Production and resource estimates for currently producing fields in the Santa Maria Basin in 2013 (BOEM, 2013).

Field**	**Original Recoverable Reserves**		**Cumulative Production**		**Annual Production**		**Remaining Reserves**	
	Oil, (m^3) x10^6 (bbl#) x10^6	Gas, (m^3) x10^6 (Mcf##) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6
Point Arguello	31.8 (200)	3,940 (139)	29.6 (186)	4,870 (172)	0.234 (1.47)	77.3 (2.73)	2.21 (13.9)	1,260 (44.5)
Point Pedernales	16.9 (106)	1,140 (40.3)	14.8 (93.2)	946 (33.4)	0.263 (1.65)	19.1 (0.675)	2.03 (12.8)	195 (6.87)
Rocky Point	3.34 (21.0)	425 (15.0)	0.435 (2.74)	61.5 (2.17)	0.0140 (0.0881)	2.46 (0.0868)	2.90 (18.3)	363 (12.8)

**Volumes of gas that have been injected into the reservoir are added to remaining reserves (Point Arguello)*

***All fields are in federal waters. # bbl = oil barrel (one bbl = 42 gallons);*

Mcf = one thousand cubic feet (one Mcf = 7481 gallons)

Other undeveloped reservoirs are shown in Figure 2.4-5. These are expected to be similar to the existing reservoirs, in that most of the remaining oil is likely to be in the identified plays, with current oil production in the Santa Maria Basin today.

Properties of the main producing reservoirs currently under production are given in Table 2.4-4. Reservoir depths are in excess of 1,000 m below the ocean floor, and reservoir permeabilities are in the millidarcy to darcy range, similar to ranges found for the Santa Barbara Basin. Only the lower end of the permeability ranges are below 10 md (about 10^{-14} m^2); therefore, hydraulic fracturing is not likely to be essential for petroleum production. The API gravities show that the crude oils produced fall into the heavy oil category.

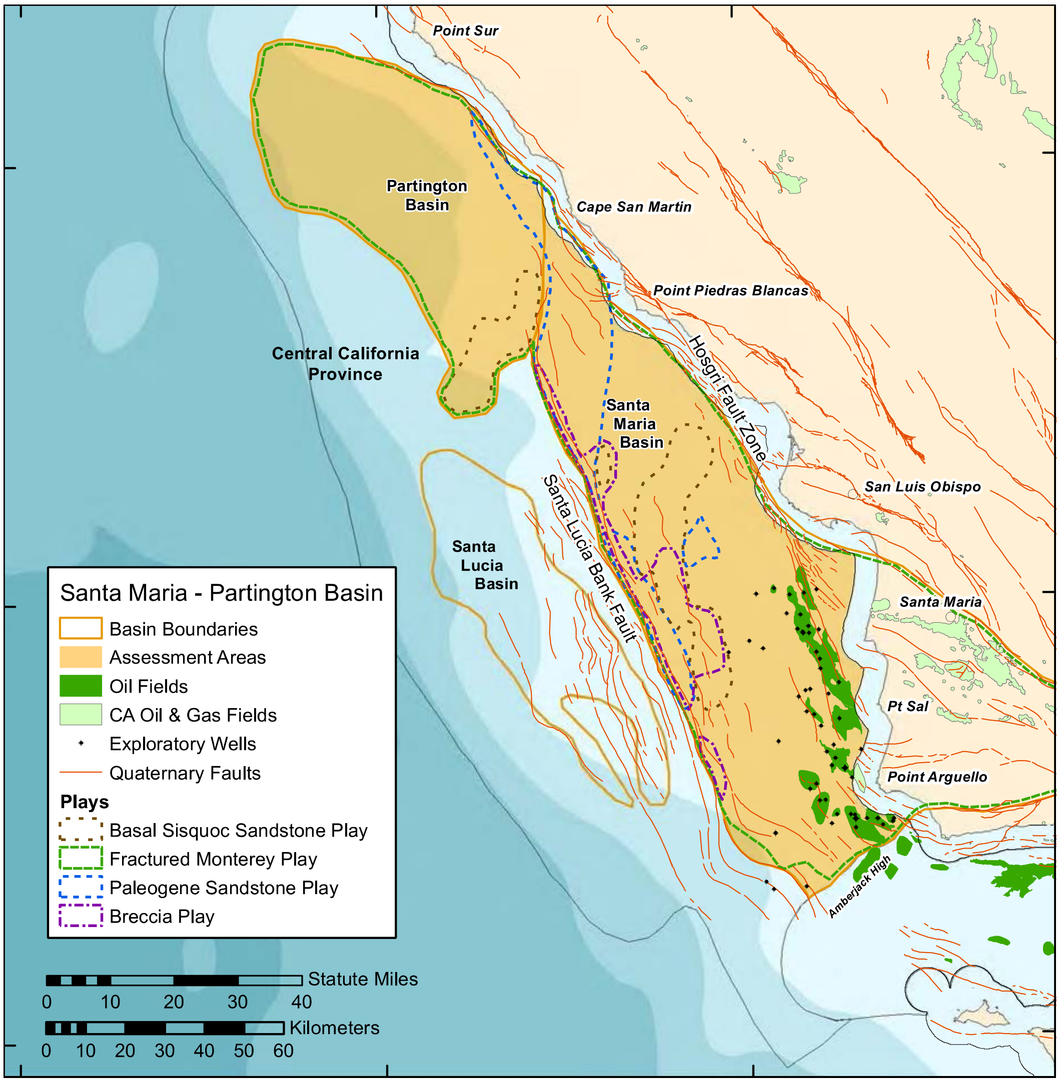


Figure 2.4-5. Partington and Santa Maria Basins (BOEM, 2014a).

Table 2.4-4. Santa Maria Basin Reservoir characteristics for some currently producing reservoirs (MMS, 1993).

Field	Formation	Epoch	Play	Average Depths (m)	Net Thickness (m)	Permeability (m²) x 10^{15}	Porosity	API Gravity (o)
Point Arguello	M	M	FM	2377 (7800)	305 (1000)	1- 2961	10 - 11	18
Point Pedernales	M	M	FM	1524 (5000)	130-145 (427-476)	0.1- 4737	2 - 39	16.3

Formation: M – Monterey, Epoch: M – Miocene , Play: FM – Fractured Monterey

2.4.3. Offshore Los Angeles Basin

The dominant feature of the Los Angeles Basin is the Central Syncline, a poorly understood north-northwest trending 72 km (45 mi) long trough within which organic-rich Miocene sediments have been buried to the oil window and beyond, beneath thick submarine fan deposits (Wright, 1991). The Central Syncline is bordered on the north by east-west trending faults and the southern edge of the Santa Monica Mountains, on the east and northeast by en echelon folds and the Whittier Fault Zone, and on the southwest by the Newport-Inglewood Fault Zone and adjacent southwest structural shelf. The offshore area probably partly shares the thick, porous, and permeable reservoir submarine fan sandstones of latest Miocene Puente Formation and the early Pliocene Repetto Formation, which contain most of the known oil onshore.

Six plays were identified by BOEM (2014a) for the federal waters area. However, only one of these plays, the Puente Fan Sandstone play, is currently being produced. The petroleum reservoirs for this play are found in the Puente and Repetto Formations, in Miocene and Pliocene fan sandstones (Figure 2.4-6).

Source rocks are found at the base of the Miocene Monterey Formation in the “nodular shale” and in Puente Formation Miocene mudstones and shales (BOEM, 2014a).

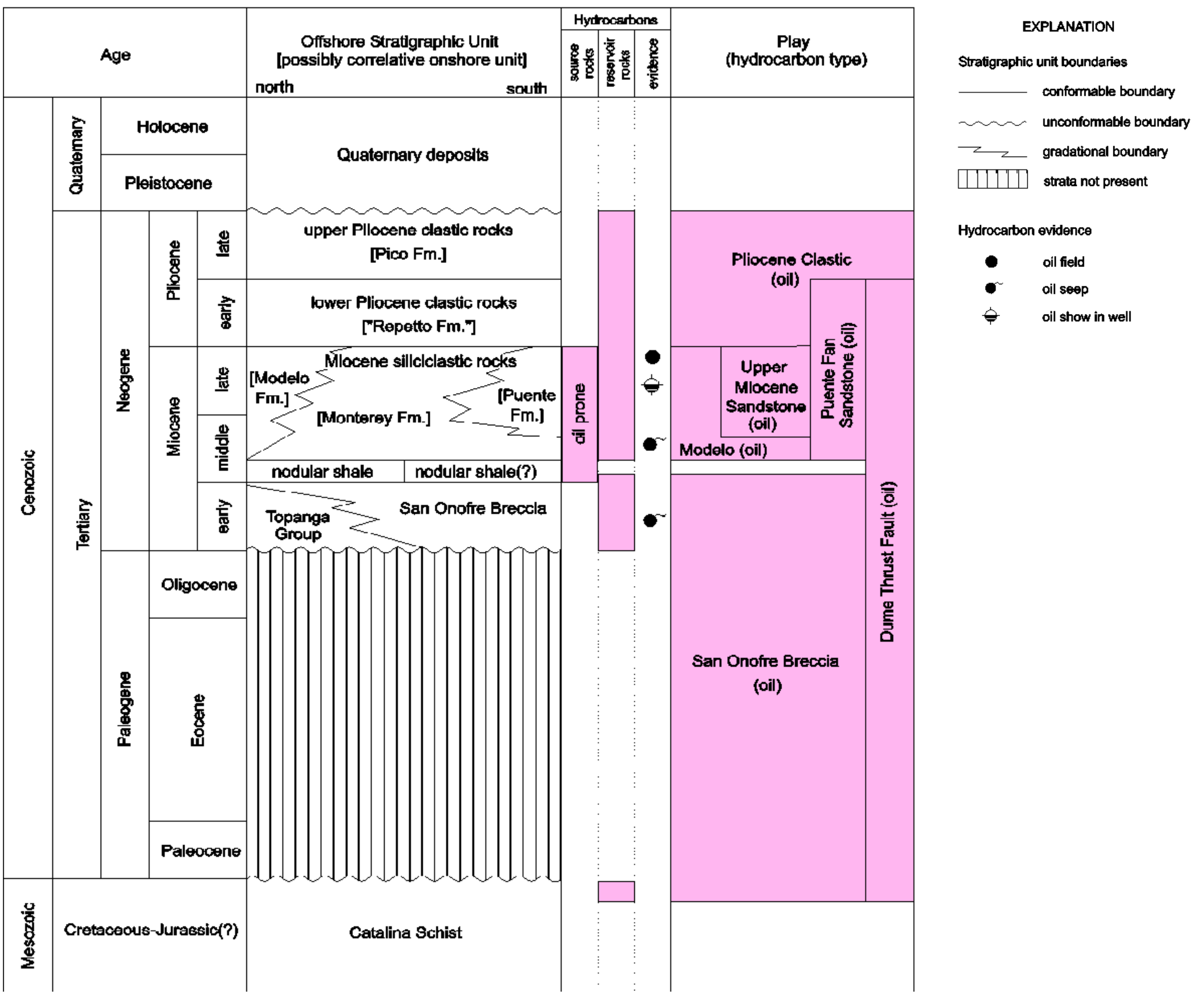


Figure 2.4-6. Offshore Los Angeles – Santa Monica – San Pedro Basins stratigraphy (BOEM, 2014a).

Unlike the Santa Barbara and Santa Maria Basins, most of the oil production activity for this basin is in state waters. There are four oil fields within state waters, three of which contain multiple reservoirs. These reservoirs all lie within the same play identified by Beyer (1995) as the Southwestern Shelf and Adjacent Offshore State Lands play. This play consists mainly of reservoirs in marine turbidite sandstones of Miocene and Pliocene epochs.

Undiscovered petroleum resources are also expected to consist primarily of marine Miocene and Pliocene turbidite sandstones, and possibly, but to a lesser degree, Miocene fractured shale and Cretaceous-Jurrasic conglomerates and breccias from the Catalina Schist.

The source rock for the relatively higher-sulfur oils in producing reservoirs is believed to be the Miocene organic-rich basal unit ("nodular shale") of the Monterey Formation.

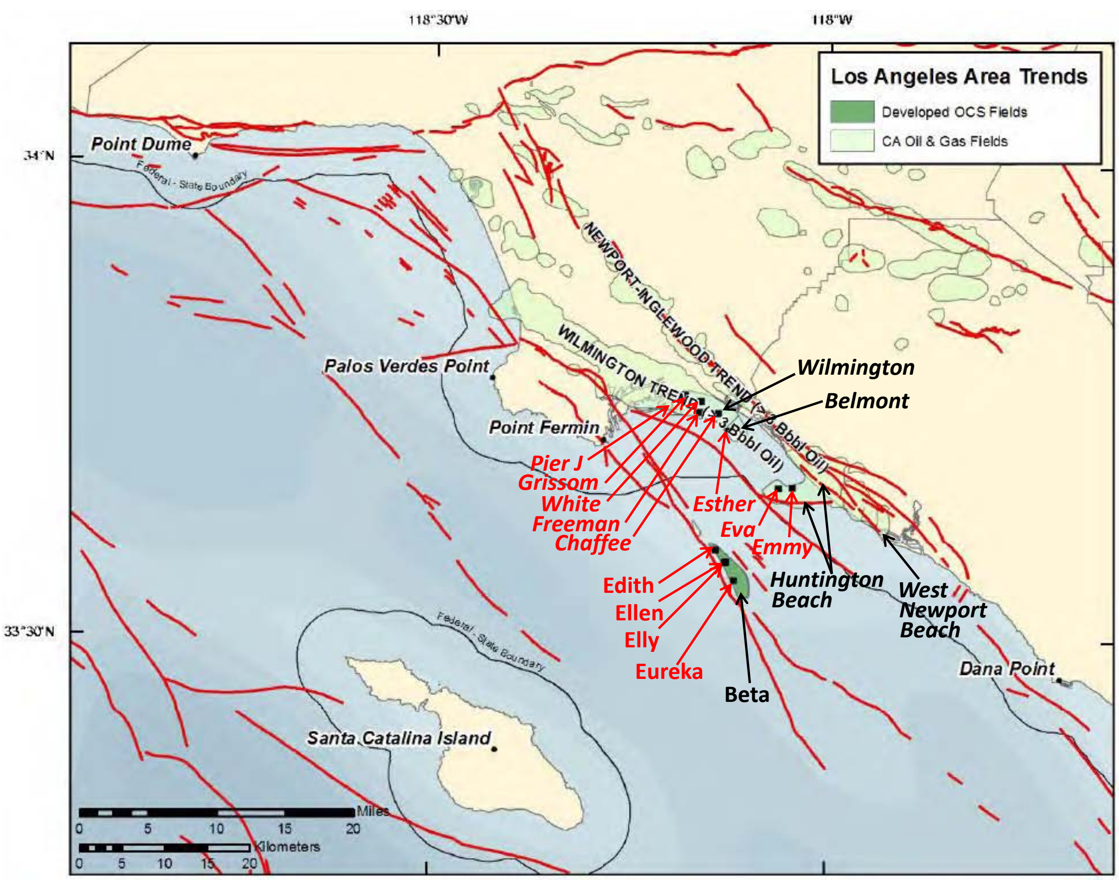


Figure 2.4-7. Operating oil fields and production facilities in the offshore Los Angeles Basin showing faults. Modified from BOEM (2014a). Black font labels with black arrows denote oil fields. Red font labels with red arrows denote offshore production facilities. Note that offshore production from the West Newport Beach field is performed using wells spud onshore. Production from the Huntington Beach field is performed from Platforms Eva and Emmy plus wells spud onshore. Facilities and field names in state waters are italicized.

Production statistics for the offshore Los Angeles Basin is given in Table 2.4-5. Annual production in 2013 for all of offshore California shows about 23% of the oil and 14%

of the gas is produced in the offshore Los Angeles Basin. About 80% of oil and gas production from this region comes from the Wilmington offshore oil field. Production is dominated by reservoirs in the middle Miocene and Pliocene turbidite sands. The undiscovered resources of the offshore Los Angeles Basin are expected to be found in sandstone reservoirs similar to those producing today. The production levels for the offshore Los Angeles Basin in 2013 are about 6.5% of the state onshore oil production and about 2.6% of the gas production.

Properties of the main producing reservoirs currently under production are given in Table 2.4-6. There are several reservoirs in which the reservoir depths are less than 1000 m (3280 ft); however, all of these shallow reservoirs have high permeabilities (> 100 md), which means that hydraulic fracturing is not likely to be essential for petroleum production. In all cases, reservoir permeabilities are in the millidarcy to darcy range. The API gravities show that the crude oils produced are mostly heavy to medium.

Table 2.4-5. Production and resource estimates for currently producing fields in the offshore Los Angeles Basin in 2013 (BOEM, 2013; DOGGR, 2010, 2011, 2012, 2013, 2014a).

Field*	Original Recoverable Reserves		Cumulative Production		Annual Production - 2013		Remaining Reserves	
	Oil, (m^3) x10^6 (bbl[#]) x10^6	Gas, (m^3) x10^6 (Mcf[##]) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6	Oil, (m^3) x10^6 (bbl) x10^6	Gas, (m^3) x10^6 (Mcf) x10^6
Beta	18.1 (114)	1,040 (36.7)	15.4 (97.0)	889 (31.4)	0.240 (1.51)	10.5 (0.370)	2.67 (16.8)	150 (5.29)
Belmont	NA	NA	11.1 (69.8)	1,100 (39.0)	0.112 (0.702)	7.90 (0.279)	NA	NA
Huntington Beach	NA	NA	94.5 (595)	9,340 (330)	0.256 (1.61)	17.1 (0.604)	NA	NA
West Newport	10.5 (65.8)	256 (9.03)	10.1 (63.8)	238 (8.39)	0.00383 (24.1)	0.277 (0.00979)	0.316 (1.98)	18.0 (0.636)
Wilmington	NA	NA	24.9 (157)	1,420 (50.1)	1.55 (9.77)	95.2 (3.36)	NA	NA

** The Beta field is in federal waters. All other fields are in state waters.*

[#] bbl = oil barrel (one bbl = 42 gallons); [##] Mcf = one thousand cubic feet (one Mcf = 7481 gallons)

Table 2.4-6. Offshore Los Angeles Basin Reservoir characteristics for some currently producing reservoirs (MMS, 1993; DOGGR, 1992; Beyer, 1995).

Field	Formation	Epoch	Play	Average Depth (m)(ft)	Net Thickness (m)(ft)	Permeability (m^2) x 10^{15}	Porosity	API Gravity (o)
Beta	D	M	PFS	1,158 (3,800)	434 (1,420)	1 - 296	16 - 26	18
Belmont	RP	P/M	SSAOSL	899 (2,950)	30 (98)	963	30 - 33	16 – 27
Belmont	P	M	SSAOSL	1,219 (4,000)	8 (26)	234	34	23 – 29
Belmont	P	M	SSAOSL	1,676 (5,500)	76 (250)	177	20	23 – 29
Belmont	RP	P/M	SSAOSL	1,128 (3,700)	32 (100)	1617	35	21 – 30
Belmont	P	M	SSAOSL	1,219 (4,000)	46 (150)	725	31	23 – 29
Belmont	P	M	SSAOSL	1,463 (4,800)	26 (85)	493	31	23 – 29
Belmont	P	M	SSAOSL	1,646 (5,400)	61 (200)	138	25	25 – 28
Belmont	P	M	SSAOSL	1,859 (6,100)	23 (76)	79	25	25 – 28
Huntington Beach	RP	P	SSAOSL	460 (1,510)	27 (89)	987	34	15
Huntington Beach	P	M	SSAOSL	671 (2,200)	38 (120)	987	32	11 – 14
Huntington Beach	P	M	SSAOSL	732 (2,400)	58 (190)	296	25	17 – 18
Huntington Beach	P	M	SSAOSL	869 (2,850)	37 (120)	395 - 888	28	14 – 19
Huntington Beach	P	M	SSAOSL	1,097 (3,600)	76 (250)	89 - 166	21 - 24	22
Huntington Beach	P	M	SSAOSL	1,158 (3,800)	137 (449)	168 - 716	23 - 24	22
West Newport	P	M	SSAOSL	1,143 (3,750)	143 (469)	NA	NA	19
Wilmington	RP	P	SSAOSL	640 (2,100)	37 (120)	987	35	12 – 15
Wilmington	RP	P/M	SSAOSL	762 (2,500)	46 (150)	1253	32	12 – 25
Wilmington	P	M	SSAOSL	914 (3,000)	91 (300)	888	33	14 – 25
Wilmington	P	M	SSAOSL	1,097 (3,600)	112 (367)	459	27	25 – 30
Wilmington	P	M	SSAOSL	1,615 (5,300)	38 (120)	74	27	25 – 32
Wilmington	P	M	SSAOSL	1,981 (6,500)	91 (300)	74	23	28 – 32
Wilmington	P	M	SSAOSL	2,438 (8,000)	61 (200)	5	10	28 – 32
Wilmington	CS	LC	SSAOSL	2,591 (8,500)	5 (16)	5	10	28 – 32

Formations: D – Delmontian; RP - "Repetto" Puente; P – Puente; CS – Catalina Schist

Epoch: P – Pliocene; M – Miocene; LC – Late Cretaceous

Play: PFS – Puente Fan Sandstone; SSAOSL - Southwestern Shelf and Adjacent Offshore State Lands

2.4.4. Other Offshore Basins

Currently, petroleum production only occurs in three offshore sedimentary basins as described in Sections 2.4.1 through 2.4.3. Figure 2.4-1 shows 19 sedimentary basins for offshore California, which means that 16 additional basins have potential for oil and gas development. Information about the physical characteristics of petroleum reservoirs in these other offshore basins is very limited, although BOEM (2014a) has estimated reserves for all of these basins. However, as noted in Section 2.3, an offshore development ban in the 1969 in state waters and a moratorium in federal waters since the 1982 has slowed offshore development. Although the moratorium in federal waters ended in 2008, no offshore lease sales have occurred since that time.

As described in Volume I, Chapter 4, potentially more significant undiscovered or undeveloped conventional accumulations are expected to be present along the central and southern California coast. If these were developed, they would likely only involve the occasional use of well stimulation for their development, because the formations where oil is likely to be found typically do not require permeability enhancement. The development of these more easily produced resources would take priority over any low-permeability plays requiring routine well stimulation. Given the limited information available about petroleum resources and development in these other offshore basins, and the low level of offshore development activity since 1990, the focus of this case study is on well stimulation associated with current offshore production.

2.5 Offshore Production Operations and Well Stimulation

Offshore petroleum production operations and their use of well stimulation split into two categories: state waters and federal waters. The main difference for these two categories is the different regulatory environments for state and federal waters governing the disposition of well stimulation fluids. California disallows discharge of fluid into the ocean in state waters if it contains any hydrocarbon or other pollutants (California Public Resources Code Section 6873), whereas in federal waters, operators can discharge restricted quantities of hydrocarbons and certain other pollutants as specified in the NPDES permit. This section summarizes operational aspects of fluids handling, treatment, and discharge, and the use of well stimulation offshore in both federal and state waters.

The conduct of offshore well stimulation in general is described in Volume I, Chapter 2. Well stimulation fundamentally applies the same way offshore as onshore. The majority of onshore hydraulic fracturing in California helps to produce low-permeability diatomite reservoirs that have permeability on the order of 10^{-15} m^2. Most offshore reservoirs are significantly more permeable than this, as seen from Tables 2.4-2, 2.4-4, and 2.4-6. Hydraulic fracturing is not essential for production from more permeable reservoirs; this is consistent with historical information discussed below. Matrix acidizing is more commonly used for higher permeability systems and could have application offshore, but data concerning the use of matrix acidizing for operations in federal waters are currently not available.

Generally speaking, there are three types of fluids that need to be handled on an offshore platform or island: (1) aqueous; (2) hydrocarbon liquids; and (3) hydrocarbon gases. Aqueous fluids include produced water from the subsurface petroleum reservoir; well treatment, completion and workover fluids; water injection fluids (for waterflooding); some drilling muds; and other fluids such as cooling water. Hydrocarbon liquids and gases are the fluids produced by the reservoir, as well as some drilling muds that consist of hydrocarbon-based fluids. In some cases, operators inject hydrocarbon fluids as part of a strategy for recovering reservoir hydrocarbons. The quantity of fluids injected and produced typically exceeds the storage capacity on a platform. Therefore, fluids must be moved off the platform in one of the following four ways: (1) transported onshore; (2) injected into the subsurface environment; (3) discharged to the ocean; (4) flared, depending on the type of fluid. For example, the release of bulk (or free) hydrocarbon phases to the ocean is not permitted, and only volatile hydrocarbon gases may be flared, subject to permit restrictions.

2.5.1. Operations in Federal Waters

Federal waters are defined to be more than 5.6 km (3 geographical miles or about 3.5 miles) offshore according to the Submerged Lands Act of 1953 (Title 43 U.S. Code, Section 1312). The locations of federal offshore operations are shown in Figure 2.2-1 and in more detail in Figures 2.4-3 and 2.4-7, which also show the federal-state boundary. Table 2.5-1 provides information about the offshore facilities.

Platforms in federal waters lie 6 to 16.9 km (3.73 to 10.5 miles) from land in water depths ranging from 29 to 365 m (95.1 to 1200 ft). There are 15 to 96 slots on each platform, which are distinct sites on the platform deck available for drilling wells.

Table 2.5-1. Oil production facilities in Federal waters (BOEM, 2015b).

Platform	Operator**	Field	Distance to Land (km)(miles)	Location	Slots	Water Depth (m)(ft)	Date installed
A	DCOR	Dos Cuadras	9.3 (5.8)	Santa Barbara Basin	57	57.3 (188)	1968
B	DCOR	Dos Cuadras	9.2 (5.7)	Santa Barbara Basin	63	57.9 (190)	1968
C	DCOR	Dos Cuadras	9.2 (5.7)	Santa Barbara Basin	60	58.5 (192)	1977
Gilda	DCOR	Santa Clara	14.2 (8.8)	Santa Barbara Basin	96	62.5 (205)	1981
Gina	DCOR	Hueneme	6.0 (3.7)	Santa Barbara Basin	15	29.0 (95.0)	1980
Habitat	DCOR	Pitas Point	12.6 (7.8)	Santa Barbara Basin	24	88.4 (290)	1981
Henry	DCOR	Carpinteria	6.9 (4.3)	Santa Barbara Basin	24	52.7 (173)	1979
Hillhouse	DCOR	Dos Cuadras	8.9 (5.5)	Santa Barbara Basin	60	57.9 (190)	1969
Harmony	ExxonMobil	Hondo	10.3 (6.4)	Santa Barbara Basin	60	365 (1200)	1989
Heritage	ExxonMobil	Pescado/Sacate	13.2 (8.2)	Santa Barbara Basin	60	328 (1080)	1989
Hondo	ExxonMobil	Hondo	8.2 (5.1)	Santa Barbara Basin	28	257 (842)	1976
Hogan	POO	Carpinteria	6.0 (3.7)	Santa Barbara Basin	66	46.9 (154)	1967
Houchin	POO	Carpinteria	6.6 (4.1)	Santa Barbara Basin	60	49.7 (163)	1968
Gail	Venoco	Sockeye	15.9 (9.9)	Santa Barbara Basin	36	225 (739)	1987
Grace	Venoco	Santa Clara	16.9 (10.5)	Santa Barbara Basin	48	96.9 (318)	1979
Harvest	FMO&G	Point Arguello	10.8 (6.7)	Santa Maria Basin	50	206 (675)	1985
Hermosa	FMO&G	Point Arguello	10.9 (6.8)	Santa Maria Basin	48	184 (603)	1985
Hidalgo	FMO&G	Point Arguello/Rocky Point	9.5 (5.9)	Santa Maria Basin	56	131 (430)	1986
Irene	FMO&G	Point Pedernales	7.6 (4.7)	Santa Maria Basin	72	73.8 (242)	1985
Ellen	Beta	Beta	13.8 (8.6)	Offshore Los Angeles Basin	80	80.8 (265)	1980
Elly*	Beta	Beta	13.8 (8.6)	Offshore Los Angeles Basin	NA	77.7 (255)	1980
Eureka	Beta	Beta	14.5 (9.0)	Offshore Los Angeles Basin	60	213 (700)	1984
Edith	DCOR	Beta	13.7 (8.5)	Offshore Los Angeles Basin	72	49.1 (161)	1983

**Elly is a processing platform for production from Ellen and Eureka, not a production platform*

***FMO&G – Freeman McMoRan Oil and Gas, LLC; DCOR – Dos Cuadras Offshore Resources, LLC; POO – Pacific Operators Offshore, LLC; Beta – Beta Operating Company, LLC; Venoco – Venoco, Inc.; ExxonMobil – ExxonMobil Production Company*

2.5.1.1. Offshore Wells

The BOEM database (BOEM, 2015c) identifies 1370 offshore wells, but only 745 of these produced petroleum in 2013 (BOEM, 2015d). Generally the wells are not vertical but are directionally drilled with some component of horizontal offset. Directional drilling offshore California allows the wells to access laterally offset locations. (In unconventional shale reservoirs in the U.S. midcontinent, directional drilling has a different purpose. It increases the length of the production interval along a thin but horizontally extensive reservoir.) A recently drilled well (Well #SA-16) has the longest lateral reach, about 10,300 m (33,682 ft), of any well offshore California (Armstrong and Evans, 2011). This well, drilled from Platform Heritage, accesses the Sacate field (Figure 2.4-3). Figure 2.5-1 shows the well profile for Well #SA-16. As shown in Figure 2.5-1, the well does not have a long horizontal production interval, but drops angle to about 45 degrees through the producing zone. True vertical depths for the wells were not identified, but should roughly correspond to the reservoir depths given in Tables 2.4-2, 2.4-4, and 2.4-6.

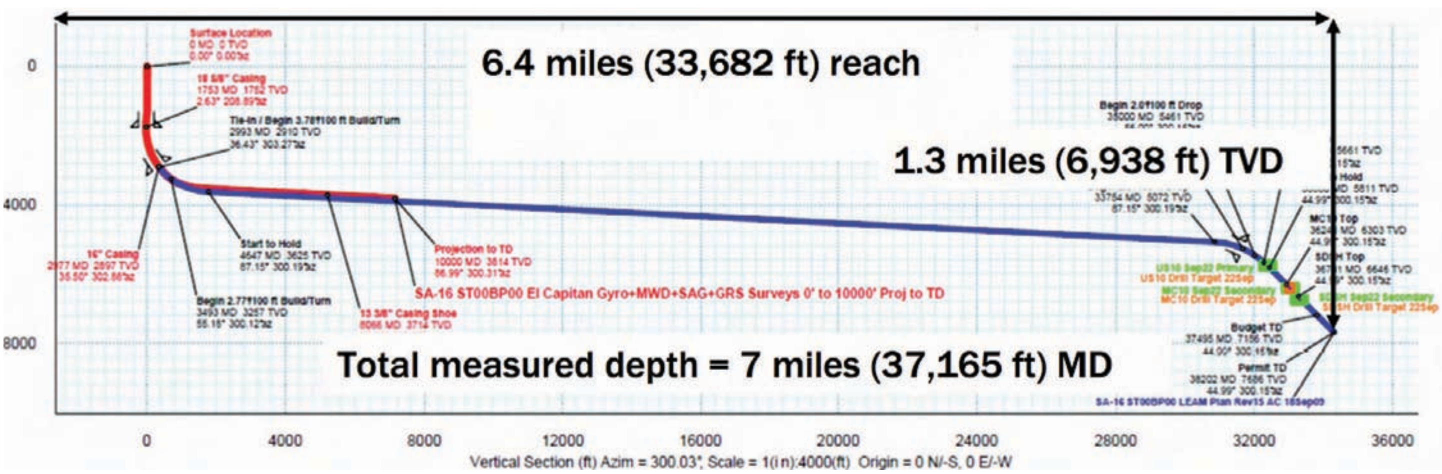


Figure 2.5-1. Well profile for #SA-16 extended reach well drilled from Platform Heritage into the Sacate oil field (modified from Armstrong and Evans, 2011).

2.5.1.2. Well Stimulation

No formal data collection system has been set up to track use of well stimulation conducted in federal waters. Estimates for hydraulic fracturing in federal waters have been made utilizing documents made available in response to requests under the Freedom of Information Act (FOIA) by various interested groups. These FOIA documents are available on the Bureau of Safety and Environmental Enforcement website (BSEE, 2015; see also Appendix A). However, they do not contain a concise listing of well stimulation activities, but rather an assortment of various types of draft and final documents, field reports, and e-mails with clues scattered throughout thousands of pages about well stimulation activities that were proposed or performed. Therefore, the estimation of past well stimulation activities can only provide an approximate idea about the level of activity. Tables 2.5-2 and 2.5-3 present the identified hydraulic fracturing and matrix acidizing treatments, respectively, identified from the records.

Table 2.5-2 shows 22 fracture treatments spanning a 22-year time frame, or about one fracture treatment per year on average. Some of the treatments involved multiple zones in the same well that are counted here as one treatment if performed in the same year. Hydraulic fractures conducted at Platform Hidalgo in the Point Arguello field were in fractured Monterey Shale and two at Platform Gail. The other treatments were mainly frac-packs in sandstones (Repetto and Sespe Formations). Fracturing fluid volumes from six of these treatments were identified in the FOIA documents; they ranged from 51.1 m^3 (13,500 gallons) to 303 m^3 (80,000 gallons), averaging about 121 m^3 (32,000 gallons). It is possible that not all such stimulations have been captured in the records obtained through FOIA simply because the records were not set up to ensure an accurate retrieval of this information. No other records or documents of hydraulic fracture stimulations in federal offshore waters beyond that obtained through FOIA have been identified. Despite this uncertainty, the information from the FOIA documents suggests that the level of hydraulic fracturing activity in federal waters is low.

Table 2.5-3 shows 12 matrix acidizing treatments identified in the FOIA documents for federal offshore waters over nearly 30 years. The FOIA requests tended to focus on hydraulic fracturing, with less emphasis on matrix acidizing. The FOIA documents clearly do not include all the matrix acidizing applications that have occurred. Thirty nine matrix acidizing treatments performed in 26 wells at the Point Arguello field in just a two-year period from 2000 through 2002 were reported by Patton et al. (2003), and none of these treatments was identified from the FOIA documents. Patton et al. (2003) indicated that the typical treatment volume was 55.8 m^3 (14,750 gallons), consisting of 7.57 m^3 (2,000 gallons) of 80%/20% hydrochloric acid (HCl) and xylene, 15.1 m^3 (4,000 gallons) of 12%/3% HCl/hydrofluoric (HF) mud acid, 21.8 m^3 (5,750 gallons) of ammonium chloride, and 11.4 m^3 (3,000 gallons) of a “foamed pill” for acid diversion. DOGGR has recently issued a draft regulation specifying a quantitative definition to distinguish matrix acidizing from other uses of acid for well maintenance (DOGGR, 2014b). Data from Patton et al. (2003) do not provide enough information to determine whether the acid treatments qualify as matrix acidizing or well cleanout. The data do suggest that operators perform acid treatments of some kind, not necessarily matrix acidizing, more frequently than hydraulic fracturing.

Table 2.5-2. Hydraulic fracturing in Federal offshore waters (BSEE, 2015).

API	Well	Lease	Operator	Platform	Field	Date
560452006200	C-1	P-0450	Chevron	Hidalgo	Point Arguello	1997
560452006701	C-11	P-0450	Chevron	Hidalgo	Point Arguello	1997
043112068200	E-11	P-0205	Venoco	Gail	Sockeye	1992
043112067402	E-8	P-0205	Venoco	Gail	Sockeye	2009
043112067402	E-8	P-0205	Venoco	Gail	Sockeye	2010
043112056101	S-60	P-0216	Nuevo/Torch	Gilda	Santa Clara	1994
043112063901	S-52	P-0216	Nuevo/Torch	Gilda	Santa Clara	1996
043112060501	S-53	P-0216	Nuevo/Torch	Gilda	Santa Clara	1996
043112063901	S-89	P-0216	Nuevo/Torch	Gilda	Santa Clara	1996
043112075400	S-87	P-0216	Nuevo/Torch	Gilda	Santa Clara	1997
043112063901	S-62	P-0216	Nuevo/Torch	Gilda	Santa Clara	1997
043112058201	S-28	P-0216	Nuevo/Torch	Gilda	Santa Clara	1998
043112061500	S-61	P-0216	Nuevo/Torch	Gilda	Santa Clara	1998
NA	S-68	P-0216	Nuevo/Torch	Gilda	Santa Clara	1998
043112061000	S-44	P-0216	Nuevo/Torch	Gilda	Santa Clara	2001
043112063901	S-62	P-0216	Nuevo/Torch	Gilda	Santa Clara	2001
043112061601	S-65	P-0216	Nuevo/Torch	Gilda	Santa Clara	2001
043112061000	S-44	P-0216	Nuevo/Torch	Gilda	Santa Clara	2003
043112068400	S-075	P-0216	Nuevo/Torch	Gilda	Santa Clara	2013**
043112068100	S-071	P-0216	Nuevo/Torch	Gilda	Santa Clara	2013*
043112056800	S-033	P-0216	Nuevo/Torch	Gilda	Santa Clara	2013*
043112050100	S-005	P-0216	Nuevo/Torch	Gilda	Santa Clara	2013*

NA – not available

**applied for Categorical Exclusion Review*

***received approval based on Categorical Exclusion Review for treatment*

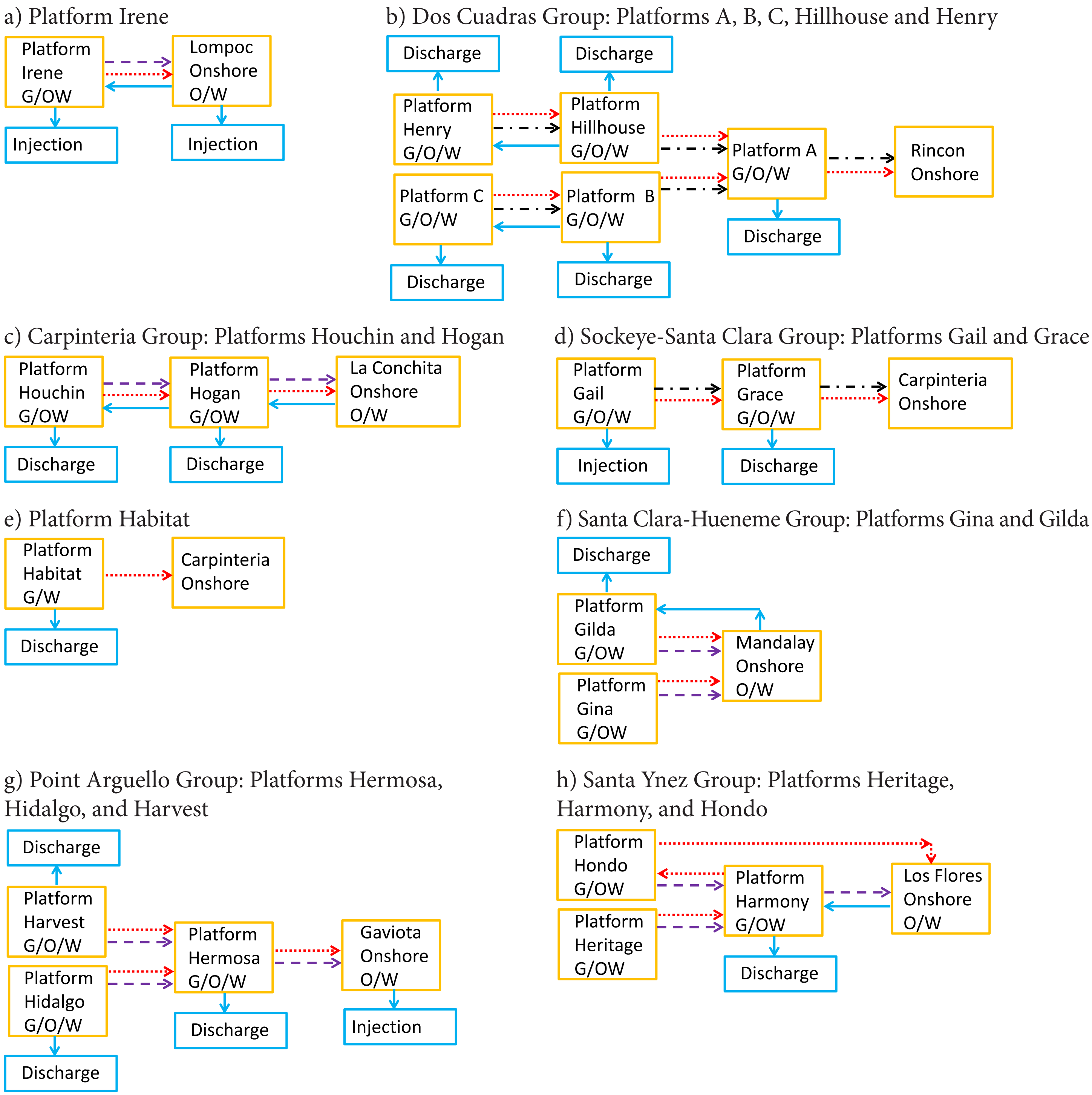
Table 2.5-3. Matrix acidizing in Federal offshore waters (BSEE, 2015).

API	Well	Lease	Operator	Platform	Field	Date
560452006200	C-1	P-0450	Chevron	Hidalgo	Point Arguello	1992
560452006500	C-4	P-0450	Chevron	Hidalgo	Point Arguello	1992
560452006200	C-1	P-0450	Chevron	Hidalgo	Point Arguello	1997
560452006701	C-11	P-0450	Chevron	Hidalgo	Point Arguello	1997
560452006701	C-11	P-0450	Chevron	Hidalgo	Point Arguello	1999
043112067402	E-8	P-0205	Venoco	Gail	Sockeye	2010
043112061000	S-44	P-0216	Nuevo/Torch	Gilda	Santa Clara	1985
043112061000	S-44	P-0216	Nuevo/Torch	Gilda	Santa Clara	1988
043112061000	S-44	P-0216	Nuevo/Torch	Gilda	Santa Clara	2001
043112051300	S-07	P-0216	Nuevo/Torch	Gilda	Santa Clara	2002
043112054600	S-19	P-0216	Nuevo/Torch	Gilda	Santa Clara	2002
043112075400	S-87	P-0216	Nuevo/Torch	Gilda	Santa Clara	2011

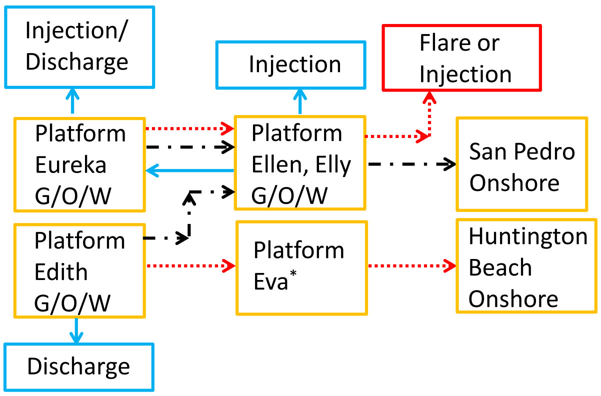
2.5.1.3. Fluids Handling

Pipelines transport fluids between facilities and between offshore and onshore locations. Pipelines exclusively transport oil and gas destined for sale onshore, with potential exceptions for temporary system breakdowns and delivery of well stimulation fluids to offshore facilities. Fluid handling includes separation of oil, gas, and produced water, and in some cases water treatment. Subject to restrictions of the NPDES permit, well stimulation fluids can be mixed with produced water for disposal, with potential impacts on the marine environment.

In several cases, the fluids-handling systems operate cooperatively for groups of platforms; each platform does not necessarily operate independently for delivery of oil and gas onshore and for produced water disposal. Figure 2.5-2 below shows the connections for transporting oil, gas, and water by platform groups that interact for fluids handing and the expected disposition of produced water disposal. Where one cell expands laterally to two cells, a separation is indicated (e.g., an oil/water mixture separated into bulk oil and water phases). Where two cells expand laterally into one cell, the fluid streams are combined.


a) Platform Irene
Platform Irene G/OW
Lompoc Onshore O/W
Injection
Injection
b) Dos Cuadras Group: Platforms A, B, C, Hillhouse and Henry
Discharge
Discharge
Platform Henry G/O/W
Platform Hillhouse G/O/W
Platform A G/O/W
Rincon Onshore
Platform C G/O/W
Platform B G/O/W
Discharge
Discharge
Discharge
c) Carpinteria Group: Platforms Houchin and Hogan
Platform Houchin G/OW
Platform Hogan G/OW
La Conchita Onshore O/W
Discharge
Discharge
d) Sockeye-Santa Clara Group: Platforms Gail and Grace
Platform Gail G/O/W
Platform Grace G/O/W
Carpinteria Onshore
Injection
Discharge
e) Platform Habitat
Platform Habitat G/W
Carpinteria Onshore
Discharge
f) Santa Clara-Hueneme Group: Platforms Gina and Gilda
Discharge
Platform Gilda G/OW
Mandalay Onshore O/W
Platform Gina G/OW
g) Point Arguello Group: Platforms Hermosa, Hidalgo, and Harvest
Discharge
Platform Harvest G/O/W
Platform Hermosa G/O/W
Gaviota Onshore O/W
Platform Hidalgo G/O/W
Discharge
Injection
Discharge
h) Santa Ynez Group: Platforms Heritage, Harmony, and Hondo
Platform Hondo G/OW
Platform Harmony G/OW
Los Flores Onshore O/W
Platform Heritage G/OW
Discharge

i) Beta Group: Platforms Ellen, Elly, Eureka, and Edith



*Eva is a platform in state waters – see Section 2.5.2

Figure 2.5-2. Fluids handling for offshore facilities in Federal waters (BOEM, 2014b). Separation process indicated by G/OW for gas separation only, G/O/W for gas/oil/water separation, O/W for oil water separation and G/W for gas/water separation. Blue solid lines designates water, red dotted lines for gas, black dash-dot lines for oil, purple dashed lines for water-oil mixtures, orange solid lines for facilities, and red solid lines for gas flaring/injection.

Platforms Irene, Ellen/Elly, and Gail are reported to inject 94% or more of their produced water (CCC, 2013) while the other platforms inject less than 15%. Therefore, in Figure 2.5-2, injection is indicated for Irene, Ellen/Elly, and Gail, and discharge is indicated for the others. For the Point Arguello and Beta groups in Figure 2.5-2g and 2.5-2i, some separation of oil and water is done on the platform and/or further oil/water separation could be done onshore.

In addition to gas, oil, and water that must be handled as a result of production, platforms use and typically discharge drilling muds to the ocean. Some platforms use cooling water, mainly to cool down gas after being compressed (Shah, 2013). In other cases, gas compression cooling is performed using air. Volumetrically, cooling water was found to be 86% of the total discharge to the ocean in a 2005 survey of offshore California platform discharges to the ocean (Lyon and Stein, 2010). Produced water represented the second largest discharge at 14%, and other discharges comprised than 1%.

While the description given here indicates the general ways in which operators handle fluids at the different offshore facilities, the specific modes of fluids handling may vary with time and conditions, especially where alternatives are available without requiring changes in permitting or infrastructure.

2.5.2. Operations in State Waters

State waters lie within 5.6 km (3 geographical miles or about 3.5 miles) offshore, according to the Submerged Lands Act of 1953 (Title 43 U.S. Code, Section 1312). Figure

2.2-1 above shows the locations of state offshore operations, and Figures 2.4-3 and 2.4-7 show these in more detail along with the federal-state boundary. Table 2.5-4 provides information about the offshore facilities. Platforms in state waters lie as far as 3.2 km (2.0 miles) from land in water depths ranging up to 64.3 m (211 ft).

Table 2.5-4. Oil production facilities in State waters (CSLC, 2008; 2009; 2010a; 2010b; 2012; 2013; Goleta, 2015).

Offshore Facility	Operator**	Field	Distance to Land (km)(miles)	Location	Slots	Water Depth (m)	Date installed
Platforms							
Holly	Venoco	South Elwood	3.2 (2.0)	Santa Barbara Basin	30	64.3 (211)	1966
Emmy	Occidental	Huntington Beach	1.9 (1.2)	Los Angeles Basin	52	14.3 (46.9)	1964
Eva	DCOR	Huntington Beach	2.9 (1.8)	Los Angeles Basin	37	17.4 (57.1)	1963
Esther	DCOR	Belmont	1.9 (1.2)	Los Angeles Basin	64	6.7 (22.0)	1990
Artificial Islands							
Rincon	Rincon LP	Rincon	0.8 (0.5)	Santa Barbara Basin	NA	13.4 (44.0)	1958
Grissom	Oxy LB	Wilmington	0.2 (0.1)	Los Angeles Basin	NA	12.2 (40.0)	1967
White	Oxy LB	Wilmington	0.7 (0.4)	Los Angeles Basin	NA	12.2 (40.0)	1967
Chaffee	Oxy LB	Wilmington and Belmont	1.3 (0.8)	Los Angeles Basin	NA	12.2 (40.0)	1967
Freeman	Oxy LB	Wilmington	2.0 (1.2)	Los Angeles Basin	NA	12.2 (40.0)	1967
Seafloor Completion							
Rincon	Rincon LP	Rincon	0.7 (0.4)	Santa Barbara Basin	N/A	16.8 (55.1)	1961
Onshore***							
West Montalvo	Hunter	West Montalvo	0	Santa Barbara Basin	N/A	N/A	NA
Huntington Beach	*	Huntington Beach	0	Los Angeles Basin	N/A	N/A	NA
West Newport	*	West Newport	0	Los Angeles Basin	N/A	N/A	NA

*NA – not available; N/A – not applicable; *Numerous operators; ** DCOR – Dos Cuadras Offshore Resources, LLC; Rincon LP, Rincon – Rincon Island Limited Partnership; Hunter - Hunter Oil and Gas, Inc. LLC; Venoco – Venoco, Inc.; Oxy LB – Oxy Long Beach; Occidental – Occidental Petroleum Corporation; *** Onshore - Onshore Well Locations for Offshore Production*

2.5.2.1. Offshore Wells

The DOGGR database identifies 1,972 active or idled offshore wells (DOGGR, 2015). As in federal waters, wells in state waters typically have some amount of lateral offset achieved with directional drilling (Section 2.5.1.1). As a result, true vertical depths were not identified in most cases, but should roughly correspond to the reservoir depths given in Tables 2.4-2, 2.4-4, and 2.4-6.

2.5.2.2 Well Stimulation

Records given in Appendix M, Volume I of this report allow evaluation of past use of well stimulation conducted in state waters. All of the offshore hydraulic fracturing in state waters has occurred on the THUMS islands and Platform Esther that operate in the Wilmington and Belmont fields. The data shows hydraulic fractures that were performed between January 2002 and December 2013. In total, operators conducted 117 hydraulic fracture treatments, with 106 conducted on the THUMS islands in the Wilmington field, 5 conducted on Island Chaffee (one of the THUMS islands) in the Belmont field “old area” and 6 conducted on Platform Esther in the Belmont field “surfside area.” No hydraulic fracturing was reported from facilities in state waters in the Santa Barbara Channel or from Platforms Eva and Emmy in the Los Angeles Basin. Treatment volumes for 19 stimulations conducted on the THUMS islands were recorded. The volumes ranged from 114 to 803 m^3 (30,000 to 212,000 gallons) of stimulation fluids, with an average of 530 m^3 (140,000 gallons). It is not known whether these stimulations used fresh water or seawater.

Only the South Coast Air Quality Management District has records that include matrix acidizing information for facilities in state waters in the Los Angeles Basin. This data shows that from June 2013 to April 2014 there were 135 acid treatments offshore, with 111 on the THUMS islands, 17 on Pier J, and 7 at Huntington Beach for wells that extend offshore. Treatment volumes ranged from 12.5 to 319 m^3 (3,300 to 84,300 gallons), with an average of 15,900 gallons. However, these treatments may not meet the matrix acidizing thresholds established by DOGGR per Senate Bill 4. The average treatment volume is close to the average treatment volume of 60.2 m^3 (14,750 gallons) reported by Patton et al. (2003) for acidizing in federal offshore waters at the Point Arguello field (see Section 2.5.1.2). Given the limited coverage for acid treatments, the numbers reported here strongly suggest that acid treatments (including both well cleanout and matrix acidizing) are performed more frequently than hydraulic fracturing.

2.5.2.3. Fluids Handling

As in federal waters, pipelines transport fluids between facilities and between offshore and onshore, separation of oil, gas, and produced water, and in some cases water treatment. Pipelines exclusively transport oil and gas destined for sale onshore, with potential exceptions for temporary system breakdowns and delivery of well stimulation fluids to offshore facilities. Fluid handling includes separation of oil, gas, and produced water, and in some cases water treatment.

Disposal of produced water for facilities in state waters is mainly done by injection into the reservoir, with some disposal onshore. Figure 2.5-3 shows the connections for transporting oil, gas, and water by platform groups that interact for fluids handing and the expected disposition of produced water disposal. Where one cell expands laterally to two cells, a separation is indicated (e.g., an oil/water mixture separated into bulk oil and water phases). Where two cells expand laterally into one cell, the fluid streams are combined.

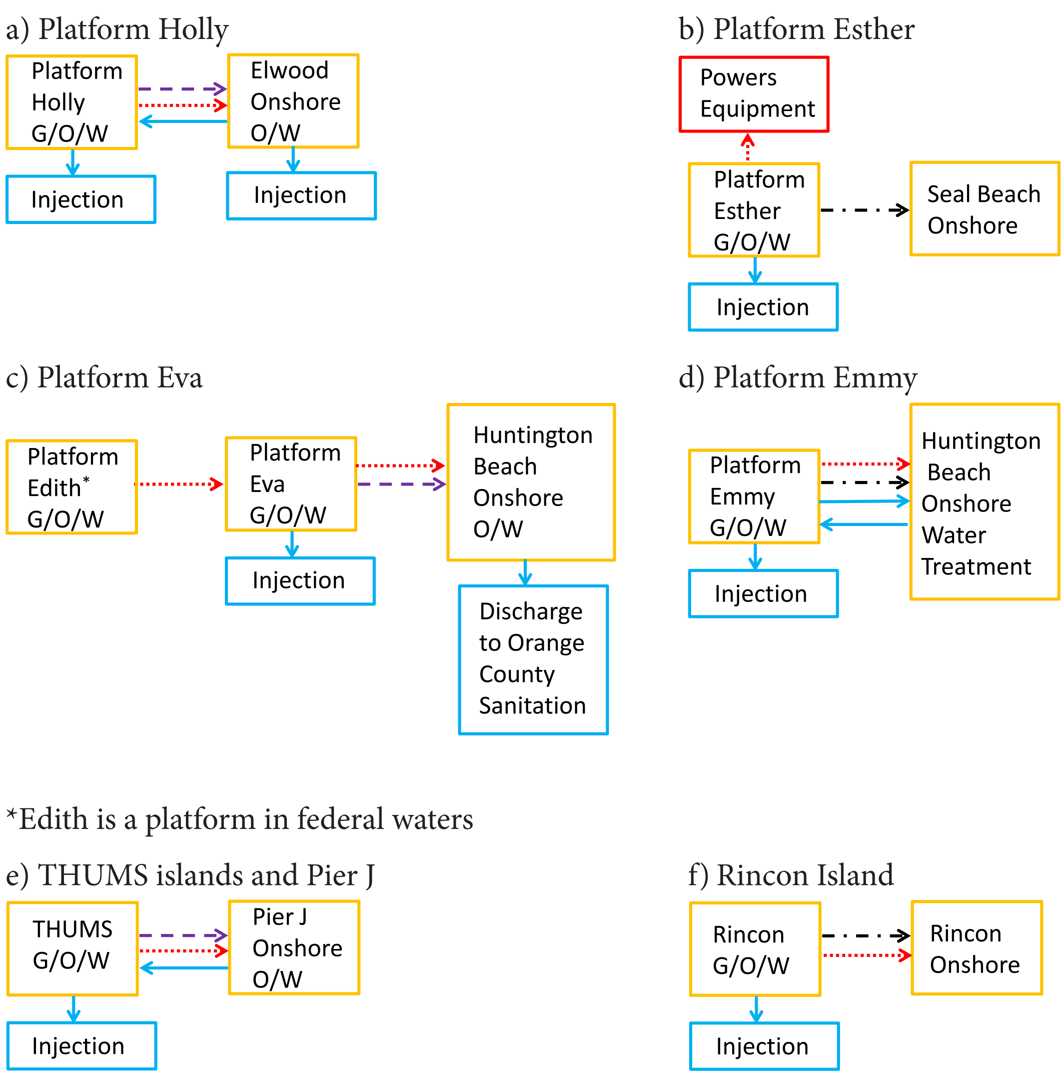


Figure 2.5-3. Fluids handling for offshore facilities in State waters (CSLC, 2008; 2009; 2010a; 2010b; 2012; 2013; Santa Barbara, 2011). Separation process indicated by G/OW for gas separation only, G/O/W for gas/oil/water separation, O/W for oil water separation and G/W for gas/water separation. Blue solid lines designates water, red dotted lines for gas, black dash-dot lines for oil, and purple dashed lines for water-oil mixtures, orange solid lines for facilities, and red solid lines for gas use in powering operations.

For the Holly (Figure 2.5-3a), Eva (Figure 2.5-3c), Emmy (Figure 2.5-3d), and THUMS (Figure 2.5-3e), some separation of oil and water is done on the platform, and further oil/water separation can be done onshore, which is either injected onshore, discharged into a sanitary sewer, or sent back offshore for injection. Therefore, the table shows water discharge from the platform with oil/water mixtures still sent onshore. Rincon produced water is injected into disposal wells on Rincon Island.

2.6. Ocean Discharge and Atmospheric Emissions

Environmental impacts from any activity are often connected to some type of discharge or emission of a material or possibly energy (e.g., heat, sound, light). This section focuses on intentional discharges to the ocean and atmospheric emissions, but also provides some discussion of accidental releases. In general, it is difficult to separate impacts from overall oil and gas operations from those directly associated with well stimulation. For this reason, many of the impacts discussed are based on oil and gas operations overall, with the recognition that well stimulation is only applied to a small, but difficult to quantify, subset of the producing wells.

2.6.1. Ocean Discharge from Offshore Facilities

As discussed in Section 2.5, intentional discharge to the ocean is only allowed at facilities in federal waters. Ocean discharge from offshore California operations in federal waters is regulated by the U.S. EPA under the NPDES permit CAG280000 (U.S. EPA, 2013a). This permit sets up specific limits for the types and quantities of materials that may be discharged to the ocean, as well as the ways in which the discharge is monitored. The results of the monitoring are recorded in discharge monitoring reports (DMRs) for each offshore facility. In Section 2.6.1.1, the permit limitations and monitoring requirements are summarized. The DMR information is summarized in Section 2.6.1.2.

2.6.1.1. NPDES Permit CAG280000

NPDES permit number CAG280000 covers the following categories of discharge: (1) drilling fluid and cuttings; (2) produced water; (3) well treatment, completion, and workover fluids; (4) deck drainage; (5) domestic and sanitary wastes; and (6) 17 miscellaneous other discharge categories, including noncontact cooling water and water-flooding discharges. The most recent general permit was reissued on March 1, 2014, and replaces the previous general permit; also, permit number CAG280000, issued on September 22, 2004 (U.S. EPA, 2013b), is applicable through February 28, 2019 (U.S. EPA, 2013a) and applies to all 23 platforms in federal waters.

Well stimulation fluids fall under well treatment, completion, and workover fluids (collectively called TCW fluids). For TCW discharge, the permit disallows any free oil discharge and restricts the amount of oil and grease in the discharge to 42 mg/L maximum and 29 mg/L monthly average. The permit does not restrict the volume of

TCW fluids that can be discharged per se, but specifically provides for discharge of these fluids mixed with produced water under the restrictions for produced water discharge. Although the NPDES permit covers well stimulation under the TCW category, it does not specifically refer to acidizing, and hydraulic fracturing is only mentioned in its section on definitions for the term “produced sands.” Consequently, the NPDES permit governing ocean discharges from oil platforms in federal waters does not specifically account for stimulation chemicals or their potential impact on the marine environment.

Some earlier EPA documents discuss fracturing and acidizing in the context of offshore effluent limitations and general information about typical additives (U.S. EPA, 1993; 1995; 1996). In particular, U.S. EPA (1993) provides a chemical analysis of an acidizing fluid used at THUMS and metals content of a California fracturing fluid. The following conclusion by U.S. EPA (1995) provides the basis for the current NPDES permit strategy for well treatment, completion, and workover fluids: “EPA has determined, moreover, it is not feasible to regulate separately each of the constituents in well treatment, completion and workover fluids because these fluids in most instances become part of the produced water waste stream and take on the same characteristics of produced water. Due to the variation of types of fluids used, the volumes used and the intermittent nature of their use, EPA believes it is impractical to measure and control each parameter. However, because of the similar nature and commingling with produced water, the limitations on oil and grease and/or free oil in the Coastal Guidelines will control levels of certain toxic priority and nonconventional pollutants for the same reason as stated in the previous discussion on produced water.” The “previous discussion” referred to a statement (U.S. EPA, 1995) that “oil and grease serves as an indicator for toxic pollutants in the produced water waste stream which includes phenol, naphthalene, ethyl benzene, and toluene.” This list of toxic substances of concern does not include toxic substances used in stimulation treatments, nor does it provide justification for oil and grease being an effective indicator of the presence or absence of stimulation chemicals.

More complex requirements for produced water vary from platform to platform, as shown in Table 2.6-1, where “S” indicates a sampling requirement and specific concentration limits are indicated by numerical values. Where the NPDES permit requires sampling but no specific limit is given, the limits given in Table 2.6-2 apply. The last six facilities in Table 2.6-1 must comply with all the restrictions imposed by Table 2.6-2. All facilities must conform with a uniform requirement for oil and grease concentrations in produced water identical to the discharge limits quoted above for TCW fluids.

The limits in Table 2.6-1 and 2.6-2 are based on the Best Conventional Pollutant Control Technology (BCT) and the Best Available Treatment Economically Achievable (BAT) as originally published by the U.S. EPA in the Federal Register (FR, 1993) The limits also rely on an analysis of the Ocean Discharge Criteria, section 403(c) of the Clean Water Act (1972) (see also 33 USC §1343), assuming BCT and BAT are in place (CCC, 2013).

The NPDES permit provides additional detail concerning sampling frequency and method of collection. Concentrations in the measured effluent are reduced by a site-specific dilution factor that corresponds to a point with a 100 m lateral offset from the discharge release point. The diluted concentration is then compared with the concentration limits in the permit. Dilution factors for offshore California platforms have been found to range from 467:1 to 2,481:1 (MMS, 2001).

Table 2.6-1. NPDES produced water limits for all platforms; constituent sampling requirements and concentration limits for some platforms (U.S. EPA, 2013a)

Platform	Annual Discharge Limit (m^3) x10^6 (bbl#)x10^6	Amn	Copr	Benz	BzA	BzP	BzkF	BzbF	Chry	DBzA	USulf	Znc	HC
A	2.09 (13.140)		S			S	S	S					
B	2.61 (16.425)					S	S	S					
Edith	0.522 (3.285)											S	
Elly***	1.74 (10.950)											S	
Gail	0.696 (4.380)			S		S					5.79 1.67		
Gilda	4.05 (25.500)		S		S	S	S	S	S	S	5.79 1.39		
Gina	*	S	S			S	S	S					
Habitat	0.261(1.6425)		S	S		S	S	S		S	S		
Harmony, Heritage, Hondo**	5.37 (33.7625)												
Harvest	5.22 (32.850)	S	S	22 5.9	S	S	S	S	S	S	S		
Hermosa	6.40 (40.250)		S	S	S	S	S	S	S	S	5.77 4.9		
Hidalgo	2.90 (18.250)			S			S	S	S		S		
Hillhouse	1.16 (7.300)				S	S	S	S	S	S			
Hogan	2.21 (13.900)		S	17.6 5.9		S	S	S		S			S
#C	2.09 (13.140)												
#Eureka	***												
#Grace	0.348 (2.190)												
#Henry	1.04 (6.570)												
#Houchin	2.21 (13.900)												
#Irene	8.88 (55.845)												

*Limits for Amn, Copr, Benz, BzA, BzP, BzkF, BzbF, Chry, DBzA, USulf, Znc, and HC are in µg/L. #bbl=oil barrel (42 gallons) * Limit given for Gilda is a combined limit for both Gina and Gilda. **Discharge for these platforms are combined and discharged from Platform Harmony. ***Limit for Elly is for combined discharge with Ellen and Eureka. #Limits on chemical constituents discharged in produced water are given in Table 2.6-2 for these platforms. Amn = Ammonia, Copr = Copper, Benz = Benzene, BzA = Benzo (a) Anthracene, BzP = Benzo (a) Pyrene, BzkF = Benzo (k) Fluoranthene, BzbF = Benzo (b) Fluoranthene, Chry = Chrysene, DBzA = Dibenzo (a,h) Anthracene, USulf = Undissolved Sufides, Znc = Zinc, HC = Hexavalent Chromium. "S" denotes a requirement to measure without any specified limits. Quantified limits are given as maximum daily value – upper number; average monthly value – lower number.*

In addition to total discharge and chemical concentration limits, the NPDES permit also specifies quarterly whole effluent toxicity (WET) tests for produced water. These tests are conducted to estimate the chronic toxicity of produced water. WET tests are conducted for the following species:

- Red abalone, *Haliotis rufescens*, larval development test
- Giant kelp, *Macrocystis pyrifera*, germination and germ-tube length tests
- Topsmelt, *Atherinops affinis*, larval survival and growth tests

Various triggers and effluent limits are defined for the different tests, and testing requirements and frequency are modified by the test results. For example, consistent passing scores for the WET tests lead to reduced testing frequency. The tests are only performed for the following platforms: A, B, Edith, Elly, Gail, Gilda, Gina, Habitat, Harmony, Harvest, Hermosa, Hidalgo, Hillhouse, and Hogan. So nine platforms, C, Henry, Houchin, Ellen, Eureka, Grace, Irene, Hondo, and Heritage are not tested. As stated previously, all discharge for the Santa Ynez group, platforms Harmony, Hondo, and Heritage, is released from platform Harmony. It appears that discharge from platforms Ellen and Eureka are combined with Elly. Platform Irene does not discharge to the ocean at this time. The reasons for not performing WET tests for platforms C, Henry, Houchin, and Grace are not clear. As discussed in Section 2.5.1.2, the historical record indicates that hydraulic fracturing has only been used on platforms Gilda, Gail, and Hidalgo.

Another observation is that the more extensive tests required for produced water, including chemical constituent and toxicity tests and limits, do not apply to TCW fluids if they are not mixed with produced water for discharge. Also, because of the transient nature of well stimulation discharge, the WET tests may not capture toxicity effects from well stimulation fluid discharge if the tests are not conducted at the time of the discharge. However, the timing of WET tests is not linked to well stimulation events in the NPDES permit.

Table 2.6-2. NPDES constituent concentration limits for platforms for which limits were not specified in Table 2.6-1 (U.S. EPA, 2013a).

Constituent	Limit (μg/L)
Ammonia	1300/600; 2400
Arsenic	36/8; 32
Cadmium	8.8/1; 4
Copper	3.1/3; 12
Cyanide	1/1; 4
Lead	8.1/2; 8
Manganese	100; NA

Mercury	0.051/0.04; 0.16
Nickel	8.2/5; 20
Selenium	71/15; 60
Silver	1.9/0.7; 2.8
Zinc	81/20; 80
Benzene	5.9
Benzo (a) Anthracene	0.018; NA
Benzo (a) Pyrene	0.018; 3
Chrysene	0.018; NA
Benzo (k) Fluoranthene	0.018; NA
Benzo (b) Fluoranthene	0.018; NA
Dibenzo (a,h) Anthracene	0.018; NA
Hexavalent Chromium	50/2
Phenol	1,700,000; 120
Toluene	15,000; 50
Ethylbenzene	2,100; 4.3
2,4-Dimethylphenol	850; none
Undissociated Sufides	5.79; NA
Napthalene	none; 23.5
Total Chromium	NA; 8
Bis (2-ethylhexyl) phthalate	NA; 3.5

The limits for all platforms are the numbers preceding the semicolon. Limits following the semicolon are for platform Irene. Limits separated by a "/" represent differing federal and state limits, respectively. The most stringent limits are applied where conflicting limits exist. NA – limit not applicable; "none" means constituent was listed without a limit.

2.6.1.2. NPDES Discharge Monitor Reports

The historical discharge quantities and testing results stipulated by the NPDES permit are recorded in the U.S. EPA's Integrated Compliance Information System and Permit Compliance System database (ICIS/PCS) (U.S. EPA, 2015a). The database at present contains discharge data for some but not all of the platforms. The platforms and their data status are given in Table 2.6-3. Only 9 of the 23 platforms have data. Table 2.6-4 shows the 6 platforms with complete produced water flow records for 2012 through 2014. In general, the actual produced water discharges are significantly lower than the NPDES permit limits. Oil and grease are regularly measured and exceeded the limit in two instances. Values for ammonia, copper, undissociated sulfides, and zinc remained within the discharge limits. Measurements of Benzo (a) Anthracene, Benzo (a) Pyrene, Benzo (k) Fluoranthene, Benzo (b) Fluoranthene, Chrysene, Dibenzo (a,h) Anthracene are required for many of the platforms listed in Table 2.6-4, but no measurements were reported in the DMRs. WET tests are reported on a pass/fail basis; all test results in the DMRs have been reported as "pass." The DMRs do not track the quantity or composition of any specific constituents associated with well stimulation flowback fluids.

Table 2.6-3. Discharge monitoring report status (U.S. EPA, 2015a).

Platform	Facility-specific NPDES number	Data Status
A	CAF001156	Data – 2011 - 2014
B	CAF001157	Data – 2011 - 2014
C	CAF001300	Data – 2011 - 2014
Edith	CAF001150	Data – 2011 - 2014
Ellen	CAF001147	No data
Elly	CAF001148	No data
Eureka	CAF001149	No data
Gail	CAF000002	No data
Gilda	CAF001152	Data – 2011 - 2014
Gina	CAF001151	Data – 2011 - 2014
Grace	CAF000005	No data
Habitat	CAF001304	Data – 2011 - 2014
Harmony	CAF000006	No data
Harvest	CAF001305	No data
Henry	CAF001301	Data – 2011 - 2014
Heritage	CAF000007	No data
Hermosa	CAF001306	No data
Hidalgo	CAF001307	No data
Hillhouse	CAF001154	Data – 2011 - 2014
Hogan	CAF000003	No data
Hondo	CAF001302	No data
Houchin	CAF000004	No data
Irene	CAF001153	No data

Table 2.6-4. DMR values for produced water discharge and constituent concentrations (U.S. EPA, 2015a).

Platform	Annual Produced Water Flow (m^3) x10^6 (#bbl) x10^6	Annual Produced Water NPDES Limit (m^3) x10^6 (bbl) x10^6	Oil and grease (mg/L)	Ammonia (µg/L)	Copper (µg/L)	Undissociated sulfides (µg/L)	Zinc (µg/L)
A – 2014	0.248 (1.559)	2.09 (13.140)	40	NA	NM	NA	NA
A – 2013	0.373 (2.345)		62	NA	2.01	NA	NA
A – 2012	0.187 (1.177)		20	NA	2.01	NA	NA
B – 2014	0.348 (2.188)	2.61 (16.425)	29.3	NA	NA	NA	NA
B – 2013	0.267 (1.682)		28	NA	NA	NA	NA
B – 2012	0.368 (2.317)		42	NA	NA	NA	NA
Edith – 2014	0.0382 (0.240)	0.522 (3.285)	11.3	NA	NA	NA	8
Edith – 2013	0.0266 (0.1670		16.5	NA	NA	NA	8.008
Edith – 2012	0.0499 (0.314)		46.6	NA	NA	NA	8.1
Gilda – 2014	0.354 (2.227)	4.05 (25.500)	39	NA	2	0.82	NA
Gilda – 2013	0.318 (1.999)		19	NA	2.01	0.73	NA
Gilda – 2012	0.369 (2.321)		20	NA	2	0.48	NA
Gina – 2014	0.118 (0.740)		25	24.83	2	NA	NA
Gina – 2013	0.809 (0.509)		27	26.55	2.01	NA	NA
Gina – 2012	0.0585 (0.368)		20	39.13	2	NA	NA
Hillhouse – 2014	0.370 (2.327)	1.16 (7.300)	14	NA	NA	NA	NA
Hillhouse – 2013	0.454 (2.856)		18	NA	NA	NA	NA
Hillhouse – 2012	0.431 (2.709)		21	NA	NA	NA	NA
Limits	NA	NA	42	600	3	5.79	20

Concentrations are maximum measured values; limits are maximum daily values;

NA – not applicable; NM – no measurement; #bbl=oil barrel (one barrel = 42 gallons)

Lyon and Stein (2010) reported on the results of a 2005 special monitoring study for offshore California discharge into federal waters as part of a "reasonable potential analysis" for the EPA. This study provided a more comprehensive data set (but just for 2005) than available from the current DMRs, with measurements for all of the platforms in federal waters. A complete set of measurements was made for all the constituents in Table 2.6-2 plus undissociated sulfides, with the exception of one or two constituents at three platforms.

In summary, the NPDES permit provides protection against contamination expected from hydrocarbons and produced water. However, for well stimulation fluid flowback, it relies on an assumption that dilution, exposure, and toxicity for any different chemicals present in the discharge are sufficiently similar to those in petroleum fluids and produced water to prevent adverse impacts.

2.6.1.3. Offshore Spills

Spills in federal waters associated with offshore oil and gas exploration and production have been recorded by the BOEM. In general, the database displays spills of crude oil and or other chemicals, but the material most often released by accident is crude oil. When looking only at spills in federal waters offshore California, all but two of the 16 recorded spills of 10 barrels or more is crude oil (Table 2.6-5). In terms of spill volume, the 1969 Santa Barbara oil spill represents 98% of the releases over a 40-plus year record (see Section 2.3.3). Accidental releases of well stimulation fluids have not been reported. Despite the relatively small quantities of spills since the 1969 oil spill, events such as the 2010 Macondo blowout in the Gulf of Mexico and similar major oil spills elsewhere have influenced the current regulatory climate for offshore California oil and gas development.

Table 2.6-5. Offshore California spills in federal waters from oil and gas exploration and production (BOEM, 2015e).

Date	Facility	Spill Volume (m^3) (bbl)	Product(s) Spilled	Operation
1969-01-28	Platform A	12,700 (80000)	crude oil	Drilling
1969-12-16	Platform C	143 (900)	crude oil	Pipeline
1981-08-24	Platform Ellen	2.7 (17)	crude oil	Production
1981-09-13	Platform Henry	1.6 (10)	crude oil	Production
1981-10-23	Platform Henry	1.6 (10)	diesel	Production
1981-10-24	Platform Elly	2.7 (17)	crude oil	Production

1984-07-19	Rig Diamond M. Eagle	4.9 (31)	crude oil	Abandonment
1987-11-25	Platform Hondo	3.2 (20)	crude oil	Pipeline
1990-05-07	Plat Habitat	16 (100)	16 m^3 (100 bbl) mineral oil in 22.9 m^3 (144 bbl) of oil-based mud	Drilling
1991-05-10	Plat Gina	7.9 (50)	crude oil	Pipeline/Motor Vessel
1991-11-21	Platform C	1.6 (10)	crude oil	Production
1994-05-25	Plat Hondo	4.8 (30)	crude oil	Production
1994-12-17	Plat Hogan	7.9 (50)	crude oil	Production
1996-05-01	Plat Heritage	23.8 (150)	crude oil	Pipeline
1999-06-05	Platform Eureka	1.6 (10)	crude oil	Pipeline
2008-12-07	Platform A	4.8 (30)	crude oil	Production

Note: Database for spills > 50 bbl covers years 1964 through 2011.

Database for spills between 10 and 50 bbl covers years 1970 through 2011. #bbl=oil barrel (one barrel = 42 gallons)

A California Office of Emergency Services (19 CCR 2703(a)) database of spills from 2009 through 2014 also records about 170 spill incidents offshore. The database covers facilities in both state and federal waters. The spill reports generally involve small or unknown quantities, with the largest quantified spill occurring on platform Eva on 1/6/2009. This spill of 1.3 m^3 (8 barrels) of drilling mud on the platform resulted in about 0.02 m^3 (0.14 barrels) being released into the ocean. No reports specifically identified spills of well stimulation fluids.

Unintentional release in connection with hydraulic fracturing can also occur if the hydraulic fracture extends out of zone and provides a leakage pathway to the sea floor. Fracture height is limited by natural boundaries, stresses, leakoff, and volume of injection (see Volume I, Chapter 2). The maximum fracture height observed in hydraulic fracturing operations is 588 m (1,930 ft) in the Barnett shale in Texas. The statistics of observed fracture heights show that only 1% exceeds 350 m (1,150 ft). Reservoir depths from Tables 2.4-2, 2.4-4, and 2.4.6 are all greater than 350 m (1,150 ft), and only two are less than 588 m (1930 ft), Dos Cuadras at 488 m (1,600 ft) depth and the shallowest reservoir in the Huntington Beach field at 460 m (1,510 ft) depth. Both of these reservoirs have high permeability (Dos Cuadras, 49-987 md; Huntington Beach shallowest reservoir, 987 md) making the use of hydraulic fracturing less likely. Furthermore, there are no reports of hydraulic fracturing having been used in these reservoirs. Therefore, the possibility of a spill caused by hydraulic fracturing between a reservoir and the ocean floor appears to be remote.

2.6.2. Atmospheric Emissions from Offshore Facilities

Offshore facility operations incur emissions of air pollutants and greenhouse gases (GHGs). Intentional emissions include combustion products. Unintentional emissions result from process inefficiencies such as fugitive methane releases from natural gas production. The primary pollutants are nitrous oxides (NOx), sulfur oxides (SOx), carbon monoxide (CO), volatile organic compounds (VOCs), and particulate matter (PM). Other pollutants are grouped into the classification of hazardous air pollutants (HAPs), which include some VOCs but also other items such as crystalline silica, hydrochloric acid, and methanol. GHGs include carbon dioxide (CO_2), methane (CH_4), carbon monoxide (CO), nitrous oxide (N_2O), VOCs, and black carbon.

The emissions estimates in this case are done for all offshore facilities as a group. Unlike the ocean discharge issue, there is no significant distinction in air emissions discharge handling between facilities in state and federal waters. The fraction of air emissions caused by well stimulation activities is not available, but is expected to be a small fraction of the overall emissions for oil and gas activities.

2.6.2.1. Air Pollutant Emission Estimates

Specific air pollutant emission estimates for each offshore facility were obtained from the California Air Resources Board (CARB, 2015a) database for 2012. These consist of the following criteria pollutants that comprise the major components of air pollution: total organic gases (TOG), reactive organic gases (ROG), carbon monoxide (CO), nitrous oxides (NOX), sulfur oxides (SOX), particulate matter (PM), particulate matter less than 10 microns in diameter (PM10); particulate matter less than 2.5 microns in diameter (PM2.5). The emissions are available by offshore facility. Table 2.6-6 shows the summary of mass emissions grouped for the Santa Maria and Santa Barbara Basins and the offshore Los Angeles Basin. This does not include air emissions from onshore wells that reach offshore. As discussed in Section 2.7.2.1, these emissions are typically a small fraction of the overall emissions in the corresponding air basins.

Table 2.6-6. Criteria pollutant emissions (metric tons (lbs), 2012) (CARB, 2015a).

Region	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5
Santa Barbara and Santa Maria Basins	912 (2,010,000)	471 (1,040,000)	346 (763,000)	368 (811,000)	100 (221,000)	51.7 (114,000)	50.9 (112,000)	49.0 (108,000)
Offshore Los Angeles Basin	113 (250,000)	58.0 (128,000)	29.3 (64,600)	219 (484,000)	0.1 (220)	6.9 (15,200)	6.7 (14,800)	6.7 (14,800)
Total	1,030 (2,260,000)	529 (1,170,000)	375 (827,000)	587 (1,290,000)	100 (221,000)	58.6 (129,000)	57.6 (127,000)	55.7 (123,000)

In addition, numerous toxic pollutant emissions are reported (Table 2.6-7). Toxic air pollutants are substances that have a direct adverse health effect and are known or suspected of being carcinogens, endocrine disruptors, or cause other serious health effects. Common toxic pollutants to both regions include 1,3-Butadiene, arsenic, benzene, cadmium, formaldehyde, lead, methylene chloride, ammonia (NH_3), naphthalene, nickel, and polycyclic aromatic hydrocarbons (PAHs). Toxic air pollutant emissions in Table 2.6-7 are from CARB's 2012 emissions inventory, but these emissions are not tabulated for each year and may be estimated from data over a range of years.

Air emissions resulting directly from well stimulation have not been reported; however, these are presumably included in the total emissions given in Tables 2.6-6 and 2.6-7, and are expected to represent a small percentage of the overall air emissions.

Table 2.6-7. Toxic air pollutant emissions (kg/yr (lbs/yr), 2012) (CARB, 2015a).

Toxic pollutant	Santa Maria and Santa Barbara Basins	Offshore Los Angeles Basin	Total
1,3-Butadiene	392 (863)	250 (551)	642 (1,410)
2MeNaphthalene	0.00	0.48 (1.1)	0.48 (1.1)
Acenaphthene	0.00	0.02 (0.04)	0.02 (0.04)
Acenaphthylene	2,370 (5,230)	0.08 (0.18)	2,370 (5,230)
Acrolein	316 (696)	0.00	316 (696)
Arsenic	2.36 (5.20)	1.81 (3.99)	4.17 (9.19)
Asbestos	0.00	4.99 (11.0)	4.99 (11.0)
B[b]fluoranthen	0.00	0.00	0.00
B[e]pyrene	0.00	0.01 (0.02)	0.01 (0.02)
B[g,h,i]perylen	0.00	0.01 (0.02)	0.01 (0.02)
Benzene	1,680 (3,700)	625 (1,380)	2,300 (5,080)
CCl4	0.72 (1.6)	0.53 (1.2)	1.25 (2.76)
Cadmium	4.03 (8.88)	1.70 (3.75)	5.73 (12.6)
Chlorobenzn	0.81 (1.8)	0.00	0.81 (1.8)
Choroform	0.56 (1.2)	0.00	0.56 (1.2)
Chromium	18.6 (41.1)	0.00	18.6 (41.1)

Copper	7.33 (16.2)	0.00	7.33 (16.2)
Chrysene	0.00	0.01 (0.02)	0.01 (0.02)
Cr(VI)	0.14 (0.31)	0.11 (0.24)	0.25 (0.55)
DieselExhPM	74.9 (165)	0.00	74.9 (165)
DieselExhTOG	83.6 (184)	0.00	83.6 (184)
EDB	0.87 (1.9)	0.64 (1.4)	1.51 (3.3)
EDC	0.00	0.34 (0.75)	0.34 (0.75)
Ethyl Benzene	917 (2,020)	0.00	917 (2,020)
Fluoranthene	0.00	0.02 (0.04)	0.02 (0.04)
Fluorene	0.00	0.08 (0.18)	0.08 (0.18)
Fluorocarb(Cl)	0.00	90.7 (200)	90.7 (200)
Formaldehyde	21,900 (48,400)	2,930 (6,450)	24,900 (54,800)
H_2S	0.00	0.00	0.00
HCl	264 (582)	0.00	264 (582)
Hexane	10,200 (22,600)	0.00	10,200 (22,600)
Lead	13.4 (29.5)	9.39 (20.7)	22.8 (50.2)
Manganese	22.6 (49.9)	0.00	22.6 (49.9)
Mercury	2.87 (6.33)	0.00	2.87 (6.33)
Methanol	125 (276)	0.00	125 (276)
Methylene Chlor	1.68 (3.70)	0.29 (0.64)	1.97 (4.34)
NH_3	742 (1,640)	1,570 (3,460)	2,310 (5,100)
Naphthalene	65.0 (143)	24.4 (53.7)	89.4 (197)
Nickel	23. 8 (52.4)	4.41 (9.72)	28.2 (62.1)
PAHs	116 (256)	41.4 (91.2)	157 (347)
Perc	111 (244)	0.00	111 (244)
Phenanthrene	0.00	0.15 (0.33)	0.15 (0.33)
Propylene	1,490 (3,270)	0.00	1,490 (3,270)
Propylene Oxide	738 (1,630)	0.00	738 (1,630)
Pyrene	0.00	0.02 (0.04)	0.02 (0.04)
Selenium	3.13 (6.90)	0.00	3.13 (6.90)
Styrene	0.49 (1.1)	0.00	0.49 (1.1)
Toluene	31,300 (68,900)	0.00	31,300 (68,900)
Vinyl Chloride	0.00	0.22 (0.49)	0.22 (0.49)
Xylenes	2,710 (5,970)	0.00	2,710 (5,970)
Zinc	31.8 (70.2)	0.00	31.8 (70.2)

2.6.2.2. Greenhouse Gas Emission Estimates

GHG emissions for 2013 in terms of CO_2-equivalent mass (CO_2eq.) are reported for eight offshore facilities in the EPA's flight tool (U.S. EPA, 2015b). These facilities are platforms Hermosa, Hidalgo, Harvest, Gail, Edith, Ellen, Elly, and Eureka. Emissions from the Beta field (Edith, Ellen, Elly, and Eureka) were reported as a single emission value. Oil and gas production for Platform Gail (only platform in the Sockeye field) and for the Beta field are given in Tables 2.4-1 and 2.4-5, respectively. Oil and gas production data for platforms

Hermosa, Hidalgo, and Harvest were computed individually from BOEM production data (BOEM, 2015d). The production data were correlated with the CO_2eq. emissions as shown in Figure 2.6-1. Barrels of oil equivalent (BOE) were computed using a conversion factor of (5,620 cubic feet) of gas per BOE (BOEM, 2014a). A weighting factor of 6.3 on the gas BOE was found to produce the best correlation with CO_2eq.

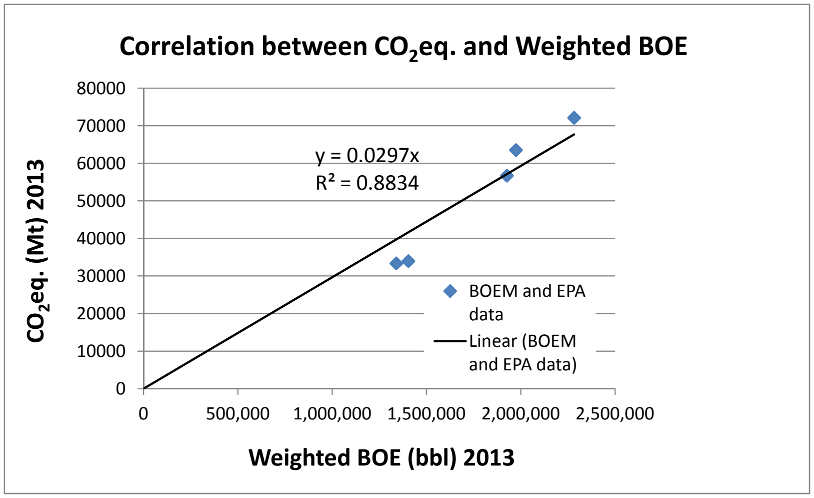


Figure 2.6-1. Correlation between oil production and CO_2eq. emissions.

Production data from Tables 2.4-1, 2.4-3, and 2.4-5 are used with the correlation to estimate GHG emissions. The values are shown in Table 2.6-8.

Table 2.6-8. Oil and gas production values for offshore regions in 2013 and GHG (CO_2eq.) emission estimates.

Region	Oil (m^3) x10^6 (#bbl) x10^6	Gas (m^3) x10^6 (##Mcf) x 10^6	BOE* (m^3) x10^6 (bbl) x10^6	Weighted BOE (m^3) x10^6 (bbl) x10^6	CO_2eq. (metric tons) x10^6 (lbs) x10^6
Santa Barbara Basin	2.53 (15.9)	696 (24.6)	3.23 (20.3)	6.91 (43.5)	1.29 (2,850)
Santa Maria Basin	0.511 (3.21)	98.9 (3.49)	0.511 (3.21)	1.13 (7.10)	0.212 (466)
Santa Barbara and Santa Maria Basins	3.04 (19.1)	795 (28.1)	3.74 (23.5)	8.04 (50.6)	1.50 (3,310)
Offshore Los Angeles Basin	2.17 13.6	131 (4.62)	2.30 (14.4)	2.99 (18.8)	0.558 (1,230)
Total	5.21 (32.8)	926 (32.7)	6.14 (38.6)	11.0 (69.5)	2.06 (4,550)

*#bbl = oil barrel (one barrel = 42 gallons); ## Mcf = one thousand cubic feet (one Mcf = 7,481 gallons); *BOE = barrels of oil equivalent*

As a check on the GHG emission estimate, GHG emissions from California oil production in 2012 can be estimated from total oil and gas production for California from DOGGR (2013) and BOEM (2012) using the correlation from Figure 2.6-1. This estimate may be compared with the CARB (2015b) GHG emission inventory report for California, which gives statewide emission estimates resulting from oil and gas production activity in 2012. The results are shown in Table 2.6-9.

Table 2.6-9. Oil and gas production values for California oil and gas production in 2012 and GHG (CO_2eq.) emission estimates.

Location	Oil (m^3) x10^6 (#bbl) x10^6	Gas (m^3) x10^6 (##Mcf) x10^6	BOE* (m^3) x10^6 (bbl) x10^6	Weighted BOE (m^3) x10^6 (bbl) x10^6	CO_2eq. (metric tons) x10^6 (lbs) x10^6
California	31.4 (198)	6,300 (222)	37.7 (237)	71.0 (447)	13.3 (29,300)
Federal offshore	2.81 (17.7)	771 (27.2)	3.58 (22.5)	7.66 (48.2)	1.43 (3,160)
Total	34.2 (215)	7,070 (250)	41.3 (260)	78.7 (495)	14.7 (32,400)

*#bbl = oil barrel (one barrel = 42 gallons); ## Mcf = one thousand cubic feet (one Mcf = 7,481 gallons); *BOE = barrels of oil equivalent*

The CARB estimate for 2012 GHG CO_2eq. emissions from oil and gas operations is 16,856,000 metric tons. It is not clear if the CARB estimate includes GHG emissions from federal offshore facilities, but if it does, the correlation-based emission estimate is about 13% smaller than the CARB estimate.

GHG emission estimates for California oil and gas production operations are also presented in Volume II, Chapter 3, Table 3.3-19. These estimates are based on a CARB industry survey conducted in 2007. The offshore CO_2eq. emissions estimates from the CARB survey are found to be much lower than the correlation-based estimates given here, which are based on CO_2eq. emissions estimates from the EPA flight tool. The reported 2013 offshore CO_2eq. emissions in the EPA flight tool totaled 260,000 metric tons but was only for 8 out of a total of 32 offshore facilities. The 2007 CARB industry survey reported 140,100 metric tons CO_2eq. emissions for all offshore operations. While the reasons behind the differences in emission estimates are not known, the higher estimates developed here are more consistent on a per unit hydrocarbon production basis with average California oil and gas production emission rates (see Section 2.7.2.3).

2.7. Impacts of Offshore Well Stimulation Activities and Data Gaps

The potential impacts of offshore well stimulation are related to the possibility of discharge of contaminants into the air and water, and the injection of stimulation fluids and produced water into the subsurface. This section explores the possibility that these may lead to contamination of the marine environment and atmosphere, and increased seismic activity.

2.7.1. Impacts of Offshore Well Stimulation to the Marine Environment

Data documenting the impacts of well stimulation fluids discharged to the marine environment have not been found. However, studies of ecological conditions and contamination in the marine environment around California offshore platforms have been conducted. Although these do not directly target the effects of well stimulation fluid discharge, the observations and findings from such investigations implicitly include the cumulative effects of all discharge that has occurred. In addition to these field investigations, laboratory investigations of toxicity of produced water discharge into the ocean have been conducted.

Ecological Studies around California Offshore Platforms

Several ecological studies have been conducted around California offshore platforms that provide information about the ecological effects of offshore platforms on marine life. Love et al. (2003) found that platforms support higher densities of many species of common reef fish at platforms compared to natural outcrops. Therefore, the platforms appear to act as a kind of marine refuge. A survey of fish counts for young-of-the-year (less than one year old) rockfishes, a dominant species at platforms and natural reefs in the Santa Barbara Channel area, shows in Figure 2.7-1 the higher density of species at Platform Hidalgo versus a natural outcrop about one kilometer from the platform, North Reef, over a six-year period. Differences in fish density were mainly due to differences in the abundance of various rockfish species, rather than differences in the kinds of species present.

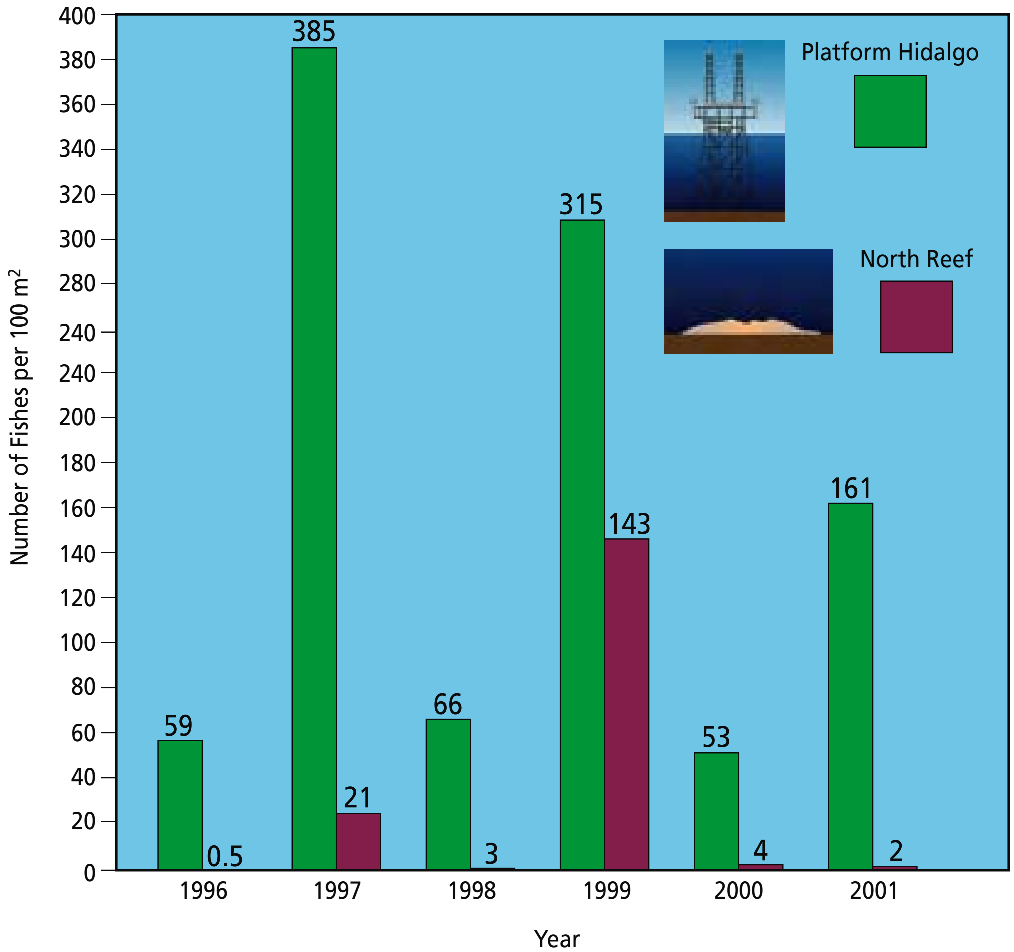


Figure 2.7-1. Young-of-the-Year Rockfish densities at Platform Hidalgo and North Reef (Love et al., 2003).

A comparison of the growth rates for young-of-the year blue rockfish at Platform Gilda and at Naples Reef is shown in Figure 2.7-2. Note that platform Gilda was found to have the most hydraulic fracturing treatments of any platform in federal waters (see Table 2.5-2). Growth rates measured using the otoliths (earbones) of the fish were found to be 0.046 cm/day (0.018 inches/day) and 0.014 cm/day (0.0055 inches/day) for Platform Gilda and Napes Reef, respectively, based on the straight-line fits in Figure 2.7-2. The difference in growth rates was found to be statistically significant (Love et al., 2003).

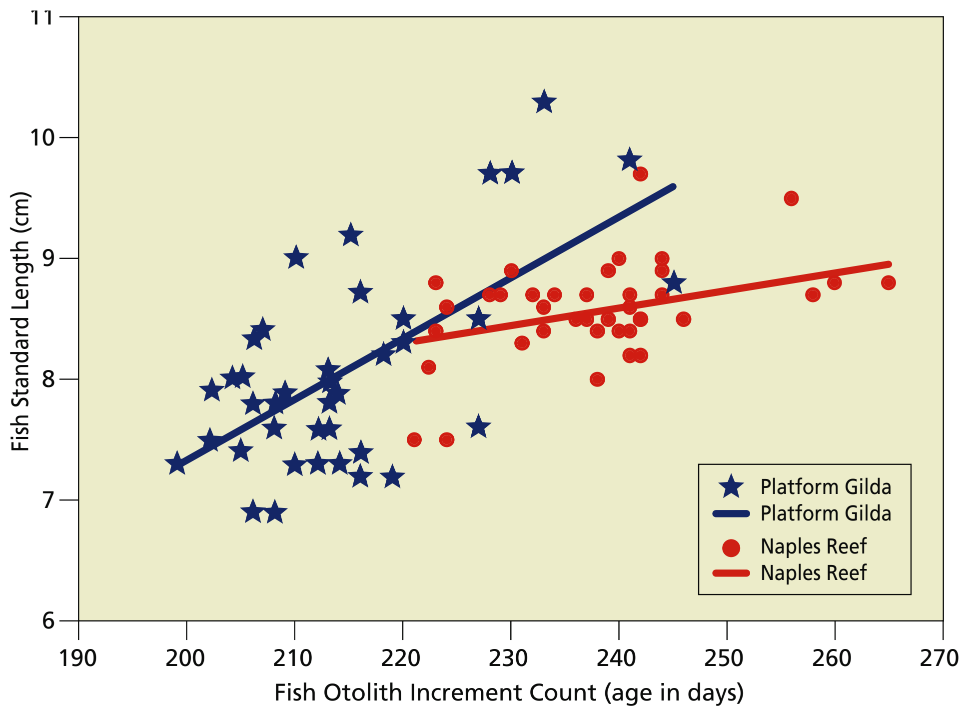


Figure 2.7-2. Growth rate comparison for Platform Gilda and Naples Reef in 1999 (Love et al., 2003).

Fish production rates have been found to be about an order of magnitude higher at California offshore platforms compared with other natural areas studied around the world (Claisse et al., 2014). Locations where production rates have been quantified are shown in Figure 2.7-3. Figure 2.7-4 presents the total production rates of fish mass per unit area at 16 platforms and 7 natural areas. This shows that higher production rates are found around platforms than in natural areas. In Figure 2.7-4, total production is divided between somatic (yellow portion of total growth bars) and recruitment production (purple portion of total growth bars). Somatic production is the increase of mass in the existing fish population, whereas recruitment production is the growth of fish mass through reproduction. Similar findings of high densities of cowcod and bocaccio around Platforms Gail and Hidalgo were reported by Love et al. (2005).

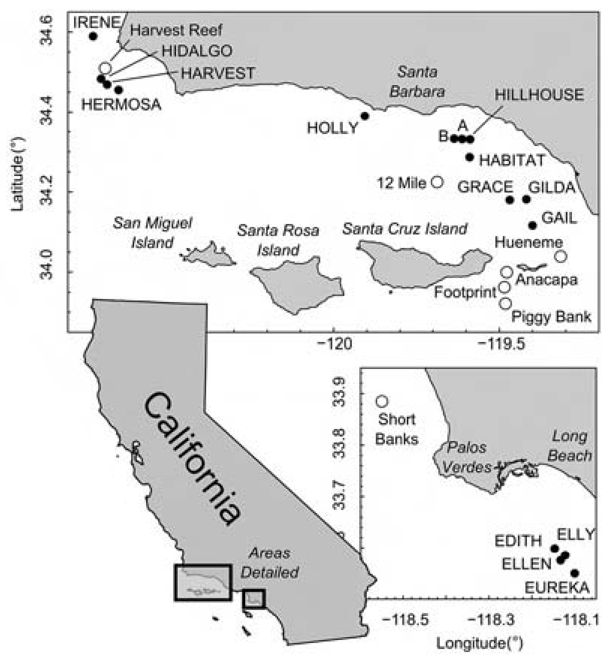


Figure 2.7-3. Locations where fish production rates have been quantified (Claisse et al., 2014). Solid circles are platforms and open circles are natural areas.

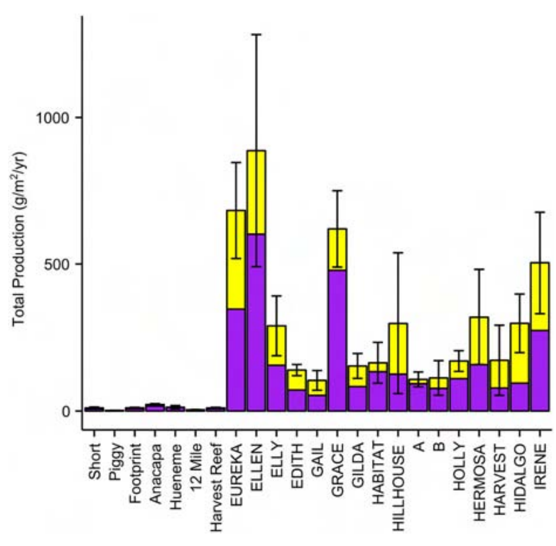


Figure 2.7-4. Fish mass production rates at platforms (with names all in upper case letters) with natural areas (denoted by names using both upper and lower case letters). (Claisse et al., 2014). The yellow and purple indicate the split in production between somatic production (the growth of individuals) and recruitment production (an increase in the number of individuals).

The underlying reason for the improved environment for marine life around platforms is thought to be a result of (1) platforms having a high ratio of habitat surface area to seafloor area and (2) platforms providing protection because access is restricted around the platform, and (3) platforms tend to be in isolated locations (Martin and Lowe, 2010; Claisse et al., 2014). Although these factors do not address the impacts of fluids discharged on the marine environment, the findings of robust fish populations around platforms imply that any adverse impacts of intentional fluid discharge are less than the other advantages afforded by the platform environment.

Osenberg et al. (1992) conducted a study of benthic marine organism densities and growth rates at a location near Carpinteria, about 200 to 300 m (656 to 985 feet) offshore in 10 to 12 m (33 to 39 feet) of water. Osenberg et al. (1992) state that produced water was discharged at this location nearly continuously at a rate of 2,640 m^3/day (16,600 bbl/day). Densities of the benthic organisms were found to be quite sensitive to distance from the diffuser within a range of approximately 100 m. One group of organisms, nematodes (roundworms), were found to benefit from exposure to the produced water, while a second group, polychaetes (segmented worms), displayed a reduction in density within 100 m (328 ft) of the produced water discharge (Figure 2.7-5). Other organisms, including mussels, showed no distinct variation in density with distance from the outfall. However, mussel growth rates were found to be more sensitive, with depressed rates found as a function of distance up to one kilometer away from the discharge point (Figure 2.7-6). However, observations of mussel growth rates at offshore platforms have been found to be higher than for corresponding natural habitats (Claisse et al., 2014). One possibility is that the effects of discharge may have been amplified in this relatively shallow environment compared with offshore platforms in the Santa Barbara Channel area, where water depths are 29 m (95 ft) or more (see Tables 2.5-1 and 2.5-4), as suggested by Gale et al. (2012). Baake et al. (2003) investigated similar impacts caused by oil production operations in the North Sea and found that the effects of produced water discharge result in sublethal effects for some species up to one to two kilometers from the discharge point.

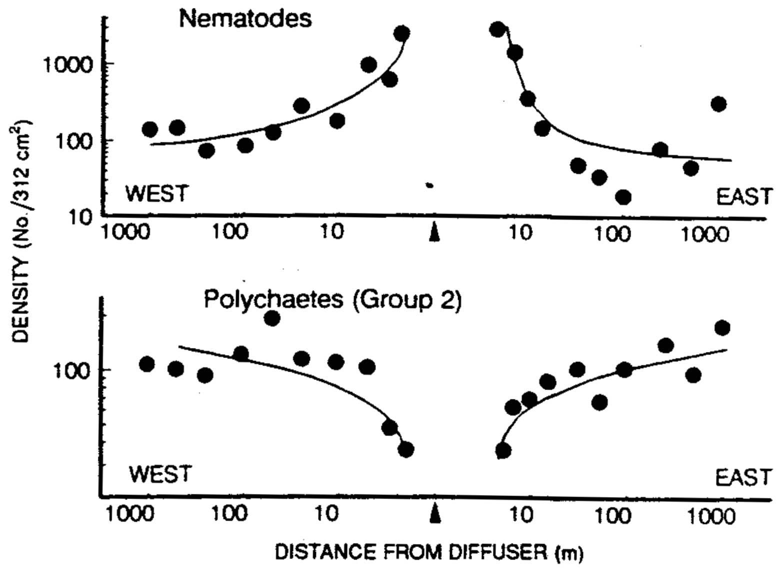


Figure 2.7-5. Densities of benthic organisms as a function of distance from the Carpinteria produced water outfall (Osenberg et al., 1992).

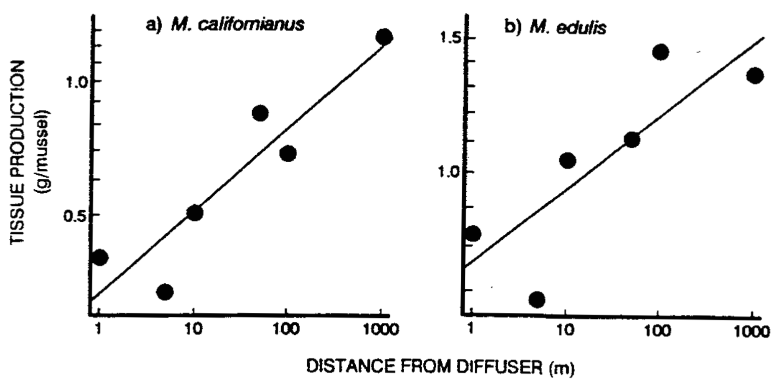


Figure 2.7-6. Variations in mussel tissue growth rates with distance from the Carpinteria outfall for two species, a) M. californianus; and b) M. edulis (Osenberg et al., 1992).

A study of pollutant-related reproductive impairment in fish called atresia was conducted by Love and Goldberg (2009) on the Pacific sanddab. Discharge of drilling muds and produced water were identified as sources of contamination at the platform sites. The study was performed at two offshore platforms, Gilda and B, and two natural areas, Rincon and Santa Cruz, for comparison. The locations of the sites are shown in Figure 2.7-7.

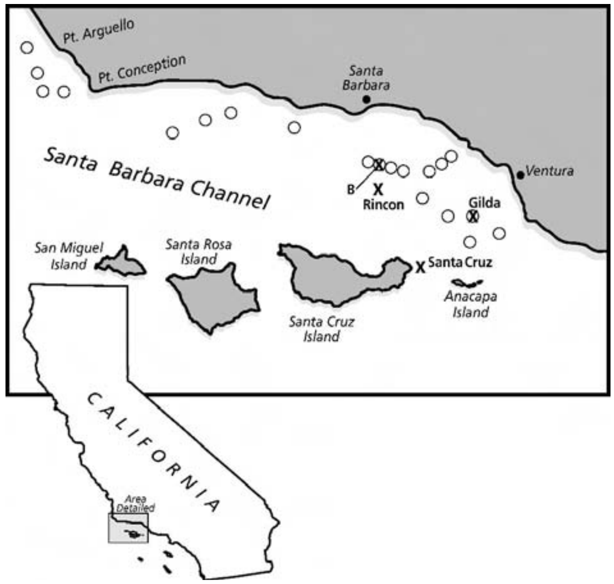


Figure 2.7-7. Locations for samples to investigate atresia in the Pacific sanddab (Love and Goldberg, 2009).

The study was conducted to compare the reproductive capability of the Pacific sanddab at oil platforms and natural areas. The following observations were used to evaluate reproductive health: (1) hydrated eggs for upcoming spawning; (2) vitellogenesis (yolk deposition) in mode of smaller eggs for subsequent spawning; (3) postovulatory follicles (evidence of recent spawning); (4) follicular atresia (degenerating oocytes (egg cell)), characterized as minor or pronounced. Results are shown in Table 2.7-1, where higher percentages of hydrated eggs, yolks in smaller modes, and post-ovulatory follicles correspond to positive reproductive characteristics, whereas occurrences of atresia, particularly pronounced atresia, correspond to reproductive impairment. Love and Goldberg (2009) concluded that the data do not show substantial reproductive impairment in fish living at the platforms, and that large-scale reproductive damage is unlikely to be occurring.

Table 2.7-1. Pacific sanddab reproductive characteristics at two platform and two natural sites (Love and Goldberg, 2009).

Site	n	Hydrated eggs	Yolks in smaller modes	Post-ovulatory follicles	Minor atresia	Pronounced atresia
Platform B	18	95	95	61	22	6
Rincon	19	50	55	5	35	16
Platform Gilda	20	100	100	35	60	0
Santa Cruz	21	85	85	65	15	0

Values in each column are in percentages of individuals sampled.

2.7.1.2. Contamination Studies around California Offshore Platforms

Studies of certain types of contamination around California offshore platforms have also been conducted. These studies include polycyclic aromatic hydrocarbons (PAH) that are a component of crude oil as well as other organic contaminants unrelated to petroleum operations (Gale et al., 2012; 2013; Bascom et al., 1976), trace metals contained in drilling muds and produced waters (Love at al., 2013; Bascom et al., 1976), and reproductive impairment in marine life (atresia) caused by exposure to environmental contamination (Love and Goldberg, 2009).

Gale et al. (2012, 2013) investigated the levels of PAH in Pacific sanddabs, kelp rockfish, and kelp bass. Pacific sanddabs are benthic-dwelling flatfish that are ubiquitous in the southern California marine environment and found both at natural sites and around oil and gas platforms. Kelp rockfish and bass are found at mid-water depths around platforms and at rocky reef natural sites. The locations investigated are shown in Figure 2.7-8, which include 7 platforms and 12 natural sites.

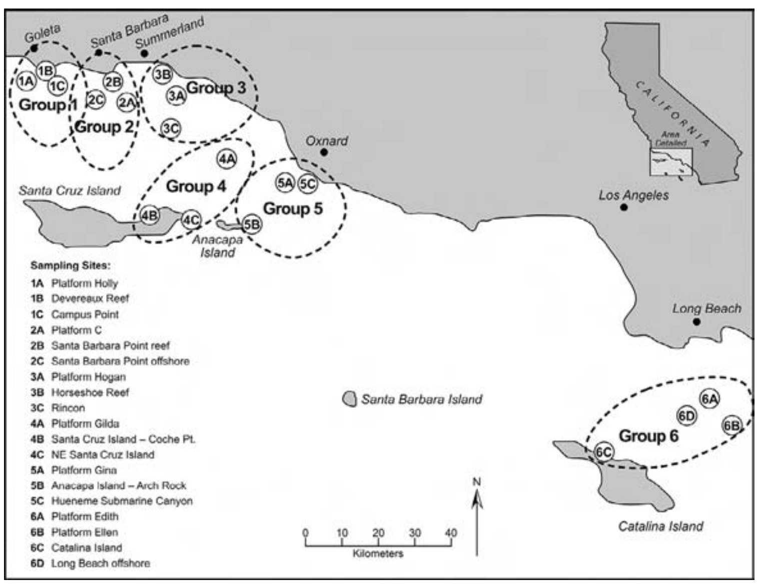


Figure 2.7-8. Sites investigated for PAH contamination (Love et al., 2013).

The investigation involved sampling bile from the fish gall bladders and measuring contamination levels. Because PAHs are rapidly metabolized in the fish livers, PAH metabolites in the bile were the target chemical species in the investigation. This methodology has been used to successfully identify PAH contamination in fish exposed to natural oil seeps relative to other areas that have not been exposed to petroleum seepage (Gale et al., 2013). The study used 74 fish samples from the platform sites and 64 fish samples from the natural sites. The results of the study found that PAH exposure in resident fish populations at platforms is not observably different than in fish from nearby natural areas. 1-Hydroxypyrene, which has been used as a bioindicator of PAH exposure of fish, was not detected in any samples from the platform sites, and only low levels of 1-hydroxypyrene were detected in 3 of 12 kelp rockfish from the Santa Barbara Point reef. The highest levels of PAH metabolites were found in fish near Platform Holly, although even these levels of contamination were considered low by Gale et al. (2012). Platform Holly is in state waters and does not discharge wastewater to the ocean. Detectable PAH metabolite concentrations at platforms in federal waters (at platforms Gilda, Gina, and Hogan) were at levels comparable to detectable concentrations at natural sites.

Gale et al. (2013) performed a follow-on study to Gale et al. (2012), which again considered PAH contamination but also included aliphatic hydrocarbons found in crude oil and several other organic contaminants (polychlorinated biphenyls, organochlorine pesticides, and polybrominated diphenylethers) not related to oil and gas production. The PAH study involved measurements of recalcitrant, higher molecular weight PAHs in fish tissues of Pacific sanddab. These allow for detection of potential chronic exposure to PAHs not readily detectable by PAH metabolite measurements in the earlier study. The same sampling sites as shown in Figure 2.7-8 were used for the follow-on study. The results of the study found that aliphatic hydrocarbon concentrations were uniformly low, less than 100 ng/g per component, in all samples from the platforms and the natural locations. Total-PAH concentrations were found to range from 15 to 37 ng/g at natural areas and from 8.7 to 22 ng/g at platforms. The types of PAHs found at all natural and platform sites were similar. Balk et al. (2011) found a somewhat different result investigating levels of four PAH metabolites in fish bile at two oil production sites in the North Sea. There were three out four metabolites at one of the sites that showed statistically significant higher concentrations than the control. None of the metabolites was significantly different than the control at the other site.

A study of trace metals in fish around California platforms was conducted by Love et al. (2013) during 2005-2006. The study was conducted at 5 of the 7 platform sites (excludes platforms C and Ellen) and 10 of the 12 natural areas (excludes Santa Barbara Point reef and Santa Barbara Point offshore) shown in Figure 2.7-8. This study evaluated results for 21 trace metals in 98 Pacific sanddabs, 80 kelp rockfish, and 18 kelp bass. These species were selected because they are common at both natural and platform sites, and because they are likely to ingest prey containing elevated concentrations of trace elements.
In particular, the benthic-dwelling sanddab, which ingests benthic infauna, might be expected to accumulate trace metals. The elements evaluated are aluminum, arsenic, barium, cadmium, chromium, cobalt, copper, gallium, iron, lead, lithium, manganese, mercury, nickel, rubidium, selenium, strontium, tin, titanium, vanadium, and zinc. These trace metals are present in drilling muds, produced water, and crude, such that they may end up in waste discharge streams from some platforms in federal waters. The trace metal measurements were conducted on whole-fish samples. Of the 21 elements, concentrations of 6 trace metals were found to exceed toxicity thresholds. These six elements of concern are listed in Table 2.7-2, along with the number of fish that exceeded the toxicity

threshold at platforms and natural areas. For example, 4 out of 10 kelp bass sampled in natural areas were found to have exceeded the toxicity threshold for arsenic, and 17 out of 48 Pacific sanddabs sampled at platforms were found to exceed the toxicity threshold for cadmium. As can be seen from Table 2.7-2, the results do not indicate that trace metal contamination at oil platforms is significantly different than in natural areas.

Table 2.7-2. Numbers of fish contaminated (with percent of total sampled in parentheses) beyond toxicity threshold (Love et al., 2013).

	Kelp Bass		**Kelp Rockfish**		**Pacific Sanddabs**	
Trace Metals	Platforms	Natural Areas	Platforms	Natural Areas	Platforms	Natural Areas
arsenic	0	4 (40%)	0	14 (35%)	7 (15%)	6 (12%)
cadmium	1 (13%)	0	2 (5%)	0	17 (35%)	22 (44%)
chromium	0	0	0	0	0	22 (44%)
lead	0	0	1 (3%)	0	0	0
mercury	3 (38%)	9 (90%)	1 (3%)	10 (25%)	7 (15%)	3 (6%)
selenium	0	0	0	0	0	2 (4%)
Number of fish sampled	8	10	40	40	48	50

2.7.1.3. Laboratory Investigations of the Impact of Waste Discharge from Offshore Oil and Gas Operations on the Marine Environment

Other investigations concerning produced water impacts on the marine ecological environment have been conducted. A laboratory toxicological study by Raimondi and Boxshell (2002) concerned the effects of produced water on the California offshore environment. In this study, the reproductive behavior of a selection of marine invertebrates was examined after exposure to various levels of diluted produced water mixed with seawater. In particular, results for the species Watersipora subtorquata, are highlighted here. A colonial marine species, W. subtorquata, spends its adult life attached to hard substrates, including rocks, shells, docks, vessel hulls, etc. Larvae are formed within the adult colony prior to release to the water column for a brief free-swimming stage lasting a few hours, after which the larvae settle out and attach to a hard surface to continue further stages of development. Laboratory experiments were conducted in which W. subtorquata larvae were exposed to different concentrations of produced water from an offshore oil and gas operation mixed with seawater. The experiments then tracked swimming time and attachment rates to assess any sublethal effects on the larval development stage. After 90 minutes, larvae not exposed to produced water were found to still be swimming, whereas none of the larvae at 10% produced water concentration were mobile after 15 minutes. Figure 2.7-9 shows the effects of exposure time and concentration on the percentage of larvae still swimming after 15 and 75 minutes. Despite the distinct sublethal effects observed, no evidence was found that these impacts in the larval stage carried over and impacted the growth or competitive abilities of the subsequent W. subtorquata adults. Similar results were found for other invertebrate species investigated.

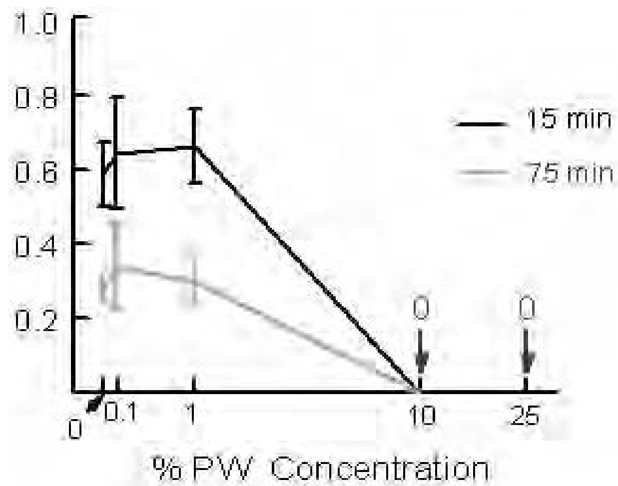


Figure 2.7-9. Impacts of produced water concentration on the fraction of W. subtorquata larvae still swimming after 15 and 75 minutes (Raimondi and Boxshell, 2002).

A study conducted by Krause et al. (1992) was performed using the same produced water investigated by Osenberg et al. (1992) (see Section 2.7.1.1). This study investigated the effects of produced water on reproductive behavior of the purple sea urchin. The reproductive behavior of the purple sea urchin is representative of other benthic marine organisms that broadcast eggs and sperm into the water where fertilization takes place. Treatments were performed using either specific dilutions of the raw produced water with seawater or samples taken from the ocean at various distances from the outfall. Although concentrations of up to 1% produced water had no effect on mortality, both specific dilutions and field samples produced sublethal effects that depressed the rate of reproductive development at dilutions as high as 1,000,000:1. The percentage of embryos reaching the pluteus (larval) stage as a function of exposure type and produced water dilution is shown in (Figure 2.7-10).

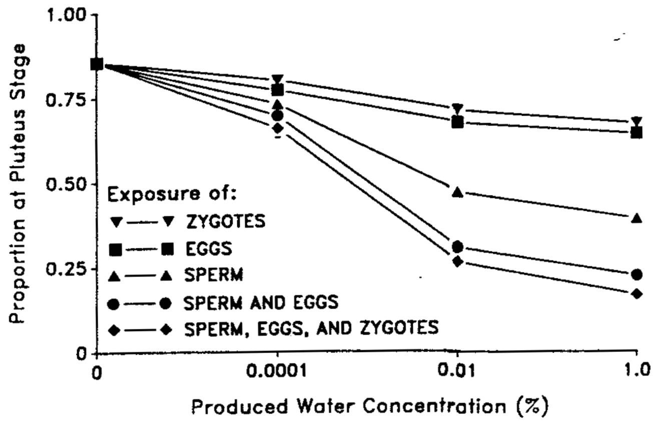


Figure 2.7-10. Effects of produced water concentration on various exposure scenarios for the development of embryos to the pluteus (larval) stage after 48 hours (Krause et al., 1992).

The depressed development, however, was shown to be temporary, in that after 96 hours the progression to the pluteus stage was independent of the level of produced water exposure (Figure 2.7-11), with the control and different exposure scenarios converging to a value of about 85% at 96 hours. While such sublethal effects may lead to increased mortality or an overall reduction in reproductive success in the natural environment, insufficient information exists to extrapolate these results to ecological consequences in the field.

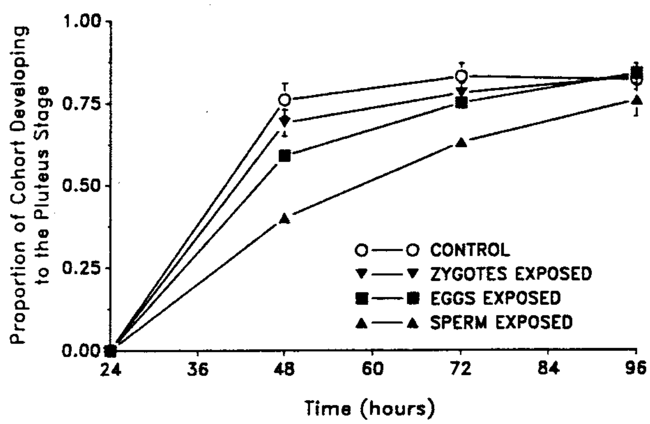


Figure 2.7-11. The effects of 1% produced water exposure scenarios on development to the pluteus stage as a function of time (Krause et al., 1992).

2.7.1.4. Evaluation of Typical Well Stimulation Chemicals and Marine Ecotoxicity

Marine ecotoxicity analyses were conducted on two stimulation fluid compositions as an alternative approach to evaluate the impacts of ocean discharge of stimulation fluid flowback. Because flowback compositions were not available, the discharge was assumed to consist of the same composition as the stimulation fluids. The hydraulic fracturing fluid composition was taken from a DOGGR public disclosure report (DOGGR, 2014c). Fracturing fluid compositions were only available for onshore treatments, and all but two of those reported were for diatomite. The two others were for Pico/Repetto sandstone, which is a more likely type of lithology offshore than diatomite. The fracturing fluid with the highest chemical load was selected, which is shown in Table 2.7-3. Acidizing stimulation fluid compositions were taken from another DOGGR public disclosure report (DOGGR, 2014d). As for fracturing fluid, the only compositions available were from onshore stimulations. The acidizing treatment selected for analysis utilized three distinct fluids that are commonly used sequentially for acidizing. The three fluids are (1) an HCl acid preflush fluid, (2) a main acidizing fluid that was generated from mixing hydrochloric acid and ammonium bifluoride to produce an HCl/HF mud acid, and (3) an ammonium chloride overflush fluid. The compositions are given in Table 2.7-4. For these acidizing fluids, some of the additives could not be analyzed because the concentrations used were not provided in the disclosure, even though the chemicals were listed as part of the fluid.

The maximum percentage by mass was converted to a diluted concentration by assuming a fluid density of 1 kg/liter and an average dilution factor of 746. The average dilution factor is based on a harmonic average of the minimum and maximum dilutions given in Section 2.6.1.1. A coarse toxicity screen was conducted by utilizing all available data in the ECOTOX database (U.S. EPA, 2015c). The predicted average concentration of each chemical following dilution was compared to the lowest available acute or chronic LC50 or EC50 toxicity value for 90 marine species in the following six species groups: algae, moss, fungi; crustaceans; fish; invertebrates; molluscs; and worms. The hydraulic fracturing case study included 33 chemicals. Seven (21%) of these chemicals had toxicity data for marine organisms, and 26 (79%) did not. Out of the seven chemicals with toxicity data, none was predicted to occur at concentrations above acute or chronic toxicity levels. The acidifying case study included 17 distinct chemicals (note that several of the chemicals in Table 2.7-4 are used in more than one of the three acidizing stages). Twelve (71%) had toxicity data in marine organisms, and 5 (29%) did not. Out of the 12 chemicals with toxicity data, two were predicted to occur at concentrations above acute or chronic toxicity levels: ammonium chloride and dodecylbenzenesulfonic acid.

The biocide 5-Chloro-2-methyl-3(2H)-isothiazolone (CMIT) was associated with some of the lowest acute or chronic toxicity values for marine species out of the chemicals screened for this case study. However, the volume of CMIT used in the offshore case study resulted in very low predicted concentrations in surrounding waters. Further study of the use of CMIT and its potential toxicity to marine species is needed.

The lack of toxicity data for 31 of the 48 distinct chemicals (methanol and ethylene glycol are in both hydraulic fracturing and acidizing fluids and both have toxicity data) is a significant problem with this evaluation approach. An additional important caveat is that the approach used here cannot address toxic interactions between chemicals in a complex mixture such as these stimulation fluids. Similarly, very little data were available on chronic impacts of these chemicals in the marine environment. These represent critical data gaps in the analysis of potential impacts of offshore drilling to sensitive marine species.

Table 2.7-3. Hydraulic fracturing fluid composition (DOGGR, 2014c)

Chemical Constituent	CAS	Maximum percentage by mass
Crystalline Silica: Quartz (SiO_2)	14808-60-7	29.08368%
Guar Gum	9000-30-0	0.25305%
Paraffinic Petroleum Distillate	64742-55-8	0.12652%
Petroleum Distillates	64742-47-8	0.12652%
Oxyalkylated Amine Quat	138879-94-4	0.04739%
Methanol*	67-56-1	0.03048%
Diatomaceous Earth, Calcined	91053-39-3	0.02959%
Sodium Chloride*	7647-14-5	0.02564%
1-Butoxy-2-Propanol	5131-66-8	0.02109%
Isotridecanol, Ethoxylated	9043-30-5	0.02109%
Cocamidopropylamide Oxide	68155-09-9	0.01588%
Cocamidopropyl Betaine	61789-40-0	0.01588%
Boric Acid (H_3BO_3)*	10043-35-3	0.01524%
Methyl Borate	121-43-7	0.01524%
Ammonium Persulfate*	7727-54-0	0.00667%
Nitrilotris (Methylene Phosphonic Acid)	6419-19-8	0.00444%
Quaternary Ammonium Chloride	61789-71-7	0.00444%
Hemicellulase Enzyme Concentrate	9025-56-3	0.00379%
Potassium Bicarbonate	298-14-6	0.00311%
Glycerol	56-81-5	0.00159%
Caprylamidopropyl betaine	73772-46-0	0.00159%
Acid Phosphate Ester	9046-01-9	0.00148%
Vinylidene Chloride-methylacrylate polymer	25038-72-6	0.00062%
5-Chloro-2-Methyl-4-Isothiazolin-3-One*	26172-55-4	0.00049%
Magnesium Nitrate	10377-60-3	0.00049%
2-Butoxy-1-Propanol	15821-83-7	0.00042%
2-Methyl-4-Isothiazolin-3-One	2682-20-4	0.00024%
Magnesium Chloride*	7786-30-3	0.00024%
Phosphonic Acid	13598-36-2	0.00015%
Ethylene Glycol*	107-21-1	0.00015%
Crystalline Silica: Cristobalite	14464-46-1	0.00005%
Hydrated magnesium silicate	14807-96-6	0.00002%
Poly(tetrafluoroethylene)	9002-84-0	0.00001%

Note: Stimulation fluid for well API 411122247, Ventura Oil Field

** Chemical with toxicity data.*

Table 2.7-4. Matrix acidizing fluid composition

Stages	Chemical Constituent	CAS	Maximum percentage by mass
HCl preflush	Acetic acid*	64-19-7	0.9828%
	Citric acid*	77-92-9	0.8288%
	Hydrochloric acid*	7647-01-0	15.3241%
	Methanol*	67-56-1	0.0795%
	Diethylene glycol*	111-46-6	0.3136%
	Cinnamaldehyde	104-55-2	0.3136%
	Formic acid*	64-18-6	0.8317%
	Isopropanol*	67-63-0	0.1233%
	Dodecylbenzene sulfonic acid*†	27176-87-0	0.4780%
	2-butoxyethanol*	111-76-2	1. 9997%
	Ethoxylated hexanol	68439-45-2	0.1514%
	Ethylene glycol*	107-21-1	0.0022%
	Poly(oxy-1,2-ethandiyl), a-(nonylphenyl)-w-hydroxy-*	9016-45-9	0.0088%
main acid (HCl/HF)	Hydrochloric acid*	7647-01-0	14.7779%
	Ammonium bifluoride	1341-49-7	4.3887%
	Methanol*	67-56-1	0.0795%
	Diethylene glycol*	111-46-6	0.3136%
	Cinnamaldehyde	104-55-2	0.3136%
	Formic acid*	64-18-6	0.8317%
	Isopropanol*	67-63-0	0. 1215%
	Citric acid*	77-92-9	0.0395%
	Hydroxylamine hydrochloride	1304-22-2	0.0395%
	Silica, amorphous - fumed	7631-86-9	0.0003%
	Dodecylbenzene sulfonic acid*†	27176-87-0	0.4707%
	2-butoxyethanol*	111-76-2	1.9687%
	Ethoxylated hexanol	68439-45-2	0.1491%
	Ethylene glycol*	107-21-1	0.0022%
	Poly(oxy-1,2-ethandiyl), a-(nonylphenyl)-w-hydroxy-*	9016-45-9	0.0087%
overflush	Isopropanol	67-63-0	0.0854%
	Ammonium chloride*†	12125-02-9	5.0009%
	2-butoxyethanol*	111-76-2	0.1685%
	Ethylene glycol*	107-21-1	0.0012%
	Poly(oxy-1,2-ethandiyl), a-(nonylphenyl)-w-hydroxy-*	9016-45-9	0.0047%

Note: Stimulation fluid for well API 403052539, Elk Hills Oil Field.

** Chemical with toxicity data.*

†These chemicals exceeded the toxicity limits for some species.

2.7.1.5. Discussion of Impacts of Well Stimulation Fluids Discharge to the Marine Environment

Direct evidence for impacts of well stimulation fluid discharge into the marine environment is not available. The available information only provides a rough idea concerning the magnitude of stimulation activity conducted offshore, and the composition and disposition of stimulation flowback fluids are not known. There are no studies of stimulation or flowback fluids effects on the marine environment. Our analysis of stimulation fluids indicated that some constituents of matrix acidizing fluids could be discharged at levels that are acutely toxic to marine organisms; this seems less likely for hydraulic fracturing fluid constituents. However, our analysis was based on a number of reasonable assumptions; empirical data on the constituents of discharges from offshore platforms following stimulation is lacking. Wastewater discharge conducted by facilities in federal waters, including produced water, drilling muds, and well stimulation fluids, contain a number of toxic contaminants, including hydrocarbons, heavy metals, and chemical additives such as corrosion inhibitors and biocides (Volume II, Chapter 2). The effects of produced water have been shown to have some sublethal impacts on reproductive behavior and possibly on the overall health of some species. However, studies of the fish populations and contamination levels in fish around California offshore facilities appear to indicate that adverse affects are offset by the increased habitat afforded by the offshore oil and gas facilities. Contamination studies suggest that contaminant exposure levels, presumably as a result of the level of dilution of contaminants discharged, have remained below levels that result in significant adverse impacts. While some level of adverse impacts are likely as a result of wastewater discharge in general, these appear to be subtle relative to positive effects of habitat associated with offshore oil and gas facilities.

2.7.2. Impacts of Offshore Well Stimulation to Air Emissions

The main impacts of offshore air emissions of criteria and toxic pollutants are on air quality locally, while GHG emissions impact climate globally.

2.7.2.1. Criteria Pollutants

Offshore air emissions of criteria pollutants contribute to air pollution within geographical domains identified by CARB as “air basins.” These basins are shown in Figure 2.7-12. Offshore oil and gas production facilities in the Santa Maria and Santa Barbara Basins are closest to the South Central Coast Air Basin. This air basin consists of San Luis Obispo, Santa Barbara, and Ventura counties. Offshore oil and gas production facilities in the offshore Los Angeles Basin are closest to the South Coast Air Basin. This air basin consists of parts of Los Angeles, San Bernardino and Riverside counties, and all of Orange County. Pollutants released within an air basin move freely within the basin and are generally retained within the basin, but may sometimes be transported from one basin to another.

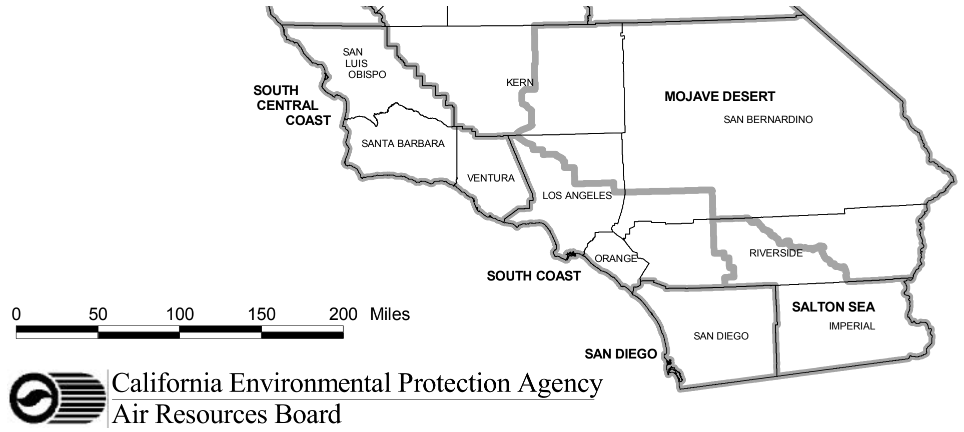


Figure 2.7-12. Southern California air basins and counties.

Offshore emissions reported in Table 2.6-6 are compared in Table 2.7-5 with emissions within the respective air basins.

Table 2.7-5. Offshore oil and gas production criteria pollutant emissions for 2012 compared with overall air basin emissions,(metric tons (lbs)) a) South Central Coast Air Basin; b) South Coast Air Basin. (CARB, 2015a).

a)

Emission Location	TOG	ROG	CO	NOx	SOx	PM	PM10	PM2.5
South Central Coast Air Basin	60,600 ($1.34x10^8$)	25,600 ($5.63x10^7$)	109,000 ($2.40x10^8$)	23,400 ($5.15x10^7$)	729 ($1.61x10^6$)	25,300 ($5.57x10^7$)	14,400 ($3.16x10^7$)	4,310 ($9.51x10^6$)
Offshore Oil and Gas Production	912 ($2.01x10^6$)	471 ($1.04x10^6$)	346 ($7.63x10^5$)	368 ($8.11x10^5$)	100 ($2.21x10^5$)	51.7 ($1.14x10^5$)	50.9 ($1.12x10^5$)	49.0 ($1.08x10^5$)
Percentage	1.5%	1.8%	0.3%	1.6%	13.8%	0.2%	0.4%	1.1%

b)

Emission Location	TOG	ROG	CO	NOx	SOx	PM	PM10	PM2.5
South Coast Air Basin	503,000 ($1.11x10^9$)	209,000 ($4.61x10^8$)	853,000 ($1.88x10^9$)	171,000 ($3.77x10^8$)	6,630 ($1.46x10^7$)	82,200 ($1.81x10^8$)	60,900 ($1.34x10^8$)	31,100 ($6.87x10^7$)
Offshore Oil and Gas Production	113 ($2.50x10^5$)	58.0 ($1.28x10^5$)	29.3 ($6.46x10^4$)	219 ($4.84x10^5$)	0.1 (220)	6.9 ($1.52x10^4$)	6.7 ($1.48x10^4$)	6.7 ($1.48x10^4$)
Percentage	0.023%	0.028%	0.003%	0.128%	0.002%	0.008%	0.011%	0.021%

Criteria pollutants emitted by offshore oil and gas production facilities have been found to be less than 2% of the total emissions in the South Central Coast Air Basin (San Luis Obispo, Santa Barbara, and Ventura counties) except for SOx, where offshore emissions account for 13.8% of the overall air basin emissions. For offshore Los Angeles, the air emissions from offshore oil and gas production facilities are an even smaller fraction of the total criteria pollutant emissions compared with emissions within the South Coast Air Basin. Well stimulation and well-stimulation-enabled production are expected to contribute only a small fraction of the total criteria pollutants emitted by offshore oil and gas production. Therefore, the impacts to the total air emissions are believed to be small.

2.7.2.2. Toxic Pollutants

Toxic air pollutants are also emitted by offshore oil and gas production facilities. The role of well stimulation in the emission of these toxic pollutants cannot be ascertained, because the fraction of emissions due to well stimulation has not been documented. However, several of the toxic pollutants emitted are also components of well stimulation fluids, including methanol, hydrochloric acid, xylene, ethyl benzene, toluene, and naphthalene. Given that offshore oil and gas production facilities have a buffer zone between the location of the emissions and the public, the public health effects may be expected to be reduced as a result of attenuation of impacts with distance. The impacts of toxic pollutant emissions on public health in Volume II, Chapter 6, indicate that the distance at which effects become negligible is about 3 km. Distances of the offshore facilities to land given in Tables 2.5-1 and 2.5-4 suggests that toxic air emissions from the facilities in federal waters should have negligible public health effects, but facilities in state waters (and onshore facilities that access offshore reservoirs) may have some impact, depending on population distributions in the near-shore areas around these facilities. However, these impacts are likely to be small compared with the emissions from onshore oil and gas production activities in the same air basins. Therefore, the impacts of toxic air emissions are expected to be low with respect to public safety, but may be of more concern for worker safety. Of the 12 facilities within 3 km of the coastline, nine are near Los Angeles and Orange Counties. A more detailed analysis of the proximity effects of air emissions in a populated urban setting is given in Chapter 4 of this volume for the Los Angeles case study.

2.7.2.3. Greenhouse Gases

The impact of GHG emissions is on global climate behavior rather than local air quality. Therefore, a comparison to air basin GHG emissions is not useful. Instead, the comparison is made to California GHG emissions for oil production activities per unit BOE output. This is a comparison indicating the level of GHG emissions relative to the value of the activity. Higher GHG emissions per unit BOE output indicate greater cost of production in terms of global climate impact. A more complete analysis would consider the total life-cycle GHG emissions per BOE, including refining, transportation, and combustion downstream of oil production activities, but this lies outside the domain of this study. From Table 2.6-9, the level of GHG emissions for California oil production activities (including offshore) per unit

BOE production can be computed to be 0.057 Mt CO_2eq./BOE, while offshore production alone is found to have a value of 0.053 Mt CO_2eq./BOE. Therefore, offshore oil production is estimated to have a 6% lower GHG emission rate per BOE production than for overall California oil production activities. For comparison, using the 2012 CARB CO_2eq. emission estimate of 16.9 million tons for all California oil and gas production, the emission rate lies between 0.065 and 0.071 metric tons CO_2eq./BOE, depending on whether or not the CARB estimate includes federal offshore emissions. Given the uncertainties in these estimates, the GHG emissions for offshore operations on a unit oil and gas production basis are about the same as for average California operations.

2.7.3. Impacts of Offshore Well Stimulation on Induced Seismicity

As described in Volume II, well stimulation itself does not result in sufficient quantities of fluid injected into the subsurface to be a significant hazard in terms of induced seismicity. Produced water disposal, which involves much greater volumes of water, has a greater potential to facilitate seismic activity if this water adds to the total volume of fluid in the local underground environment. Injection of produced water back into the formation from which it was withdrawn does not involve a net increase in fluid volume within the injection horizon. Therefore, this type of injection process is not expected to have much influence on seismic activity.

Most of the wastewater generated at offshore oil and gas production facilities in federal waters is discharged to the ocean. Three platforms in federal waters (Irene, Gail, Ellen) inject most of their produced water (> 94%). The 20 other platforms in federal waters inject only a small fraction of their produced water (< 15%), and the remainder is discharged into the ocean (CCC, 2013). The volume of produced water injected in federal waters has not been quantified, nor has whether or not this injection is into producing reservoirs or some other horizon used for disposal.

The state offshore oil and gas production operations produced 7.2×10^7 m^3 (4.5×10^8 bbl) of water in 2013. There are only 11 active, idle, or new water disposal wells in state waters. These wells dispose of only about 1.3% of all produced water generated by offshore facilities in state waters. Most of the remaining produced water is injected into the producing oil reservoirs.

The water disposal volumes cannot be quantified in all cases for operations in federal waters. However, using the maximum of 15% injection for platforms other than Irene, Gail, and Ellen, a maximum volume can be estimated. This is a maximum disposal volume because some platforms inject less than 15% of the produced water, and some of this injection is not disposal but injection back into the producing oil reservoir. The estimated maximum water disposal volume offshore in the Santa Barbara and Santa Maria basins is about 9.1 million m^3 (57 million barrels) in 2013, including facilities in federal and state waters. Although difficult to quantify, only a small fraction of this would be attributed to production enabled by well stimulation. To put this number in context, the onshore water disposal volume in Santa Barbara and Ventura counties in 2013 was about 10 million m^3 (63 million barrels).

The estimated maximum volume of water disposal in the offshore Los Angeles Basin in 2013 is about 1 million m^3 (6 million barrels), including facilities in both federal and state waters. More than 0.8 million m^3 (5 million barrels) of this water disposal is for the Beta field, which has no record of hydraulic fracturing. To put this number in context, the onshore water disposal volume in Los Angeles and Orange counties in 2013 was about 3.5 million m^3 (22 million barrels).

The results indicate that the volume of water injected into water disposal wells offshore associated with well-stimulation-enabled production is much smaller than the volume of water disposal for onshore oil and gas production in counties adjacent to these offshore operations. Therefore, the hazard of induced seismicity caused by offshore produced water disposal linked with well-stimulation-enabled production is expected to be significantly lower than the hazard of induced seismicity associated with water disposal associated with onshore oil and gas production in these same locations.

2.7.4. Data Gaps

Data gaps have been identified in several areas throughout this report and are summarized here. These can be divided into two areas: well stimulation activities and environmental effects of emissions and discharge.

2.7.4.1. Well Stimulation Activities

Records of federal offshore activities do not include information on well stimulation sufficient to assess this activity. While information on well stimulation exists in records submitted and made available through FOIA document releases, it is extremely difficult to decipher from these documents with confidence what well stimulation activities have been conducted. Records of the activities need to be maintained in a way that can be accessed and understood. Furthermore, other available records indicate that the documentation present in the FOIA documents is extensively incomplete.

The documentation both on a state and federal level is incomplete and inadequate in terms of the compositions and quantities of stimulation fluids used, the depth intervals treated, the composition and quantities of stimulation fluid flowback, and the disposition of this fluid for disposal.

State records of well stimulation are now improved as a result of the Senate Bill 4 reporting requirements. The evaluation of well stimulation activity should be revisited when a more substantial record of treatments has been captured. However, no similar actions have been initiated to improve records of well stimulation in federal waters that are also needed to repair the existing serious gaps in reporting and record keeping.

2.7.4.2. Air Emissions, Ocean Discharge, Injection and Associated Impacts

The impacts of ocean discharge are hampered by the lack of complete records, or even any records for several facilities, concerning the quantities of materials released into the ocean. Separate samplings and monitoring requirements are needed for discharge of well stimulation fluids. If well stimulation fluids are mixed with produced water for discharge, samplings for contaminants are needed when this mixture of wastes is discharged.

An assessment of the discharge of wastewater well stimulation fluids into the ocean should be done. Acute and chronic toxicity data for well stimulation chemicals, as well as chemicals identified in flowback fluids that may be discharged to the ocean, should be determined to provide a basis for understanding environmental effects of this discharge, just as these types of studies have been performed to assess the impacts of produced water discharge. Alternatively, WET testing that clearly includes stimulation fluid chemicals at discharge concentrations could be used to assess and limit impacts.

If well stimulation fluids are injected, the type of injection needs to be documented, i.e., if the injection is into the producing reservoir or into a disposal horizon. For injection into a disposal horizon, the time profile of pressure and injection rate needs to be monitored for evaluation of potential induced seismicity.

Records concerning air emissions are more detailed, complete, and easier to access than wastewater discharge. Nevertheless, the information is still not adequate to quantitatively assess the atmospheric emissions related to well stimulation activities as distinct from air emissions caused by other oil and gas activities.

2.8 Findings, Conclusions, and Recommendations

The findings regarding the conduct of well stimulation treatments for offshore California operations are not substantially different from findings already made for well stimulation activities discussed in Volume I. Hydraulic fracture stimulations at platforms in federal offshore waters have used small injection volumes, whereas the bulk of the activity at THUMS islands close to Los Angeles uses larger treatment volumes similar to onshore California stimulations. Matrix acidizing treatment volumes are even more poorly documented than hydraulic fracturing, but appear to use significantly smaller treatment volumes than hydraulic fracturing; however, they also appear to be used more frequently.

The potential role of hydraulic fracturing in causing leakage from the subsurface is complex, but fracturing from the reservoir to the seafloor is highly unlikely in most cases, because the depths of the reservoirs exceed the maximum potential hydraulic fracture heights that have been observed. However, hydraulic fracturing does involve the temporary use of high pressures in the well. Given the uncertainty surrounding the effects of this pressure on well integrity and potential leakage, precautions as recommended in Appendix D of Volume II should be considered, including injection of hydraulic fracturing fluids through protective tubing and shutting in offset wells within the zone of pressurization of a hydraulic fracturing treatment.

The effects of produced water have been shown to have some sublethal impacts on reproductive behavior and possibly on the overall health of some species. However, studies of the fish populations around California offshore facilities appear to indicate that adverse affects are offset by the increased habitat afforded by the offshore oil and gas facilities. Contamination studies suggest that contaminant exposure levels, presumably as a result of the level of dilution of contaminants discharged, have remained below levels that result in significant adverse impacts. While some level of adverse impacts are likely as a result of wastewater discharge in general, these appear to be subtle relative to the positive effects of habitat on fish populations associated with offshore oil and gas facilities.

The requirements for TCW wastes discharged without mixing with produced water should be reconsidered. For example, the WET test requirements under NPDES that are applicable to produced water (and produced water mixed with TCW wastes) should be considered for TCW discharged on its own. Furthermore, WET testing should be performed when stimulation fluid discharge occurs. Data collection and records concerning well stimulation should be improved for stimulations conducted in federal waters to at least match the requirements of Senate Bill 4. When representative data become available, an assessment of ocean discharge should be conducted and, based on these results, the necessity of alternatives to ocean disposal for well stimulation flowback should be considered.

Criteria pollutants emitted by offshore oil and gas production facilities have been found to be a small fraction of total emissions in the associated air basins. Well stimulation and well-stimulation-enabled production are expected to contribute only a small fraction of the total criteria pollutants emitted by offshore oil and gas production. Therefore, the impacts to the total air emissions are believed to be small. Because of distances between offshore oil and gas production and local populations, toxic air emissions from the facilities in federal waters should have minor to negligible public health effects. But facilities in state waters may have somewhat greater impact because of closer proximity to population. The impacts of toxic air emissions are expected to be low with respect to public safety, but may be of more concern for worker safety. GHG emissions for offshore operations on a unit oil and gas production basis are about the same as for average California operations. The associated GHG impact relative to benefits of usable energy produced from these operations is not exceptional. GHG emissions linked to well stimulation and well-stimulation-enabled production are expected to contribute only a small fraction of the total.

The results indicate that the volume of water injected into water disposal wells offshore associated with well-stimulation-enabled production is much smaller than the volume of water disposal for onshore oil and gas production in counties adjacent to these offshore operations. Therefore, the hazard of induced seismicity caused by offshore produced-water disposal linked with well-stimulation-enabled production is expected to be significantly lower than the hazard of induced seismicity associated with water disposal related to onshore oil and gas production in these same locations.

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Chapter Three

Case Study of the Potential Development of Source Rock in the Monterey Formation

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3.1. Abstract

Recent estimates of vast resources in the Monterey formation have focused attention on Monterey source rock as an untapped oil resource. Historically, most California production has been migrated oil in conventional traps, rather than oil produced directly from source rocks. Here we evaluate Monterey source rock geology and examine prior estimates of its resources. High-volume hydraulic fracturing in conjunction with long-reach horizontal wells is the key technological advance that has allowed source-rock production outside California. However, horizontal drilling and hydraulic fracturing have not yet enabled commercial production of Monterey source rocks. One major barrier is that the Monterey is highly discontinuous – that is, rather than lying flat, it is folded and faulted. As a result, horizontal wells cannot run for great lengths along the Monterey Source Rock, and without a long well bore, it is difficult to conduct massive, multi-stage hydraulic fractures. We conclude that large-scale production from Monterey source rock is unlikely without some as-yet unforeseen technological advance.

In order to fully understand the potential resources in the Monterey source rock, we recommend that the state commission a comprehensive, peer-reviewed probabilistic resource assessment of continuous-type (shale) oil resources in California. We undertake one important initial step in such a resource assessment by mapping the extent of potential Monterey-equivalent source rocks in California. The Monterey formation and its equivalents form a much larger than the area of potential source rock. Potential Monterey source rock is restricted to the same six basins that have hosted the largest proven oil

reserves and production in California. Some, but not all, of the footprint of potential Monterey source rock overlaps with oil fields tapping shallower, migrated deposits. About 8% of the area within the footprint of potential Monterey source rock reservoirs has already been developed for oil and gas production. The remaining 92%, while not presently producing oil, is at most about 20 kilometers (12 miles) from an existing oil field.

We outline how one can use public records to identify exploration of Monterey source rock so the public can be apprised of the leading indications of likely source-rock development. Information collected by the Division of Oil, Gas and Geothermal Resources (DOGGR) would conceivably allow state agencies to identify successful early exploration of Monterey source rocks and conduct a more detailed evaluation of potential impacts at that time. However, data on exploratory wells would most likely be classified as confidential and would not be made publicly available until the confidentiality of the well(s) expired. Therefore, the public would most likely be unaware of the extent of source-rock production until the first stages of non-exploratory, commercial development were already underway.

We evaluate potential environmental impacts of Monterey source rock development by examining the setting of the source rock footprint in terms of water resources, air quality, potential for seismic activity, and sensitive species and habitats. Given the many uncertainties about how source rock would be developed, as well as data gaps about the environmental impacts of well stimulation identified in Volume II, we cannot make detailed predictions about how impacts from source rock production would differ from the effects of current production. The greatest changes we expect from large-scale development of source rock would be an increase in quantity of oil and gas production and its associated impacts, and an expansion of oil and gas activity into new areas near existing oil fields.

3.2. Introduction

In California, most of the oil and gas (referred to in this chapter as petroleum) originated in deep portions of the Monterey formation – the state's most prolific source rock – and yet most petroleum is not produced directly from Monterey source rocks. Rather, California's production consists of petroleum that has migrated away from source rock into conventional traps. Production of migrated petroleum in conventional traps differs from source-rock production in a number of ways, including: (1) Source rock (also known as "shale oil and shale gas") plays generally cover larger geographic areas than do migrated conventional accumulations; (2) Well stimulation and horizontal drilling are necessary for commercially successful production of source rock, and (3) Source rocks are found at greater average depths than conventional reservoirs of migrated oil.

Direct production of oil from source rocks would represent a fundamental shift in the geographic scale, technology employed, and quantity of petroleum production in the state.

Sections 3.3.1. through 3.3.6. describe source rock production, how it has been carried out in other states, and how it differs from current practice in California. Section 3.3.7 describes the geologic conditions that must be met for successful Monterey source rock production to be possible.

Monterey source rock might never be extensively developed in California. The volume of recoverable resources in Monterey source rock remains uncertain, and no rigorous, probabilistic resource assessment of the Monterey has ever been conducted. The U.S. Energy Information Administration (U.S. EIA's) resource projection for the Monterey Formation dropped from 2.4 billion m^3 (15.4 billion barrels) in 2011 to 0.1 billion m^3 (0.6 billion barrels) in 2014 (U.S. EIA, 2011; U.S. EIA, 2014), but we regard both estimates as problematic. To fully understand the range of possible recoverable resources from Monterey source rock, one would need to undertake a probabilistic assessment that takes into account the geological uncertainties of the resources and of the technologies that might be used to produce them. Section 3.3.8 discusses the estimates issued by the U.S. EIA and outlines the steps required for a systematic resource assessment.

While there has been no clear demonstration that Monterey source rock will be a viable commercial play, there has been some exploratory drilling. We describe the publicly available information on exploratory drilling in Monterey source rock in Section 3.3.9, and outline how one can use public records to identify exploration and production of Monterey source rock in Section 3.3.9.1. Such a search could be conducted using well-stimulation disclosures, which include the two key pieces of information: total well depth and the formation stimulated. However, most exploratory wells are likely to be confidential, and so the relevant information would not be released to the public until confidentiality expired.

In Section 3.3.10 we identify the maximum possible surface footprint of Monterey source-rock plays in California. This footprint is the surface projection of where the Monterey Formation is thought to have been buried deeply enough to convert its solid organic matter (kerogen) to petroleum. In this case study we consider the footprint of potential source rocks within the six major oil-producing basins in California. For brevity, we refer to this area as simply as "potential Monterey source rock." We emphasize that the footprint we identify is a maximum estimate. The true extent of a Monterey source rock play will likely be smaller because of a number of other conditions that must be met to produce oil commercially from source rocks, and the end result may be that there is no viable source rock play.

We discuss potential environmental and human health impacts of Monterey source-rock development in Section 3.4. We evaluate the location of potential Monterey source rock with respect to developed oil fields and associated infrastructure, water resources, air quality, potential for seismic activity, and sensitive species and habitats.

We end with a summary of data gaps, recommendations on how to rectify the data gaps, and a summary of findings and conclusions. Though we regard the potential for large-scale development of Monterey source rock with skepticism, there are concrete methods that could reduce the uncertainties about recoverable resources and forewarn the public if and when there was successful source-rock production. It is also important to recognize that the maximum extent of potential Monterey source rock is much smaller than the full extent of the Monterey formation, and is restricted to basins where oil and gas are already being produced.

3.3. Geological Framework for the Source-Rock Case Study

3.3.1. What is a Source Rock?

Petroleum (which we use in this chapter to refer to oil and gas) originates in source rocks from insoluble organic matter (kerogen), which has been deposited along with inorganic materials in sedimentary basins (Hunt, 1995). In petroleum geology, a source rock is an identifiable sedimentary rock unit (typically a formation or member of a formation) having sufficient concentration of kerogen of suitable composition for the chemical or biological generation of petroleum.

The rate at which temperature increases with depth in the earth is the geothermal gradient. When a potential source rock is progressively buried beneath younger sediments, it is increasingly heated until its kerogen begins to thermally degrade in a process called "cracking." During cracking, shorter-chain hydrocarbon molecules are released from the original complex organic compounds of the kerogen. Source rocks that have been heated enough to crack kerogen into hydrocarbons are said to be "thermally mature" with respect to oil and/or natural gas generation (Figure 3.3-1). A thermally mature source rock is a fundamental component of a petroleum system.

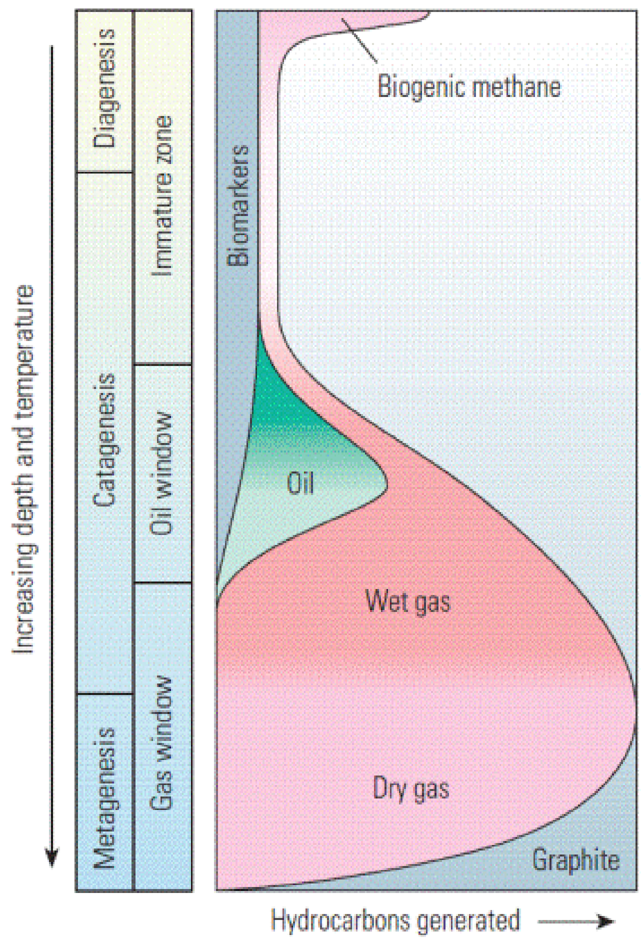


Figure 3.3-1. Thermal transformation of kerogen to oil and gas, depicting the depths of the oil and gas windows (McCarthy et al., 2011). When source rocks are exposed to adequate heat and pressure, they become "thermally mature," generating oil and/or natural gas.

Three broad categories of source rocks are recognized based on the type of kerogen they contain. Monterey Formation has Type II source rocks, which are sedimentary successions with high concentrations of the remains of phytoplankton and bacterial organic matter deposited under oxygen-deficient conditions in marine environments. When heated sufficiently during burial, Type II source rocks generate both oil and natural gas. Worldwide, most known oil has been formed by the thermal alteration of kerogen in Type II source rocks.

Box 3.3-1. What to Call the Monterey?

The Monterey Formation looms large in the public discourse about hydraulic fracturing because a 2011 EIA report estimated 2.4 billion m^3 (15 billion barrels) of oil could be produced from the Monterey Formation using hydraulic fracturing, much like the "shale" oil that is being produced from the Bakken Formation in North Dakota and the Eagle Ford Formation in Texas. The public identifies the idea of having similar developments in California through the use of the term "Monterey Shale."

This report uses more accurate terms than "Monterey Shale" in order to carefully describe the issues and potential of the Monterey. For over a hundred years, geologists have used the term "Monterey Formation" for rocks that were originally deposited off the coast of California between about 17.5 and 6 million years ago (middle to late Miocene Epoch). The Monterey Formation underlies much of California, but varies greatly from place to place in thickness and includes many different rock types, not just shale (for example: diatomite, porcelanite, chert, and siliceous shale, highly organic-rich and phosphatic shale, marlstone, clay shale, sandstone, and volcanic rocks).

Generations of geologists have studied the Monterey and given it different names, leading to much confusion. For example, Antelope Shale, Devilwater Shale, Fruitvale Shale, Gould Shale, McDonald Shale, Modelo Formation, Monterey, Monterey Formation, Monterey Shale, Nodular Shale, Puente Formation, and Stevens Sandstone are just some of the names used to describe strata that could be considered part of the Monterey Formation. For simplicity, this report uses the terms "Monterey Formation" and "Monterey" interchangeably to describe all of these as a single class.

The Monterey source rocks are those parts of the Monterey Formation that are sources of petroleum. Oil forms in those parts of the formation that include concentrated organic material and that have been buried deeply enough so that chemical reactions triggered by heat and pressure transform the organic matter into oil (i.e. the rocks are in the "oil window"). Some of this oil floats upwards (migrates by buoyancy) until it meets a barrier or "trap". The rest of the oil remains behind in the source rock. Nearly all the petroleum so far produced in California has migrated from these prolific Monterey source rocks to the near-surface reservoirs that are now under production. The EIA report was not about this migrated oil. The EIA based their estimate of potential new production on the idea that the oil remaining behind in the source rocks could also be produced. This case study, like the EIA report, focuses on the resources present in the Monterey source rocks themselves.

3.3.2. What is Monterey Source Rock?

In California, the volumetrically most important petroleum source rocks, by far, are found within the Monterey Formation and its stratigraphic equivalents. Stratigraphic equivalent formations share similar physical characteristics, geographic occurrence, and age but have different names. In this case study, we refer to the Monterey Formation and its stratigraphic equivalents simply as the Monterey. The Monterey is a classic petroleum source rock that has been intensively studied for more than 100 years (Tennyson & Isaacs, 2001).

The Monterey originally consisted of marine sediments deposited at mid-bathyal depths (500 to 1,500 meters, or 1,640 to 4,921 ft of water) along the continental margin of California during the latter half of the Miocene Epoch, between about 7 and 18 million years ago (mya). The geologic times referred to in this chapter are shown in Appendix 3.B, "Geologic Time Scale." The Monterey is known to be present in many of the onshore basins of California, including the Cuyama, La Honda, Los Angeles, Salinas, San Joaquin, Santa Maria, and Santa Barbara-Ventura Basins. It is also known or postulated to be present in the offshore basins from Point Arena on the North to the Oceanside Basin on the south (Figure 3.3-2). The Monterey is believed to be the principal source of oil in the largest oil fields of the Salinas, San Joaquin, Santa Maria, Santa Barbara-Ventura, and Los Angeles Basins.

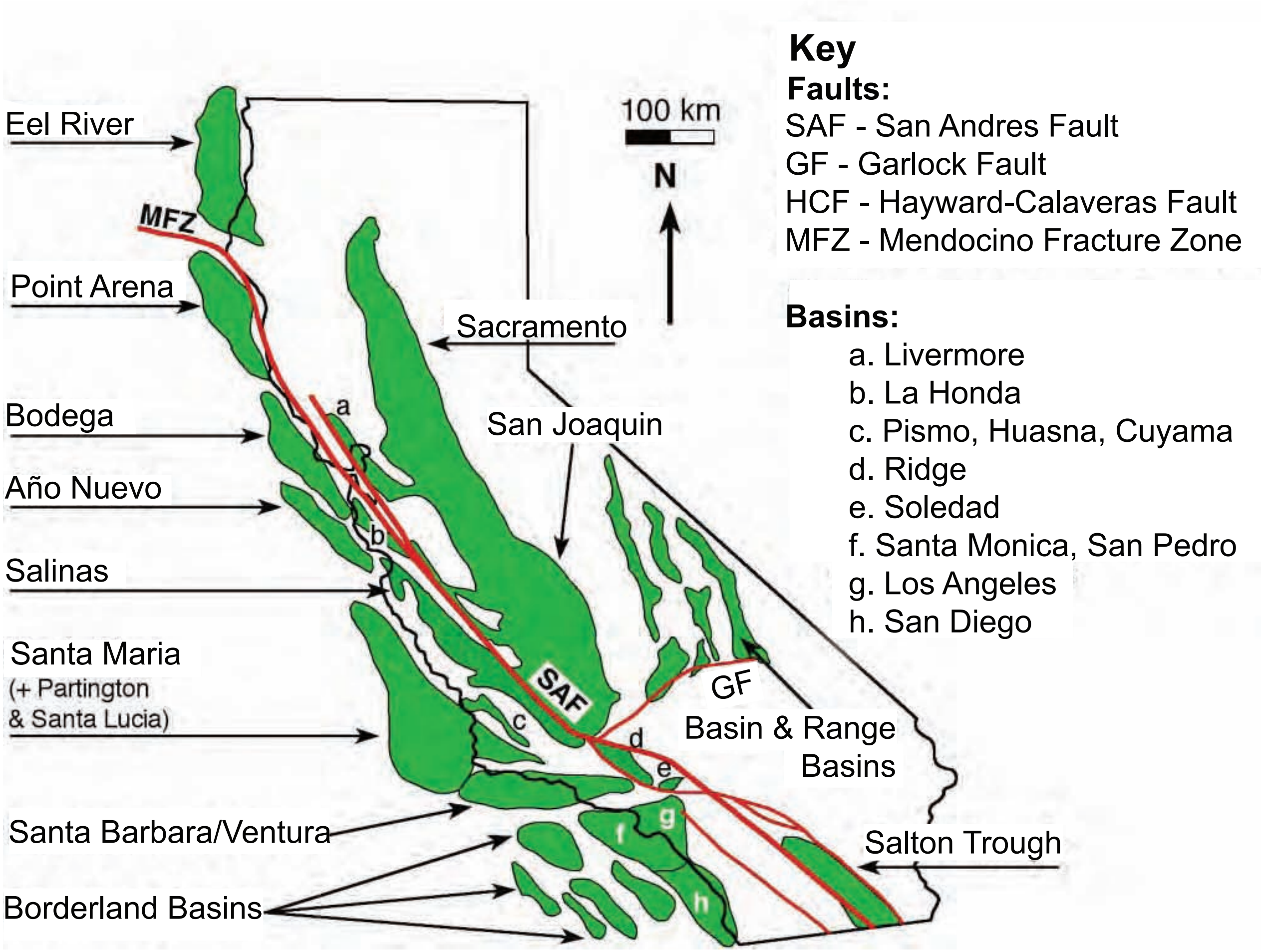


Figure 3.3-2. Neogene sedimentary basins in and along the coastal margins of California, from Behl (1999). The Monterey occurs as thick and extensive deposits within many of the Neogene sedimentary basins in California, including all of the major oil-producing basins. The Monterey Formation or its equivalents are known from most coastal basins from Point Arena southward to the Borderland Basins. The Central Valley, or Great Valley of California comprises the Sacramento Valley in the north and the San Joaquin Valley in the south.

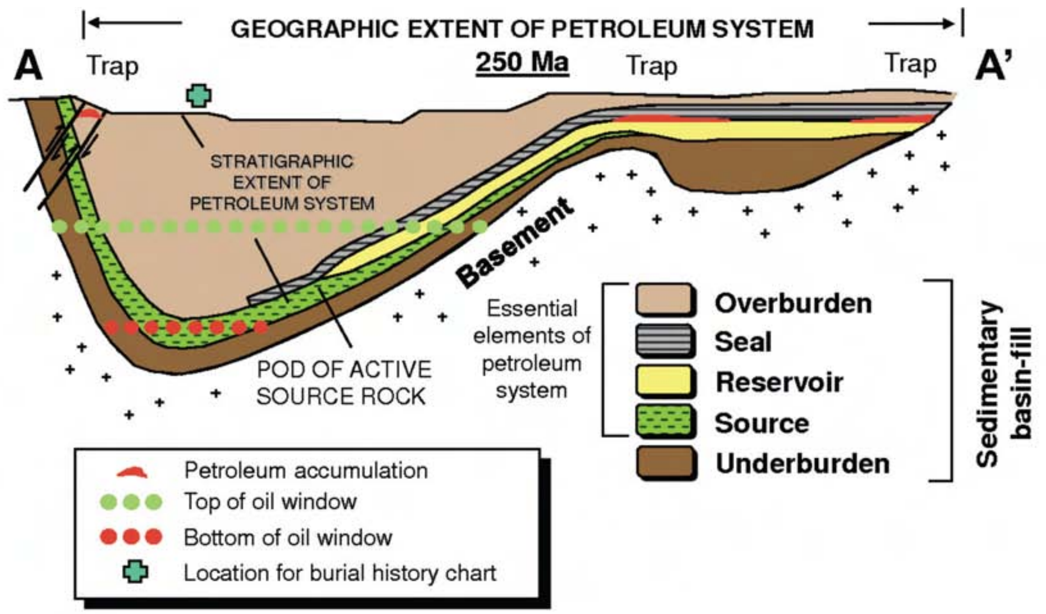
The lithology (physical characteristics) and thickness of the Monterey vary greatly both within and among the basins. This variability makes it challenging to produce oil directly from the source rock, as described in greater detail in Sections 3.3.7 and 3.3.8. For greater detail on the lithology of the Monterey, see Volume I, Chapter 4, Section 4.4.

3.3.3. Non-Monterey Source Rocks in California

In this case study we focus principally on the Monterey because it is the volumetrically dominant source-rock system in the state. However, it is important to recognize that other active source rocks have been identified. Lillis (1994) interpreted the Soda Lake Member of the Vaqueros Formation to be the source of much of the oil that has been produced in the Cuyama Basin. Magoon et al. (2009) interpreted the Late Eocene Tumey Formation to be the source rock for more than 130 million m^3 (800 million barrels) of recoverable oil in fields on the west side of the San Joaquin Basin. The Eocene-age Kreyenhagen Formation is another petroleum source rock in the San Joaquin Basin. At the location of its reference section at Reef Ridge, just south of Coalinga in the San Joaquin Basin, it is a siliceous, shale-rich formation more than 305 m (1,000 ft) thick (Von Estorff, 1930). The Kreyenhagen is interpreted as the source rock for almost 0.32 billion m^3 (2 billion barrels) of oil in accumulations along the northwest side of the San Joaquin Basin, including oil in the Coalinga and Kettleman North Dome oil fields, among others (Magoon et al., 2009). The Moreno Formation is a shale-rich formation of Cretaceous to Paleocene age (McGuire, 1988), which is known to be the source rock for the small quantities of oil produced from the Oil City pool of the Coalinga oil field (Magoon et al., 2009). Locally, other formations may serve as petroleum source rocks as well. For a more detailed discussion of these source rocks and references describing them, please see Volume I, Chapter 4.

3.3.4. What is a Source-Rock System Petroleum Play?

In source-rock plays, hydrocarbons are produced directly from the rock where they were generated. Such plays, also referred to as “continuous accumulations,” tend to cover large areas, have low matrix permeability, and low recovery factors. Low matrix permeability means that hydraulic fracturing is often required to increase hydrocarbon flow rates to an economic level, and low recovery rates mean that only small proportion of the total hydrocarbons in place are produced. In conventional reservoirs, hydrocarbons have migrated out of the source rock and accumulated in a natural trap in a geological layer. Conventional reservoirs cover relatively small areas, have comparatively high matrix permeabilities, and have higher recovery efficiencies than unconventional reservoirs. Figure 3.3-3 shows a stratigraphic section that illustrates the relationship between source rock and conventional plays. Active source rock is at depth in the oil window, while conventional petroleum deposits are petroleum that has migrated out of the active source rock and accumulated under traps.(See Volume I, Section 4.3.1: “Introduction to Unconventional Resources in the United States”)



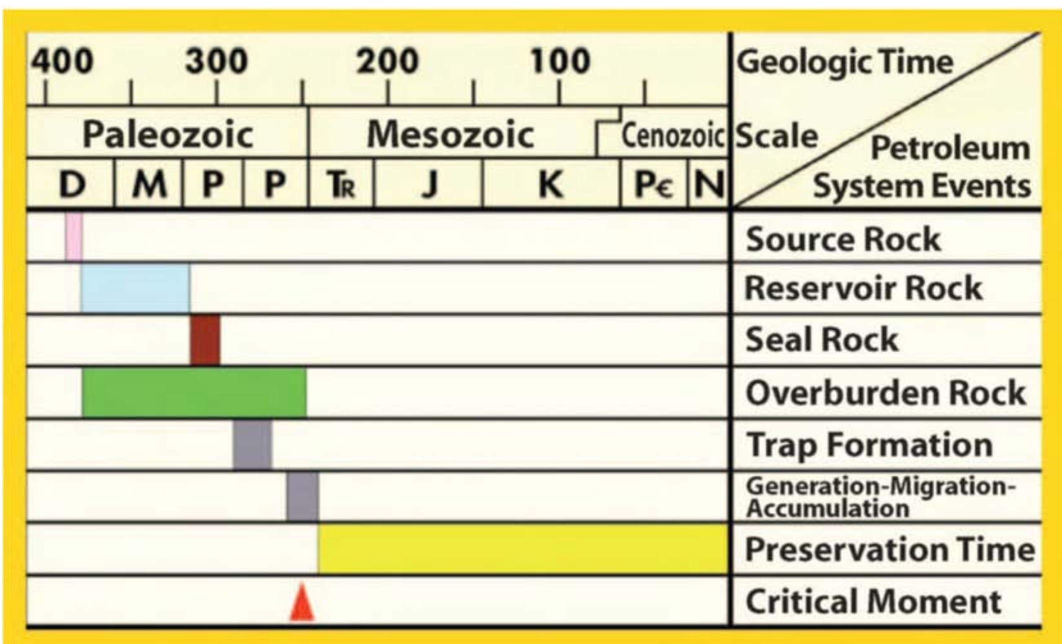


Figure 3.3-3. Example of a hypothetical petroleum system showing, cross section, and timeline for system formation. Figure from Magoon & Dow, 1994.

When potentially productive source rocks are buried and heated to thermal maturity, high pore-fluid pressures resulting from hydrocarbon generation, combined with sediment compaction, cause some of the newly-formed hydrocarbons and other fluids, such as water and non-hydrocarbon gases, to be expelled from the source rocks in a process termed “primary migration.” If these fluids are effectively expelled into adjacent formations that are porous and permeable, the hydrocarbon fluids move preferentially upward due to their buoyancy relative to water. The buoyant movement of hydrocarbons is termed “secondary migration.” The expelled hydrocarbons migrate upward through the sedimentary basin until they either accumulate at a permeability barrier to migration (a trap) or they seep out at the surface, where bacteria and inorganic oxidation decompose them. Trapped accumulations of migrated hydrocarbons are the traditional target of petroleum exploration. When found and developed such accumulations become conventional oil or gas fields and the rocks containing the entrapped hydrocarbons are conventional reservoirs. Nearly all production in California has been of migrated oil from conventional reservoirs.

Although large amounts of hydrocarbons are expelled during thermal maturation, as long as the source rock remains in the “oil generation window,” at least some oil will remain in the source rock, both as free hydrocarbons in pore spaces within the kerogen, and adsorbed on the surfaces of kerogen and other sedimentary particles. Oil producers have long been aware that residual hydrocarbons remain in source rocks during and after oil generation and operators drilling through source-rock intervals have routinely reported oil “shows.” However, owing to the extremely low permeability of the source rocks, the residual hydrocarbons were not believed to be commercially producible. This view is now changing.

In recent years, as conventional fields have become depleted, harder to find, and more difficult to access, technological advances in directional drilling, down-hole imaging, and reservoir stimulation have enabled explorationists to commercially produce residual hydrocarbons directly from source rocks or from other low-permeability sedimentary rocks that are intimately associated with the source rocks.

Hydrocarbons produced from source rocks are called shale oil or shale gas. In shale oil and shale gas accumulations, the source rock and the reservoir rock are essentially one and the same.

3.3.5. Source-Rock Plays Versus Current Petroleum Production Practice in California

Most conventional oil accumulations have clearly identifiable and distinctive source rocks, reservoirs, traps, and seals, but in continuous-type shale-oil accumulations, source rocks, reservoir rocks, traps and seals are the selfsame formation. A summary of the major differences between source rock and conventional reservoirs is presented in Table 3.3-1.

Table 3.3-1. Comparison of source rock and conventional reservoirs. The table reflects typical patterns and trends; some formations may be exceptions to the rule.

Characteristic	Source Rock Reservoirs	Conventional Reservoirs
Permeability	Lower	Higher
Geographic extent	Larger	Smaller
Depth	Deeper	Shallower
Recovery rate	Lower	Higher
Role of hydraulic fracturing	Necessary for economic production	Sometimes necessary for economic production
Role of horizontal drilling	Nearly always necessary for economic production	Sometimes necessary for economic production

From a technical development perspective, perhaps the most important distinction between conventional reservoirs and unconventional shale oil reservoirs is permeability. In contrast to reservoirs in most conventional oil fields, shale oil reservoirs exhibit extremely low permeability. Whereas typical conventional reservoirs are sandstones or limestones with permeabilities measured in hundreds or even thousands of millidarcies (Levorsen, 1967), shale oil reservoirs, such as the Eagle Ford shale, are Total Organic Carbon (TOC)-rich fine-grained rocks having permeabilities measured in tens of nanodarcies (Hentz & Ruppel, 2011). A nanodarcy is a unit of measurement of permeability equivalent to $1x10^{-9}$ Darcy, whereas a millidarcy is a unit of measurement of permeability equivalent to $1x10^{-3}$ Darcy.

Box 3.3-2. Conventional and Unconventional Resources Versus Migrated and Source Rock Resources

In this chapter, we prefer to use the terms source rock and migrated reservoirs to avoid conflicting definitions of the terms "unconventional" and "conventional." Unconventional versus conventional can differentiate between source rock and migrated resources or between low- and high-permeability formations. Low-permeability formations require well stimulation to produce (Vol. I, Ch. 2). Source rock plays are low-permeability and therefore are unconventional by either definition. However, California has large migrated petroleum resources in low-permeability formations, such as the diatomite in the southwestern San Joaquin, which would be considered conventional by the first definition (they are migrated accumulations), but unconventional by the second (they are in low-permeability rocks). To avoid this confusion we prefer to use the terms source rock and migrated resources. The term source rock resource is synonymous with the term "continuous resources." Shale gas and oil are one major category of source rock resources, and the type under consideration in this case study.

The development footprint of a source-rock play is typically much larger than that of traditional oil fields. In most migrated oil fields, particularly in California, resources are geographically concentrated, with large volumes of petroleum contained in comparatively small areas. For example, the Long Beach oil field in the Los Angeles Basin originally contained between 18.9 billion and 22.6 billion m^3 (3 billion and 3.6 billion barrels) of oil in place, with recoverable oil volumes (cumulative historical production plus reported remaining reserves) of almost 1 billion barrels, all within a productive area of only 7 square kilometers (~143,000,000 barrels/km^2). In contrast, source-rock accumulations extend across thousands or tens of thousands of square kilometers. For example, in its study of the Bakken Shale/Three Forks oil resources in North Dakota and Montana, the USGS estimated that between 7 and 8 billion barrels of oil is recoverable from a potentially productive area of more than 98,000 square kilometers (~80,000 barrels/km^2) (Gaswirth et al., 2013).

In addition to being highly concentrated, conventional accumulations of migrated oil are typically found at much shallower depths than are source rock plays. This is because the shale oil accumulations can only be developed at depths where source rocks are thermally mature for oil generation, whereas conventional accumulations are found in structures where oil has become trapped after buoyancy-driven secondary migration. For example, at South Belridge oil field, on the west side of the San Joaquin Basin, migrated oil is produced from diatomites at average depths of about 1,000 feet, whereas the source rock for the oil at South Belridge is probably the Monterey-equivalent McLure Shale, which is thermally mature at depths of 13,000 to almost 20,000 feet (Magoon et al., 2009).

Without fracture stimulation and horizontal drilling, economic production is generally not possible from source-rock systems. In Texas, North Dakota, and elsewhere, large-scale commercial production of oil and gas from low-permeability source-rock system reservoirs has been achieved by drilling thousands of “horizontal” wells, coupled with multi-stage massive hydraulic fracturing (e.g., Texas Railroad Commission, 2015). Well known productive source-rock systems include the gas and liquids produced from the Barnett Shale in the Fort Worth Basin of northern Texas (Pollastro et al., 2007), the oil, gas, and natural gas liquids produced from the Eagle Ford Shale in the Gulf Coast Basin of southern Texas (Harbor, 2011; Hentz and Ruppel, 2011), and oil produced from the Bakken Formation in the Williston Basin in Montana and North Dakota (Price & LeFever, 1992; Nordeng, 2009).

For example, in the Eagle Ford shale of south Texas, wells are drilled vertically downward until the shale is encountered, at which point the drilling direction is changed to follow the formation for 1,000 to 2,500 m (3,281 ft to 8,202 ft). Then, 10 to 30 massive hydraulic fracture treatments are conducted, in which the pore fluid pressure inside the target source/reservoir rock is raised until the rock breaks (fractures) and free hydrocarbons flow through the fractures to the wellbore. The fracturing accesses large areas of the source rock, often opening natural fractures, which are common in most shales, and enabling flow through manufactured conduits that are much higher permeability than the matrix permeability in unfractured shale. In this manner, hydraulic fracturing makes a distinct reservoir within the contacted areas of the source rock.

Production from such source-rock systems has become economically and politically important in the United States, significantly reducing the quantities of oil being imported, (U.S. EIA, 2014), driving down natural gas prices (U.S. EIA, 2014b), and replacing large quantities of coal by natural gas for electricity generation (Macmillan et al., 2013).

3.3.8. Patterns of Development of Source-Rock Plays Outside California

Shales have long been known to contain producible hydrocarbons, but widespread production was not feasible until innovations in technology, coupled with sustained high commodity prices, made commercial production possible. The first large-scale commercially successful source-rock development was in the Barnett Shale in the Fort Worth Basin of northern Texas. Beginning in 1981, persistent efforts by Mitchell Energy and Development Corporation achieved modest production rates from vertical wells. But in the late 1990s Mitchell began testing horizontal drilling, massive hydraulic fracturing, and friction-reducing “slick-water” chemicals. In so doing, Mitchell demonstrated that high-volume shale production could be achieved by the consistent application of advanced technologies. In the 2000s, gas prices rose and costs of horizontal drilling declined to the extent that by 2005 horizontal wells outnumbered vertical wells in the Barnett. At the end of 2012 more than 16,000 wells, the vast majority of them horizontal, were producing hydrocarbons from the Barnett Shale.

The commercial successes in the Barnett attracted numerous other operators, both to the Fort Worth Basin and to potential shale plays elsewhere. In addition to the Barnett, volumetrically large shale gas production has been demonstrated in the Fayetteville Shale in the Arkoma Basin in Arkansas, the Woodford Shale in the Arkoma basin of Oklahoma and Arkansas, the Haynesville Formation in Louisiana and Texas, and the Marcellus Shale in the Appalachian Basin in Pennsylvania and West Virginia, among others.

In recent years shale developments have been victims of their own success, as burgeoning reserves and production have pushed commodity prices down to levels that made many shale gas operations sub-economic. As natural gas prices fell relative to oil operators increasingly focused on producing liquids rather than gas from source rocks. As of this writing, oil prices have also declined to the extent that investments in shale oil developments have also slowed.

Although hundreds of organic-rich shales are known in North America and thousands are recognized worldwide, most shale oil production has come from just two productive intervals: the Bakken/Three Forks strata in the Williston Basin of North Dakota and Montana and from the Eagle Ford Formation in southern Texas. As of 2013 these two “plays” accounted for more than 94% of reserves and slightly less than 94% of production of shale oil in the United States (U.S. EIA, 2015). The Bakken Formation is described and compared to the Monterey Formation in Volume I, Chapter 4 of this study.

Numerous other source-rock system oil plays have been tested in the U.S. and in Canada, resulting in relatively minor (compared to the Bakken or Eagle Ford) proven reserves and production. The volumetrically most important of these plays are the oil-productive Bone Spring/Wolfcampian strata in the Permian Basin of west Texas and eastern New Mexico, the oil production from the mainly gas-prone Marcellus Shale in the Appalachian Basin of Pennsylvania and West Virginia, oil production from the mainly gas-productive Barnett Shale, and oil from the Niobrara Formation in Colorado, Kansas, Nebraska, and Wyoming.

The Eagle Ford Formation, which is arguably the most commercially successful shale oil development in the world, comprises a succession of fine-grained calcareous strata that underlie much of southern and southeastern Texas. The potentially productive area of the Eagle Ford Formation covers roughly 52,000 km^2 (20,000 mi^2) between the Mexican border and the Sabine uplift in East Texas in a band 80 km (50 mi) wide, 644 km (400 mi) long, and about 75 m (250 ft) thick. Throughout its productive area, the Eagle Ford is largely undeformed, gradually dipping into the subsurface from an arcuate band of outcrops near Del Rio, San Antonio, Austin, and Fort Worth to greater and greater depths. The Eagle Ford produces oil, gas, and natural gas liquids in various combinations, depending upon depth and thermal maturity. The formation probably enters the oil window (the temperature at which oil begins to be generated in significant quantities) at a depth of about 1,800 m (5,906 ft). The Eagle Ford is most oil-productive between about 2,400 and 3,700 m (7,874 and 12,139 ft). At greater depths production becomes increasingly gas-rich. Natural gas has been produced from the Eagle Ford at depths as great as 5,500 m (18,000 ft). Fundamental to the success of large-scale operations in the Eagle Ford is its great lateral continuity. It lies flat enough to run long horizontal well bores (Figure 3.3-4). Over large distances it dips very gradually, allowing for highly consistent well construction across a large area (Figure 3.3-5). Consistent, repeatable well construction, stimulation and production over large areas are key to profitable source rock production.

Figure 3.3-4. Schematic of a horizontal well with multi-stage hydraulic fractures superimposed on a road cut in the Eagle Ford Formation, west Texas (public domain image, courtesy of Halliburton 2013). The curved black line originating at the left represents a well bore turning horizontal. Potential locations for hydraulic fractures are indicated with vertical black lines. The yellow lines indicate depositional layers. The schematic demonstrates the lateral continuity of the Eagle Ford Formation, which lends itself to industrial-scale drilling of extended-reach horizontal production wells with multi-stage hydraulic fractures.

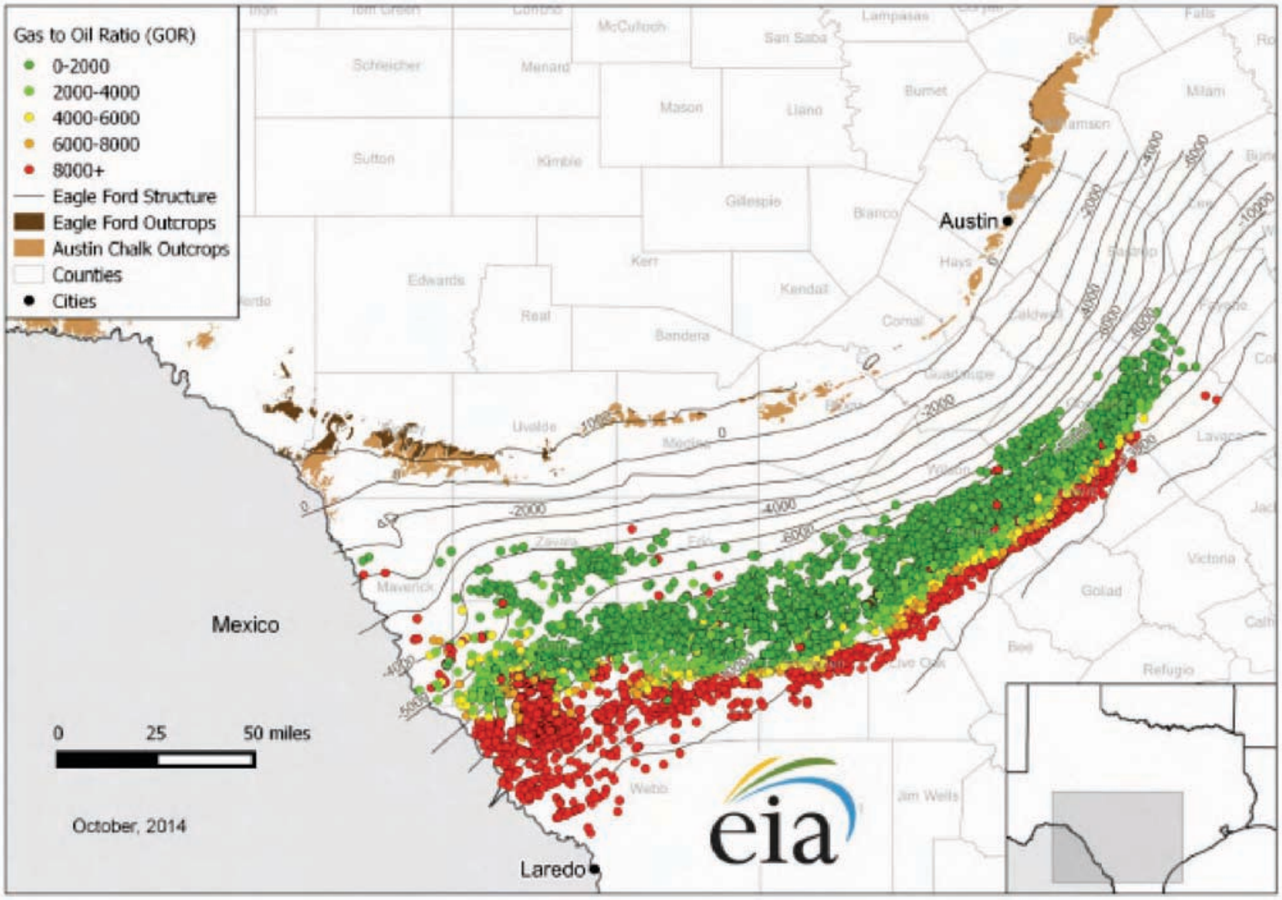


Figure 3.3-5. Structure map showing depth to top and initial gas oil ratio of wells producing from the Eagle Ford Formation as of October 2014. The GOR (gas-oil ratio) values shown are the amount of natural gas produced (standard cubic feet) per barrel of oil. Image from EIA, 2014.

According to the Texas Railroad Commission (TRRC) Petrohawk Energy drilled the first Eagle Ford well in 2008. The discovery well was directionally drilled with approximately 975 m (3,200 ft) of lateral displacement at a total depth of 3,396 m (11,141 ft.). The well initially flowed 215,208 m^3 (7.6 million cubic feet) of gas per day. As of December 4, 2014 the TRRC reported that 7,334 oil wells and 3,786 gas wells were on schedule[1] with a further 6,565 permitted locations representing pending oil or gas wells (Figure 3.3-6). In 2008, Eagle Ford oil production was a mere 56 m^3 (352 barrels) per day, but in

1. "On schedule," or "on proration schedule," is a term the TRRC uses to refer to wells that are in their lists as actively producing or plugged. It excludes wells that are shut in or are not yet producing.

September 2014 the TRRC reported that Eagle Ford oil production exceeded 148,494 m^3 (943,000 barrels) of oil per day during the period of January through September 2014. According to the Oil and Gas Journal, more than $13 billion dollars were invested in Eagle Ford production in 2013, with 260 rigs drilling about 300 wells per month (Oil and Gas Journal, 2015).

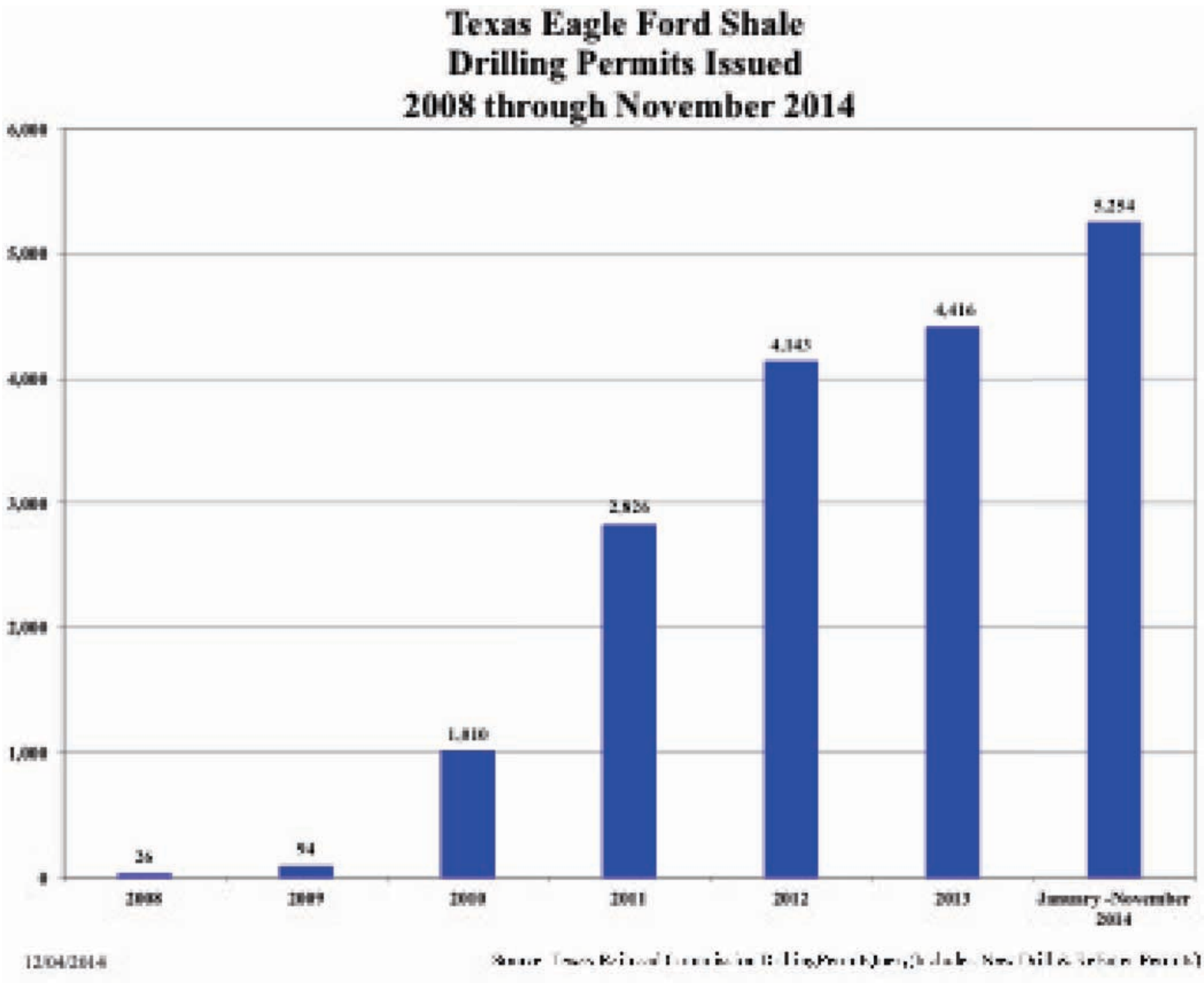


Figure 3.3-6. Texas Eagle Ford drilling permits issued by the Texas Railroad Commission between 2008 and November 2014. Image courtesy of the Texas Railroad Commission (2015).

3.3.7. What is the Potential for Production from Source-Rock (Shale Oil) in California?

The Monterey is present in large portions of many of the Tertiary[2] sedimentary basins of California, but its potential for production as a source-rock system (shale oil) reservoir has not been demonstrated. The basic physical requirements for productive shale oil reservoirs are quite specific; the Monterey may meet these requirements in certain, restricted areas of its geographic distribution, as discussed in Section 3.3.10, "The Geographic Footprint of Thermally Mature Monterey Source Rock in California."

Highly productive source-rock (shale oil) systems share several physical/geological characteristics; some are displayed by Monterey Formation source rocks, as summarized in Table 3.3-2. These characteristics are as follows:

1. High concentration of Type II (marine) kerogen
2. Thickness of highly organic-rich strata in excess of 20 meters.
3. Thermal maturity for oil (%R_o[3] of 0.8 to 1.3)
4. Abnormally high pore-fluid pressures (overpressuring, above a normal water pressure gradient)
5. Brittle[4] lithology capable of sustaining natural or induced fractures
6. Simple tectonic history and minimal structural complexity
7. Retention of producible hydrocarbons

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2. Technically, the International Commission on Stratigraphy no longer formally recognizes the term "Tertiary." The time period covered by the Tertiary is now referred to as the Paleogene and Neogeone, but for simplicity, we will refer to this period as the Tertiary. A full geologic timeline is provided in Appendix 3.B.

3. Ro stands for vitrinite reflectance in immersion oil, an optical microscopic measure of thermal maturity first developed by German coal petrographers. Vitrinite is a particular type of organic particle commonly found in coals and shales, which becomes increasingly reflective to incident light with greater temperature exposure. For this reason, vitrinite reflectance, or % Ro, is a commonly used measure of the time-temperature exposure of the organic matter in source-rocks

4. A material is brittle if, when subjected to stress, it breaks rather than deforms. In fine-grained rocks, brittleness is typically imparted by a significant content of silica or carbonate minerals and a relatively low content of clay minerals such as illite or kaolinite, which deform readily under stress and do not, in general, sustain fractures.

Table 3.3-2. Summary of seven characteristics of productive source rocks, the status of data availability on the Monterey Formation, and our evaluation of whether large portions of the Monterey are likely to display this characteristic.

	Data available on Monterey formation?	Large portions of Monterey display this characteristic?
High concentration of Type II (marine) kerogen	Yes	Yes
Thickness of highly organic-rich strata in excess of 20 meters.	Yes	Yes
Thermal maturity for oil (%R_o of 0.8 to 1.3)	Yes	Yes
Abnormally high pore-fluid pressures (overpressuring)	Limited	Likely
Brittle lithology capable of sustaining natural or induced fractures	Limited	Likely
Simple tectonic history and minimal structural complexity	Yes	No
Retention of producible hydrocarbons	Limited	Unlikely

3.3.7.1. High Concentration of Type II Kerogen

Parts of the Monterey that are highly enriched in marine kerogen are known to be prolific petroleum source rocks (Isaacs, 1989; Isaacs, 1992; Peters et al., 2013; Peters et al., 2007; Tennyson & Isaacs, 2001). According to Graham and Williams (1985), shales of the Monterey in the San Joaquin Basin have TOC concentrations ranging from 0.40 to 9.16 percent by weight (wt. %), with a mean value of about 3.43 wt. %. Isaacs (1987) reported TOC concentrations ranging from 4 to 8% from Monterey shales collected in the Santa Maria Basin and along the Santa Barbara coast, with highest TOC values in the phosphatic shales of the middle Monterey. In the Los Angeles Basin similar Monterey-equivalent phosphatic shales (locally named the Nodular Shale) have from 2 to 18% TOC, and average about 4% (Jeffrey et al., 1991; Hoots et al., 1935). Many of these measured values are well in excess of the 2 wt. % average TOC believed to be the necessary minimum concentration for a commercially successful source-rock reservoir.

3.3.7.2. Thickness of Organic-Rich Strata

In wells and outcrops along the Santa Barbara coast and in the adjacent Santa Maria and Santa Barbara-Ventura Basins, TOC-rich shales are more than 100 m (328 ft) thick. In the Los Angeles Basin, west of the Central Syncline, the phosphatic Nodular Shale is 50 to 100 m (164 to 328 ft) thick (Isaacs 1980). In the southwestern San Joaquin Basin, where the entire Monterey is more than 1,830 m (6,000 ft) thick, it contains four major shale sequences: the Gould, Devilwater, McDonald, and Antelope shales (Mosher et al. 2013), each of which probably contains net thicknesses of tens of meters of strata having concentrations of organic matter sufficient for consideration as possible source-rock reservoirs.

3.3.7.3. Thermal Maturity

Two variables determine where, when, and at what depths source rocks become thermally mature: (1) the local geothermal gradient (the rate at which temperature increases with depth) and (2) the reaction kinetics - the rates at which various sedimentary organic compounds crack to release hydrocarbons when heated. The Monterey Formation is known to be in the oil window in the deep parts of most major petroleum basins in California, but the geothermal gradient varies greatly from basin to basin (e.g., Jeffrey et al. 1991). Because the reaction kinetics of Monterey source rocks remains somewhat uncertain, the locations of thermally mature Monterey are also to some degree uncertain (Tennyson & Isaacs, 2001). Nevertheless, much has been learned in recent decades and the depth range of the Monterey oil window is generally known in the most petroliferous basins. In Appendix 3.A, we present maps of the thermally mature sections of the Monterey.

3.3.7.4. Abnormally High Pore-Fluid Pressures

Commercially successful shale oil developments have generally been in areas where the target formations display fluid pressures in excess of the hydrostatic pressure of water (the pressure in a column of water due to the weight of the fluid above it). Both the highly productive areas of Bakken/Three Forks (Sonnenberg et al., 2011) and Eagle Ford Formation (Hentz & Ruppel, 2011) display abnormally high fluid pressures. Most commercially successful shale gas plays, such as the Barnett Shale in the Fort Worth Basin and the Fayetteville Shale in the Arkoma Basin, also exhibit abnormally high fluid pressures.

In California, few wells have penetrated thermally mature source rock intervals, but abnormally high fluid pressures are indicated by certain deeply drilled wells. In the San Joaquin Basin, wells drilled near Lost Hills for deep gas resources, encountered extremely high fluid pressures at the depths where source-rock intervals are believed to be thermally mature. In the Los Angeles Basin, the American Petrofina Central Core Hole No. 1 (Redrill) demonstrated abnormally high pore fluid pressures below about 18,000 feet, presumably related to hydrocarbon generation in Monterey-equivalent source rocks at greater depths (Wright, 1991).

3.3.7.5. Brittle Lithology

The remains of diatoms (silica-rich phytoplankton) are an important component of the Monterey. The physical properties of diatomaceous deposits change systematically during burial as a result of increasing temperature: Non-crystalline “Opal-A” diatom frustules are first transformed into crystobalite-type crystallinity “Opal-CT” and at higher temperatures to microcrystalline quartz chert (Isaacs, 1981). This temperature-controlled mineralogical transformation is accompanied by significant shifts in porosity, permeability, elasticity, and brittleness. As a result, certain Monterey lithologies, such as chert, porcelanite, and siliceous mudstone, are particularly susceptible to fracturing (Hickman & Dunham, 1992; Isaacs, 1984). Although by no means certain, it seems reasonable to postulate that the highly organic-rich source-rocks of the Monterey in the Los Angeles, San Joaquin, and other basins are interbedded with brittle rocks that could sustain natural or induced fractures and, therefore, might support petroleum production.

3.3.7.6. Simple Tectonic History and Minimal Structural Complexity

In comparison to the mid-continent settings where most commercially successful shale plays have been developed, California basins exhibit extreme structural complexity owing to their tectonic setting along the active continental margin of North America. In the Williston Basin where the Bakken/Three Forks production has been developed, and in the Gulf Coast area of southern Texas, where the Eagle Ford shale production has been demonstrated, productive formations are continuous and essentially undeformed for tens or hundreds of kilometers. The petroleum producers exploit this lateral continuity by drilling thousands of similar long-reach horizontal production wells within the target formation. In contrast, the richest petroleum areas of California are located in tectonically active settings and exhibit extremely complex faulting and folding, and highly discontinuous formations, which pose technical challenges to those who would wish to develop continuous-type plays. Whereas operators in southern Texas can dependably predict the depths and thermal maturities of Eagle Ford strata over distances of more than 400 km (49 mi), in California basins it is difficult to predict formation characteristics over distances of even a few hundred meters.

Highly variable lithology, combined with temperature-dependent silica phase transitions (El Shaari et al., 2011), and complex tectonic settings, set the Monterey apart from most other source-rock systems (e.g., Wright, 1991; Ingersoll and Rumelhart, 1999). This inherent stratigraphic, mineralogical, and structural complexity will make it challenging to discover and develop source-rock oil in California, as evidenced by the largely negative results of deep drilling in the San Joaquin Basin (Burzlaff and Brewster, 2014). Closely spaced faults or folds disrupt the reservoir to such an extent that vertical well success would be unlikely. In any event, this development will only be economic with very high oil prices with current technology. Because of its extreme variability, effective hydraulic stimulation methods would need to vary significantly over short distances in various portions of the Monterey (El Shaari et al., 2011). For these reasons, the techniques and technologies successfully employed in Texas, North Dakota, and Pennsylvania where many similar long-reach horizontal wells are drilled over large areas cannot be simply copied for development of the Monterey (e.g., El Shaari et al., 2011).

3.3.7.7. Retention of Producible Hydrocarbons

In the Bakken/Three Forks formations in the Williston Basin, in the most productive areas of the Eagle Ford in south Texas, and in most other highly productive shale plays, significant volumes of oil and gas have been generated and then retained in the source rock over long periods of geological time. In contrast, in highly productive California basins, oil from the Monterey has apparently been effectively expelled to migrate and accumulate in conventional traps of the major oil fields. The complex tectonic history of sedimentary basins in California and the extensive presence of natural fractures in the siliceous Monterey mudstones seem to have facilitated the efficient expulsion and migration of oil generated in the basin depocenters via higher-permeability fracture and fault pathways to the producing conventional fields. Therefore, the amount of free hydrocarbons retained within the thermally mature Monterey source rocks is uncertain, and lack of oil retention is a significant risk to potential Monterey shale oil production.

3.3.8. Uncertainties Surrounding the Monterey Formation as a Petroleum Reservoir

The lithological variability of the Monterey, its diverse rock types, its vertical and lateral heterogeneity, and its mineralogical transformations resulting from silica mineral phase changes during burial make it challenging to predict its reservoir rock properties in advance of drilling. Superimposed on its sedimentological and stratigraphic heterogeneity is the structural complexity of many California basins resulting from their tectonic setting on an active continental plate margin. These complexities, which are inherent to the Monterey, result in uncertainty that is not easily reduced.

In spite of careful geochemical work (Isaacs and Rullkötter, 2001), the rate at which Monterey organic matter is converted to petroleum liquids (reaction kinetics) remain incompletely understood. For this reason, the precise depths and locations where organic-rich Monterey rocks are actively generating oil and gas are still difficult to predict with certainty. Moreover, these depths vary greatly from basin to basin.

The geological complexities of the Monterey and its source rocks are sure to make widespread production technically difficult. The successful shale plays, which have been transforming the physical and economic landscapes of Texas and North Dakota, now depend upon industrial-style drilling programs, in which hundreds or thousands of horizontal wells, each extending laterally for long distances, are efficiently drilled in rapid succession, using similar techniques and yielding comparable volumes of produced hydrocarbons. The lithological, structural and geochemical complexities of the Monterey make the performance of such long-reach horizontal wells difficult or impossible to predict. Closely spaced vertical wells are an alternative, but they, too, suffer from the highly variable rock properties encountered in the Monterey Formation in the subsurface.

Source-rock formations are generally low-permeability, and consequently require stimulation to allow hydrocarbons to flow to the well (King 2012). Successful shale plays in Texas and North Dakota employ multi-stage hydraulic fracturing in tandem with long-reach horizontal wells (Bazan et al., 2012; Pearson et al., 2013). The stimulation methods that could be used on the Monterey shale are not well understood at this point. Matrix acidizing or hydraulic fracturing could be used depending on the local formation characteristics, in particular, natural fracturing. If there is sufficient permeability from natural fractures, acidizing may be the preferred method, otherwise hydraulic fracturing is more likely to be used (El Shaari et al., 2011). Moreover, the social and economic climate in much of California does not, in general, encourage widespread drilling in previously undeveloped areas.

In the final analysis, only exploratory and development drilling can significantly reduce the range of possible development scenarios. However, at present the quantity, quality, and distribution of potentially recoverable source-rock resources are poorly constrained and it is extremely difficult to set policy or plan for mitigation against possible environmental impacts when we are uncertain if, where, and with what technology source rock would be developed.

3.3.8.1. The EIA Assessment of the Monterey/Santos Shale Oil Play

To our knowledge, no systematic geology- or engineering-based assessment of either in-place or technically recoverable petroleum resources in unconventional, source-rock systems (shale oil) of California has ever been published. However, much of the media focus and public concern about hydraulic fracturing and the potential for widespread development of shale oil resources in California stem from two point estimates of technically recoverable resources released by the DOE Energy Information Administration (EIA). As part of a larger special report entitled "Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays", the EIA announced in 2011 that the "Monterey/Santos Play" contains some 2.4 billion m^3 (15.4 billion barrels) of technically recoverable "shale oil." This estimated recoverable volume, which represented the majority of U.S. shale oil resources reported by EIA, was considerably larger than the reported recoverable resources attributed to two most active and productive shale oil plays in North America: the Bakken/Three Forks formations in the Williston Basin and the Eagle Ford Formation of Texas. Just three years later, in their Annual Energy Outlook for 2014, the EIA reported the technically recoverable oil in the same "Monterey/Santos play" to be 95.4 million m^3 (0.6 billion barrels). Both estimates were supposedly based on a calculation involving the geographic extent of the play, number of producing wells per unit area, and oil production per well (Table 3.3-3). Given the position of authority from which EIA reports energy information and the wildly differing values of these two point estimates, it is not surprising that these estimates have been the source of much confusion and consternation.

Neither the methodology nor the sources of input data were documented in sufficient detail to adequately evaluate these deterministic estimates. However, the reduced estimates of 2014 were explained as follows: "Key factors driving the adjustment included new geology information from a U.S. Geological Survey review of the Monterey shale and a lack of production growth relative to other shale plays like the Bakken and Eagle Ford" (U.S. EIA, 2014b).

Box 3.3-3: Scientific Estimates and the Incorporation of Uncertainty

A “deterministic” or “point” estimate generates a single result. This is in contrast to a probabilistic estimate, which will generate a range of outputs and associated degrees of confidence. An example of a probabilistic resource estimate is the USGS estimate of additional recoverable oil from nine of the largest oil fields in the San Joaquin Basin (Tennyson et al., 2012). The USGS estimated with 95% confidence that at least 572.4 million m^3 (3.6 billion barrels) of additional oil could be recovered, and 50% confidence that 1 billion m^3 (6.3 billion barrels) of additional oil could be recovered. A common-sense example of deterministic estimates versus probabilistic interval estimates would use a six-sided die as an example. An example of a deterministic estimate of the output from rolling a die is to take the mean value of the six sides and estimate the likely result to be 3. A probabilistic interval estimate would say that the result can range from 1 to 6 and we can say with 100% confidence that the value will be at least 1, 83% confidence that the value will be at least 2, and so forth.

Table 3.3-3. Comparison of model parameters for the 2011 U.S. EIA/INTEK and 2014 U.S. EIA estimates of technically recoverable oil from the "Monterey/Santos play."

Model Parameters	US EIA/INTEK (2011)	US EIA (2014)
Areal extent (mi^2)	1,752.0	192.0
Wells/mi^2	16.0	6.4
Production/well (Kbbl[5] oil)	550.0	451.0
Total recoverable oil (Bbbl[6] oil)	15.4	0.6

While the EIA estimates cannot be effectively evaluated on the basis of the information provided, several issues concerning these estimates warrant comment.

1. Given the highly uncertain geological and technical situation surrounding direct recovery of oil from California source rocks, it seems crucial that any credible estimate must define exactly what is being evaluated. In the case of the Monterey Formation, which is both a source rock and, in places, a reservoir for migrated petroleum, it is particularly important that the scope of the assessment be made clear. The EIA routinely reports so-called "tight oil" production from California, but makes no distinction between migrated "tight oil" and source-rock system shale oil. This lack of clarity makes their estimates nearly impossible to interpret unambiguously.

2. The great uncertainty inherent in an unproven play concept such as shale oil production in California makes it imperative that any credible estimate be clearly defined in terms of probability. In other words, is the estimate a mean resource value? Is it a median estimate? If so, what is the uncertainty surrounding the estimate? Or, is it a maximum value? Or something else? From the EIA report it is impossible to tell.

3. The U.S. EIA purports to provide estimates of technically recoverable resources, but technical recoverability can only be meaningfully evaluated in terms of the application of a particular technology. In the case of the Monterey source rocks, no appropriate production technology has yet been identified, so a deterministic estimate of technical recoverability is highly speculative. The 2014 EIA estimate seems to assume development with horizontal wells, but no technology is specified for the 2011 estimate.

4. The confusion surrounding the range of uncertainty in shale oil resources of California could be clarified by a systematic, geology- and engineering-based assessment of in-place and technically recoverable resources in the source-rock systems of each of the principal petroleum basins. Such an assessment should be

5. Kbbl = kilobarrels or a thousand barrels of oil.

6. Bbbl = a billion barrels of oil.

probabilistic rather than deterministic, and include an evaluation of the principal sources of uncertainty, with clearly explained methodology and sources of input data. The USGS is said to be working on such an assessment, but nothing has yet been published.

3.3.8.2. Recommendation: Comprehensive Peer-Reviewed Probabilistic Resource Assessment of Continuous-Type (Shale) Oil Resources in California

As of now, the range of possibilities for development of shale-oil type resources is unconstrained. Consequently the State of California has an insufficient understanding of the resource situation to understand or develop policy for future development of Monterey source rock. Therefore, the immediate need is for a systematic resource assessment. Such an assessment would provide an integrated set of geology- and engineering-based probabilistic estimates of the resource endowment, technical recoverability, and (possibly) unit costs for development of continuous-type source-rock or shale oil resources in California. The assessment of resource endowment gives an understanding of the magnitude of the potential and provides a tool for prioritization of effort. The assessment of technically recoverable resources quantifies the volumes and uncertainties of resources that can be delivered given the application of specific technology and links the estimated resource with the types and intensities of technologies that would be involved possible development. Given that the technology that could be used to successfully develop the Monterey source rock is unknown, the range of possibilities of recoverable resources would cover the use of various technologies. A resource-cost analysis would add a measure of monetary value to the volumetric assessments, extend the geological uncertainty through to its impact on economic measures, and enable the assessment results to be used in economic models.

3.3.8.2.1. Basic Principles of Assessment

The proposed assessment should be designed to both meet the immediate need to constrain the uncertainties surrounding the measurement of the potential for petroleum production from source-rock systems, and be carried out within basic and certain standards of scientific credibility. These standards should include a careful statement of the problem to be addressed; clear specification of the desired deliverable output; peer review; transparent presentation of the exact methodology to be employed; open presentation of the input data, including data, their sources, and limitations; and a presentation of the assessment output, including the full range of probabilistic results. In many cases, the range of values and quantified uncertainty are more important than the estimates of the central tendency (such as the mean value). Finally, the assessment should be reproducible within the specified uncertainties by any qualified scientific group attempting to replicate the study.

3.3.8.2.2. Scope of the Assessment

The study should include all continuous-type source-rock system (shale-oil) resources in the Tertiary Basins of California. This initial step, the geological screening of potentially productive areas within the state, has already been undertaken in Volume I Chapter 4 of this SB4 report, and is reiterated in this Case Study.

The assessment could be completed by organizations with proper staffing and experience. Organizations with a record of producing similar assessments include the U.S. Geological Survey, which has long-experience in such quantitative assessments. An example is the 2013 USGS study of the technically recoverable resources in the Bakken/Three Forks petroleum system of the Williston Basin (Gaswirth et al., 2013). The Texas Bureau of Economic Geology has also completed high-quality resource assessments, as has the Norwegian Petroleum Directorate, and the Geological Survey of Canada, among others.

3.3.8.2.3. Components of the Analysis

The recommended assessment would need to comprise several modules, each of which would have specific deliverables and timeframe, as follows:

1. *Geological Screening:* As discussed above, an initial basin screening is included in Volume I, Chapter 4, and reiterated in this Case Study. The potentially productive basins identified by the screening process are: Cuyama, Los Angeles, Salinas, Santa Barbara-Ventura, San Joaquin, and Santa Maria.

2. *Geological interpretation:* The geological framework of the potentially productive petroleum basins determines the occurrence, distribution, and quality of yet-to-find and yet-to-be-developed continuous-type resources. Therefore, development of a geological model for hydrocarbon occurrence in each basin is the starting point for assessment.

3. *Play and Sub-Play Identification:* Identification, geological description, and specification of each play and sub-play for analysis. This activity would include preparation of narrative summaries, mapping play-concept boundaries, and stratigraphic specifications of play and sub-play extents.

4. *Industry/Public Meeting:* Convene an open forum for description and discussion of assessment strategy, methodology, and play concepts to be evaluated during the assessment project. This would be a solicitation of external comments and recommendations.

5. *Assessment of the State of Nature:* Conduct a probabilistic assessment of the total resource endowment, also known as the original oil in place (OOIP), of each specified play and or sub-plays identified within each of the petroleum basins.

Such an assessment identifies those areas of greatest resource potential and therefore their likely desirability for resource exploitation.

6. *Assessment of Technically Recoverable Resources:* Probabilistic geological and engineering assessment of total recoverable resources of each play and sub-play for specified technical development model(s). Probabilistic estimates of technically recoverable resources are fundamental to further use of the assessments, but must of necessity include an engineering analysis, based upon the geological models of the plays and sub-plays in order to specify technological applications that would be required to develop the plays/sub-plays.

7. *Appraisal of Resource Costs:* The technical model used in the assessment of technically recoverable resources might include an analysis of the types of wells and related infrastructure required for development of the postulated shale oil resources. This technical evaluation is a link between the geological uncertainty and the financial costs and environmental consequences of development of each play and sub-play.

8. *Aggregation and Allocation of Results:* Depending upon the specifications of the study, results would be aggregated to totals for each play or basin, and, if desired, allocated to geographic subsets such as water districts, ecological regions, etc.

9. *Preparation of Final Report:* Final report of methods, input, and results

10. *Further Refinement Using Empirical Data:* At present, any assessment of the potential for development of California source rock reservoirs will be highly uncertain because of the lack of empirical data. If private companies decide to drill wells in California source rock, publicly reported data from those wells could be used to revisit the results and reduce the uncertainties of the resource assessment. See section 3.3.6., “Identifying production from source rock,” for further details on how information on production is reported to the state.

3.3.9. Exploratory Drilling in Monterey Source Rock to Date

Production of a new reservoir begins with surveys to identify areas and depths of resource potential, then exploratory drilling, followed by appraisal drilling, then development, and finally, production. Each step must be successful to proceed with the next. Information on exploratory drilling is likely to be held confidential by the operators. Records for exploratory wells are expressly permitted confidential status upon request of the operator, meaning full records are not reported to the state (California Public Resources Code Section 3234). However, there is some publicly available documentation of exploratory drilling from source-rock systems in California. To our knowledge, none of these exploratory activities have achieved levels of production sufficient to justify commercial development.

Quiet exploration for development opportunities in source-rock systems has been underway for years, as various companies have developed land positions and conducted the background geological studies necessary to make exploration and development investments. In its 2011 shale oil report, the U.S. EIA stated that, on the basis of acreage positions, at least five companies (Berry Petroleum (now Linn Energy), National Fuel Gas, Occidental (now California Resources Corporation), Plains Exploration (now Freeport-McMoRan Inc.), and Venoco had active exploration efforts looking for shale oil opportunities in the Monterey. No doubt other companies have been considering Monterey source-rock exploration as well.

Although the companies are understandably quiet about their commercial intentions, the next stage in shale-play evaluation, exploratory drilling, is probably also already underway, as indicated by deep drilling programs in the vicinity of thermally mature source rocks in the San Joaquin and the Los Angeles Basins. Of the two, the San Joaquin has had, by far, the most attention devoted to it.

Venoco drilled a number of San Joaquin Basin wells targeting zones at depths between 1,830 and 4,270 m (6,000 and 14,000 ft), possibly in attempts to test source-rock intervals (Durham 2010). As part of the effort, Venoco drilled several deep wells in Semitropic oilfield that evidently targeted the Monterey. One of them, the Scherr Trust et al. 1-22 (API 03041006), which began drilling in December 2010, went to 4,243 m (13,921 ft) vertical depth in an attempt to test the Monterey, which was perforated and fractured at depths of 3,808-3,813 m (12,495-12,510 ft). Flow tests produced non-commercial amounts of oil (DOGGR, 2015).

Attempts to develop the Eocene Kreyenhagen source rocks have had similar results. Although an industry report by Petzet (2012) concerning testing of hydraulic fracturing and oil production in the Kreyenhagen indicated the presence of mobile oil, no further development or oil production from the Kreyenhagen was indicated.

Burzlaff and Brewster (2014) reported that there were 501 wells drilled between 2009 to 2013 to test unconventional oil reservoirs in the Monterey. However, of the 495 that were identified by field, none had depths in the range of thermally mature source rock for the basin where they were located. Six wells were listed as “any field” and could not be associated with a specific basin. These six were drilled by Venoco and had depths in the 2,734 – 3,048 m (9,000 – 10,000 ft) range, which is potentially deep enough to reach thermally mature source rock in some California basins. The 501 wells had average initial production rates of 12 to 24 m^3 (75-150 barrels) of oil per day, with expected ultimate recoveries of (EUR) of 3,200–4,000 m^3 (20,000–25,000 barrels) for wells in fields on the west side of the San Joaquin Basin and 14,000–16,000 m^3 (90,000–100,000 barrels) for wells in fields on the east side of the Basin. This well performance was evidently considered insufficient for economic production, as no reserves were reported and no production was established from the wells. However, for comparison, Dana van Wagener of DOE-EIA reported that horizontal production wells in the Eagle Ford Formation of

Texas have roughly comparable average EURs, ranging from 12,719 - 53,102 m^3 (80,000 to 334,000 barrels), depending upon the county in Texas (van Wagener, 2014).

Most of the area of thermally mature source rocks lies outside existing oil field boundaries (see Figure 3.3-7). One of several notable exceptions is Elk Hills oil field, where Miocene and older source rocks are thought to be in the oil window at depths of 3,930–5,850 m (12,900–19,200 ft) (Magoon et al., 2009). In order to evaluate the prospects for hydrocarbon production from deep intervals at Elk Hills, the U.S. Department of Energy (DOE) drilled three wells to depths of 5,569–7,455 m (18,270–24,426 ft) (Fishburn, 1990). The wells did not result in commercial production, but they did have shows of oil and gas. Cores of shale recovered from the Eocene Kreyenhagen Formation below 4,785 m (15,700 ft) in the 987-25R well, exuded oil and gas from fine fractures.

Another potential deep San Joaquin Basin target is shale that has been displaced due to deep thrust faulting and folding, such as that described by Wickham (1995) at the Lost Hills field. Based upon a subthrust play developed for the East Lost Hills, several exploratory deep wells were drilled into the footwall (the rocks below the fault). In 1998 the first well drilled encountered high gas pressures at 5,377 m (17,640 ft), well control was lost and the rig was engulfed in flames. It took more than six months to bring the well under control (Schwochow, 1999).

When and if the results of geological investigations and initial exploratory drilling warrant, the most likely next steps in source rock reservoir development would entail demonstrating proof-of-concept with relatively small-scale program of production wells in geographically select areas. Such development would probably begin with the drilling several additional exploratory wells that the potential operators would use to (1) determine the reservoir parameters of the target formations and to (2) prepare a development plan for production.

Commercial production would not begin until successful production had been demonstrated by the exploration wells and by geographically restricted production demonstrations. At that point, if operators had the appropriate permits, they would begin a development program in the area of the target formation found to have potential. This could expand to a large number of wells if (a) there is lateral continuity of an interval with attractive properties, and (b) the production response from initial development wells is economic. A successful beginning of large-scale production would presumably be announced with fanfare at some point, as it would be a boon to the net value of the company. We found no evidence that production in Monterey source rock has moved beyond the exploratory stage.

3.3.9.1. Identifying Production from Source Rock in Public Records

Tracking exploratory activity in source rock would be useful for allowing state agencies and the public to recognize and plan for new oil and gas development. It is not straightforward to identify a comprehensive list of exploratory wells in source rock from the public records maintained by DOGGR. There are four key characteristics that one would look for to identify an exploratory well in source rock:

1. Completion with well stimulation, either hydraulic fracturing or matrix acidizing;

2. True vertical depth (TVD) great enough to potentially reach thermally mature source rocks;

3. Production from a formation that could potentially generate oil or gas when exposed to sufficient heat and pressure (these formations are listed in Table 3.3-4), and

4. Confidential status (exploratory wells are typically filed under confidential status, as defined in California Public Resources Code Section 3234).

If a well meets all four of these characteristics, it may be exploring source rock; however, one would need information on the precise depth of thermally mature rock at those coordinates to definitely identify a well as producing from source rock.

The only place where information on the four characteristics is systematically compiled in a searchable format is in the Well Stimulation Disclosure Reports database, which compiles information on stimulated wells dating back to January 2014 (15 months before the writing of this case study).[7] Under the proposed final regulations on well stimulation, expected to go into effect July 1, 2015, the first characteristic (completion with stimulation) would be part of the public well stimulation disclosures, even for confidential wells. A well's confidential status would also be part of the public disclosures. However, true vertical depth and productive horizon would be held in confidence by the state until the information becomes public record (DOGGR, 2015b). A state agency with access to confidential information could search in the Well Stimulation Disclosure Reports (DOGGR, 2015c) for wells meeting the four criteria described above to track early evidence of source rock activity. Onshore wells are granted confidentiality for a two-year period, and offshore wells are granted confidentiality for a five-year period, with the possibility of extensions (California Public Resources Code Section 3234).

7. Information on TVD, production horizon/pool, and well completion and confidential status is mostly available in well records. The PDFs of well records are available through DOGGR's online well search database, including those of confidential wells, once confidential status has expired (DOGGR, 2015a). However, it is not possible to systematically perform a search based on the four characteristics of interest in the online database.

We performed a search in this database and found three stimulated wells[8] of sufficient depth and producing from the Monterey or Kreyenhagen, both potential source rocks, but these three wells were not filed as confidential. In fact, no confidential wells have been listed in the database to date. As a result we are skeptical that any well listed thus far in the well stimulation disclosures is an exploratory well. Most likely the three wells we identified, while quite deep, are producing from regions of the Monterey or Kreyenhagen that are shallower than thermally mature rock in that location. Information that would help one understand whether well is exploring a new formation includes (a) the location of the wells with respect to existing oil fields, (b) how close adjacent wells are located, and (c) the depths and intervals adjacent wells (or wells in the area) are completed in. One would expect an exploratory well to be either relatively distant laterally from any neighboring wells, and/or completed at a substantially different depth from nearby wells. The relevant information is available in the DOGGR online well record database (DOGGR, 2015a). Continued monitoring of the records in the stimulation disclosures would show if there is substantial interest and exploration of California source rocks.

Table 3.3-4. Potential source rocks (shales rich in total organic carbon). The pools listed below are those that could be positively identified in DOGGR's 2011-2014 production databases as shales rich in total organic carbon; when found below the top of the oil window, they are expected to generate hydrocarbons. Other pools listed in the database were not potential source rocks, or we had insufficient information to determine their status. Basin abbreviations: SJ = San Joaquin, SM = Santa Maria. Data from DOGGR (2014).

Pool Name	Basin	Field Name(s)
Antelope	SJ	Monument Junction
Antelope Shale	SJ	Asphalto
Antelope Shale/Carneros	SJ	Railroad Gap
Antelope Shale-East Dome	SJ	Buena Vista
Antelope Shale-West Dome	SJ	Buena Vista
Antelope/McDonald	SJ	Lost Hills
Fruitvale	SJ	Tejon, North
Kreyenhagen	SJ	Kettleman Middle Dome
McDonald	SJ	Belridge, South
McDonald-Devilwater	SJ	Cymric
McLure	SJ	Kettleman Middle Dome
Miocene-Oligocene	SJ	Wheeler Ridge
Monterey	SJ	Cymric
Reef Ridge-Antelope	SJ	Cymric
S Margarita-Fruitvale-Rd Mtn	SJ	Tejon

8. API numbers 02957574, 03120504, and 03052679.

Monterey Deep	SM	Orcutt
Monterey North Block	SM	Zaca
Monterey South Block	SM	Zaca
Monterey-Knoxville	SM	Guadalupe (ABD)
Monterey-Lospe	SM	Lompoc
Monterey-Pt. Sal	SM	Casmalia
Sisquoc-Monterey	SM	Barham Ranch

3.3.10. The Geographic Footprint of Thermally Mature Monterey Source Rock in California

Although the Monterey and its equivalents can be found throughout much of California, a potential Monterey source rock play is restricted to just the six basins with the largest proven oil reserves in the state. While the Monterey is a named formation in various Tertiary Basins (Figure 3.3-2), years of geological mapping and exploratory drilling demonstrate that thick successions of highly organic-rich Monterey strata at the appropriate levels of thermal maturation for active petroleum systems are only present in a handful of basins. These are the same basins that contain large conventional oil fields sourced from the Monterey: the Cuyama, Los Angeles, Salinas, San Joaquin, Santa Maria, and Santa Barbara-Ventura Basins (Figure 3.3-7, and for a detailed examination of the geological context of potential source-rock system developments in each of the basins, see Appendix 3.A). Because the Monterey is naturally highly fractured and releases much of the oil it generates, we infer that any basin with a prolific Monterey source rock would also have large pools of oil originating from the Monterey.

For a detailed examination of the geological context of potential source-rock system developments in each of the basins, see Appendix 3.A, “Source Rock Potential of Major Oil-Producing Basins in California.”

The maps of the footprint of potential Monterey source rock in Figure 3.3-7, and the supporting maps in Appendix 3.A, differ slightly from maps of potential source rock in Volume I, Chapter 4 in two ways. First, the maps of source rock in the San Joaquin basin in this chapter show a slightly larger area because they include all areas where the Monterey formation lies below the top of the oil window; the corresponding maps in Volume I, Chapter 4, show only portions in the oil window while excluding the lower regions in the gas window. Second, the maps of potential source rock in the Santa Maria and Cuyama Basins are somewhat larger in this chapter than in Volume I, Chapter 4. In this chapter we used a slightly shallower cut-off for the minimum depth of the oil window than in Volume I, Chapter 4. The cut-off points for the top of the oil window and supporting citations are given in Table 3.3-5. Our rationale was that we wished to evaluate the possible impacts within the largest reasonably defensible estimate of potential Monterey source rock.

Table 3.3-5. Characteristics of Monterey source rock in each of the six major oil-producing basins in California.

Basin	Estimated shallowest depth of thermally mature source rocks (m)	(ft)	Reference	Estimated surface area of Monterey formation in oil and gas window (km^2)	(mi^2)	Reference	Counties
Cuyama	2,500	8,200	Lillis (1994)	150	60	Lillis, 1994; Sweetkind et al., (2013)	San Luis Obispo, Santa Barbara
Los Angeles	2,400	8,000	Pitman (2014)	460	180	Wright, (1991); Gautier, (2014)	Los Angeles, Orange
Salinas	4,000	13,000	Menotti and Graham (2012)	220	80	Durham, (1974); Menotti and Graham, (2012)	Monterey, San Luis Obispo
San Joaquin (Antelope and McClure)	3,000	10,000	Magoon et al. (2009)	3,630	1,400	Magoon et al., (2009)	Fresno, Kern, Kings
Santa Maria	2,000	6,700	Tennyson and Isaacs (2001)	290	110	Tennyson and Isaacs, (2001); Sweetkind et al., (2010)	Santa Barbara
Santa Barbara-Ventura	4,600	15,000	Jeffrey et al. (1991)	1,100	420	Gautier, this chapter	Los Angeles, Santa Barbara, Ventura, Offshore

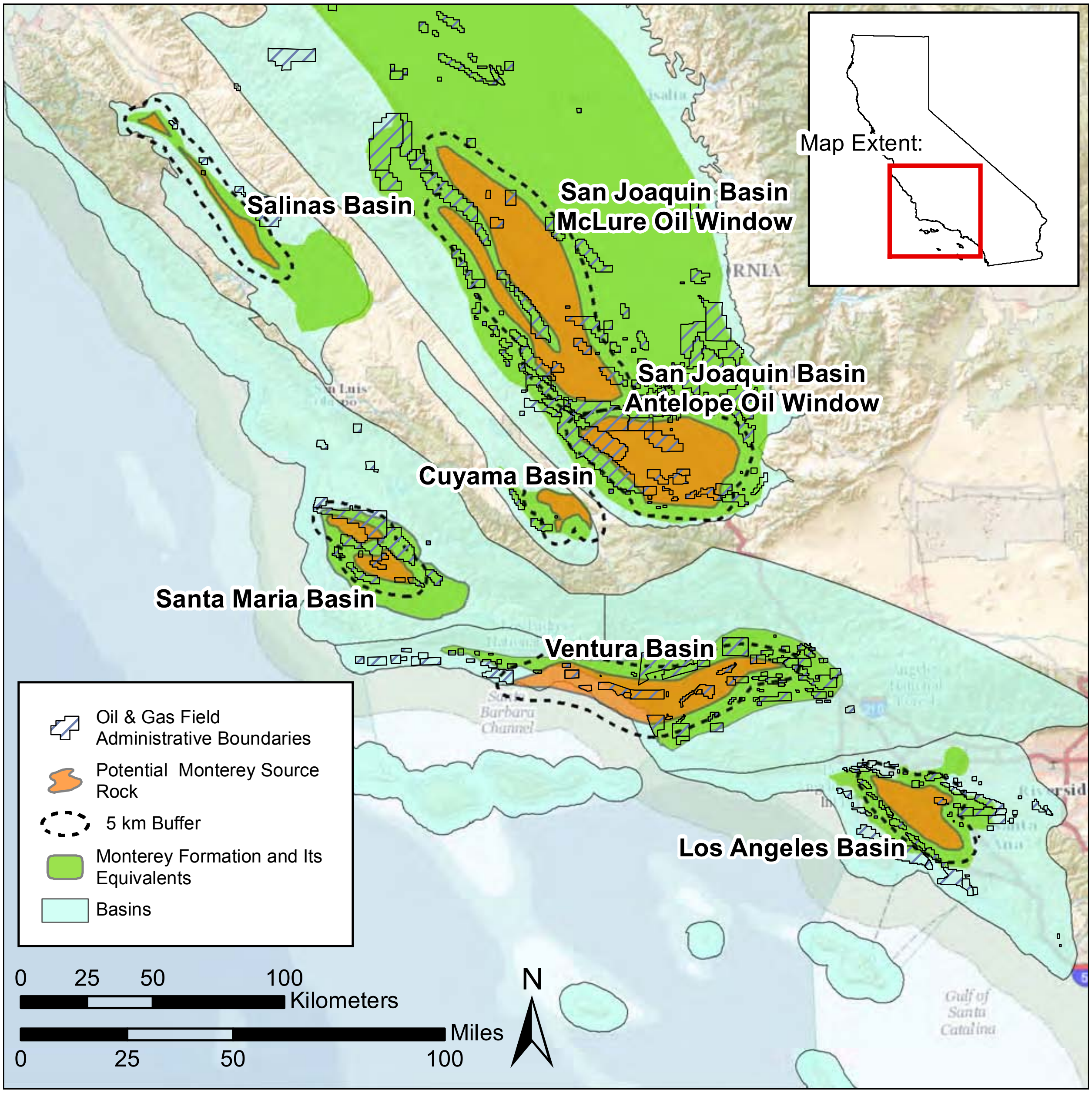


Figure 3.3-7. Extent of potential Monterey source rock in the six major oil-producing basins in California. The regions colored in orange indicate the areas overlying a maximum estimate of the portion of the Monterey that is deep enough to generate oil or gas. We added a five-kilometer buffer when assessing the area of potential environmental impacts to account for uncertainty in the true areal extent and on the assumption that impacts would extend beyond the boundaries of the source rock.

3.4. Potential Environmental Impacts of Well Stimulation in Monterey Source Rock

3.4.1. Overview of Potential Environmental Impacts of Well Stimulation in Monterey Source Rock

Large-scale development of source rock would most likely expand the location and quantity of petroleum production in the state, and make use of hydraulic fracturing and/or matrix acidizing. Consequently, we would expect development of source rock to have both direct and indirect impacts from well stimulation. Direct impacts are caused specifically and uniquely by the act of well stimulation, such as a hydraulic fracture extending into protected groundwater, accidental spills of fluids containing hydraulic fracturing chemicals or acid, or inappropriate disposal or reuse of produced water containing stimulation chemicals. These direct impacts do not occur in oil and gas production unless well stimulation has occurred. Well stimulation can also incur indirect impacts, i.e., those not uniquely attributable to well stimulation itself. A low-permeability reservoir such as Monterey source rock requires stimulation for economic production. Indirect impacts occur in all oil and gas development, whether or not the wells are stimulated. For example, disposal of produced water through underground injection may carry the risk of inducing an earthquake. If this produced water comes from a reservoir that cannot be produced without well stimulation, the injection of produced water (and associated seismic risk) would be an indirect impact of well stimulation. That is, injection of wastewater is not a unique impact of well stimulation, but well stimulation could enable petroleum production from Monterey source rock, and therefore increase the volume of wastewater injection in the state. We would expect development of Monterey source rock to result in an increase in quantity, and expansion in the geographic area, affected by the direct and indirect impacts of well stimulation.

Uncertainties about how Monterey source rock development would transpire, in addition to the data gaps in how current well stimulation affects the environment outlined in Volume II, prevent a thorough assessment of the potential environmental impacts.

Key Uncertainties about Monterey Source Rock Development:

1. What technology would be used (horizontal wells, hydraulic fracturing, and/or new innovations),

2. Density of wells and volumes of hydrocarbons produced per well,

3. Location and timeline of development,

4. How regulations, environment and demographics will have changed,

5. Probability of chance events (i.e. accidents).

Even with the availability of more comprehensive data on how Monterey source rock would be developed, it is not possible predict how the system is going to function in the future, considering the uncertainties around environmental impacts of well stimulation, and oil and gas in general, that were identified in Volume II. Accurate prediction of impacts would require adequately validated and calibrated models. Constructing such models is not possible with the current state of knowledge.

Although many factors about source rock development and its potential impacts are uncertain, it is still possible to identify the known environmental and demographic conditions in the vicinity of source rock, and impacts from source rock production that would differ from migrated oil production. Our intention in our survey of potential environmental impacts of Monterey source rock development is not to make detailed predictions about future impacts, nor to reiterate the generalities about potential impacts made in Volume II; rather, we focus on the environmental resources in the footprint of Monterey source rock to better understand the resources that could be impacted by development of the area.

3.4.2. Land Use and Infrastructure Development

Potential Monterey source rock can be found near areas already producing petroleum as of 2014 (Figure 3.4-1) – unsurprising, given that Monterey source rock is the origin of most of the oil found in California's migrated reserves. The footprint of potential Monterey source rocks can be divided into two categories: "brownfield," defined as having a well density of at least one well per square kilometer; and "greenfield," defined as areas with fewer than one well per square kilometer.

The categories of brownfield and greenfield can be further subdivided according to whether or not they are within current administrative field boundaries as defined by DOGGR. The vast majority of brownfield areas are within field boundaries, but some there are some areas with wells that fall outside administrative boundaries. Quite a bit of land within administrative boundaries is technically greenfield – that is, has less than 1 well per square kilometer.

Only 9% of the potential Monterey source rock footprint is brownfield – that is, has at least one well in a one-kilometer radius (Table 3.4-1). The area that falls within the administrative boundaries of an oil field is only somewhat larger – 16% of the potential Monterey source rock footprint.

Table 3.4-1. Percentage of potential Monterey source rock footprint; rows show portion in the brownfield category (defined as at least one well per square kilometer), and greenfield category (defined as fewer than one well per square kilometer). Columns show areas inside or outside currently designated administrative field boundaries. Total MSR = total Monterey Source Rock.

Designation	Well Density	Area Total (km²)	Area Total (%)	Area Inside Bounds (km²)	Area Inside Bounds (%)	Area Outside Bounds (km²)	Area Outside Bounds (%)
Brownfield	≥ 1	503	9	459	8	44	<1
Greenfield	< 1	5,364	91	495	8	4,869	83
Total MSR	all	5,867	100	954	16	4,913	84

However, even the portions of the footprint that are outside field boundaries are located near current oil fields: all of the footprint falls within 20 kilometers (12 miles) of the boundary of a currently designated oil field (Figure 3.4-1).

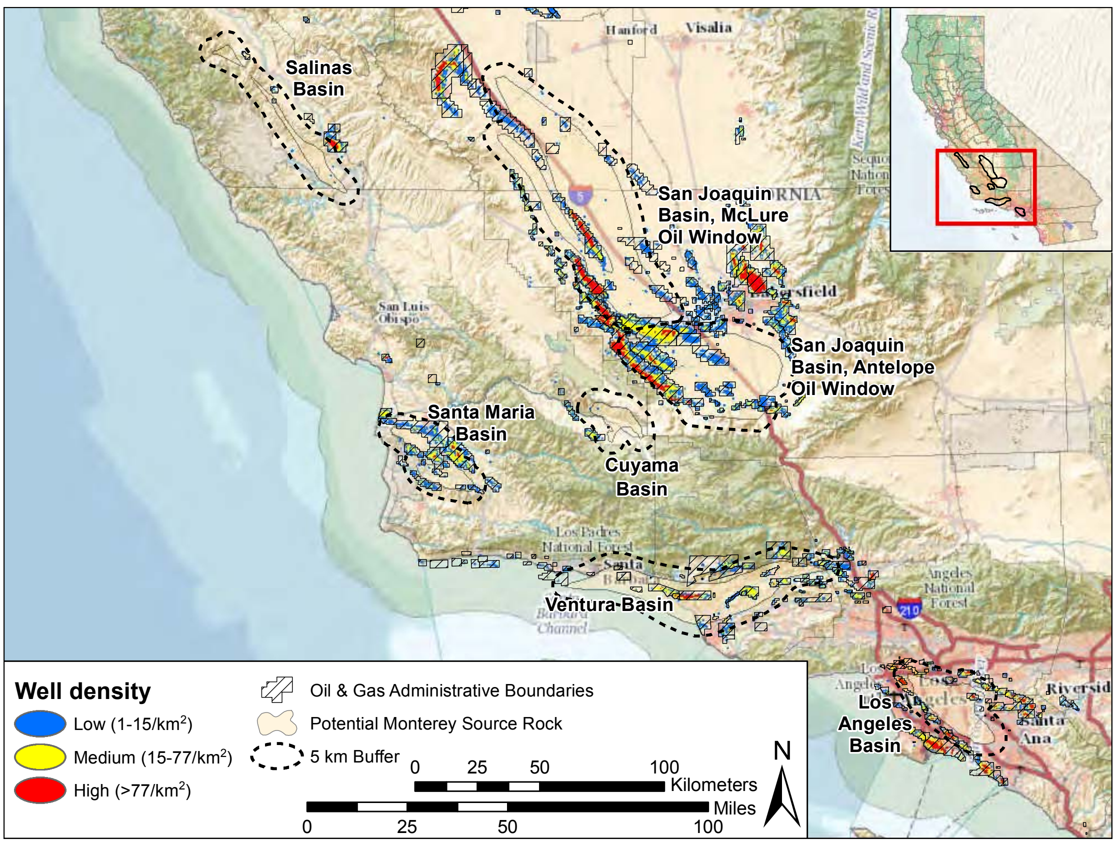


Figure 3.4-1. Oil fields, well density as of 2014, and potential Monterey source rock in California. While most area developed for oil and gas production is within administrative boundaries, some is not. Conversely, not all areas within field boundaries are developed for oil and gas and may be used for cities, farms, or open land.

The footprint of potential Monterey source rock plays is distributed over ten counties; eleven including the five-kilometer buffer. Table 3.4-2 shows the square kilometers of footprint in each county and, for comparison, the number of new and active wells identified in DOGGR's All Wells database as of March 2014. All counties with potential Monterey source rock have at least some new and active wells within their boundaries. The county with the greatest proportion of Monterey source rock is Kern County; it also is the county with 80% of new and active wells in the state.

Table 3.4-2. Area of potential Monterey source rock footprint by county. New and active wells from DOGGR All Wells database as of March 2014 (DOGGR, 2014a).

County	Over source rock		In 5 km buffer		Total Area	New & Active Wells	
	km²	%	km²	%	km²	wells	%
Fresno	78	1	177	3	255	3,356	3.8
Kern	2,629	45	1,723	28	4,351	70,615	79.3
Kings	927	16	647	10	1,575	222	0.2
Los Angeles	393	7	501	8	894	4,303	4.8
Monterey	218	4	822	13	1,041	1,100	1.2
Orange	62	1	142	2	204	1,161	1.3
San Luis Obispo	124	2	286	5	410	312	0.4
Santa Barbara	515	9	1,009	16	1,524	1,312	1.5
Tulare	0	0	3	0	3	91	0.1
Ventura	898	15	937	15	1,835	2,524	2.8
Other Counties	0	0	0	0	0	89,039	4.5
Grand Total	5,845	100	6,247	100	12,092	84,996	100.0

The proximity of potential new Monterey source rock development to existing production is important because it will affect the amount of new infrastructure that would be needed to support new production. One important piece of infrastructure for which we have spatial data is the network of oil and gas pipelines in the state; these pipelines transport petroleum from where it is produced to refineries and to its final point of use. As shown in Figure 3.4-2, oil and gas pipelines already exist in the basins where there is potential Monterey source rock, although the network varies in density across the basins, with the Salinas Basin in particular having a relatively sparse network of pipelines. Another important piece of infrastructure that would need to be developed in and around new oil fields is a means for wastewater disposal. Locations of existing Class II disposal wells are shown in Figure 3.4-11 through 3.4-15, and the current locations of evaporation-percolation ponds are shown in Figure 3.4-3. Class II disposal wells and evaporation-percolation ponds both have highly clustered distributions in and around existing oil fields. It is likely that if new areas were to be developed to produce Monterey source rock, more such features would need to be installed.

Figure 3.4-2. Pipelines for transport of oil and gas in California overlaid with potential Monterey source rock. Pipeline data from Zucca (2000).

3.4.3. Potential Impacts to Water Resources

The major potential impacts to water resources discussed in Volume II, Chapter 2 were associated with water use for well stimulation and the possibility of water contamination by stimulation fluids (and comingled produced water). In this case study, we present information on the location of potential Monterey source rock in relation to existing wastewater disposal infrastructure, surface water bodies, groundwater aquifers, water wells, and water supply systems. Because the extent of source rock is larger and differs from the current brownfield area, there is potential for new and different water resources to be affected by source rock production.

There are a few predictable differences in how impacts of source rock production would likely differ from those of current production in California. First, most of the source rock footprint is not in the immediate vicinity of existing oil and gas wells, and therefore the risk of hydraulic fractures intercepting a nearby improperly plugged, abandoned, or deteriorated well is diminished. Second, source-rock production will be on average much deeper than migrated oil production. Consequently, there will be a greater margin of safety between hydraulic fractures and shallow groundwater. Third, water produced from deeper formations in the San Joaquin Basin tends to be higher in Total Dissolved Solids (TDS); one study found that produced water in the San Joaquin Basin from depths shallower than 1,500 m (4,900 ft) had less than 4,000 mg/L TDS (and typically less than 2,000 mg/L), whereas waters from depths greater than 1,500 m typically had more than 25,000 mg/L TDS (Fisher and Boles, 1980), likely due to the transition from non-marine strata at shallow depths to marine strata at greater depths.

Below we show the geographic overlap between key water resources and the areas that could be developed as a source-rock play, and discuss possible impacts to water resources.

3.4.3.1. Wastewater Management

The main documented methods used for disposal of wastewater from stimulated wells in California are: (1) evaporation-percolation ponds (57% of total produced water volume in the first full month after stimulation), followed by (2) subsurface injection (26%), (3) “other” (14%), (4) not reported (3%), and (5) surface body of water (0.2%) (Volume II, Chapter 2). Discharge of oil field wastewater to evaporation-percolation ponds, also known as “percolation pits,” is regulated by the Regional Water Boards under their Waste Discharge Requirements (WDR). In this section we examine where percolation pits have been used in the past several years within the footprint of Monterey source rock, on the assumption that, unless regulations change, this practice will continue in the future.

As shown in Figure 3.4-3, percolation pits are presently used in at least four of the six basins with potential Monterey source rock: the Salinas, Santa Maria, San Joaquin and Cuyama Basins. The status of percolation pits in the Los Angeles and Ventura Basins is ambiguous: records in DOGGR’s production database report that wastewater is disposed of via "evaporation/percolation" in these areas, albeit a small volume compared to the San Joaquin Basin. However, state water quality regulators have no records of active ponds in the vicinity of the two basins.

Information on oil and gas wastewater disposal reported by operators to DOGGR is inconsistent with the reported pond locations. For example, the production database reports 41,000 m^3 (33 acre-feet) and 47,000 m^3 (38 acre-feet) of produced water disposed to ponds in Los Angeles and Ventura Counties, respectively, though no sump locations were reported for either county. Conversely, there was no disposal to ponds reported in Santa Barbara County, yet there were active ponds in the county. This mismatch indicates that either the records of pond locations are incomplete, wastewater disposal volumes and located reported in the production database are inaccurate, or both.

In addition to unlined sumps, Class II wells are also a likely disposal method, using either existing wells or constructing new Class II wells to handle additional wastewater flows. Wastewater can be injected into Class II wells for the purpose of enhanced oil recovery (though not in source-rock formations) or simply disposed of underground. Similar to unlined sumps, Class II wells are generally located within the perimeter of existing oil and gas fields (Figures 3.4-11 to 3.4-15).

At present, the main infrastructure for wastewater disposal (evaporation-percolation ponds and Class II wells) is located in and around existing oil fields. Development of greenfield portions of the Monterey source rock footprint would require operators to develop new wastewater disposal infrastructure. Possible strategies would be: 1) construction of new sumps and/or Class II wells in greenfield areas, 2) transport of wastewater to current sumps and/or Class II wells, or 3) increased reliance on other avenues of wastewater disposal, such as beneficial reuse at the surface (such as treatment followed by use for irrigation) or disposal to publicly-owned treatment works.

Since it is likely that produced water from Monterey source rock would be from deeper formations and have higher TDS values on average than water currently produced in the state, the options for its disposal (at least without prior treatment) may be affected. For example, it is possible that it will exceed the TDS limits set by the Central Valley Regional Water Quality Control Board for disposal in pits overlying groundwater with existing and future beneficial uses. High TDS may also compromise its usefulness for irrigation or other beneficial reuse, or as a base fluid for stimulation fluids.

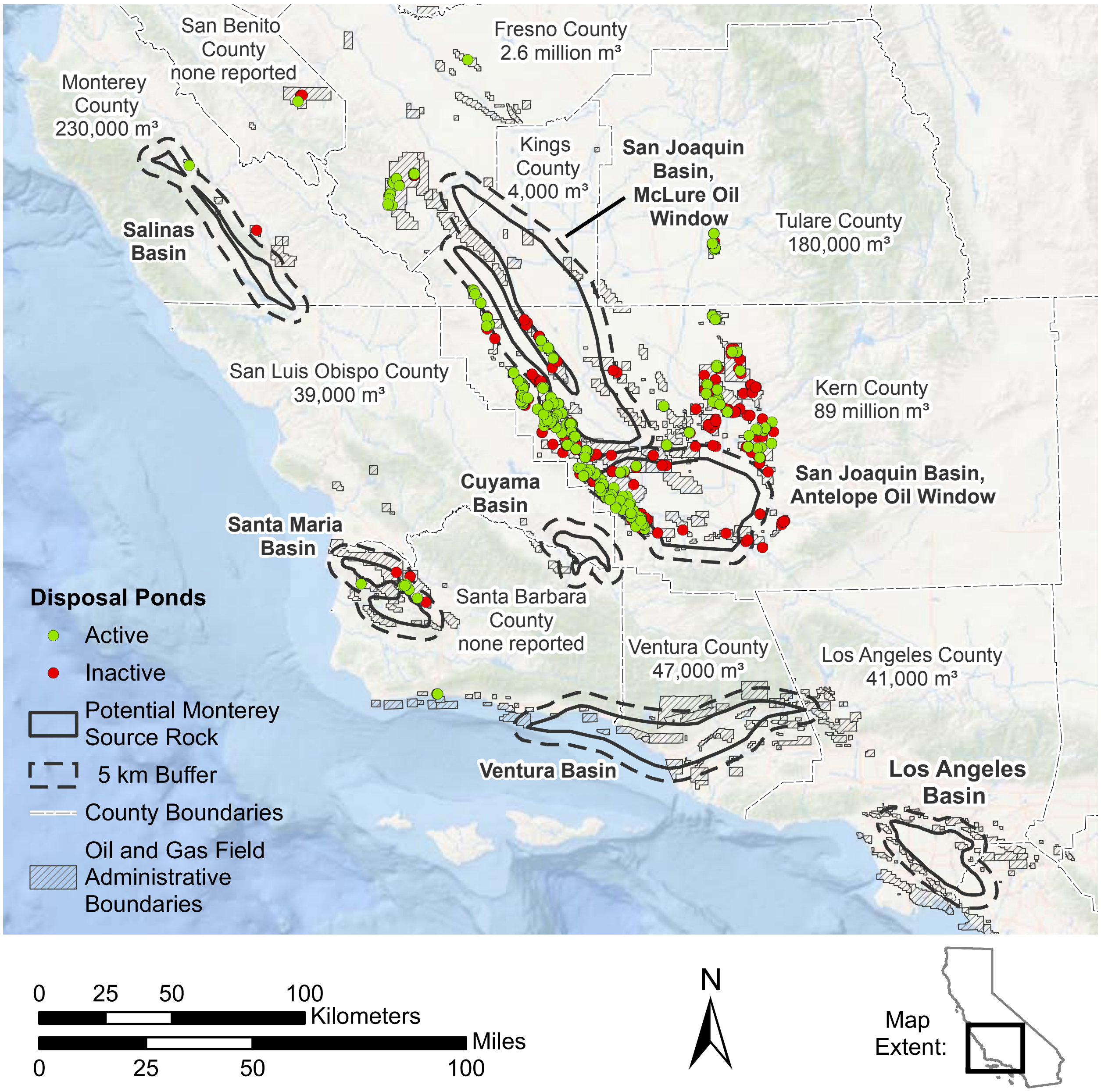


Figure 3.4-3. Potential Monterey source rock overlaid with known locations of oil and gas wastewater evaporation-percolation ponds in the state, and oil and gas field administrative boundaries. County labels indicate volume of wastewater sent to evaporation-percolation ponds by county in 2013. Data on Central Valley sump locations from the Central Valley Regional Water Quality Control Board (Holcomb, pers. comm, 2015); data on other sump locations from the California State Water Resources Control Board (Borkovich, pers. comm., 2015). DOGGR administrative boundaries from DOGGR (2014b). Volumes of wastewater calculated from DOGGR production database (DOGGR, 2014c).

3.4.4. Potential Impacts to Surface and Groundwater Quality

Below, we discuss surface water and groundwater resources that are in close proximity to the Monterey source rock and could be affected by increased oil and gas development in these areas. This includes the groundwater basins that lie immediately above or adjacent to source rock, as well as nearby surface water bodies, such as rivers, lakes, and streams. We then identify water-related infrastructure that could be impacted if these resources are contaminated. These include water wells, water supply for domestic and municipal uses, and irrigated agricultural lands.

3.4.4.1. Surface Water Bodies

Surface water bodies, such as rivers, lakes, streams, and wetlands, can be located in close proximity to oil and gas activities. For example, the Salinas River is close to the San Ardo oil field (Figure 3.4-4). Because of this proximity, oil and gas activity could release contaminants into these water bodies through a variety of pathways. One possible pathway is spills or accidental releases directly into a waterway, or on the land surface, where contaminants could run off into surface water bodies. In addition, polluted groundwater can discharge to the surface via springs or subsurface discharge to streams (via baseflow) or other surface water bodies. Pollutants released to surface water bodies have the potential of being transported with water flows, affecting downstream water bodies. In coastal watersheds, pollutants that enter the environment could be transported downstream to the ocean and coast. We inventoried the surface water bodies that overlie the Monterey source rock or that fall within 5 kilometers of this area using geographic data from the U.S. Geological Survey (USGS 2014). Figure 3.4-5 shows the surface water features that overlie the Monterey source rock.[9] A more detailed view of each source rock area is shown in Appendix 3.D (Figure 3.D-1). There are more than 4,000 km (2,485 mi) of rivers and streams overlying the Monterey source rock, and another 7,000 km (4,350 mi) above the 5 km (3 mi) buffer, for a total of over 11,000 km (6,835 mi) of rivers and streams (Table 3.4-3). In addition, there are 2,800 km (1,740 mi) of man-made canals and ditches above the Monterey source rock and its 5 km (3 mi) buffer. The San Joaquin and Los Angeles Basins have a relatively low density of surface water features compared to the other four basins.

9. Note that some of the rivers and streams shown are ephemeral, and may flow rarely or intermittently.

Table 3.4-3. Length of streams, rivers, and canals overlying the Monterey source rock, by oil basin.

	River/Stream (length in km)		Canal/Ditch (length in km)	
	Over source rock	+5 km Buffer	Over source rock	+5 km Buffer
Cuyama Basin	240	1,000	-	-
Los Angeles Basin	37	190	43	87
Salinas Basin	440	2,000	-	16
San Joaquin Basin	1,400	3,500	1,899	2,600
Santa Maria Basin	280	770	-	10
Ventura Basin	1,800	3,800	78	180
Total	**4,200**	**11,000**	**2,000**	**2,800**

Data from the National Hydrography Dataset, version 2.2 (USGS 2014).

Note: the length of river and stream miles in the second column is cumulative; in other words, it is the sum of features that above the source rock and within the 5 km (3 mi) buffer. All figures rounded to two significant digits. Figures may not sum to total due to rounding.

There are other water bodies in the study area, such as lakes, ponds, reservoirs, and other impoundments (not including the evaporation-percolation ponds identified earlier). We found 122 such features overlying the Monterey source rock, and another 79 in the 5 km (3 mi) buffer area (Table 3.4-4). These water bodies have a total surface area of 94 km² or 23,000 acres. Some water bodies shown are farm ponds or wetlands, and may only be wet at certain times, depending on the weather and how they are managed.

Table 3.4-4. Surface water bodies (lakes, ponds, and reservoirs) that overlie the Monterey source rock.

	Over source rock			In 5 km buffer		
Oil Basin	Number of Water Bodies	Surface Area km²	Surface Area acres	Number of Water Bodies	Surface Area km²	Surface Area acres
Cuyama Basin	2	0.03	8	2	0.0	8
Los Angeles Basin	6	0.2	45	13	2.7	660
Salinas Basin	1	22	5,400	9	42	10,200
San Joaquin Basin, Antelope Oil Window	36	5.9	1,500	45	6.5	1,600
San Joaquin Basin, McLure Oil Window	45	18	4,600	75	25	6,200
Santa Maria Basin	13	4.0	990	18	4.2	1,000
Ventura Basin	19	8.3	2,100	39	13	3,300
Total	**122**	**59**	**14,500**	**201**	**94**	**23,000**

Figure 3.4-4. A view of the Salinas River near San Ardo, with the San Ardo oilfield in the background. Photo by Wikipedia user Antandrus.

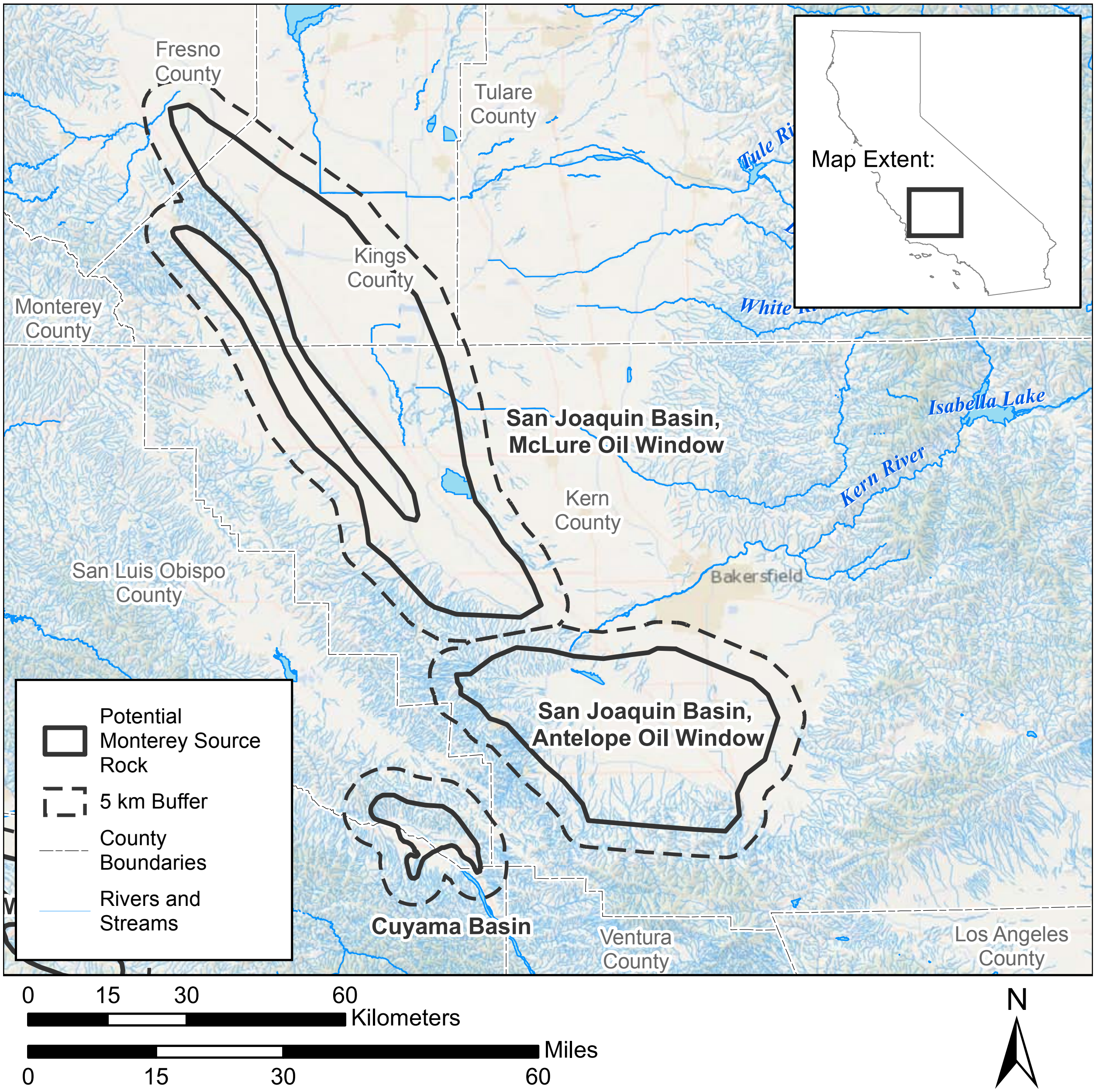


Figure 3.4-5. Surface water features overlying the Monterey source rock. A series of close-up maps for each basin is shown in Appendix 3.D. Data from U.S. Geological Survey (2014). Note that the in order to make the smallest streams visible at this scale, they are depicted larger than they are and so form an almost continuous field of blue on the map. Also, many of these rivers and streams are ephemeral, meaning they do not flow continuously or year-round.

3.4.4.2. Groundwater Aquifers

In California, groundwater is an important source of water for households, municipalities, industry, and agriculture. Groundwater also helps sustain rivers and streams, providing critical ecosystem flows. The Monterey source rock lies thousands of feet underground, below groundwater basins that provide water for human and environmental uses. Wells for oil and gas exploration, production, and waste disposal pass through groundwater basins, and above-ground activities disturb the land surface over these groundwater basins. There are several possible pathways by which contamination could occur, as discussed in Volume II, Chapter 2. Based on data from the Department of Water Resources (DWR), we identified 16 groundwater basins[10] that overlie the Monterey source rock, as shown in Figure 3.4-6 (a) through (d). Four additional groundwater basins are not located immediately above the source rock but fall within the 5-kilometer buffer zone used for this study. The San Joaquin Basin contains the largest area where groundwater overlies source rock, followed by the Los Angeles Basin and the Santa Maria Basin (Table 3.4-5). The groundwater basins which overlap the Monterey source rock are listed in Table 3.C-1. One of the potentially affected basins, the San Joaquin Valley Groundwater Basin, covers a vast area spanning the width of the Central Valley from the Tehachapi Mountains in the South to the San-Joaquin-Sacramento River Delta in the north, and spans approximately 36,000 km^2 (14,000 square miles).

The movement of groundwater is complex and, in many parts of California, poorly understood. Arguably, hydraulic fracturing in the very deep Monterey source rock is safer than operations in shallower wells, because one would expect to often find aquitards between deep hydraulically fractured zones and usable groundwater. A confining layer (aquitard) could slow flow of groundwater and contaminants. However, relying on an aquitard to keep pollutants from migrating is inherently risky; the integrity of an aquitard cannot be assumed unless it has been observed as maintaining separation between aquifers, based on observations of either pressure or water chemistry.

The groundwater basins shown in Figure 3.4-6 have been identified by DWR as areas underlain by permeable materials capable of storing or providing a significant supply of groundwater. In some areas, groundwater is salty or otherwise of low quality, such that it could not be used for public supply without costly treatment measures. In some of these areas, regulators allow the disposal of oilfield wastes into subsurface aquifers via Class II wells. Beginning in 2014, following the enactment of SB 4, state law requires operators to monitor groundwater in the vicinity of production wells that have been stimulated.[11] Regulators (the State Water Resources Control Board and the Regional Water Quality Control Boards) allow exemption to the monitoring requirement where the operator

10. The Department of Water Resources defines a groundwater basin as an alluvial aquifer or a stacked series of alluvial aquifers with reasonably well-defined boundaries in a lateral direction and a definable bottom (DWR 2003, page 88).

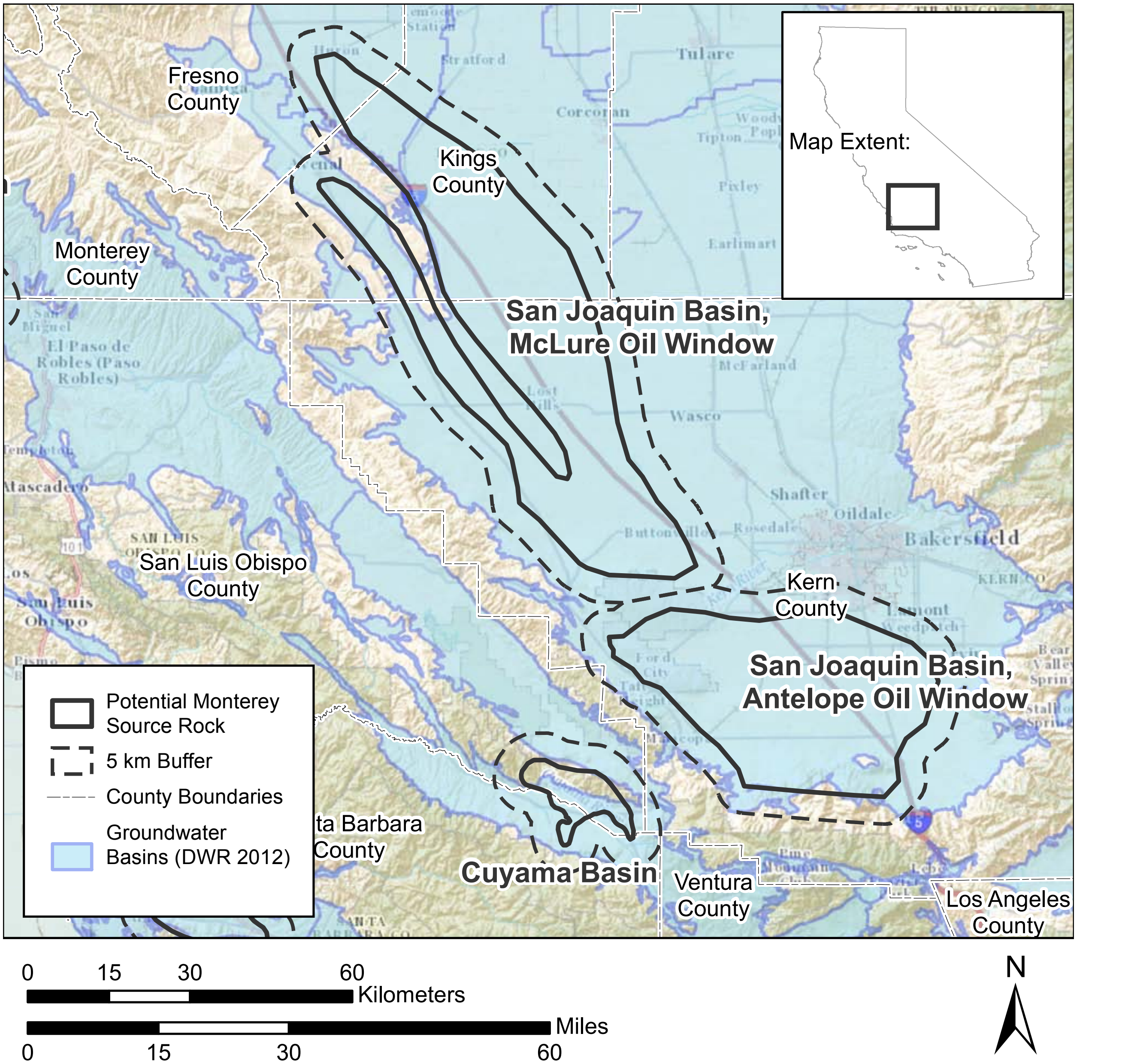
11. Public Resource Code section 3160, subdivision (d)(1)(F)(iii)

demonstrates that there are no "protected waters," meaning that water contains high levels of salt (exceeds 10,000 mg/L total dissolved solids) or traces of oil (occurs inside of a hydrocarbon-bearing zone). As of April 1, 2015, a total of 18 exemptions have been granted, generally covering 1-square mile sections or smaller areas, and all inside of four fields: North and South Belridge, Elk Hills, and Seneca-Coalinga (California State Water Resources Control Board, 2015).

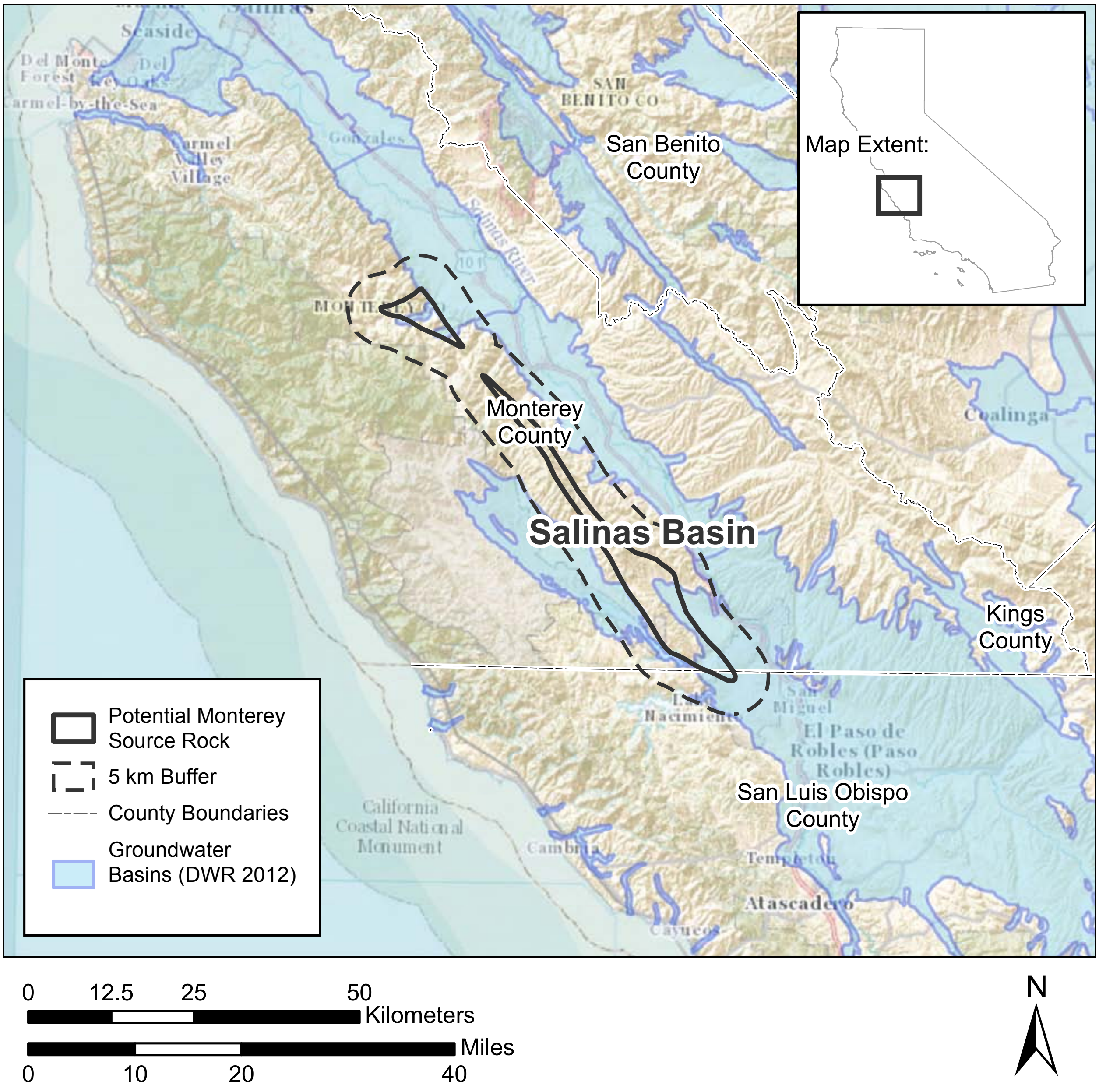
Subsurface injection was the second most common disposal method for produced water from stimulated wells, as discussed in more detail in Volume II, Chapter 2. However, there are significant concerns about whether California's Underground Injection Control (UIC) program is adequately protective of underground sources of drinking water (USDWs) – defined as groundwater aquifers that are used for water supply or could one day supply water for human consumption (Kell 2011; Walker, 2011). Currently, the State Water Board is reviewing injection wells that may be disposing of oilfield wastes in aquifers that lack hydrocarbons and contain water with less than 10,000 mg/L total dissolved solids. These wells are being reviewed for "proximity to water supply wells or any other indication of risk of impact to drinking water and other beneficial uses" (Bohlen & Bishop, 2015). We discuss this issue in more detail in Volume II, Chapter 2.

Table 3.4-5. Area of groundwater basins overlapping with Monterey source rock oil windows and their 5 km (3 mi) buffer, in square kilometers.

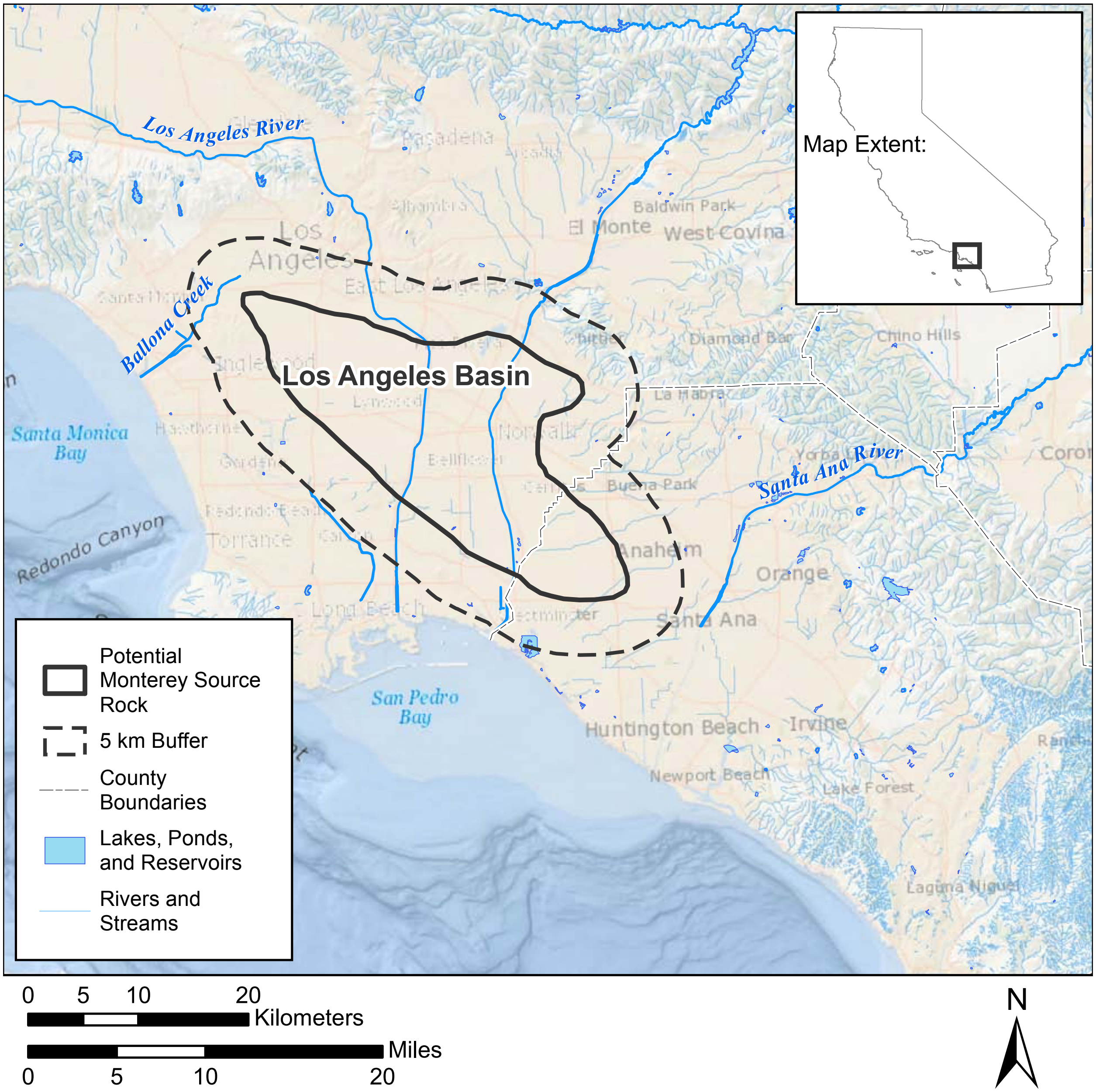
Basin	Source Rock Area (km^2)	Area of Groundwater Basin that Overlies source Rock	
		Over source rock	In 5 km Buffer
Cuyama Basin	147	82	600
Los Angeles Basin	455	455	1,492
Salinas Basin	222	48	565
San Joaquin Basin	3,634	3,584	8,703
Santa Maria Basin	290	259	1,021
Ventura Basin	1,097	388	986
Total	**5,845**	**4,817**	**13,367**


Fresno County
Kings County
Monterey County
San Joaquin Basin, McLure Oil Window
San Luis Obispo County
Kern County
San Joaquin Basin, Antelope Oil Window
ta Barbara County
Cuyama Basin
Ventura County
Los Angeles County
Map Extent:
Potential Monterey Source Rock
5 km Buffer
County Boundaries
Groundwater Basins (DWR 2012)
0 15 30 60
Kilometers
Miles
0 15 30 60
N

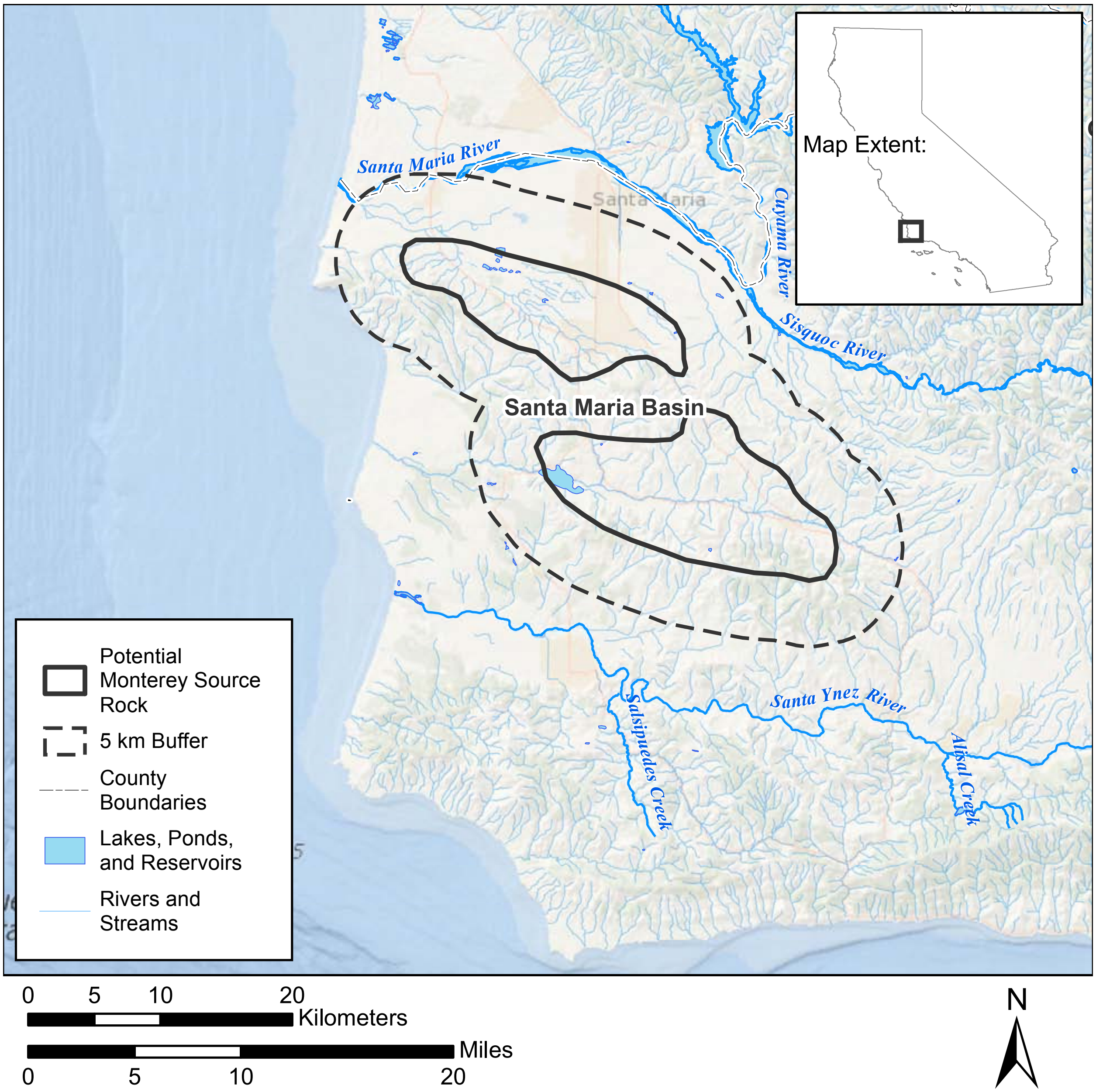
a)


Seaside
Del Monte Forest
Del Rey Oaks
Carmel-by-the-Sea
Carmel Valley Village
Gonzales
SAN BENITO CO
San Benito County
Map Extent:
Salinas River
101
MONTEREY CO
Monterey County
Coalinga
Salinas Basin
Kings County
San Miguel
Nacimiento
El Paso de Robles (Paso Robles)
San Luis Obispo County
California Coastal National Monument
Cambria
Templeton
Atascadero
Cayucos
Potential Monterey Source Rock
5 km Buffer
County Boundaries
Groundwater Basins (DWR 2012)
0
12.5
25
50
Kilometers
Miles
0
10
20
40
N

b)


Los Angeles Basin
Los Angeles River
Ballona Creek
Santa Monica Bay
Redondo Canyon
San Pedro Bay
Santa Ana River
Pasadena
Baldwin Park
El Monte
West Covina
Los Angeles
Diamond Bar
Chino Hills
Norwalk
Buena Park
Anaheim
Orange
Santa Ana
Torrance
Long Beach
Huntington Beach
Irvine
Newport Beach
Lake Forest
Laguna Niguel
Map Extent:
Potential Monterey Source Rock
5 km Buffer
County Boundaries
Lakes, Ponds, and Reservoirs
Rivers and Streams
0 5 10 20 Kilometers
Miles 0 5 10 20
N

c)



d)

Figure 3.4-6. Maps of groundwater basins (or alluvial aquifers) overlying the Monterey source rock in (a) San Joaquin and Cuyama Basins, (b) Salinas Basin, (c) Ventura and Los Angeles Basins, and (d) Santa Maria Basin. Data on groundwater basins from California Department of Water Resources (2003); further details on data in Appendix 3.C.

3.4.4.3. Water Wells

The risk of contamination from a hydraulic fracture intercepting a usable aquifer is minimal when fracturing source rock, as the depth of Monterey source rock is on the order of 3,000 m (9,843 ft),[12] while aquifers used for drinking, irrigation and domestic purposes are at much shallower depths: as deep as 1,200 m (4,000 ft) in the Los Angeles Basin, 1,000 m (3,500 ft) in the San Joaquin Basin, and 300 m (1,000 ft) in the Salinas Basin (Planert and Williams 1995). However, the other pathways for potential contamination of groundwater are still plausible; these pathways are described in Volume II, Chapter 2. This is of particular concern where water wells are in close proximity to potentially contaminated aquifers, as there is an increased likelihood of human exposure. There is no reliable information on the number and location of water wells in California. Data from water well completion reports filed with DWR, however, gives some indication of the number of water wells within a given area.[13] We note, however, that these data are incomplete and are missing at least 50,000 wells drilled over the past 65 years plus wells drilled prior 1949 (Senter, 2015, pers. comm.). The wells data file reports the approximate location for 648,514 wells in the state. Information on the type of well was not available. An unknown number of these wells are for domestic or municipal use.

There were over 14,000 documented water wells in the area overlying the Monterey source rock. Within 5 km (3 mi) of the source rock, there are an additional 14,000 wells, for a total of about 28,000 wells. The largest number of wells overlying source rock is in the San Joaquin Basin (13,000 wells), followed by the Los Angeles Basin (10,000 wells) (Table 3.4-6). Far fewer wells are located near source rock in the Ventura, Santa Maria, Salinas and Cuyama Basins (140 - 1,800 wells per basin). Figure 3.4-7 shows the density of water wells throughout most of the footprint of potential Monterey Source Rock, apart from the Los Angeles Basin, which is depicted in Figure 3.4-8. Groundwater is an important water source for residents of the study area. For example, groundwater makes up one-third of the water supply for the 4 million residents of the Los Angeles coastal plain (Hillhouse et al., 2002).

Table 3.4-7 summarizes the number of documented wells overlying Monterey source rock by county and basin. In total, nine counties have wells that directly overlie source rock. There are a total of 10 counties in this area; however, the number of wells in San Luis Obispo is unknown due to missing data. Most wells above the Monterey source rock are

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12. Monterey source rock is much deeper than most formations already developed in California. As shown in in Volume I Figure 3.15a, about 90% of hydraulically fractured wells in California reported true vertical depths shallower than 900 meters, or less than a third as deep as Monterey source rock. These relatively shallow hydraulic fractures are much closer to aquifers tapped for water use at the surface and thus the potential for contamination from them is higher than when fracturing deeper formations.

13. Since 1949, California law has required that landowners submit well completion reports to DWR, containing information on newly constructed, modified, or destroyed wells.

in Kern County, where there are 12,236 wells within the 5 km buffer. The fewest wells overlying the Monterey source rock are in Tulare County; the 5 km (3 mi) buffer zone of the San Joaquin Basin, McLure Oil Window overlaps only about 1 square mile of the southwest corner of Tulare County.

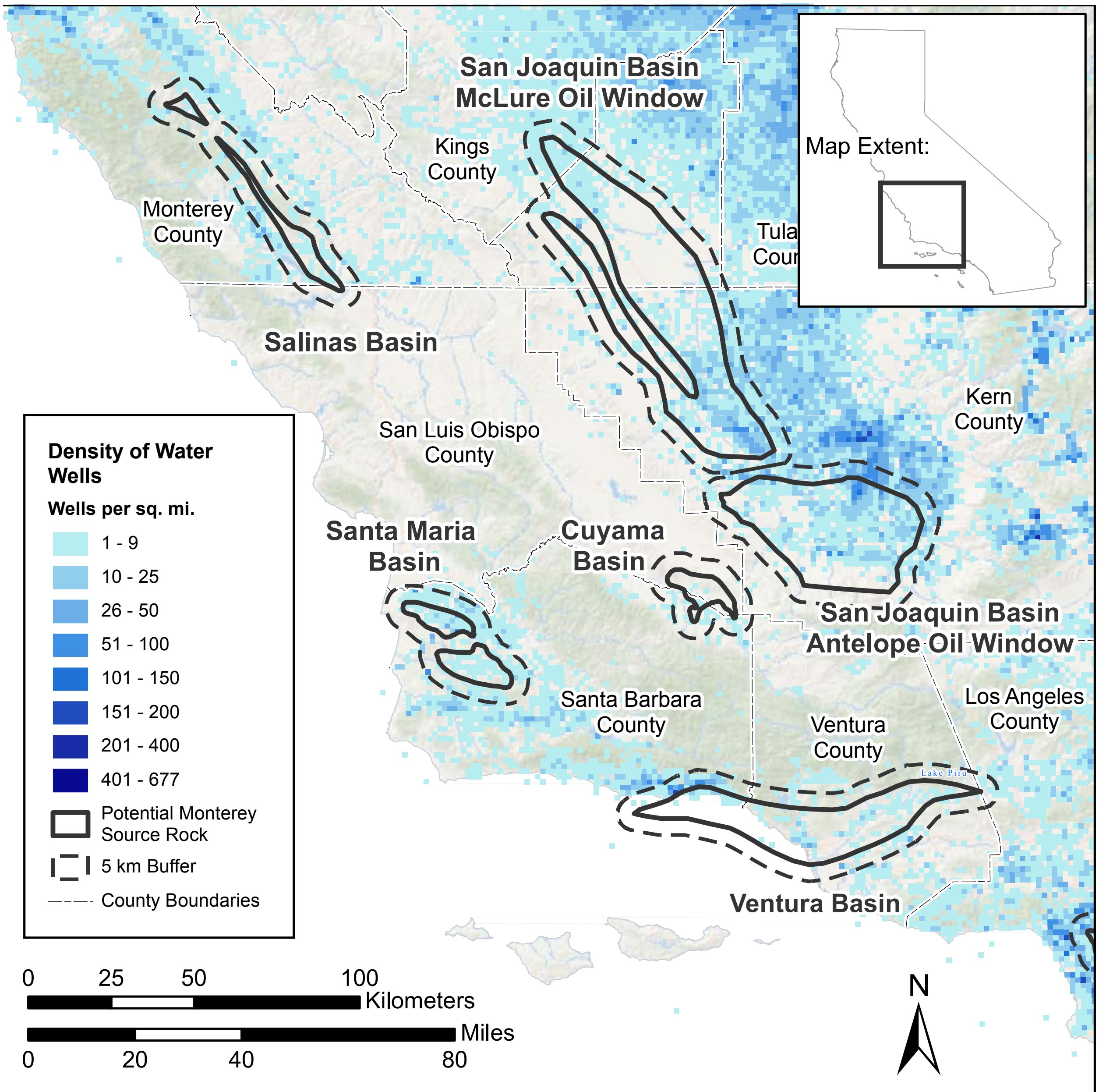

Figure 3.4-7. Density of water wells in Ventura, Santa Maria, Cuyama, San Joaquin and Salinas Basins, and footprint of potential Monterey source rock with 5 km (3 mi) buffer. Information on data source given in Appendix 3.C.

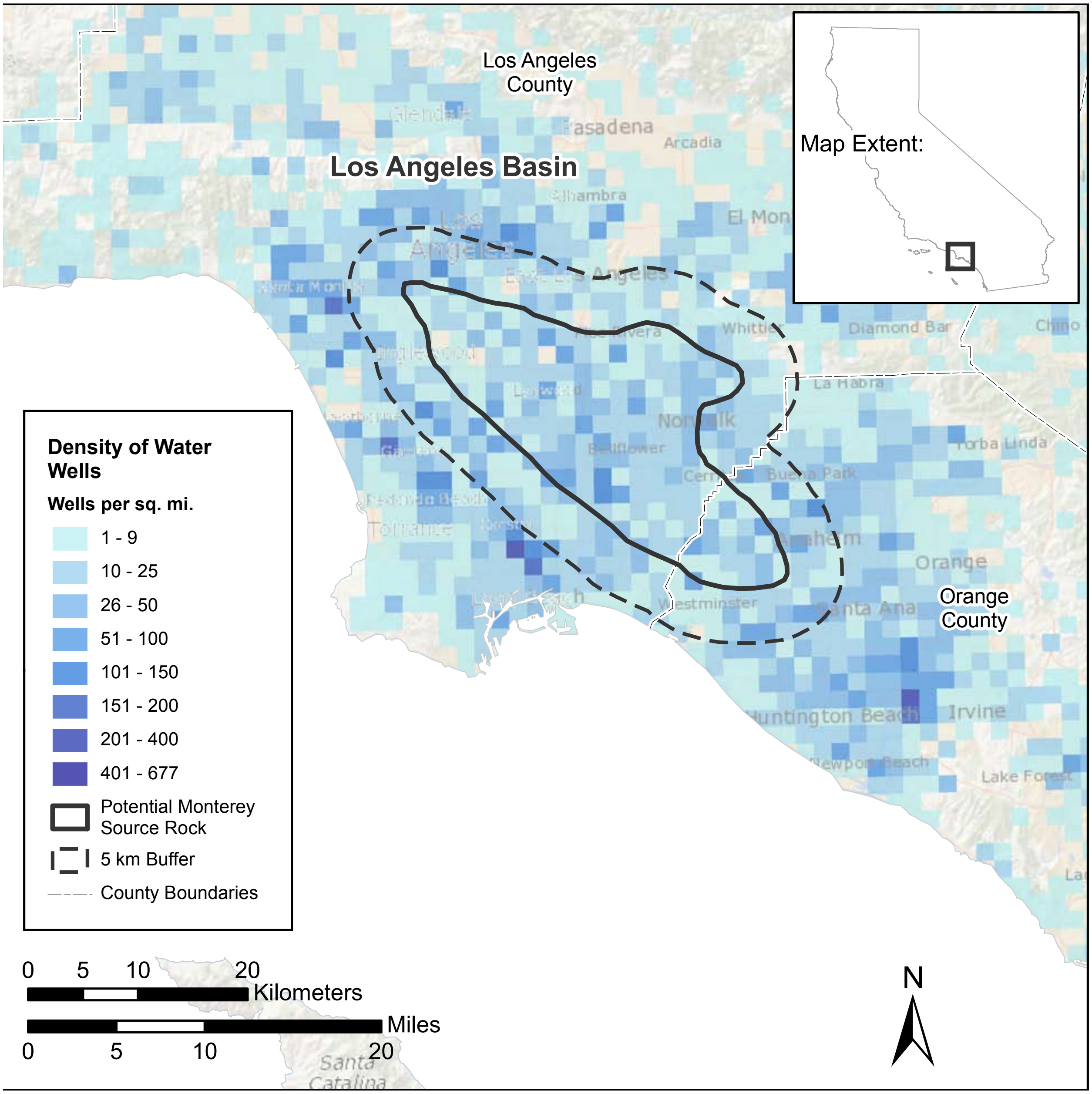

Figure 3.4-8. Density of water wells in the Los Angeles Basin and footprint of potential Monterey source rock with 5 km (3 mi) buffer. Data as in Figure 3.4-7.

Table 3.4-6. Approximate number of water wells overlying the Monterey source rock and 5 km (3 mi) buffer zone, by oil basin.

Basin	Over source rock	In 5 km Buffer	Total
Cuyama Basin	30	109	139
Los Angeles Basin	4,757	5,628	10,385
Salinas Basin	216	635	851
San Joaquin Basin, Antelope Oil Window	4,444	3,006	7,450
San Joaquin Basin, McLure Oil Window	3,575	2,081	5,656
Santa Maria Basin	559	1,224	1,783
Ventura Basin	832	958	1,790
Total	**14,413**	**13,641**	**28,054**

Table 3.4-7. Approximate number of water wells overlying the Monterey source rock and 5 km (3 mi) buffer zone, by county.

	Number of Water Wells			
County	Over source rock	In 5 km Buffer	Source Rock + Buffer	In County
Fresno	155	180	335	44,679
Kern	7,468	4,768	12,236	38,388
Kings	399	184	583	7,534
Los Angeles	3,933	3,873	7,806	20,589
Monterey	217	642	859	12,124
Orange	823	1,792	2,615	8,921
San Luis Obispo*	?	?	?	?
Santa Barbara	1,066	1,983	3,049	5,475
Tulare	0	4	4	23,717
Ventura	351	216	567	1,025
Total	**14,413**	**13,641**	**28,054**	**162,452**

** Well data was not available for San Luis Obispo County. It is highly probable that there are some wells over the Cuyama Basin, and within 5 km (3 mi) of the Santa Maria Basin, but the numbers are unknown.*

3.4.4.4. Water Supply Systems

In this section, we consider the spatial relationship between Monterey source rock and local water suppliers given the possibility of a major increase in water use to develop source rock reservoirs, and potential risks for contamination of nearby water sources. In this section, we overlay the boundaries of source rock with the boundaries of water supplier service areas to better understand the overlap and potential concerns for water supply. Local waters suppliers obtain water from a mix of sources including ground water wells, surface water withdrawals, and water imported from other areas via canals and pipelines. There is no definitive map or data source that shows the location of wells or surface water intakes for municipal water systems. Where water supplier service areas are in close proximity to well stimulation, it raises concerns, but does not mean that contamination will occur or is even likely. However, a proximity analysis can help identify those areas that are of concern.

The major source of stimulation water in recent reports has been water suppliers (a category which includes both irrigation districts and municipal water suppliers. In 2014, operators obtained water needed for well stimulation from nearby irrigation districts (68%), produced water (13%), operators' own wells (13%), a nearby municipal water supplier (4%), or a private landowner (1%). These statistics are based on 495 completion reports filed by operators and published by DOGGR between January 1 and December 10, 2014 (DOGGR, 2015c).

To begin to understand areas of potential concern, we mapped where water suppliers' service areas overlap with Monterey source rock. Using data and maps of water suppliers' service areas obtained from the California Department of Public Health (DPH), we identified 148 water systems, both public and privately owned, that overlie or are within 5 km (3 mi) of the Monterey source rock (Table 3.4-8 and Figure 3.4-9). These systems currently serve more than 10.3 million Californians. Water systems that rely on local groundwater or surface water may be more vulnerable to pollution or groundwater depletion. Some water suppliers exclusively use groundwater, while many others use a combination of local groundwater wells and imported water delivered by canal or pipeline from watersheds often hundreds of miles away. Among the 84 water suppliers with a population of over 3,000, 78 use some groundwater, four do not use groundwater, and for two others it is unknown if they use groundwater.

Table 3.4-8. Water suppliers that directly overlie or are within 5 km (3 mi) of the Monterey source rock and their population served.

Basin	**Number of Water Suppliers**	**Population served**
Cuyama Basin	2	17,600
Los Angeles Basin	72	8,555,731
Salinas Basin	12	21,996
San Joaquin Basin, Antelope Oil Window	13	443,763
San Joaquin Basin, McLure Oil Window	9	42,926
Santa Maria Basin	9	162,838
Ventura Basin	31	1,097,763
Total	**148**	**10,342,617**

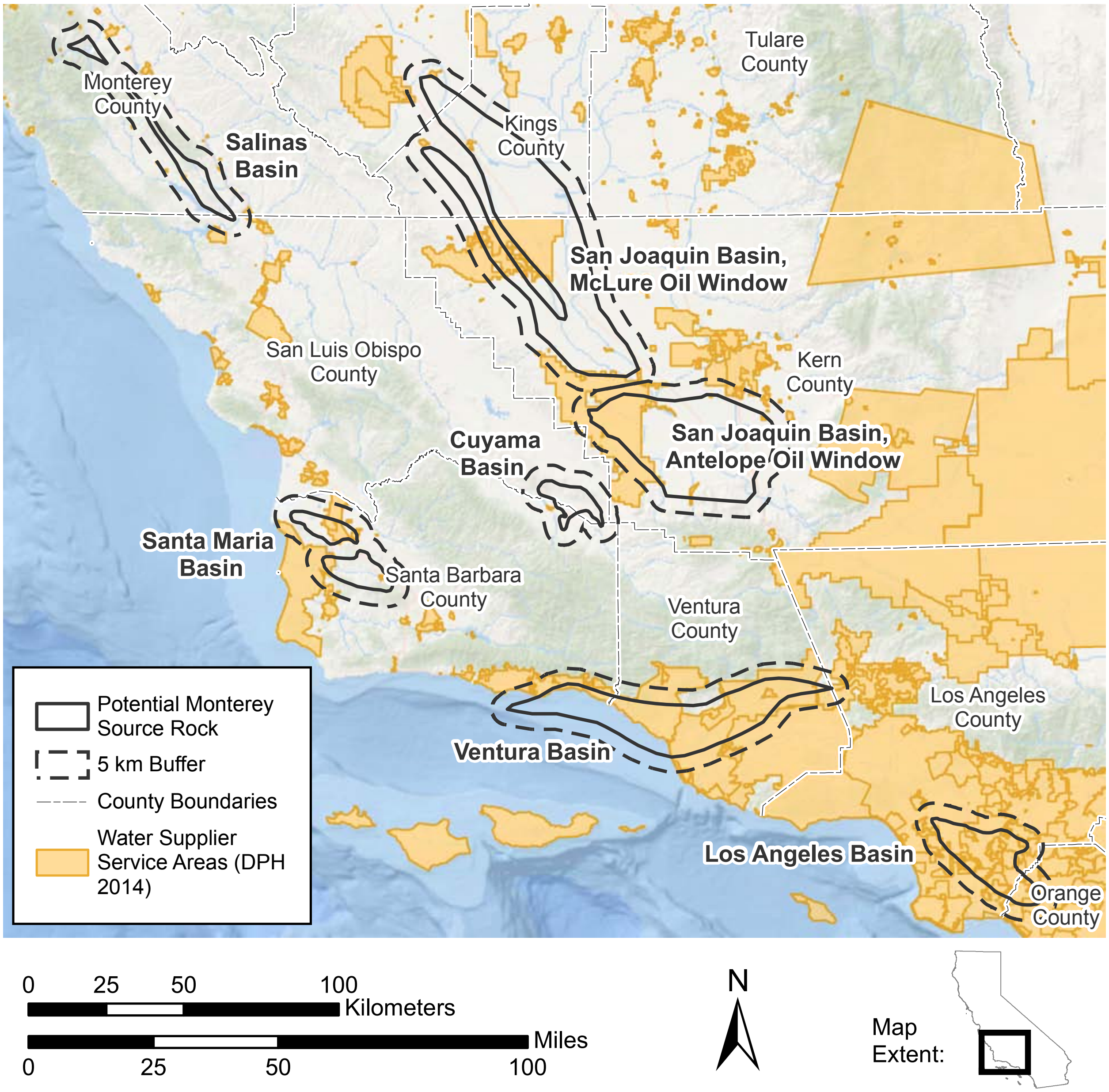

Figure 3.4-9. Water supplier service areas that directly overlie or are within 5 km of the Monterey source rock. Data from California Department of Public Health (2014); details on data in Appendix 3.C.

3.4.5. Potential Impacts to the Atmosphere

If a Monterey Shale source rock play were developed, it could occur in various densities and configurations. It is unclear what the air quality impacts of this play would be, due to the unknown nature of the technology that would be required to access and economically extract the oil.

A first approximation is that development in this play would result in air quality impacts per unit of oil production that are similar in magnitude to current California oil production. The plausibility of this assumption is supported by the following reasons:

1. Oil production from this hypothetical play would be subject to similar air quality rules as development in other California oilfields.

2. Hydrocarbon production from other source rock plays (e.g., Bakken and Eagle Ford liquids plays, Barnett gas play) has not been found to have unavoidably larger impacts per unit of production than conventional oil production. High air emissions from the Bakken play are largely due to associated gas management schemes that would not be acceptable under California regulation (e.g., flaring).

While fracturing consumes energy and results in short-term air emissions, these emissions can be expected to be small compared to emissions associated with decades of lifting, processing, injecting and transporting reservoir fluids. For example, Allen et al. (2013) found green completions technologies effective at reducing emissions from fracturing flowback to very low levels (reductions of 99% of total gas).

The air quality impacts of developing these shales could be problematic due to the general alignment between areas of mature Monterey Shale and areas with already poor air quality. For example, Figure 3.4-10 shows the spatial overlap of mature Monterey Shale source rock and California air districts that are in non-attainment status for Particulate Matter (PM2.5) and ozone. For example, as of January 2015, the San Joaquin Valley region is in "extreme" nonattainment with respect to 2008 8-hour ozone standards and in moderate nonattainment of 2006 PM-2.5 standards (U.S. EPA, 2015). Significant overlap is found between the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) and the largest area of mature Monterey Shale source rock. Other major areas of mature source rock coincide with the South Coast Air Quality Management District (SCAQMD) and the Ventura County Air Pollution Control District (VCAPCD). Development in these areas could exacerbate already problematic air quality.

Other regions of mature source rock occur in California's central coast, under largely agricultural regions of the Santa Barbara, San Luis Obispo and Monterey Bay Unified air districts. While there are active oil fields in all of these areas with source rock, these tend to be smaller in well counts and volumes of production than fields in the San Joaquin Valley and South Coast air districts. Significant development of a source rock play in these regions could impact air quality in areas with relatively good air quality.

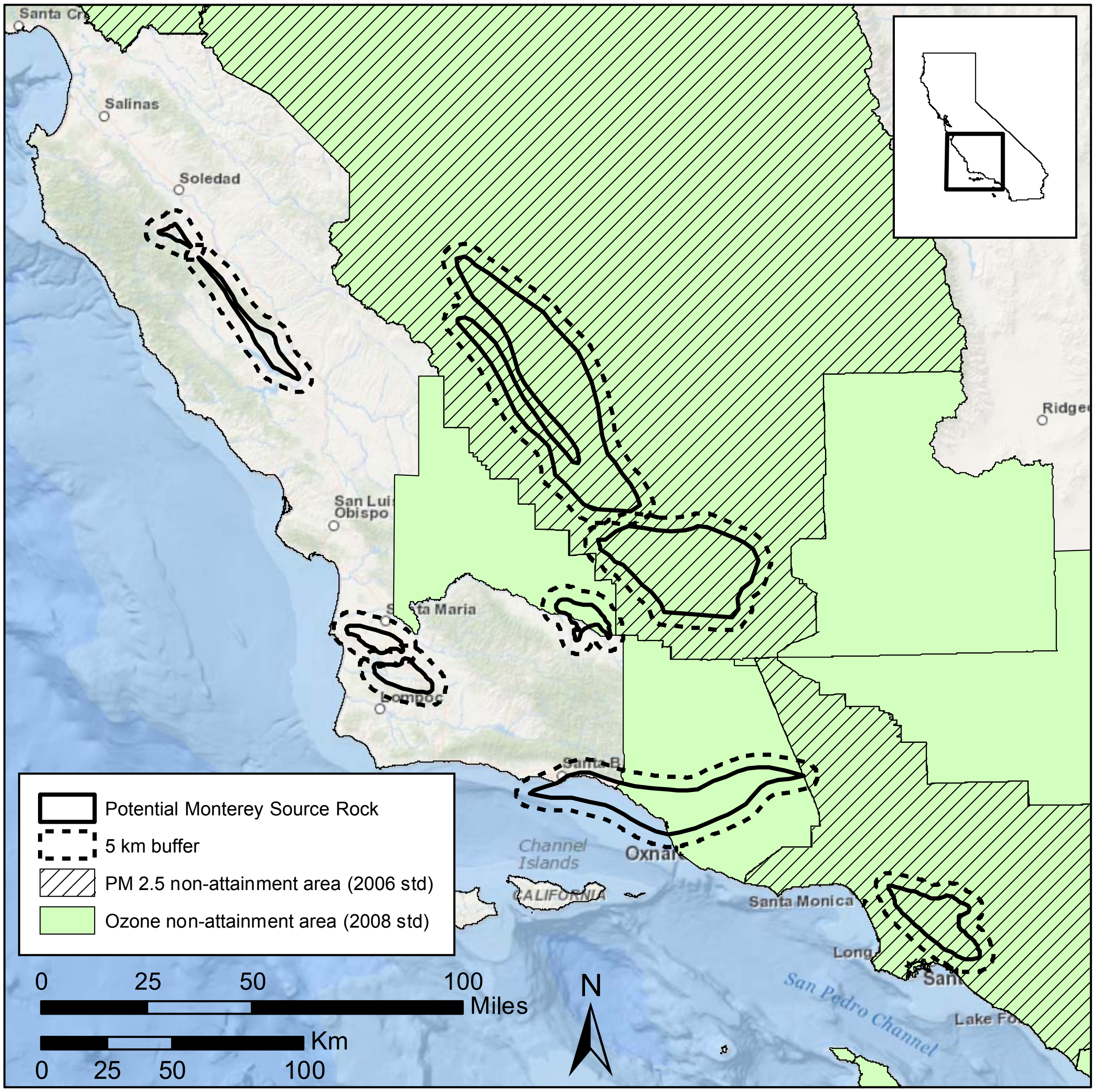

Figure 3.4-10. Spatial alignment between mature Monterey source rock (red) and air districts with PM 2.5 and ozone non-attainment.

Despite the above concerns with additional air quality impacts in non-attainment basins, the level of impact from oil and gas development from a source rock play should be expected to be minor unless development of source rock reached levels of production many times higher than current production in the state. As shown in Volume II, Chapter 3, oil and gas production is the cause of only a small fraction of most criteria air pollutants, dust, and greenhouse gas emissions in California, when measured at the scale of managed air districts (nearly always <10%, and often <1%, per air district). One exception is the emissions of HAPs in the San Joaquin Valley region, where the oil and gas sector is responsible for large fractions of emissions of some HAPs that are commonly associated with hydrocarbon production. Also, note that local impacts of oil and gas development at the county, municipality, or neighborhood scale can be significantly larger than the share of impacts across managed air districts. These local effects are discussed in Volume II, Chapter 3, Volume II, Chapter 6, and Volume III [LA and SJV case study]. Volume II, Chapter 6 describes the public health implications of local concentrations of pollutants in detail.

3.4.6. Potential Impacts to Seismicity

In rare cases, earthquakes of concern can result from well stimulation and the production it enables either through injection of wastewater into Class II wells, or hydraulic fracturing. Both activities inject fluid underground, which causes an increase in underground pressure that can lower the effective confining stress on a fault, hence allowing the fault to slip in an earthquake.

All wells generate wastewater that can be disposed of in a Class II well, not just those that are stimulated. If an earthquake of concern were to be induced by injection of wastewater, it would be considered an indirect impact of well stimulation; an earthquake related to hydraulic fracturing would be a direct impact. Wastewater disposal is associated with a larger potential hazard of induced seismicity than hydraulic fracturing operations because wastewater disposal injects greater volumes of fluid over a longer period of time. Injecting larger volumes than have been used for well stimulation in California to date at the greater depths of the Monterey source rock could increase the direct seismic impact from hydraulic fracturing to some extent; however, the indirect seismic hazard from wastewater disposal would likely still be significantly higher. While shifting to Monterey source rock targets would necessarily increase the depth of well stimulation, the depth of wastewater disposal would not necessarily change. However, production in new places as well as large increases in wastewater could necessitate finding new target horizons for wastewater disposal; we cannot predict at this time whether those horizons would be deeper or shallower as it depends on local geology.

The probability and size of an induced seismic event depends on the volumes of fluids injected, the pressure of injection, the lithology of the injection horizon, and the position of wells in relation to faults and past seismicity. The effect of the event on people depends on its size, proximity to human populations and infrastructure, as well as earthquake preparedness. Volume II, Chapter 4 discusses seismic hazard in detail. Below we present information on the footprint of the potential Monterey source rock and where it overlaps with faults, historic seismicity, and human populations to provide a brief, qualitative overview of the seismic risk that may be associated with developing Monterey source rock.

Figures 3.4-11 through 3.4-15 include faults active during the Quaternary period (last 1.6 million years) from the U.S. Quaternary Fault and Fold (USQFF) database (http://earthquake.usgs.gov/hazards/qfaults). The earthquake locations shown in the maps were determined by applying high-precision analysis techniques (waveform cross-correlation and clustering) to seismic records from the Southern California Seismic Network for the period 1981 – June 2011 (Hauksson et al. 2012). We include active and plugged UIC Class II wastewater disposal well locations from the Division of Oil Gas and Geothermal Resources (DOGGR) well database to understand where wastewater disposal has been occurring over the last few decades (1977 – 2014) (DOGGR, 2014a). If there were to be development of source rock some distance from present-day wastewater disposal wells, most likely new wells would be drilled.

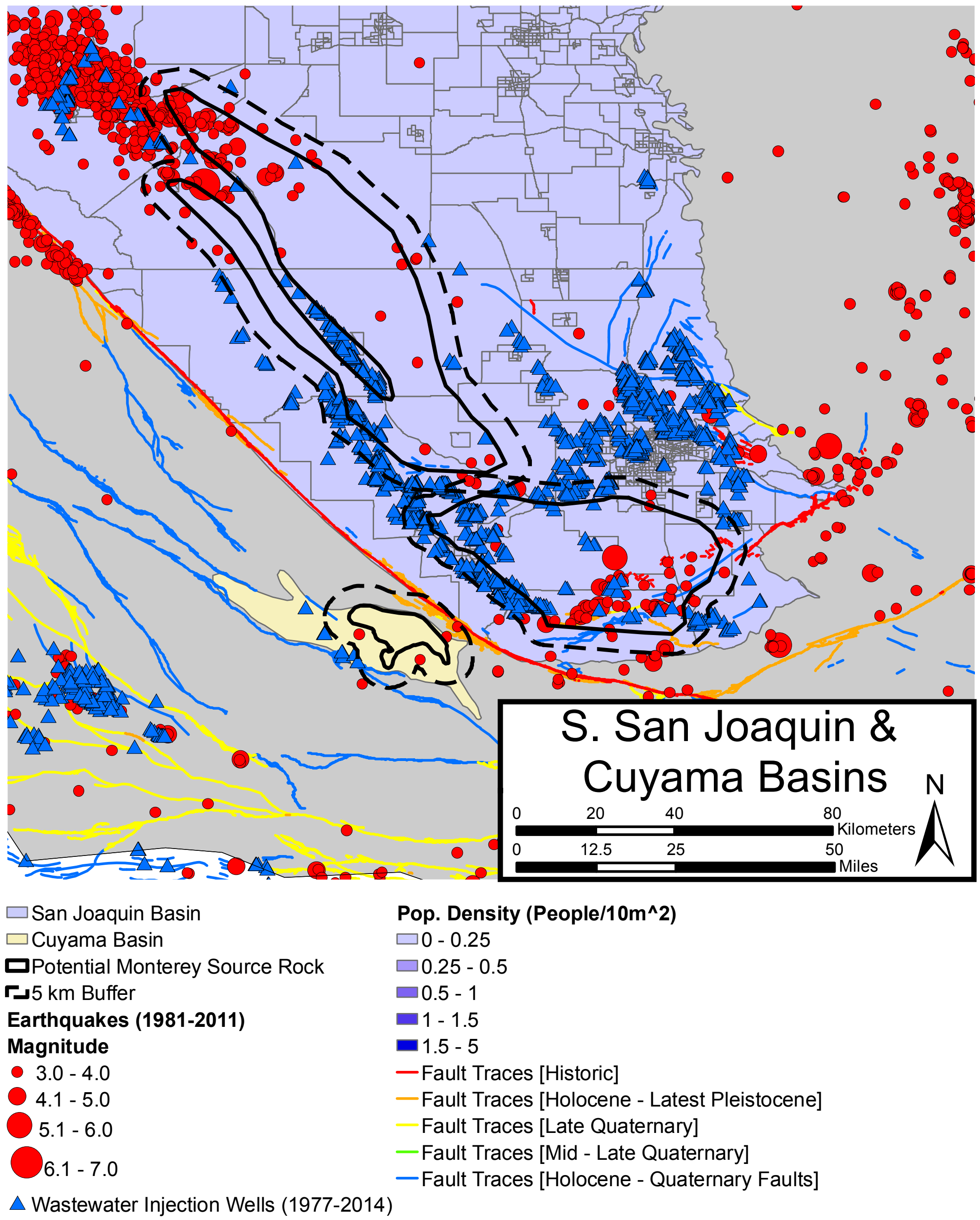

Figure 3.4-11. Factors influencing the potential for induced seismicity in the vicinity of Monterey source rock in the San Joaquin and Cuyama Basins. The maps show potential source rock, the 5 km buffer zone, seismic activity magnitude ≥ 3.0, wastewater injection wells, faults, and population density. Wastewater disposal well locations (1977-2014) from DOGGR injection database; seismic events (1981-2011) from SCEDC catalog. Traces of active faults from USQFF are color-coded by age of most recent activity.

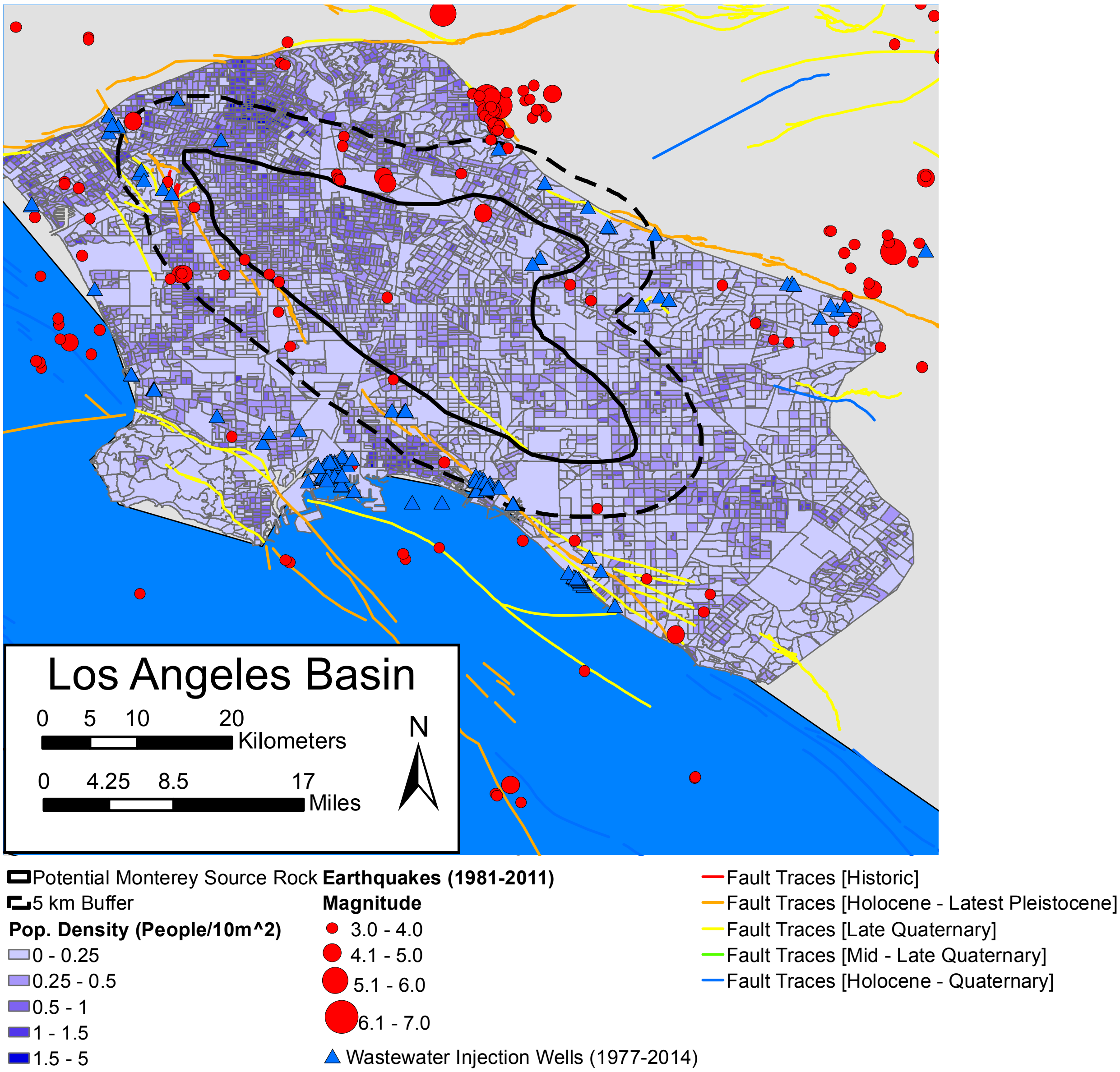

Figure 3.4-12. Factors influencing the potential for induced seismicity in the vicinity of Monterey source rock in the Los Angeles Basin. Explanation as in Figure 3.4-11.

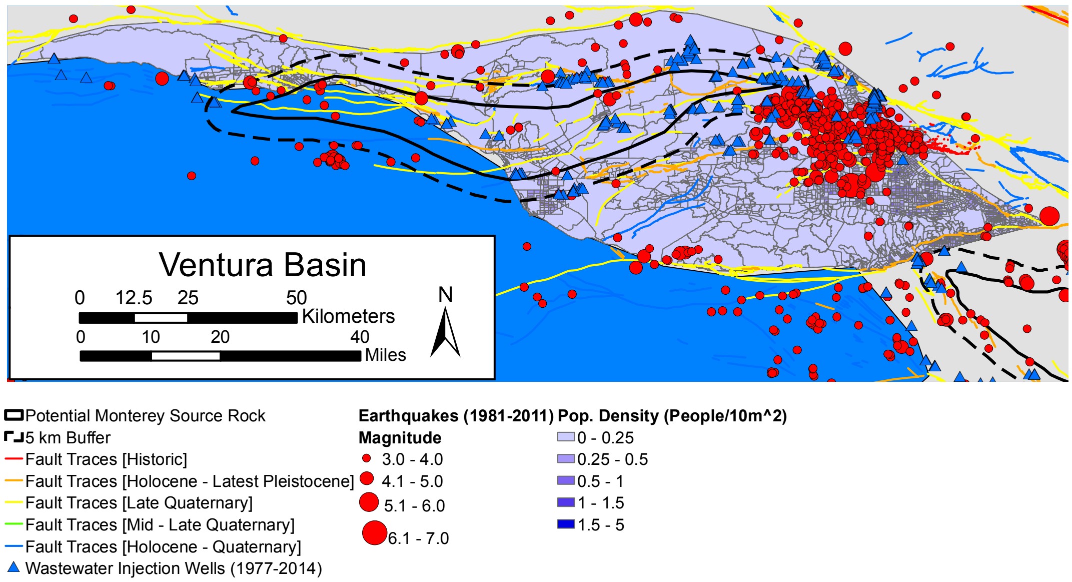

Figure 3.4-13. Factors influencing the potential for induced seismicity in the vicinity of Monterey source rock in the Santa Barbara-Ventura Basin. Explanation as in Figure 3.4-11.

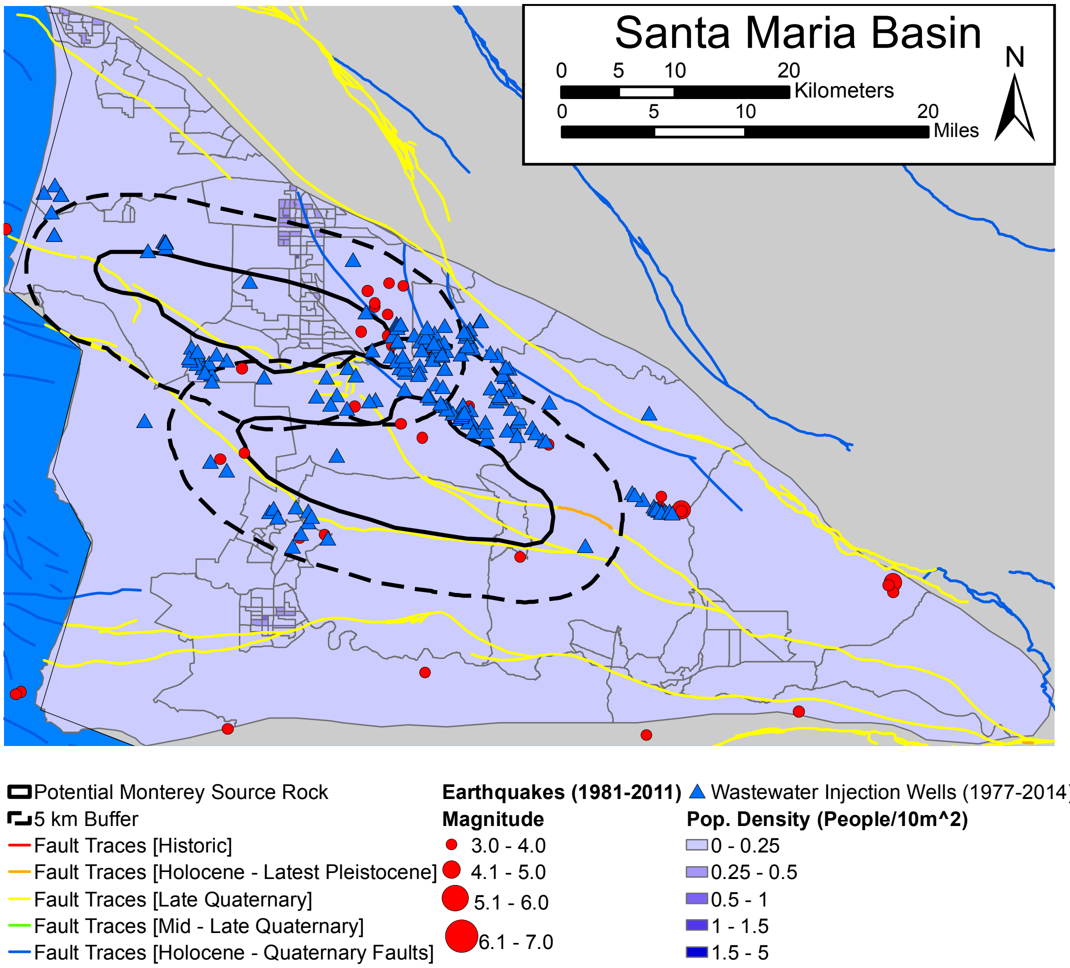

Figure 3.4-14. Factors influencing the potential for induced seismicity in the vicinity of Monterey source rock in the Santa Maria Basin. Explanation as in Figure 3.4-11.

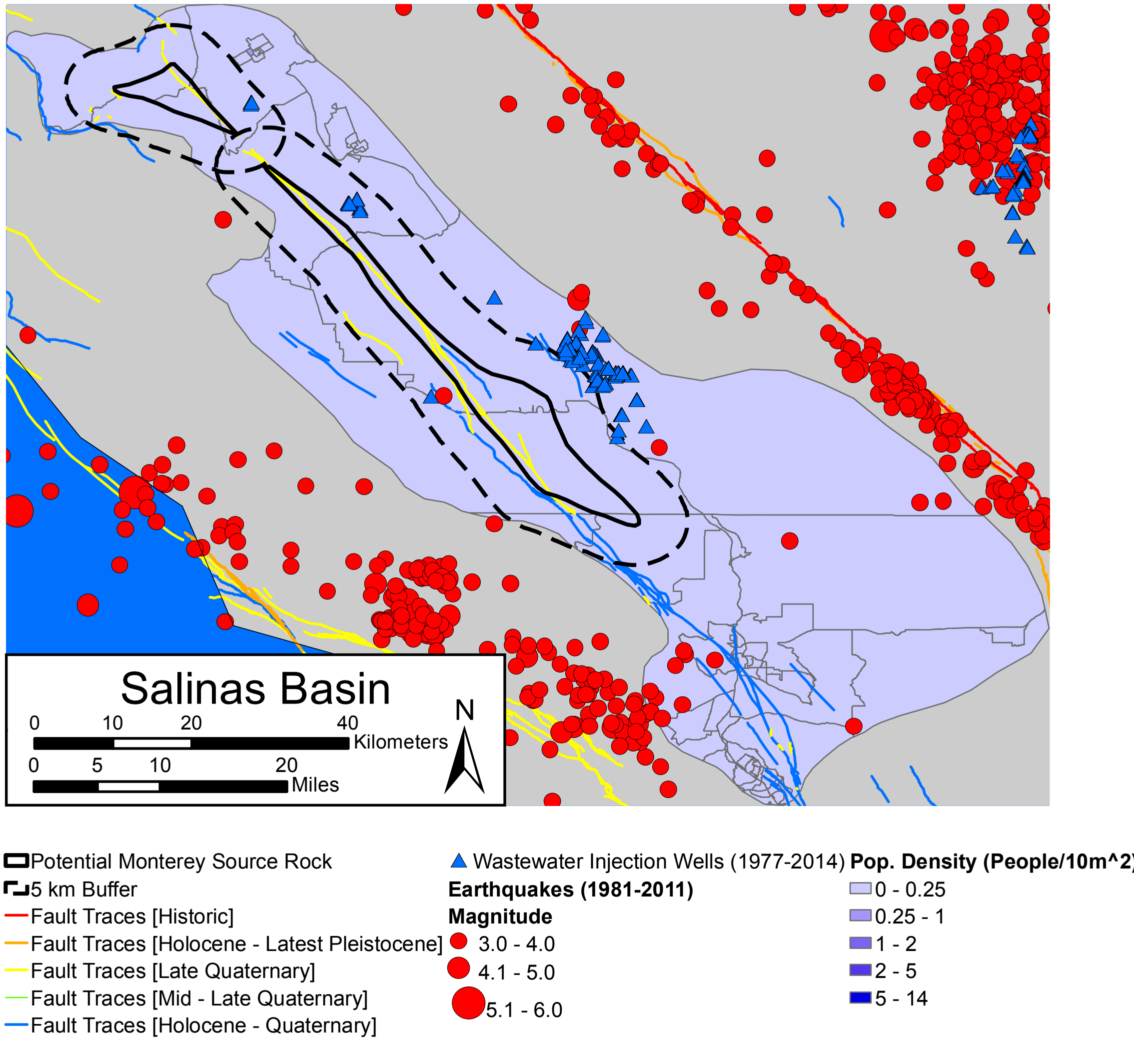

Figure 3.4-15. Factors influencing the potential for induced seismicity in the vicinity of Monterey source rock in the Salinas Basin. Explanation as in Figure 3.4-11.

Within the San Joaquin Basin (Figure 3.4-11), there are clusters of seismic events and large active faults in the southernmost portion of the Monterey source rock footprint (the events in the dense cluster to the northwest are mostly aftershocks of M6+ earthquakes that occurred on deeply buried (blind) faults in 1983 and 1985). Very few earthquakes have been recorded and no faults have been mapped in the central portion of the Monterey source rock zone within the San Joaquin Basin, suggesting a low seismic hazard there. When estimating seismic risk it is necessary to also consider population and infrastructure density. Most areas of the San Joaquin Basin have lower population and infrastructure densities than urban centers like Los Angeles, implying relatively low overall risk throughout the basin. However, large-scale development of Monterey source rock could increase both population density and the scale of infrastructure to some degree.

In the Santa Barbara-Ventura and Salinas Basins (Figure 3.4-13 and 3.4-15), Monterey source rock zones are nearly directly coincident with large active faults having relatively high slip rates slip rates (greater than 1 mm/year). Even though few earthquakes larger than m^{3}.0 have been recorded near these faults, there is a possibility of elevated potential seismic hazard if future large-volume wastewater disposal occurred within the Monterey footprint in these basins because fluid injection would be occurring near large active faults capable of generating larger magnitude earthquakes. For seismic risk assessment, this observation is especially relevant in more populated areas.

The faults within the Monterey footprint in the Santa Maria Basin have low slip rates (less than 1 mm/year) and there is only sparse, low-magnitude seismicity (Figure 3.4-14). Only one relatively short fault having uncertain activity has been mapped within the Monterey zone of the Los Angeles Basins (Figure 3.4-12), and the seismicity is similarly sparse. Thus, these Monterey source rock zones appear to have lower potential seismic hazard compared to those in the Salinas and Ventura Basins. However, the very large population density in Los Angeles results in a high potential seismic risk despite the relatively low potential incremental seismic hazard. As discussed in Volume II, Chapter 4, Section 4.4.2., microseismic monitoring has been used to monitor hydraulic fracturing in the Inglewood oilfield in the Los Angeles Basin (e.g., Cardno ENTRIX, 2012).

There is a large degree of uncertainty in the preliminary appraisal of seismic risk described above. First, it is generally understood that California has many unmapped faults, which can only be imaged with 3-D seismic reflection surveying, or inferred through analysis of earthquake patterns. Secondly, at present, records of fluid injection in the DOGGR database are likely inadequate to carry out a comprehensive assessment of the potential for induced seismicity in the state. In particular, the monthly averages of injection volume and pressure data currently reported, are too coarse to be useful in many cases. There is also a lack of readily available information on injection depth for most wastewater disposal wells. Improving the quality of these data could inform future induced seismic hazard assessments. At a more fundamental level, there is a lack of understanding of the potential for subsurface fluid injection to cause earthquakes in an active tectonic margin like California, compared with regions in the continental interior where recent cases of induced seismicity related to wastewater injection have occurred. How differences in the geology, tectonic stressing rate and seismicity between California and the continental interior influence the potential for induced seismic hazard has yet to be studied. For more discussion on this uncertainty and additional data gaps, see Chapter 4 of Volume II.

We have outlined some of the factors relevant to assessing seismic risk in the footprint of the Monterey source rock. If large-scale development of Monterey source rock were to commence, it would be important to consider not just the locations of faults, historic seismic activity, and human populations, as discussed here, but also factors such as the local lithology of the injection horizon, pressure and volume of fluid injection, and proximity to human infrastructure to evaluate seismic risk. There also are important data gaps in our understanding of seismicity induced by underground injection in

California that would need to be addressed to conduct thorough risk assessments, as described in Volume II, Chapter 4, Section 4.6. In addition, it would be useful to consider implementing practices to mitigate seismic risk as described in Volume II, Chapter 4, Section 4.5.

3.4.7. Potential Impacts to Wildlife and Vegetation

In this section we examine how the footprint of potential Monterey source rock intersects habitat for wildlife and vegetation. There are a number of ways in which new development of source rock could impact wildlife and vegetation. Construction of well pads and other oil and gas production infrastructure in areas that support native species causes habitat loss and fragmentation. Increased disturbance and traffic can promote invasive species. Increased noise, light, traffic, water contamination, and water use can adversely affect populations of organisms. We do not have enough information about future Monterey source rock development to quantify these impacts in detail, but we look at the footprint of potential source rock to understand the types of habitats and native species that could be impacted by development.

Figure 3.4-16 shows the spatial alignment of source rock with the land cover categories in the National Vegetation Classification system. As indicated in Table 3.4-9, the two biggest land cover categories are agricultural vegetation and human land use, mainly driven by the dominant land uses in the San Joaquin and Los Angeles Basins. There is also some area that is shrubland and grassland in all basins outside of Los Angeles, a small amount of water mainly because of the portion of source rock that is offshore in the Ventura Basin, and a very small amount of forested land.

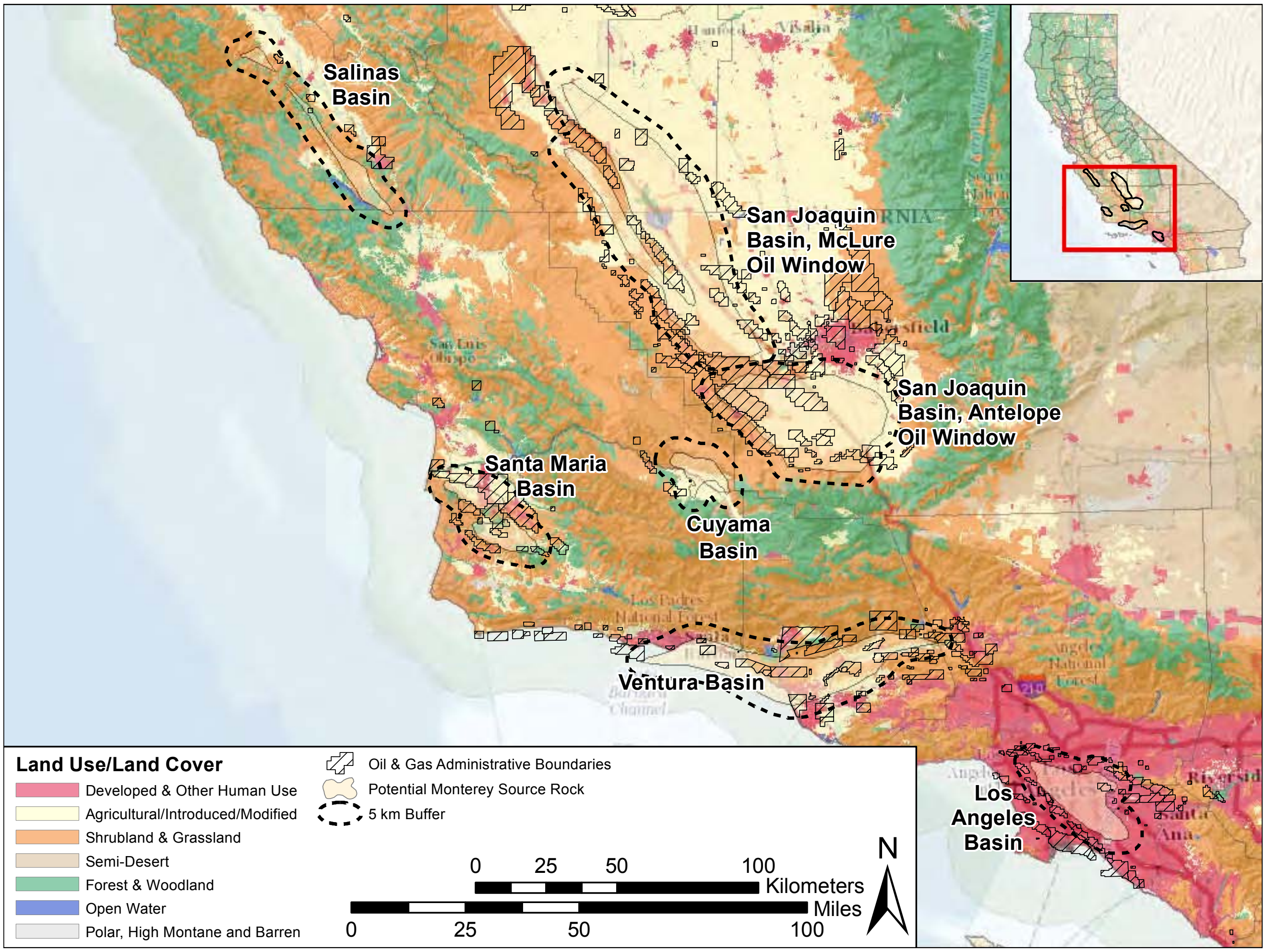

Figure 3.4-16. Overlay of potential Monterey source rock and land use. Land use data from Department of Conservation (2012) and U.C. Santa Barbara Biogeography Lab (1998).

Table 3.4-9. National Vegetation Classification category overlapping with potential Monterey source rock. For a more detailed table broken out by county, see Appendix 3.E.

	Over Source Rock (km²)	In 5 km Buffer (km²)	Over Source Rock + Buffer (km²)	Over Source Rock + Buffer (% of Total)	Outside source rock (km²)	Total (km²)
Agricultural Vegetation	2,900	1,800	4,700	8.9%	48,400	53,100
Developed & Other Human Use	700	900	1,600	7.2%	20,500	22,100
Forest & Woodland	200	400	600	0.4%	144,000	144,600
Open Water	400	400	700	3.4%	19,700	20,500
Shrubland & Grassland	1,700	2,800	4,400	6.4%	63,900	68,300

Publicly owned property, conservation lands and easements often provide important open space for native species. As shown in Figure 3.4-17 and Table 3.4-10, a relatively small proportion (13%) of the potential source rock area falls into these categories. Some of these areas are set aside expressly for conservation, such as the Wind Wolves preserve in the southern San Joaquin, and would be unlikely sites for any oil and gas development. Others, however, U.S. Bureau of Land Management and Forest Service land, are intended to serve multiple purposes and could be leased for petroleum production.

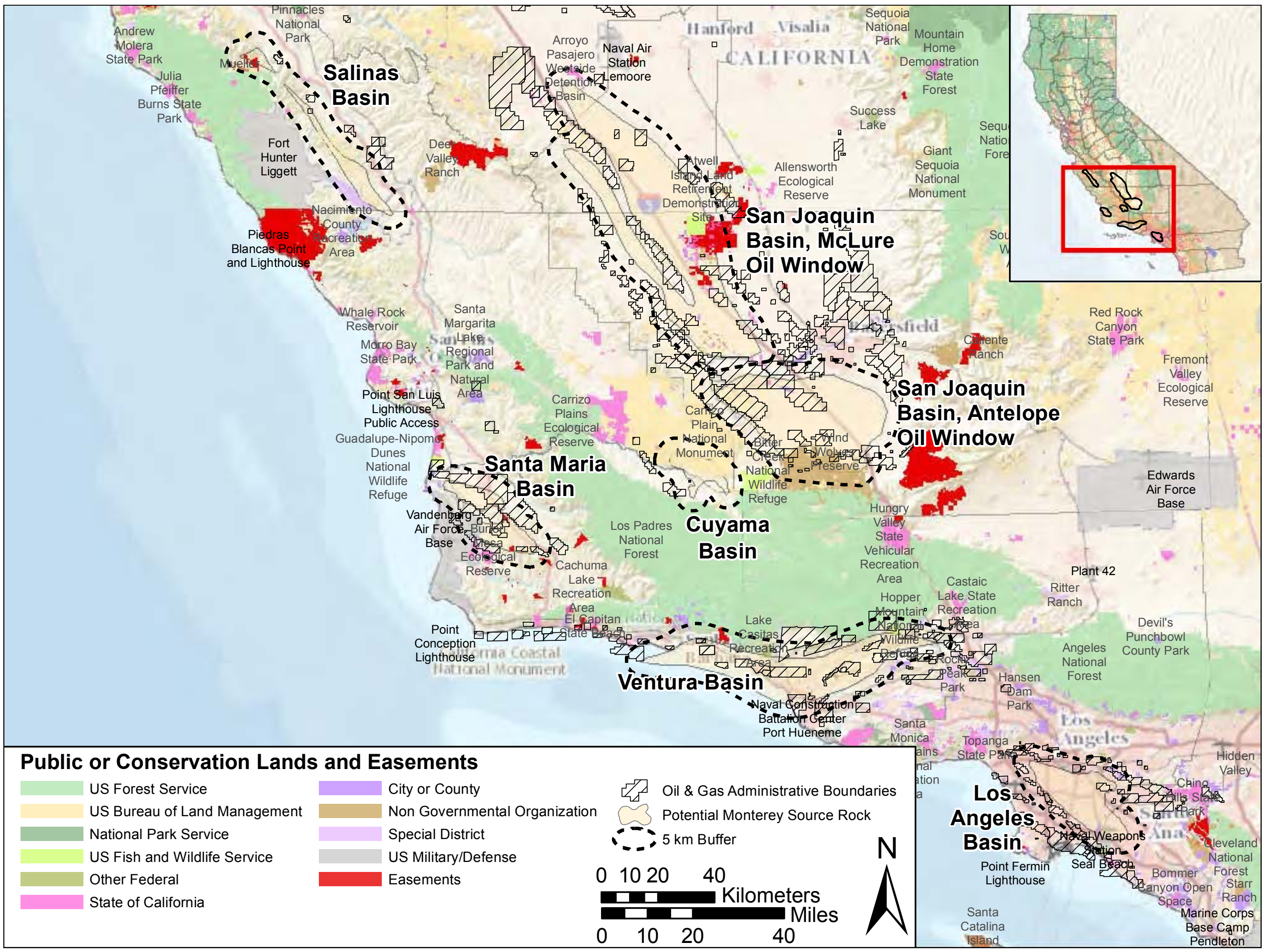

Figure 3.4-17. Overlay of potential Monterey source rock with public lands, conservation lands and easements.

Table 3.4-10. Proportion of potential Monterey Source Rock that is public land or conservation land and easements compared with other ownership types.

	Over Source Rock (km^2)	In 5 km Buffer (km^2)	Over Source Rock + Buffer (km^2)	Over Source Rock + Buffer (% of Total)	Outside Source Rock + Buffer
Public Land or Conservation Lands and Easements	600	1,000	1,600	13%	219,800
Other Ownership	5,300	5,200	10,500	87%	193,300
Total	5,900	6,300	12,100	100%	413,100

The United States Fish and Wildlife Service can designate lands essential for the survival of a threatened or endangered species as critical habitat. Shown in Figure 3.4-18 are the areas of critical habitat that overlap with potential source rock. As indicated by Table 3.4-11, there are a few cases in which much or even all of a species' critical habitat is within the footprint of potential Monterey source rock, such as the Buena Vista Lake Shrew, which has a very small amount of critical habitat in the San Joaquin Basin, and the Ventura marsh milk-vetch. Others, such as the California condor, have a substantial amount of critical habitat in the vicinity of potential source rock.

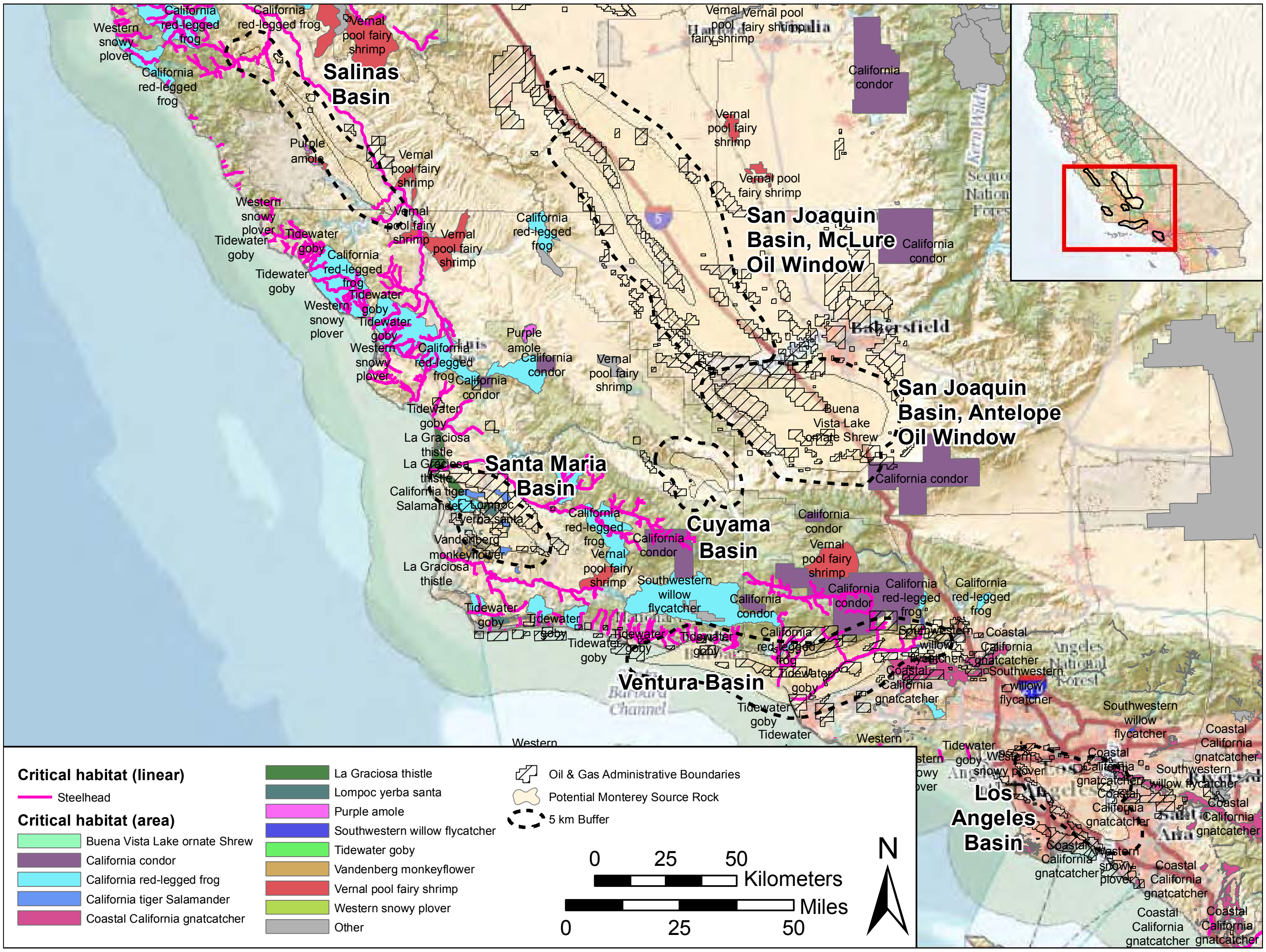

Figure 3-4-18. Overlay of potential Monterey source rock and federally-designated critical habitat. Land use data from U.S. Fish and Wildlife Service (2014).

Table 3.4-11. Overlap of potential Monterey source rock with U.S. Fish and Wildlife Service designated critical habitat for threatened and endangered species. Only those with at least 1% of their critical habitat overlying the potential source rock + 5 km (3 mi) buffer are listed.

	Over Source Rock (km^2)	In 5 km Buffer (km^2)	Over Source Rock + Buffer (km^2)	Over Source Rock + Buffer (% of Total)	Outside potential source rock (km^2)	Total (km^2)
Buena Vista Lake ornate shrew	.3	0	.3	100	0	.3
California condor		76	76	3	2,374	2,449
California red-legged frog	15	45	60	1	6,580	6,640
California tiger salamander	24	19	43	5	810	853
Coastal California gnatcatcher		37	37	2	1,471	1,508
La graciosa thistle	39	17	56	57	42	98
Least bell's vireo	0	12	13	9	137	150
Lompoc yerba santa		9	9	35	17	26
Southwestern willow flycatcher	28	13	41	26	118	159
Tidewater goby	2	0	2	5	38	41
Vandenberg monkeyflower		15	15	37	25	40
Ventura marsh milk-vetch	1	1	2	100		2
Western snowy plover	2	1	3	4	64	67

Critical habitat is not designated for all threatened and endangered species. In particular, despite a large number of threatened and endangered species in the San Joaquin Basin, very little critical habitat has been designated. To show lands that tend to be of high value for native species in the San Joaquin, we show San Joaquin kit fox habitat suitability. Kit foxes tend to co-occur with other native species in the region, although they are more tolerant of human disturbance than most of the native plants and animals in the local species assemblage. As a result the map of their habitat (Figure 3.4-19) likely reflects a slight overestimate of habitat that supports high densities of native species in the area. As indicated by Table 3.4-12, approximately 44% of the area of high suitability for San Joaquin kit fox is within the footprint of potential Monterey source rock or in the 5 km buffer. If development were to occur in Monterey source rock, it would be likely to disproportionately affect native species in the San Joaquin Basin, given the large extent of source rock in that region, the high density of endangered species, and the fact that this region most likely has the greatest potential to be developed as a shale oil play (see the section on the San Joaquin Basin in Appendix 3.A).

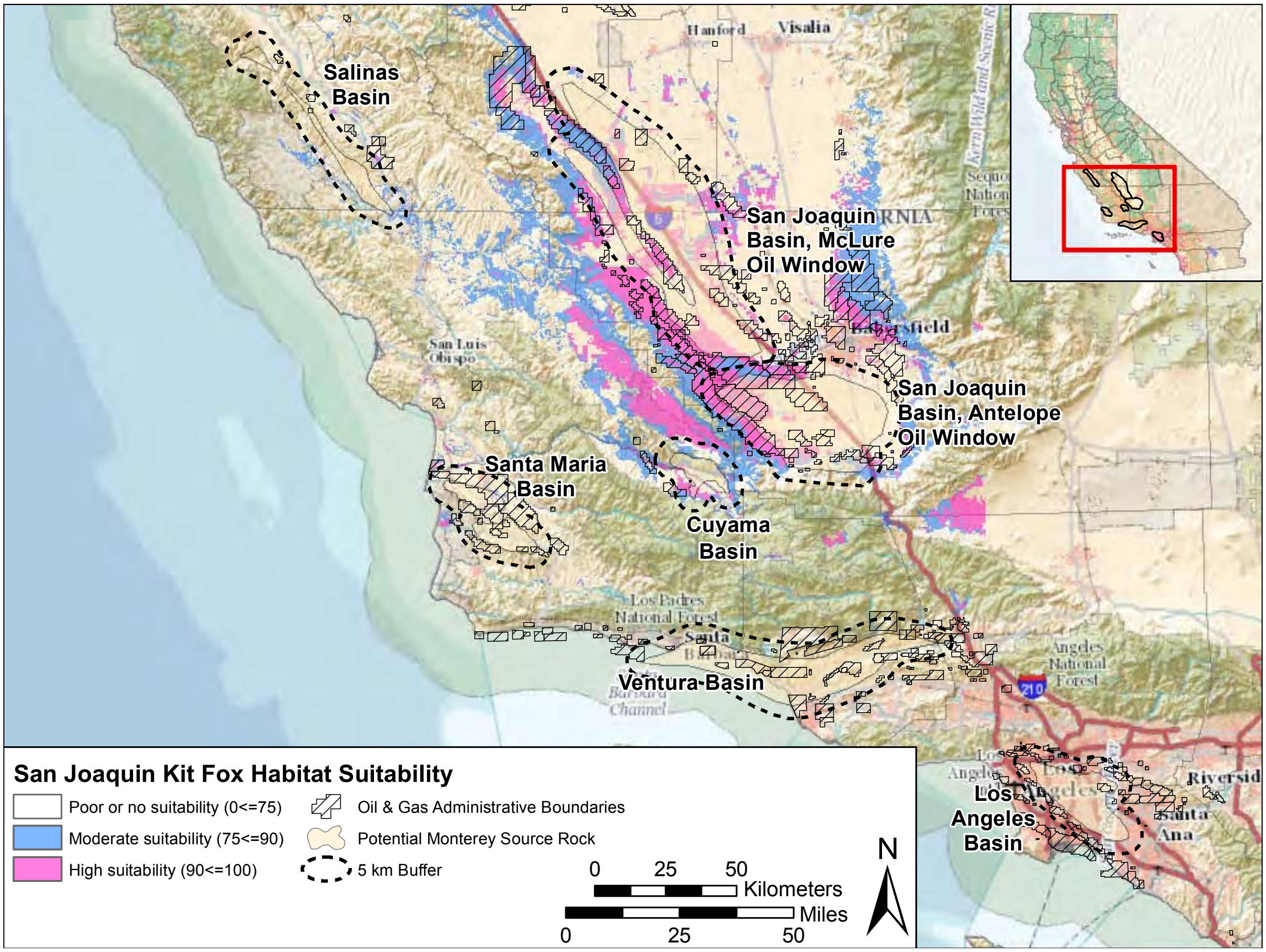

Figure 3.4-19. Overlay of potential Monterey source rock and San Joaquin kit fox habitat suitability.

Table 3.4-12. Overlap of San Joaquin kit fox habitat suitability with potential Monterey source rock.

	Over Source Rock (km²)	In 5 km Buffer (km²)	Over Source Rock + Buffer (km²)	Over Source Rock + Buffer (% of Total)	Outside (km²)	Total (km²)
High	881	863	1,743	44%	2,224	3,968
Moderate	279	563	841	13%	5,888	6,729
Unsuitable	4,686	4,822	9,508	2%	404,068	413,575

3.5. Data Gaps in Understanding the Future of Monterey Source Rock Development and its Impacts

Despite the attention and speculation about the possible resources in Monterey source rock, there is still tremendous uncertainty about its potential resources and indeed whether it will ever be commercially developed. If it were developed, we do not know what technology would be used or the precise locations and density of the activity. As a result we cannot yet predict the environmental and public health consequences of Monterey source rock development. Indeed, as noted throughout Volume II, there are many aspects for which we lack the data necessary to fully evaluate even the past and present impacts of well stimulation in the state. We recommend four studies or groups of studies that would need to be undertaken at the appropriate stage of Monterey source rock development.

Present:

1. Conduct a comprehensive, peer-reviewed, probabilistic resource assessment of Monterey source rock, as described in Section .

2. Fill data gaps described for the environmental impacts of well stimulation described in this report. Here we present a summary of the data gaps described in more detail in Volume II.

    a. Water quality impacts

    b. Water supply impacts

    c. Atmospheric impacts

    d. Seismic impacts

        i. California has many unmapped faults.

        ii. Records of fluid injection in the DOGGR database are likely inadequate to carry out a comprehensive assessment of the potential for induced seismicity in the state. Need to collect more detailed information on injection volume, pressure data, and injection depth for wastewater disposal wells.

        iii. We do not fully understand the potential for subsurface fluid injection to cause earthquakes in an active tectonic margin like California. Most recent cases of induced seismicity related to wastewater injection have occurred in the continental interior.

iv. For more discussion on data gaps for seismic impacts, see Chapter 4 of Volume II.

e. Wildlife and vegetation impacts

Ongoing:

3. Monitor for experimental wells and early stages of commercial development in Monterey source rock, as described in Section .

If commercial-scale development commences,

4. Re-evaluate resource assessment in (1) – does it need to be updated to account for new technology and/or production data from wells?

5. Conduct a rigorous risk assessment of source rock development, using input from Volumes II and III of this report.

3.6. Findings and Conclusions

3.6.1. Findings Concerning Source-Rock Development in California

3.6.1.1. Geologic Basis

A source-rock is a sedimentary formation containing a sufficient concentration of organic matter for the generation of petroleum. The Monterey Formation includes active source rocks from which most California petroleum was generated. Other active petroleum source rocks are also present in certain California basins.

In continuous shale-oil reservoirs, the source rock and the reservoir rock are one and the same. Instead of the geographically concentrated oil in conventional oil fields, low-permeability shale reservoirs extend over vast areas. Technological advances now enable oil and/or gas to be produced directly from source rocks in certain places, particularly from the Bakken and Three Forks formations in the Williston Basin and from the Eagle Ford Formation in Texas. Large-scale shale oil production is enabled by hundreds or thousands of long-reach directional wells, each having been developed with multi-stage massive hydraulic fractures. This approach is not easily transferable to the highly discontinuous and heterogeneous Monterey formation.

Parts of several sedimentary basins in California, which are underlain by thermally mature petroleum source rocks, may have potential for source-rock reservoir production. Potentially productive areas occur in the Cuyama, Los Angeles, Salinas, Santa Barbara-Ventura, Santa Maria, and San Joaquin Basins.

Published EIA estimates of Monterey shale oil do not provide sufficient information for scientific evaluation. We recommend a systematic, probabilistic assessment of California source-rock resources be undertaken to quantify the uncertainty in shale-oil resource potential. Ultimately, the uncertainty can be efficiently reduced or eliminated by drilling exploration and production wells.

3.6.1.2. Exploration of Monterey Source Rock

Impending shale oil development would be signaled by land acquisition, exploratory drilling, and then small-scale production, most likely in the San Joaquin Valley. Identification of likely exploratory wells is possible with information on well depth and target productive horizon. However, exploratory wells are likely to be confidential and the relevant data would not be available outside of state agencies until confidentiality on the well expired.

3.6.1.3. Potential Environmental Impacts

Much of what we can predict about potential future impacts of Monterey Source Rock hinges on the maximum footprint of source rock, and its greater depth relative to current production.

a. Footprint: While the Monterey Formation and its equivalents extend over much of California, only a fraction of it has the potential to be developed as a source-rock play. The total area of estimated Monterey source rock is about 5,900 km^2 (2,300 mi^2). 92% of that area is already developed for oil and gas production (that is, has at least one well per km^2). The remaining 8% is not developed for oil and gas (that is, has less than 1 well per square kilometer). However, the entire extent of potential Monterey source rock is within the six basins with the greatest proven oil reserves in the state; no point of the footprint is more than 20 kilometers (12 miles) from the nearest oil field. Potential Monterey source rock underlies significant water resources, including groundwater basins used by municipal, domestic, and agricultural users. Increased oil exploration in the Monterey source rock could increase the potential for water contamination by stimulation fluids (and comingled produced water).

b. Depth: Thermally mature source rocks are deeper on average than the currently producing formations in California. This means the stimulated interval tends to be far below usable groundwater, reducing the risk of an accidental intersection of a fracture with a usable aquifer. Deeper formations also tend to produce saltier formation water. Development far away from existing wells – both horizontally and vertically – reduces the probability of leakage via an improperly sealed nearby well. However, these formations are overlain by significant water resources, including groundwater basins used by municipal, domestic, and agricultural users. Increased oil exploration in the Monterey source rock increases the potential for water contamination by stimulation fluids (and comingled produced water).

3.7. Acknowledgments

Many people contributed thoughts and helpful comments on this case study. Patrick Dobson of Lawrence Berkeley National Laboratory generated much of the work in Volume I Chapter 4 of this report, which formed the basis of this chapter, and provided helpful comments on the text. Michelle Robertson of Lawrence Berkeley National Laboratory provided invaluable assistance with Geographic Information Systems.

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Chapter Four

A Case Study of the Petroleum Geological Potential and Potential Public Health Risks Associated with Hydraulic Fracturing and Oil and Gas Development in The Los Angeles Basin

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4.1. Introduction to the Los Angeles Basin Case Study

The Los Angeles Basin is unique in its exceptional natural concentration of oil directly beneath a dense urban population. In few other places in the world has simultaneous petroleum development and urbanization occurred to such an extent. Conflicts of oil and city life are not new to Los Angeles, but recent reports suggesting the possibility of additional large-scale oil production enabled by hydraulic fracturing, coupled with the ever increasing encroachment of urbanization on the existing oil fields, lends a particular urgency to the need to understand the public health implications of having millions of people who live, work, play, and learn in close proximity to billions of barrels of crude oil.

The Los Angeles Basin Case Study contains two components. In Section 4.2, Gautier reviews the history and current trends of oil production in the Los Angeles Basin combined with a geology-based analysis of the potential for additional petroleum development. We conclude in this section that oil production in the Los Angeles Basin has been in decline for years, and that continued oil development is likely to be within existing oil fields rather than widespread development of previously undeveloped source-rock (shale tight oil) resources outside of these boundaries. Based on this scenario of future oil development, in the second part of the Los Angeles Basin Case Study, Section 4.3, Shonkoff and colleagues review the numbers and demographics of residents, schools, daycare centers and other "sensitive receptors" in proximity to existing active oil and gas development operations. The authors then use criteria air pollutant and toxic air contaminant data from southern California and elsewhere to evaluate the potential implications of oil and gas activities for public health. Next, Shonkoff and colleagues assess the potential for protected groundwater contamination attributable to hydraulic fracturing-enabled oil and gas development and potential exposure pathways. Finally, conclusions, research needs, and recommendations are presented.

4.2. History, Distribution, and Potential for Additional Oil Production in the Los Angeles Basin

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4.2.1. Abstract

Beneath the city of Los Angeles is a deep geological basin with all the components and timing of a nearly ideal petroleum system. As a consequence, the basin has one of the highest known natural concentrations of crude oil, located directly beneath a modern megacity. Petroleum has been exploited in Los Angeles since prehistoric times, but more than 90 percent of the known oil was found during a 15-year flurry of exploration in the first half of the twentieth century. Petroleum development and urbanization have gone hand in hand and been in conflict since the beginning. In spite of intense development, large quantities of recoverable oil probably remain. Besides known oil, the basin has resource potential in three categories: (1) Relatively small volumes of oil in undiscovered conventional oil fields, (2) Large volumes of additional recoverable oil in existing fields, and (3) The possibility of unconventional “shale oil” resources in Monterey-equivalent source rock systems near the center of the basin. Extensive development of any of these resources with existing technology would entail conflicts between oil production and the needs of the urban population. Therefore, technological innovations would probably be required for large-scale additional petroleum development in the Los Angeles Basin.

4.2.2. Introduction

The City of Los Angeles (L.A.) is unique in the large volumes of petroleum that underlie the city. Close proximity of a large urban population to intensive oil development poses potential hazards not necessarily present in areas of lower population density. Therefore, the possibility of extensive new development of additional petroleum resources raises concerns about potential consequences to human health. This part of the Los Angeles Basin Case Study discusses the petroleum resources of the basin and the potential for additional development.

4.2.3. Historical Summary of Petroleum Development

Native Americans used oil from natural seeps long before Europeans arrived in southern California (Merriam, 1914; Harris and Jefferson, 1985; Hodgson, 1987), and commercial production came in the mid-nineteenth century from hand-dug pits. In 1880 the Puente Oil Company drilled an exploratory well near the seeps in Brea Canyon and found Brea-Olinda oil field. At that time, Los Angeles had a growing population of about 11,000 people. In 1890, Edward Doheny and Charles Canfield started developing Los Angeles City Field; the ensuing oil boom made them rich, but also upset locals with its noise, smell, and mess. Only 50,000 people then lived in L.A., but conflicts between oil and the urban population had already begun (Rintoul, 1991).

Exploratory drilling was wildly successful in the second and third decades of the twentieth century. The biggest fields were found in a 15-year period beginning with Montebello in 1917 and ending with Wilmington-Belmont in 1932. In the frenzy of the early years of the petroleum boom, operators seemed to have little regard for efficiency, safety, human health, or environmental consequences. Wells interfered with one another and reservoirs were ruined; spills, well failures, fire, injury, and death were common.

With unrestricted production, output from each giant field spiked, flooding the market and collapsing prices. Wells on Signal Hill flowed 41,200 m^3 (259,000 barrels) per day in October of 1923 (Rintoul, 1991). That year, Long Beach field produced more than 11 million m^3 (68 million barrels) and Santa Fe Springs field more than 13 million m^3 (81 million barrels). Inglewood output exceeded 2.9 million m^3 (18 million barrels) in 1925, and Huntington Beach yielded more than 4.1 million m^3 (26 million barrels) in 1927. Wilmington-Belmont was the only giant field initially developed in a more orderly fashion, and as production from other fields declined, it provided an ever-greater share of L.A. production. In 1969 Wilmington gave up more than 14 million m^3 (89 million barrels) of oil, while all of California Division of Oil, Gas, and Geothermal Resources (DOGGR) District 1 (L.A., Orange and San Bernardino counties), including Wilmington, produced about 26.9 million m^3 (169 million barrels). By the late 1970s, with few new discoveries and increasing pressure from urbanization, wildcat drilling at had all but ceased in the Los Angeles Basin (Figure 4.2-1).

Greater L.A. is now home to more than 18 million people, many of who have a high demand for refined petroleum, but who struggle to reconcile oil production and city life. Field operations are increasingly constrained by federal, state, county, and local policies, and by competing commercial interests. Many small fields have been shut in with reservoirs still on primary production, and operations of most large fields have been contracting for years. In 2013, all onshore wells in District 1 produced just 2.2 million m^3 (14 million barrels) of oil, less than 10% of the 1969 output.

Inefficient development practices and highly restricted application of secondary and tertiary recovery technologies are the main reasons for the low recovery efficiencies (the portion of the original oil in place that has been produced or is in remaining proved reserves) now observed in the Los Angeles Basin oil fields (Gautier et al., 2013. Geologists and engineers who know the basin believe that large amounts of additional oil could be recovered with the systematic application of modern technology (Gautier et al., 2013). However, even when oil prices soared between 2007 and 2014, operator’s efforts in Brea Olinda, Huntington Beach, Long Beach, Inglewood, Santa Fe Springs, Wilmington, and other fields only managed to flatten the decline (Figure 4.2-2), suggesting that without some sort of technological innovation, the petroleum era in southern California could end with billions of barrels of recoverable oil still in the ground.

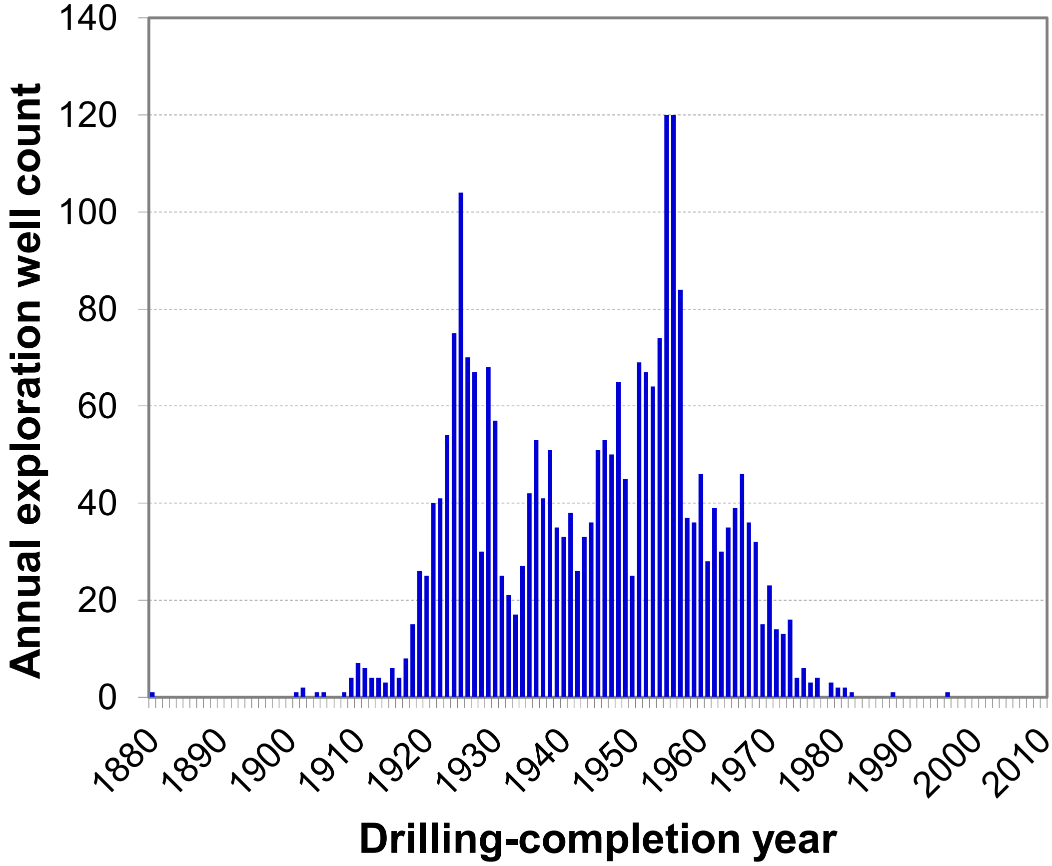

Figure 4.2-1. Numbers of wildcat exploration well drilled as a function of time in the Los Angeles Basin (Figure courtesy of T.R. Klett, U.S. Geological Survey).

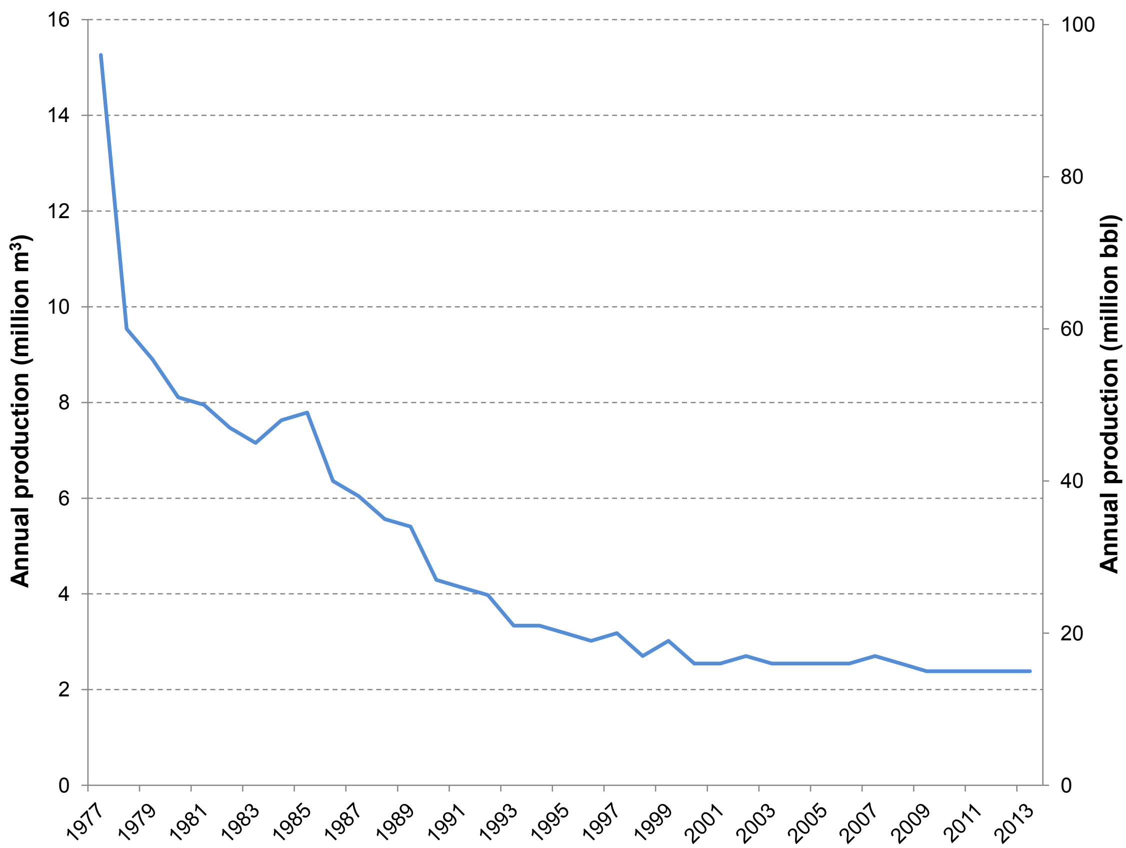

Figure 4.2-2. Graph showing onshore production of crude oil from reserves in the Los Angeles Basin between 1977 and 2015. Data from the Energy Information Administration (downloaded 2 May 2015).

4.2.4. Distribution of Known Petroleum

To geologists, the Los Angeles Basin is a small (5,700 km²; 2,200 mi²) but deep structural chasm filled with more than 8,000 meters (>26,000 feet) of sediments and sedimentary rock. A nearly ideal petroleum system and fortuitous timing of geological events have endowed the basin with what may be the world's highest concentration of crude oil (Barbat, 1958; Biddle, 1991; Gardett, 1971; Wright, 1987; Yerkes et al., 1965) (Figure 4.2-3). Petroleum is still forming in Los Angeles, as demonstrated by numerous oil and gas seeps such as those at Rancho La Brea (Hancock Park) and Brea Canyon. The fact that gas caps are almost nonexistent in the oil fields suggests that most gas-phase hydrocarbons have been naturally lost to the atmosphere, while much of the migrated oil has accumulated in conventional traps.

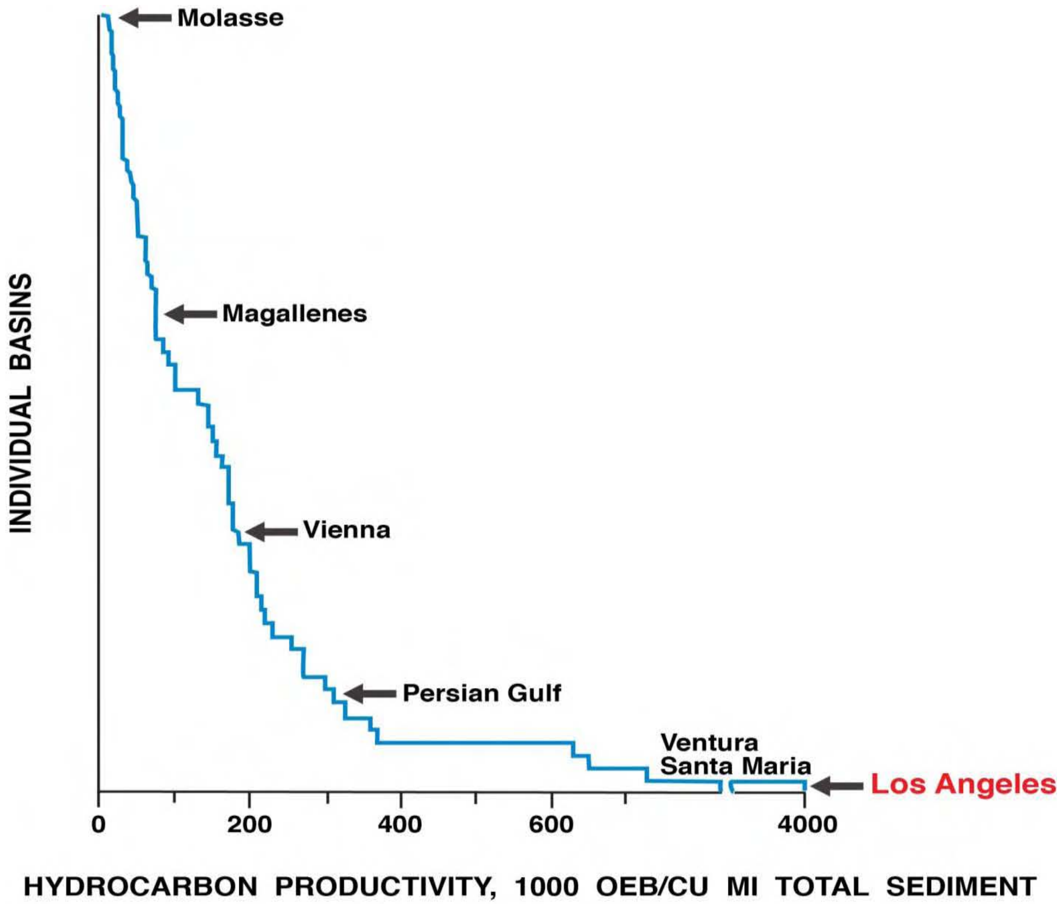

Figure 4.2-3. Relative hydrocarbon concentration by basin. Source: Kevin Biddle 1991: American Association of Petroleum Geologists Memoir 52 (OEB/CU MI = Oil equivalent barrels per cubic mile).

No petroleum province of comparable richness exists in the midst of a megacity. Petroleum has been produced from 68 named fields, most of which are closely related to the basin's principal structures (Wright, 1991). The largest oil accumulations, by known oil (cumulative production and reported remaining reserves), are: Wilmington-Belmont, Huntington Beach, Long Beach, Santa Fe Springs, Brea-Olinda, Inglewood, Dominguez, Coyote West, Torrance, Seal Beach, Richfield, Montebello, Beverly Hills East, Coyote East, Rosecrans, and Yorba Linda. These 15 accumulations, which account for more than 91 percent of recoverable oil in the basin, were all found before 1933. The most recent discoveries occurred during the early-to-mid 1960s when Beverly Hills East, Las Cienegas (Jefferson area), Riviera, and San Vicente were found. Another large field, Beta Offshore, was found in federal waters in 1976.

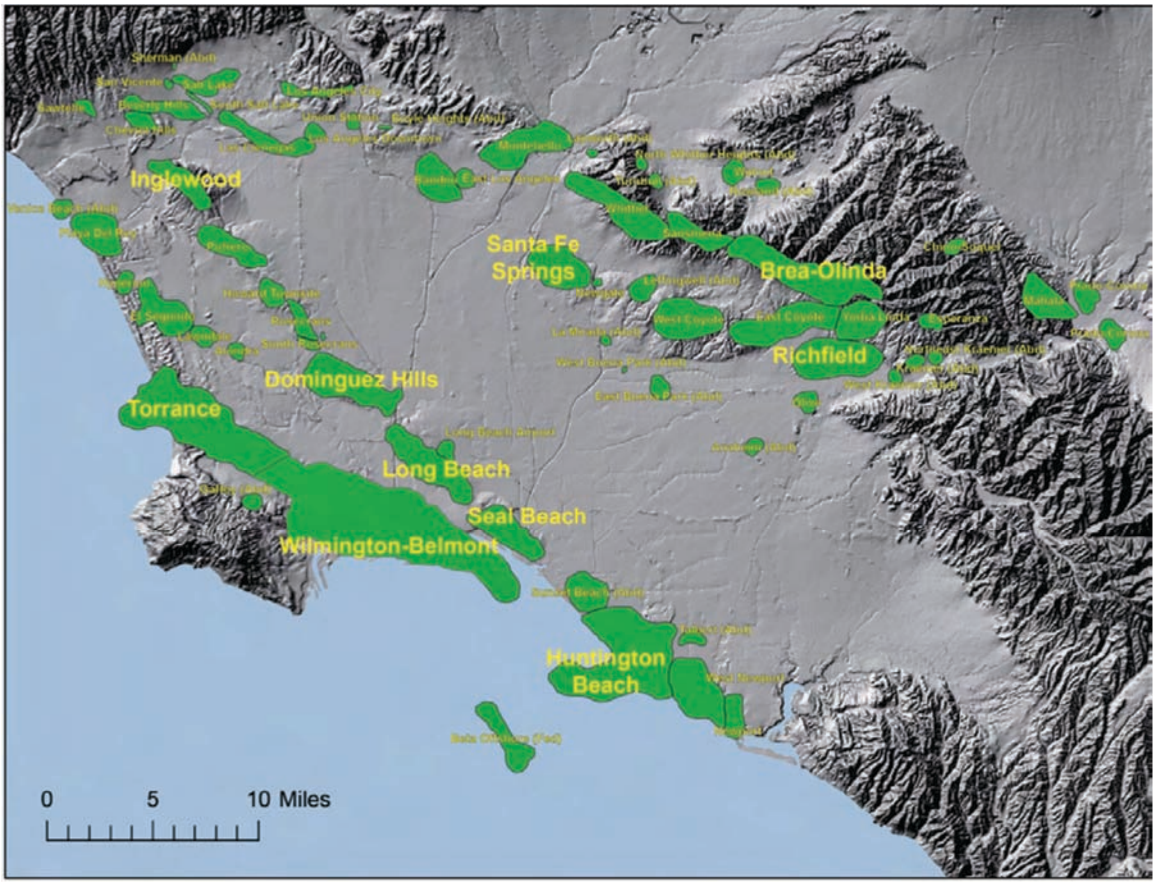

Figure 4.2-4. Map showing shaded relief topography and named oil fields of the Los Angeles Basin. The ten largest fields, studied by Gautier et al. (2013) are labeled in bold type.

4.2.5. Resource Potential of the Los Angeles Basin

In addition to its cumulative production and reported remaining reserves, the basin has resource potential in three categories: (1) Undiscovered conventional oil fields, (2) Growth of reserves in existing fields, and (3) Development of unconventional resources.

4.2.5.1. Undiscovered Conventional Oil Fields

The last systematic assessment of undiscovered conventional oil and gas resources in the Los Angeles Basin was conducted by the United States Geological Survey (USGS) and published in 1995 (Beyer, 1995; Gautier et al., 1995). At that time, the mean undiscovered conventional oil resource for the basin, including state waters but excluding federal waters, was estimated to be approximately 980 million barrels of technically recoverable oil (MMBO).

These estimated undiscovered resources were distributed among seven confirmed (meaning historically productive) USGS-defined plays (Volume I, Chapter 4,) having an aggregated mean estimated undiscovered conventional resource of 160 million m^3 (1 billion barrels) of oil (Gautier et al., 1995). A mean basin-level estimate of almost 0.16 billion m^3 of oil (1 billion barrels of oil (BBO)) would be considered quite significant in almost any untested petroleum basin. However, in Los Angeles, where the original oil in place probably exceeded 6.4 billion m^3 of oil (40 BBO), an undiscovered technically recoverable volume of less than 0.16 billion m^3 of oil (1 BBO) represents the aggregate recoverable resource remaining in many small and hard-to-find accumulations that may not warrant much expensive exploration effort. If found, these undiscovered accumulations would be expected to share many of the geological features of the known field population.

4.2.5.2. Growth of Reserves in Existing Fields

In order to evaluate the volumes of potentially recoverable oil remaining in existing fields of the Los Angeles Basin, the USGS recently assessed the 10 largest fields in the basin (Figure 4.2-4) (Gautier et al., 2013), using production, reserves, and well data published by the California Division of Oil, Gas, and Geothermal Resources. The geology of each field was analyzed, and the history of its engineering and development practices was reviewed. Probability distributions for original oil in place and maximum potential recovery efficiency were developed. The maximum recovery was evaluated on the basis of recovery efficiencies that have been modeled in engineering studies, achieved in similar reservoirs elsewhere, or indicated by laboratory results reported in technical literature. Probability distributions of original-oil-in-place and recovery efficiency were combined in a Monte Carlo simulation to estimate remaining recoverable oil in each field. The results were then probabilistically aggregated. Those aggregated results from the USGS study suggest that between 0.22 and 0.89 billion m^3 (1.4 and 5.6 billion barrels) of additional oil, recoverable with current technology, remain in the 10 analyzed fields, with a mean estimate is approximately 0.51 billion m^3 (3.2 billion barrels). In addition to the estimated remaining recoverable resources in the ten largest fields, recoverable oil likely also remains in the other 58 oil fields in the Los Angeles Basin. It is likely that some of these fields contain reservoirs that are of low permeability.

Recovery of these resources would probably require field-level redevelopment and unrestricted application of current technology, including use of improved imaging and widespread application of directional drilling, combined with extensive water, steam, and carbon dioxide flooding. Because the majority of petroleum reservoirs of the giant Los Angeles Basin fields are sandstones with high porosity and permeability, redevelopment of these fields would not generally require hydraulic fracturing as a common practice. However, certain lower permeability reservoirs are probably present in many of these large fields, the development and production of which could require the local and limited application of hydraulic fracturing in conjunction with other techniques.

4.2.5.3. Unconventional Resources

In principal, any petroleum source rock in the proper state of thermal maturation could be a reservoir for shale oil or shale gas production. Given the large concentrations of petroleum in the Los Angeles Basin, it is certain that prolific organic-rich source rocks are present in the basin, and that they are thermally mature for oil generation. Therefore, it is possible that thermally mature source rocks might be directly developed for oil in the Los Angeles Basin as they have been in Texas, North Dakota, and elsewhere.

During its 1995 National Assessment (Gautier et al., 1995), the USGS described a potential play involving technically recoverable resources in source rocks and adjacent strata in the Los Angeles Basin (Beyer, 1995). Although the play was not quantitatively assessed at the time, its resource potential and geological properties were described. The identification and descriptions of this postulated petroleum accumulation, named the "Deep Overpressured Fractured Rocks of Central Syncline Play", were based largely on the results of the American Petrofina Central Core Hole No. 1 (Redrill) well (APCCH). The APCCH, located in Sec. 4, T. 3 S., R. 13 W., is the deepest well yet drilled in the Los Angeles Basin (Wright 1991; Beyer 1995). It encountered abnormally high pore fluid pressures and tested moderately high-gravity oil below about 5,500 m (18,000 ft). The well bottomed in lowermost Delmontian (Late Miocene) rocks at a measured depth of 6,466.3 m (21,215 ft) and did not reach the presumed Mohnian (Late Middle Miocene) Monterey-equivalent source rock. The unconventional reservoir was postulated to consist of fractured strata within and immediately adjacent to the source rock interval.

The potentially productive area of the postulated source-rock play includes most of the Central Syncline and its deep flanks, at depths below which the source rock interval has been heated sufficiently for maximum petroleum generation and formation of an over-pressured condition (Figure 4.2-5). The deep southwestern flank of the Central Syncline was regarded by Beyer (1995) as the most favorable location for potentially productive continuous source-rock reservoirs.

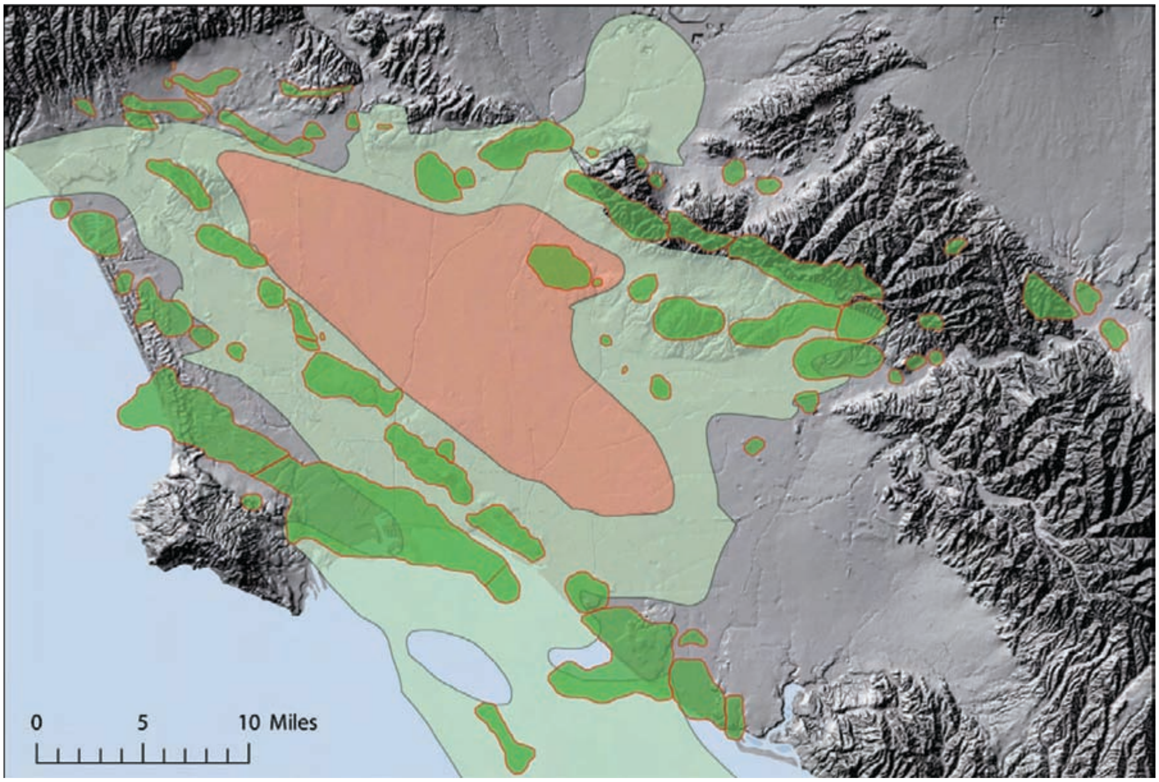

Figure 4.2-5. Map showing shaded relief topography of the Los Angeles Basin, with oil fields shown on Figure 4.2-4 in dark green and the areas where Monterey-equivalent (Mohnian-age) strata are at depths of 2,400 m (8,000 ft) or more and 14,000 feet (4,300 m) or more,shown in light green and red, respectively. Oil field outlines from DOGGR, and Monterey-equivalent depths from Wright (1991). There area in red approximately corresponds to the deepest part of the Central Syncline of the basin.

The postulated fracturing of potential reservoir rocks is inferred to result from extremely high pore fluid pressures formed during maturation of kerogen in organic-rich shales. Late Miocene and early Pliocene extensional faulting and more recent tectonic compression may also contribute to fracturing. Natural fractures are thought to provide efficient pathways for oil expulsion and migration away from source rocks. The likelihood of natural fracturing thus may constitute a technical risk to the potential shale oil play. However, the presence of overpressuring in the APCCH suggests that at least some seals remain intact and that at least some oil is retained. Several petroleum geochemists, including Price (1994), have suggested that large amounts of generated hydrocarbons may remain in or near source rocks in basins where expulsion routes have not been effectively provided by tectonics; an example of this phenomenon would be the large quantity of oil retained by the Bakken Formation in North Dakota.

The postulated continuous-type play is unexplored. The APCCH confirmed the presence of hydrocarbons and overpressuring, but did not directly demonstrate the play, as its total depth did not reach the reservoir level. Other, less deep, wells west of the Central Syncline on the east flank of the Newport-Inglewood Zone have penetrated interbedded sandstone and shale containing marine kerogen in lower Mohnian strata. Recently, hydraulic fracturing has been applied to a number of deep wells in the Inglewood oil field to enhance oil recovery (Cardno ENTRIX, 2012), and perhaps to test the concept of an unconventional source-rock system play in the Los Angeles Basin.

The geological evidence suggests that large volumes of hydrocarbons were generated from source rocks in the Central Syncline, and that at least some oil remains. However, the idea that large recoverable volumes of petroleum are present at great depth in suitable reservoir rocks is hypothetical. Moreover, because of the likely highly fractured condition of the potentially productive source rock intervals, the degree to which hydraulic fracturing would be needed for development of this hypothetical play is also a subject of speculation. The presence of at least some recoverable oil in fractured reservoirs closely associated with source rocks in the deep Central Syncline has been demonstrated by the APCCH. Burial history modeling and the occurrence of overpressured oil in the APCCH suggests that the potential shale play would be at depths of 4,270 m (14,000 ft) or more in the Central Syncline. These possible "shale oil" resources would be located beneath the central Los Angeles Basin, largely outside existing oil field boundaries (Figure 4.2-5). Testing their development potential would require drilling deep wells specifically targeting the shale oil potential.

4.2.5.4 Summary of Resource Potential

The available geological, drilling, and production data suggest that oil development in the Los Angeles Basin is likely to continue to focus on existing fields rather than on widespread development of previously undeveloped source-rock (shale tight oil) resources. Undiscovered conventional fields may contain hundreds of millions of barrels of oil, but they would probably be scattered around the basin in mostly small to medium-size accumulations. The largest remaining quantities of recoverable oil are believed to be in existing fields. The ten largest conventional fields are estimated to still contain in the range of 0.22 to 0.89 billion m^3 (1.4 billion to 5.6 billion barrels) of oil that could be recovered with today's technology, and large volumes of additional oil may be present in the other 58 named fields of the basin. This remaining oil would probably be easier and cheaper to develop on a large scale than would postulated unconventional resources in deeply buried source rocks outside of existing fields.

Production of the remaining recoverable oil in existing fields might be enhanced by hydraulic fracturing, such as has been used recently in Inglewood, Brea-Olinda and Wilmington-Belmont fields. As costs of hydraulic fracturing have come down, it is becoming a common practice, even in Los Angeles. Widespread massive hydraulic fracturing is probably not essential for additional oil production. Instead, water flooding, carbon dioxide injection, and thermally enhanced oil recovery methods such as steam injection, could probably be used to produce most of the remaining oil, with or without hydraulic fracturing. However, any large-scale new petroleum development in Los Angeles would probably require technological innovations to reduce potential conflicts with the urban population.

Assuming the recoverable source-rock resources exist, our analysis suggests that even with social acceptance by the local population, geological and petroleum engineering obstacles would need to be overcome prior to a full build-out of a source-rock play in the Los Angeles Basin. Moreover, the quantity of oil that could be recovered from such source rocks is highly uncertain.

4.2.6. Summary of Findings

- The Los Angeles Basin is extremely rich in petroleum.
- No petroleum province of comparable size underlies such a populated urban area.
- The largest onshore fields in the basin were discovered before 1933.
- Exploratory ("wildcat") drilling largely ceased by 1980.
- Oil production in most fields has been declining for years.
- Oil fields were developed inefficiently, and much recoverable oil remains in existing fields. Remaining undiscovered conventional oil fields are probably relatively small and scattered.
- A source-rock (shale oil) play is hypothetically possible in the deeper parts of the basin, largely outside of existing fields.
- Given the large quantities of recoverable petroleum remaining in conventional oil fields, large-scale development of continuous-type oil source rocks outside of existing fields is considered unlikely in the near future.
- Technological innovation is probably necessary for any widespread new petroleum development in the basin.

4.3. Public Health Risks Associated with Current Oil and Gas Development in The Los Angeles Basin

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4.3.1. Abstract

The Los Angeles Basin has among the highest concentrations of oil in the world, and simultaneously is home to a global megacity. Oil and gas development in Los Angeles occurs in close proximity to human populations. In this case study, we investigate locations of currently active oil and gas development, the proportion of these wells that have been enabled or supported by well stimulation treatments, the emissions of criteria air pollutants and toxic air contaminants from this development, and the numbers and demographics of residents and sensitive receptors (schools, daycare centers, residential elderly care facilities) in close proximity to these operations. We then assess potential risks to potable groundwater posed by hydraulic fracturing in the Los Angeles Basin.

The public health proximity analysis elucidates the location of populations that might be disproportionately exposed to emissions of criteria air pollutants and toxic air contaminants from the development of oil and gas. With few exceptions, most of the documented air pollutant emissions of concern from oil and gas development are associated with oil and gas development in general and are not unique to the well stimulation process. In the Los Angeles Basin, approximately 1.7 million people live, and large numbers of schools, elderly facilities, and daycare facilities are sited, within one mile of an active oil and gas well—and more than 32,000 people live within 100 meters (328 feet) of such wells. Even where the proportion of the total air pollutant emission inventory directly or indirectly attributable to well stimulation and oil and gas development in general is small, atmospheric concentrations of pollutants near oil and gas production sites can be much larger than basin or regional averages, and can present risks to human

health. Studies from outside of California indicate that community public health risks of exposures to toxic air contaminants (such as benzene and aliphatic hydrocarbons) are most significant within ½ mile (800 meters or 2,625 feet) from active oil and gas development. These risks will depend on local conditions and the types of gas and petroleum being produced. Actual exposures and subsequent health impacts in the Los Angeles Basin may be similar or different, but they have not been measured.

The results of our groundwater risk investigation, based upon available data, indicate that a small amount of hydraulic fracturing in the Los Angeles Basin has occurred within groundwater with <10,000 mg/L total dissolved solids (TDS) and in close proximity to groundwater with <3,000 mg/L TDS. This creates a risk of hydraulic fractures extending into or connecting with protected groundwater and creating a possible pathway for human exposures to chemicals in fracturing fluids for those that rely on these water resources.

4.3.2. Introduction

As described by Gautier in Section 4.2 above, the Los Angeles Basin is one of the most petroleum-rich basins on earth (Barbat, 1958; Biddle, 1991; Gardett, 1971; Wright, 1987; Yerkes et al., 1965). Oil development has occurred in this region since the 1800s and continues today. As reported in Volume I, well stimulation—hydraulic fracturing and acidizing—occurs in this basin, but the Los Angeles Basin is a distant second to the San Joaquin Valley in terms of total oil development and the fraction of oil and gas production enabled with stimulation treatments.

The Los Angeles Basin, in general, has relatively high population density and simultaneously hosts intensive oil and gas development. Given this high population density, the environmental public health dimensions of upstream oil and gas development in the Los Angeles Basin differ from those in other basins. For instance, while any industrial activities that emit criteria air pollutants and toxic air contaminants (TACs) in areas of low human population density create human health risks, conducting the same industrial processes in dense urban areas exposes a larger number of people to risks and as such, increases population health risks.

In this case study we examine the proximity of human populations—including vulnerable populations and sensitive receptors such as schools, daycare centers and residential elderly care facilities—to currently active oil and gas wells and those wells that have been stimulated. Many health hazards of well-stimulation-enabled oil and gas development that have been identified in the peer-reviewed literature and in Volume II, Chapter 6 of this report are indirect; that is, the hazards are not directly attributable to well stimulation. However, these hazards are an effect of potential exposures associated with enabled oil and gas development. The corollary to this is that many of the health impacts we discuss as due to proximity to stimulated wells will likely be the same for proximity to all oil and gas wells, whether they are stimulated or not. This is particularly relevant in California, where high-volume hydraulic fracturing—which, due to its large scale, is a far more industrially intensive process—is rarely conducted in California and only once in the Los Angeles Basin (Cardno ENTRIX, 2012) as a test well under likely non-generalizable conditions. In Volume II, Chapter 3 (Air Quality) the TACs that are known to be emitted from oil and gas development are not specific to stimulation fluids or stimulation processes (also see Volume II, Chapter 6 for a deeper explanation of this issue). Further, available data in California only allows for analyses of total air pollutant emissions from all oil and gas development, and the proportion from stimulation can only be estimated.

In light of the urban density of the Los Angeles Basin and findings from Volume II, Chapter 3 (Air Quality), this case study focuses primarily on potential public health hazards and risks associated with the development of oil and gas—in general and from wells that have been stimulated—from an air quality perspective. As such, this case study evaluates existing data about the public health implications of oil and gas development in a densely populated mega-city. In turn, it compensates for the lack of adverse health outcome data by investigating information on risk factors that suggest, but does not confirm with certainty, the risks to human health. The precepts of the field of public health include an emphasis on the anticipation of risk to human health even though the impact of these risks has not been proven. A primary goal of public health research is to anticipate and prevent harm rather than observe harm after if has occurred.

First, we examine the public health literature pertinent to the intersection of public health and oil and gas development. We then analyze available California state inventories on emissions of criteria air pollutants and TACs from upstream oil and gas development. From our assessment of air pollutant emissions, we distinguish which contaminants from oil and gas development in the Los Angeles Basin pose concerns, and we look more closely at the health risks of inhalation of benzene in particular. Given the fact that benzene levels may be elevated near active oil and gas production wells of all sorts, we examine the proximity of the population to active oil and gas wells, as well as the fraction of those active wells that were stimulated. With this approach, we assess human health risks in the context of all oil and gas development, rather than the smaller portion of the risks associated with only stimulation-enabled oil and gas development.

Finally, we examine the possibility that water supply in the Los Angeles Basin could become contaminated due to hydraulic fracturing and oil and gas development enabled by hydraulic fracturing.

Noise pollution, light pollution, industrial accidents, and truck traffic are also potentially important environmental stressors associated with well-stimulation-enabled and other types of upstream oil and gas development. These factors are covered in Volume II, Chapter 6, but are outside of the scope of this case study.

4.3.3. Air Pollution Attributable to Upstream Oil and Gas Development and Public Health Risks in the Los Angeles Basin

4.3.3.1. Background and Scientific Basis for Focus on Air Quality

There have been few epidemiological studies that measure health effects associated with oil and gas development enabled or supported by well stimulation, and there have been none in California. The studies that have been published are focused on exposures to toxic air contaminants or TACs (many TACs are referred to as "hazardous air pollutants" outside of California) while fewer studies have evaluated associations between oil and gas development and exposure to water contamination.

Each of the studies discussed in Volume II, Chapter 6 (Human Health), and again discussed below in this subsection has limitations in study design, geographic focus, and capacity to evaluate associations between cause and effect. These studies suggest that health concerns attributable to air pollution from oil and gas development are not specifically direct effects of the well stimulation process, but rather health damaging air pollutant emissions are associated with indirect effects of oil and gas development in general. For example, the studies in Colorado (McKenzie et al., 2012; McKenzie et al., 2014) found that the most likely driver of poor health outcomes were aliphatic hydrocarbons and benzene. These compounds are part of the hydrocarbons in the reservoir and so they are co-produced and co-emitted with oil and gas production and processing. It is important to note that available human health studies are insufficient to accurately understand the potential air impacts of direct well stimulation activities, which may expose both site workers and local communities to higher air concentrations of a different mixture of chemicals than would be experienced during enabled-production activities.

Finally, a broad conclusion in many of the studies discussed in Volume II, Chapter 6 (Human Health) and below is that distance from oil and gas development matters in terms of potential human health hazards, primarily associated with exposure to TACs.

4.3.3.2. Summary of Air Pollution and Public Health Study Findings

The environmental public health literature suggests that one of the primary toxic air contaminant (TAC) exposure risk factors associated with oil and gas development is geographic proximity to active oil development (see Volume II Chapter 6). This is further corroborated by atmospheric studies on dilution of conserved pollutants such as benzene once emitted to the atmosphere (United States Environmental Protection Agency (U.S. EPA), 1992). While oil and gas development throughout the U.S.—both enabled by hydraulic fracturing and in general—has been linked to regional air quality impacts (Pétron et al., 2012; Pétron et al., 2014; Thompson et al., 2014; Helmig et al., 2014; Roy et al., 2013), a number of TACs have been observed at even higher concentrations in close proximity to where active oil and gas development takes place (Macey et al. 2014;

Colborn et al., 2014; Brown et al., 2014; Brown et al., 2015). Additionally, an analysis by Brown et al. (2014) found that there might be intermittent spikes in emissions from activity and infrastructure during oil and gas development. A study on air pollutant emissions during hydraulic fracturing activities conducted by Allen et al. (2013) also found that spikes in emissions of methane and associated volatile organic compounds (VOCs) occurred during liquid unloadings. While intermittent spikes in emission may not impact regional atmospheric concentrations, they are likely to be associated with increased exposures to local populations in close proximity to the source of emission activity. Thus, regional concentrations of air pollutants may provide estimates of low- to moderate-level chronic exposures experienced by a regional population, but it is important to consider the proximity of receptors to sources in order to capture the range of potential public health risks.

Using United States Environmental Protection Agency (U.S. EPA) guidance to estimate chronic and sub-chronic non-cancer hazard indices (HIs) as well as cancer risks, a study in Colorado suggested that those living in closer geographical proximity to active oil and gas wells (≤ 800 m; 0.5 mile or ≤ 2,640 feet) were at an increased risk of acute and sub-chronic respiratory, neurological, and reproductive health effects, driven primarily by exposure to trimethyl-benzenes, xylenes, and aliphatic hydrocarbons. It also suggested that slightly elevated excess lifetime cancer risk estimates were driven by exposure to benzene and aliphatic hydrocarbons (McKenzie et al., 2012). The findings of this study are corroborated by atmospheric dilution data of conserved pollutants, for instance a U.S. EPA report on dilution of conserved TACs indicates that the dilution at 800 m (0.5 mile) is on the order of 0.1 mg/m^3 per g/s (U.S. EPA, 1992). Going out to 2,000 m (6,562 ft) increases this dilution to 0.015 mg/m^3 per g/s, and going out to 3,000 m (9,843 ft) increases dilution to 0.007 mg/m^3 per g/s. Given that, for benzene, there is increased risk at a dilution of 0.1 mg/m^3, it is not clear that atmospheric concentrations of benzene out to 2,000 m and 3,000 m (6,652 ft and 9,843 ft) can necessarily be considered safe. However, beyond 3,000 m (9,843 ft), where concentrations fall more than two orders of magnitude via dilution relative to the ½ mile radius, there is likely to be a sufficient margin of safety for a given point source.

In contrast, an oil and gas industry study in Texas compared volatile organic compound (VOC) concentration data from seven air monitors at six locations in the Barnett Shale with federal and state health-based air concentration values (HBACVs) to determine possible acute and chronic health effects (Bunch et al., 2014). The study found that shale gas activities did not result in community-wide exposures to concentrations of VOCs at levels that would pose a health concern. The key distinction between McKenzie et al. (2012) and Bunch et al. (2014) is that Bunch and colleagues used air quality data generated from monitors focused on regional atmospheric concentrations of pollutants in Texas, while McKenzie et al. (2012) included samples at the community level. Finer geographically scaled air sampling often captures local atmospheric concentrations that are more relevant to human exposure than sampling at the regional scale (Shonkoff et al., 2014).

Arriving at similar results as the Bunch et al. (2014) study, a cursory public health outcome study was conducted by the Los Angeles County Department of Public Health near the Inglewood Oil Field in Los Angeles County in 2011 (Rangan et al., 2011). This study compared incidence of a variety of health endpoints including all cause mortality, low birth weight, birth defects, and all cancer among populations nearby the Inglewood Oil Field and Los Angeles County as a whole. The study found no statistically significant difference in these endpoints between these two populations. While this may seem to indicate that there is no health impact from oil and gas development, as the study notes, the epidemiological methods employed in this study do not allow it to pick up changes in “rare events” such as cancer and birth defects in studies with relatively small numbers of people. In addition to this study being underpowered, the Inglewood Oil Field Study is a cluster investigation with exposure assigned at the group level (i.e., an ecological study). It also appears that only crude incidence ratios were calculated. This type of study design is insufficient for establishing causality and has many major limitations, including exposure misclassification and confounding, which may have obscured associations between exposure to environmental stressors from oil and gas development and health outcomes.

Using a community-based monitoring approach, Macey et al. (2014) analyzed air samples from locations near oil and gas development in Arkansas, Colorado, Ohio, Pennsylvania, and Wyoming found levels for eight volatile chemicals, including benzene, formaldehyde, hexane, and hydrogen sulfide, exceeded federal guidelines Agency for Toxic Substances and Disease Registry (ATSDR) minimal risk levels (MRLs) and U.S. EPA Integrated Risk Information System (IRIS) cancer risk levels in a number of instances (Macey et al., 2014). Of the 35 grab samples taken in the study, 16 contained chemicals at concentrations that exceeded these health-based risk levels, and those samples that exceeded thresholds were mostly collected in Wyoming and Arkansas. Fourteen out of 41 passive samples collected for formaldehyde exceeded health-based risk levels, and these were mostly collected in Arkansas and Pennsylvania. No samples collected in Ohio contained chemicals with concentrations exceeding health-based risk levels. The Macey et al. (2014) study does not specify whether or not well stimulations were used in the oil development being monitored. Importantly, the chemicals that exceeded health-based risk levels were primarily detected in samples collected near separators, gas compressors, and discharge canals.

Macey et al. (2014) noted two exceedances of hydrogen sulfide concentrations reported in samples collected near an operation that may have involved well stimulation. One was collected near a work-over rig and the other near a well pad. The residents who collected the samples self-reported a number of common health symptoms, including “headaches, dizziness or light-headedness, irritated, burning, or running nose, nausea, and sore or irritated throat” (Macey et al., 2014). This study suggests that concentrations of hazardous air pollutants near oil and gas development operations may be elevated to levels where health impacts could occur, although epidemiological studies would need to be performed to understand the extent to which health impacts have occurred. As noted elsewhere in Volume II, Chapter 6, and throughout this case study, the hazardous air pollutants observed in this study are all not directly attributable to well stimulation (e.g., they are not often added to well stimulation fluids), but rather are compounds that are co-produced with the development of oil and gas in general.

In addition to population health hazards at varying distances from active oil and gas development, other studies have assessed the effect of the density of oil and gas development on health outcomes. In a retrospective cohort study in Colorado, McKenzie et al. (2014) examined associations between maternal residential location and density of oil and gas development. The researchers found a positive dose-response association between the prevalence of some adverse birth outcomes, including congenital heart defects and increasing density of natural gas development (McKenzie et al., 2014). The observed risk of congenital heart defects in neonates was 30% (odds ratio (OR) = 1.3 (95% confidence interval (CI): 1.2, 1.5)) greater among those born to mothers who lived in the highest density of oil and gas development (> 125 wells per mile) compared to those neonates born to mothers who lived with no oil and gas wells within a 16 km (10-mile) radius. Similarly, the data suggest that neonates born to mothers in the highest density of oil and gas development were twice as likely (OR = 2.0, 95% CI: 1.0, 3.9) to be born with neural tube defects than those born to mothers living with no wells in a 10-mile radius (McKenzie et al., 2014). The study, however, showed no positive association between the density and proximity of wells and maternal residence for oral clefts, preterm birth, or term low birth weight. The authors of this retrospective cohort study report that one explanation given for the observed increased risk of neural tube defects and congenital heart disease with increasing density of gas development could be increased atmospheric concentrations of benzene, a compound known to be associated with both of these conditions (Lupo et al., 2011). However, given that there was no air quality monitoring or field-based exposure assessment, this study may suffer from exposure misclassification.

It should be noted that the presence and concentration of VOCs that are known air toxics associated with oil and gas development, such as benzene, varies between and within oil and gas reservoirs throughout the United States and abroad. The presence and concentration of these TACs in the source (the oil and gas reservoir) partially drives the potential emissions of benzene and other natural gas liquids; if they are more concentrated, it is more likely that they could be emitted. As such, on this point, there is uncertainty as to how directly applicable current out-of-state public health studies on oil and gas development may be to California. However, as noted in our analysis below, benzene emissions from upstream oil and gas development in the Los Angeles Basin are a significant percentage of the total South Coast Air Basin benzene emission inventory from all sources.

Given that exposures to conserved air pollutants (that tend to not be strongly reactive in the atmosphere) such as benzene decrease with distance from a pollutant source and approach background or regional exposures at some distance (U.S. EPA, 1992)—as explained above and in Volume II, Chapter 6 (Human Health)—the question arises, “How far is far enough to protect human health?" Residents and sensitive receptors near oil and gas wells—stimulated or not—may be more exposed either acutely or chronically to TACs emitted by oil and gas development compared to the general population. California has no setback requirement for oil and gas development, well-stimulation-enabled or otherwise, but some local jurisdictions have set minimum distances from which oil and gas development and associated ancillary infrastructure is allowed to be from residences and sensitive receptors. In the United States, setback distances range from 91 m (300 ft) in Pennsylvania to 457 m (1,500 ft or 0.28 miles) in the Dallas-Fort Worth metropolitan area, in order to reduce potential exposures of human populations to air pollutant emissions, odors, noise, and other environmental stressors (City of Dallas, 2013; Richardson et al., 2013).

4.3.3.3. The Context of Air Quality Non-Attainment in the Los Angeles Basin

The South Coast Air Basin has historically had very poor air quality, with portions of the region often in non-attainment for national and state ambient air quality standards. For example, in 2014, the Los Angeles-Long Beach area was listed #1 in ozone pollution (see Figure 4.3-1), #3 in year-round particulate matter pollution, and #4 in short-term particle pollution (see Figure 4.3-2) out of all cities in the United States (American Lung Association (ALA), 2015). The reasons for poor air quality in the Los Angeles Basin are myriad—from the diverse mobile and stationary emission sources to the topographical characteristics that discourage the transport of atmospheric pollutants out of the basin (ALA, 2015).

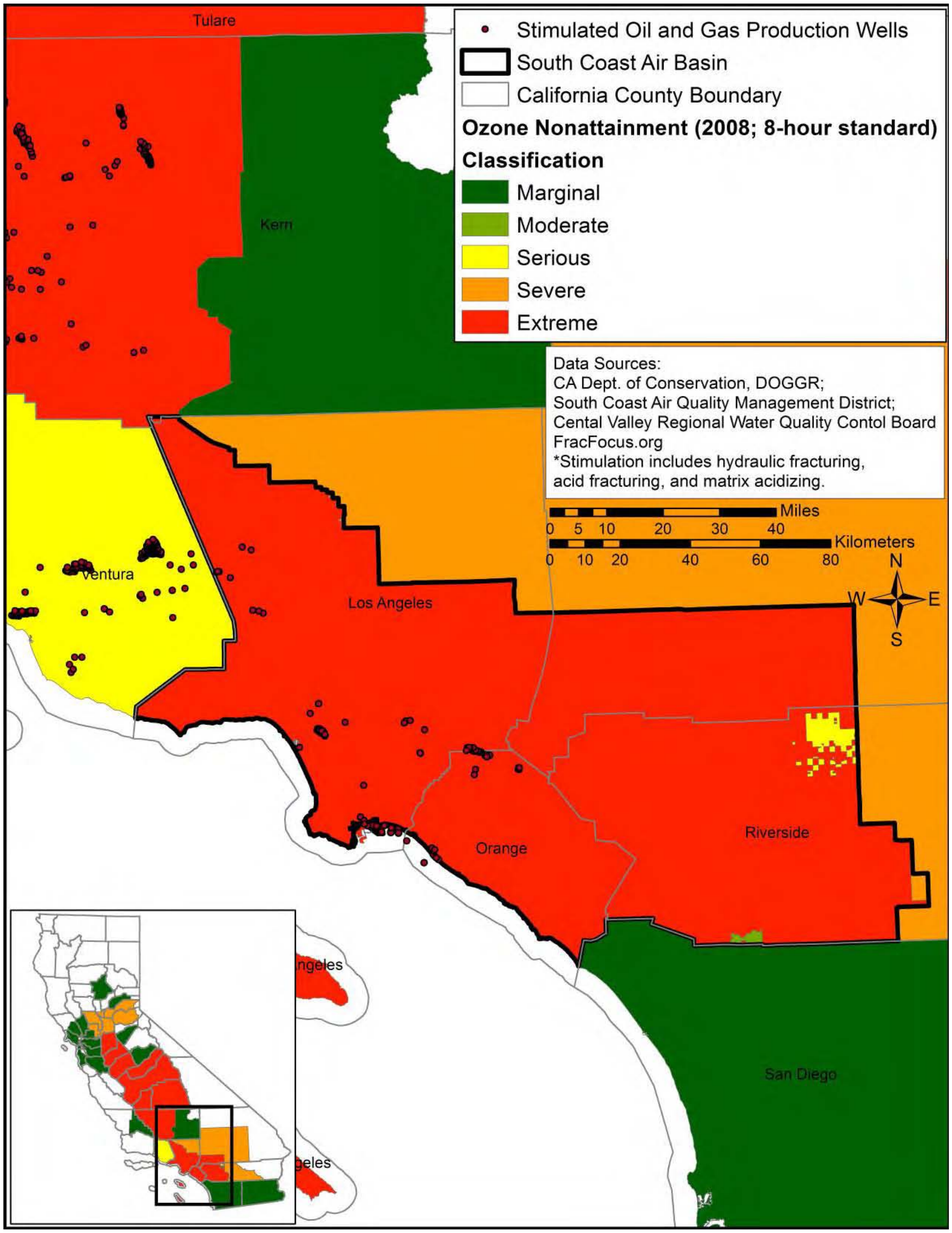


Figure 4.3-1. Ozone attainment by county in California. Note that the South Coast Air Basin (Los Angeles County, Orange County, and part of Riverside Countyy are in extreme non-attainment status.

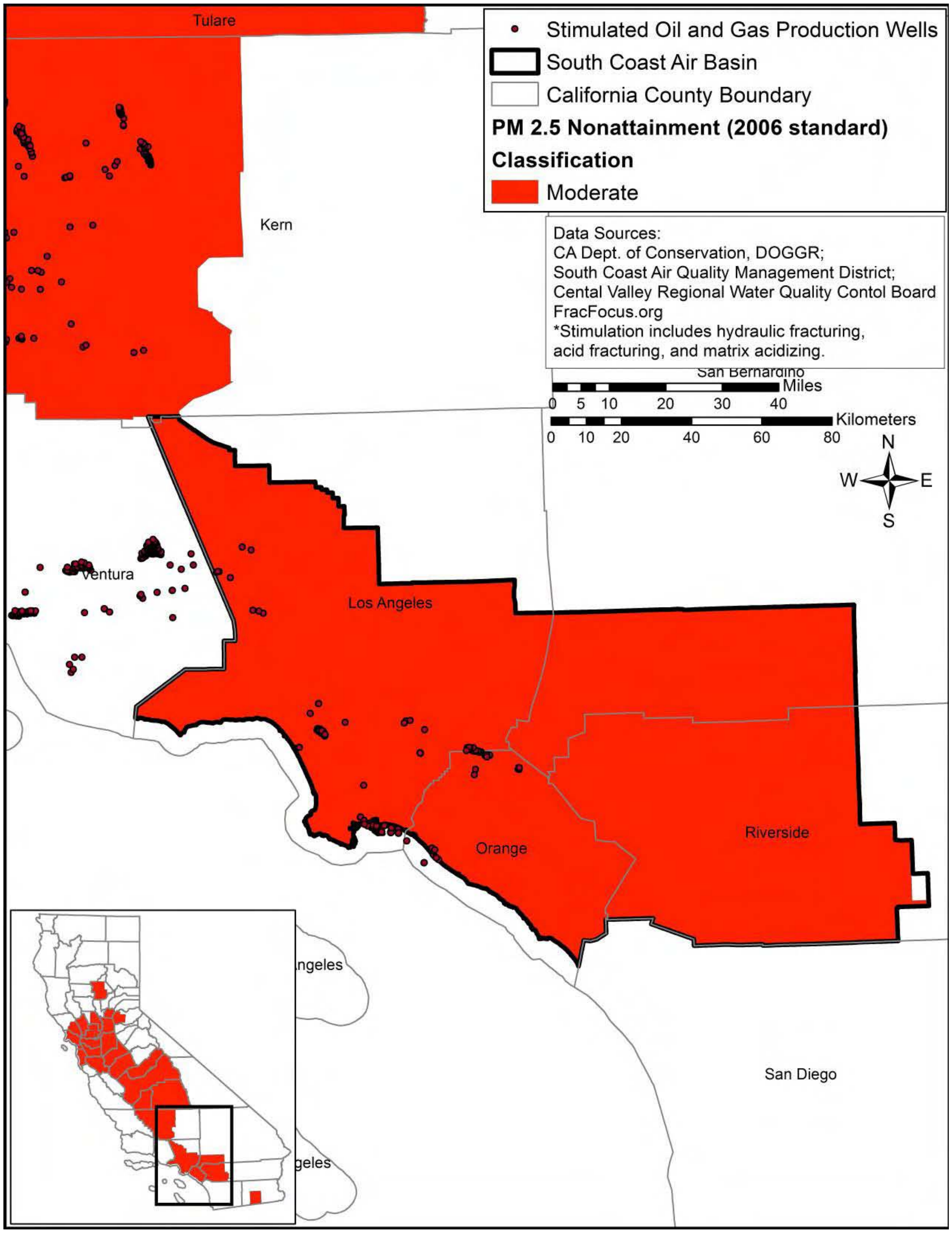


Figure 4.3-2. PM$_{2.5}$ attainment by county in the South Coast Air Basin on California. Note that. the South Coast Air Basin is in moderate non-attainment status.

Data suggests that environmental public health risks associated with an emission source should be approached from a cumulative risk perspective that takes into account the air pollution context within which these emissions occur (Pope et al., 2009). The California Air Resources Board (CARB) and the United States Environmental Protection Agency (U.S. EPA) have noticed this issue and now conduct air pollution and public health assessments in the context of a cumulative risk framework (Sadd et al., 2011). Populations exposed to cumulative air pollution burdens from multiple sources tend to be at increased risk of negative health impacts compared to populations that are exposed to lower concentrations of air pollutants from fewer sources (Morello-Frosch 2002; Morello-Frosch et al., 2010; Morello-Frosch et al., 2011).

Due to the air quality issues of the Los Angeles Basin, populations in this region are often exposed to elevated atmospheric concentrations of air pollutants (e.g., benzene, particulate matter, and VOCs), many of which are emitted by oil and gas development as well as numerous other sources within the Basin. Any additional emissions of volatile organic compounds, reactive organic gases (ozone precursors), nitrogen oxides, particulate matter, and TACs from the development of oil and gas (enabled by stimulation or not) in this region stacks additional emissions upon the cumulative air pollution burden that populations are already disproportionately exposed to.

4.3.3.4. Regional Air Pollutant Emissions in the Los Angeles Basin

Air pollutant emissions in the South Coast Region are discussed in Volume II, Chapter 3. In that volume, emissions of criteria air pollutants, greenhouse gases, and TACs are discussed, and emissions by air districts are derived from regional inventories. In Volume II, the South Coast Air Quality Management District (SCAQMD) is used as the indicator region of interest for the Los Angeles Basin.

Counties are the only common jurisdiction where all oil and gas development occurs in the Los Angeles Basin. We henceforth focus our regional air pollutant emission analysis on Los Angeles and Orange counties (See Figure 4.3-1. above), including fields partially or fully contained in the offshore areas of these counties, as per DOGGR definitions. These counties contain nearly all oil production in the greater Los Angeles metropolitan area. These counties also line up with the most populous regions of the South Coast Air Quality Management District, although that district contains some portions of nearby suburban regions (e.g., parts of Riverside and San Bernardino counties). Therefore, the alignment between these counties and the SCAQMD is expected to be generally close. These counties also do not contain production in the Santa Barbara/Ventura regions, which are not included in the SCAQMD and suffer from fewer air quality impacts.

In this case study, we take a more detailed look at regional contributions of air pollutants from all active oil and gas development, as well as that enabled or supported by well stimulation within the South Coast Region. In order to make these estimations, we join datasets from DOGGR and CARB air pollution inventories. Because DOGGR regional jurisdictions do not align with CARB air districts, we perform an analysis using counties as the regions of interest.

The data in regional inventories are not of sufficient spatial resolution to allow emissions estimates of TACs and reactive organic gases (ROGs) at the local level, and a full photochemical modeling assessment is beyond the scope of this report. Only two studies, neither of which is peer-reviewed, have attempted to answer these questions. Sonoma Technology, Inc. (2015) conducted monitoring of particulate matter (measured as black carbon as a surrogate) and limited monitoring of VOCs and heavy metals at four sites near the periphery of the Inglewood oil field. The study found a marginal contribution of particulate matter (PM) emissions that was only a small fraction of total PM emissions in the region. There were similar findings for VOCs. It is not clear, however which operations were active and at what geographic distance from the air pollutant monitors, and as such, the interpretation of these data is limited.

4.3.3.4.1. Emission Inventory Estimate of Air Pollutants from All Sources in the South Coast Region

Estimates of criteria air pollutant and TAC emissions from all active upstream oil and gas activities, and the fraction of these activities that are supported or enabled by well stimulation, requires information on total emissions of criteria air pollutants and TACs in the region of interest. From the most recent CARB criteria air pollutant inventory from 2012, emissions of criteria air pollutants from all sources in the South Coast Region are summarized in Table 4.3-1. TAC emissions for ten indicator TACs discussed in Volume II, Chapter 3, are listed in Table 4.3-2. These TAC emissions are derived from the California Toxics Inventory for 2010, reported by county for all sources, including point sources, aggregated point sources, area wide sources, diesel sources, gasoline sources, and natural sources. While many TAC species are co-emitted during hydrocarbon development (see Volume II, Chapter 3), these 10 species are prevalent in hydrocarbon production and of human health relevance. In the following sections, we evaluate the subset of these data that is attributable to all active oil and gas development, and then the portion of that which is associated with active oil development from wells that have been stimulated.

Table 4.3-1. Total emissions in 2012 of criteria air pollutants and ROGs in the South Coast Region from all sources (tones/d).

Pollutant	Los Angeles County	Orange County	South Coast Region
Reactive organic gases (ROG)	267.8	87.2	355.0
Nitrogen oxides (NO_x)	330.2	79.0	409.2
Sulphur oxides (SO_x)	14.5	1.5	16.0
PM_{10}	90.3	21.4	111.7
$PM_{2.5}$	39.1	9.7	48.8

Table 4.3-2. Total emissions in 2010 of selected TACs in the South Coast Region from all sources (tonnes/y). Data from California Toxics Inventory (CTI) county-level data.

	Los Angeles County	Orange County	South Coast Region
1,3-Butadiene	293.2	89.1	382.3
Acetaldehyde	1,238.7	313.5	1,552.1
Benzene	1,239.6	419.6	1,659.2
Carbonyl sulfide	0.0	0.0	0.0
Ethyl Benzene	749.1	251.1	1,000.2
Formaldehyde	1,827.0	548.2	2,375.1
Hexane	1,197.6	410.7	1,608.3
Hydrogen Sulfide	6.2	0.0	6.2
Toluene	5,050.1	1,810.0	6,860.2
Xylenes (mixed)	937.2	338.3	1275.5

4.3.3.4.2. Emission Inventory Estimate of Air Pollutants from All Upstream Oil And Gas Development Activities in the South Coast Region.

Here, we estimate the contribution to South Coast air pollutant emissions from all upstream oil and gas development activities. We combined emissions of criteria pollutants and TACs reported above in Tables 4.3-1 and 4.3-2 with estimates of active oil development activities in the counties of interest. As described in detail in Volume II, Chapter 3, a variety of sources in the criteria pollutants inventory and facility-level toxics database can be linked to the oil and gas industry.

In order to estimate criteria pollutant emissions from the oil and gas sector in the South Coast Region, we sum the emissions from the following sources (see Volume II, Chapter 3, for a detailed listing of the constituent subsectors and sources and attributes of each emission inventory):

- Stationary sources + petroleum production and marketing + oil and gas production + all subsectors and sources
- Stationary sources + fuel combustion + oil and gas production (combustion) + all subsectors and sources
- Mobile sources + other mobile sources + off-road equipment + oil drilling and workover

The oil and gas sector will also likely cause emissions from use of on-road light and heavy-duty trucks (e.g., maintenance trucks used in non-drilling operations and therefore not included in the "Oil drilling and workover" subsector). We cannot differentiate these emissions using reported inventory information (on-road vehicles are classified by weight class rather than industry).

Table 4.3-3 below shows the result of summing all oil- and gas-sector sources in the South Coast Region. We report the estimate from our bottom-up inventory analysis. It should be noted that recent top-down analyses of methane have noted that the methane emission inventory may be underestimated by two to seven times what is reported in the emissions inventories (Peischl et al., 2013; Jeong et al., 2013). Emissions of methane may provide insight into the emission of light alkane VOCs (a subset of ROGs) and to a certain extent, TACs, as they are often co-emitted during oil and gas development processes. As such, the values provided below should be taken as a conservative estimate of emissions from this sector. More field-based research should be conducted to understand to what degree the criteria air pollutant emission inventories are accurate and how to improve them. Additionally, these publicly available data do not allow us to analyze the geographic, corporate, or facility distribution of emissions, only the total amount emitted by the entire upstream oil and gas sector. For a detailed assessment of the discrepancy between these bottom-up inventories and recent field-based monitoring, see Volume II, Chapter 3.

Table 4.3-3. Contribution of upstream oil and gas sources to criteria pollutants and ROGs emissions in South Coast Region, data for 2012. (tonnes/d).

	ROG	NO_x	SO_x	PM_{10}	$PM_{2.5}$
Stationary oil and gas	0.99	1.64	0.02	0.09	0.09
Mobile oil and gas	0.09	1.06	0.00	0.04	0.04
Total oil and gas	1.08	2.70	0.02	0.12	0.12
Oil and gas fraction of all sectors	0.31%	0.66%	0.12%	0.11%	0.25%

Table 4.3-4. lists upstream oil and gas development stationary source facility-reported contributions to selected TACs in the South Coast Region. It also lists all source emissions of these TACs for 2010 in comparison (most recent year for which data are available). In addition, a number of potential TACs are injected into formations as part of fracturing fluids, as noted in SCAQMD datasets. These potential TACs are discussed in Volume II, Chapter 3.

Hydrogen sulfide and carbonyl sulfide emissions were not reported from the upstream oil and gas sector in the South Coast Region (Table 4.3-4). The reporting facilities in the state inventories include refineries and landfills, but none of the oil production sectors. As these compounds are reported in the San Joaquin Valley, they are likely also emitted in the South Coast Region. Moreover, a U.S. EPA preliminary risk assessment places carbonyl sulfide near the top of its table of emissions of TACs by mass from studied facilities (U.S. EPA, 2011). The lack of records could be a reporting loophole or an error in the database, and deserves further investigation. Because these data are missing, the proportion of the total emissions of hydrogen sulfide and carbonyl sulfide emissions attributable to upstream oil and gas development in the Los Angeles Basin remains unknown.

Table 4.3-4 Contribution of upstream oil and gas sources to TAC emissions in South Coast Region (kg/y). Fraction is approximate because all source inventory of TACs was last completed for year 2010 emissions.

	Stationary oil and gas sources (kg/y) (2012)	Fraction of emissions from stationary sources	Emissions from all stationary and mobile sources (kg/y) (2010)	Fraction of all emissions from all sources (kg/y) (stationary and mobile)
1,3-Butadiene	56	1.60%	382,307	0.01%
Acetaldehyde	1	0.00%	1,552,128	0.00%
Benzene	2,361	9.60%	1,659,155	0.14%
Carbonyl sulfide	not available	not available	20	not available
Ethyl Benzene	28	0.50%	1,000,213	0.00%
Formaldehyde	5,846	3.80%	2,375,149	0.25%
Hexane	1	0.00%	1,608,302	0.00%
Hydrogen Sulfide	not available	not available	6,238	not available
Toluene	1	0.00%	6,860,168	0.00%
Xylenes (mixed)	1	0.00%	1,275,480	0.00%

4.3.3.4.3. Emission Inventory Estimate of Air Pollutants Attributable to Well Stimulation-Enabled Upstream Oil and Gas Development in the South Coast Region

Following the methodology used in Volume I to identify hydrocarbon pools considered to be facilitated or enabled by well stimulation, we generated a list of stimulated pools and fields in the South Coast Region. This list is generated from Volume I, Appendix N. DOGGR county codes that represent the South Coast Region include Los Angeles (code 37), Los Angeles Offshore (code 237), Orange County (code 59) and Orange County Offshore (code 259). These pools are presented in Table 4.3-5.

Using queries to the DOGGR well-level production database, we can sum all production from these facilitated or enabled pools in 2013 and compare this to all production in the South Coast Region. As can be seen from Table 4.3-5, the well-stimulation-facilitated or -enabled pools represented a total of 874,430 m^3 (5.5 million bbl) of production, approximately 19% of production in the South Coast Region.

Table 4.3-5. Pools in South Coast Region determined to be facilitated or enabled by hydraulic fracturing. Production derived from queries to 2013 full-year well-level DOGGR database for wells that match the field, area, and pool combinations noted to be stimulated in Volume I, Appendix N.

DOGGR county code	Field	Area	Pool	Oil production (2013 bbl)
237, 259	Belmont Offshore	Surfside Area	No Pool Breakdown	243,034
37, 59	Brea-Olinda	Any Area	No Pool Breakdown	1,111,985
37	Inglewood	Any Area	No Pool Breakdown	2,731,733
37	Montebello	West Area	No Pool Breakdown	15,299
37	San Vicente	Any Area	Clifton, Dayton and Hay	271,235
37	Whittier	Rideout Heights Area	No Pool Breakdown	31,766
37	Whittier	Rideout Heights Area	Pliocene	39,982
37, 237	Wilmington	Fault Block 90	Ford	105,564
37, 237	Wilmington	Fault Block 90	Union Pacific	503,655
37, 237	Wilmington	Fault Block 98	237	0
37, 237	Wilmington	Fault Block 98	Ford	20,604
37, 237	Wilmington	Fault Block 98	Union Pacific	18,892
37, 237	Wilmington	Fault Block I	237	6,815
37, 237	Wilmington	Fault Block IV	Ford	15,442
37, 237	Wilmington	Fault Block VII	Union Pacific (ABD)	28,902
37, 237	Wilmington	Fault Block VIII	Terminal	212,055
37, 237	Wilmington	Fault Block VIII	Union Pacific	148,305
37, 59, 237, 259	Total production from facilitated pools			5,505,268
37, 59, 237, 259	Total production in South Coast Region			29,150,660
37, 59, 237, 259	Fraction of production from facilitated or enabled pools			18.9%

We use these activity factors for production and drilling to scale the stationary source and mobile source emissions from the entire oil and gas sector. (For more information on specific emission sources used for this analysis please see Volume II, Chapter 3.) This result then generates an estimate of those emissions enabled or facilitated by well stimulation. Note that we estimate added emissions resulting from stimulation-enabled production, but do not attempt to estimate the emissions associated directly with the well stimulation activity.

We scale all stationary oil and gas related source emissions (combustion and non-combustion) shown in Table 4.3-5 by the fraction of oil production in the facilitated or enabled pools (19%). We scale mobile source off-road emissions from rigs and workover equipment shown in Table 4.3-5 by the fraction of wells drilled in facilitated or enabled pools (31%). The results of this scaling for criteria air pollutants are shown below in Table 4.3-6 and the results for the representative TACs are shown in Table 4.3-7. An important assumption inherent to this analysis is that oil and gas development has the same emission intensity across all pools. This may or may not be the case and deserves further study.

Table 4.3-6. Fraction of South Coast total criteria and TAC emissions from well stimulation facilitated or enabled pools.

	ROG	NO_x	SO_x	PM_{10}	$PM_{2.5}$
Fraction of all criteria pollutants from well stimulation-enabled oil and gas activities	0.05%	0.14%	0.02%	0.01%	0.04%

Table 4.3-7. Fraction of South Coast total toxic air contaminant emissions from well stimulation facilitated or enabled pools.

	Fraction from well stimulation enabled or facilitated pools
1,3-Butadiene	0.000%
Acetaldehyde	0.001%
Benzene	0.000%
Carbonyl sulfide	0.020%
Ethyl Benzene	0.001%
Formaldehyde	0.009%
Hexane	0.000%
Hydrogen Sulfide	0.000%
Toluene	0.049%
Xylenes (mixed)	0.000%

4.3.3.4.4. Known TACs Added to Well Stimulation Fluids in the South Coast Air Quality Management District

As noted in Volume II, Chapter 3, there are more than 30 TACs that are reported to the SCAQMD as included in hydraulic fracturing and acidizing fluids in the South Coast. While the TACs are known (See Volume II, Chapter 3), there are no data on the rate at which these TACs are emitted and in what quantity (the emission factors have not been studied) these TACs are emitted during oil and gas development. As such, it is not possible to estimate their emissions and in turn their potential risks to public health.

4.3.3.4.5. Discussion of Regional Air Pollutant Emissions from Oil and Gas Development in the South Coast Region

California inventories suggest that the upstream oil and gas development sector is likely responsible for a small fraction (<1%) of criteria pollutants emitted in the South Coast

Region. This is expected, because the South Coast Region is a comparatively small oil production region compared to the San Joaquin Valley, and is also home to large numbers of other mobile and industrial emission sources of these pollutants. We found that 2,361 kg/year of benzene is emitted by the stationary components of upstream oil and gas development in the Los Angeles Basin. This amount represents a significant proportion of stationary sources (9.6%) and a smaller proportion of benzene emissions from all sources (including mobile source emissions) (0.14%) in the South Coast Air Basin. Our state inventory analysis also indicates that 5,846 kg/year or 3.8% of the stationary source emissions of formaldehyde and <1% of all source emissions (including mobile) are attributable to the upstream oil and gas sector. Smaller proportions of other indicator TAC species were identified. These indicator TAC species included in our assessment are not used in well stimulation fluids, but rather are co-produced with oil and natural gas during development.

Since approximately only 26% of the wells currently active in the Los Angeles Basin are hydraulically fractured, emissions of TACs and ROGs are a smaller subset of those emitted by the upstream oil and gas sector in general.

The proportion of the total TAC inventory (mobile and stationary sources) attributable to upstream oil and gas development is not high, and from a regional air quality perspective, these results seem to indicate that TAC emissions from the upstream oil and gas sector are unimportant. However, from a public health perspective, fractions of total emissions are not as important as the quantity or the mass of pollutants emitted, or the location and proximity to humans where the emissions occur. Some of the TACs—especially benzene and formaldehyde and potentially hydrogen sulfide, but problems with the inventory does not allow us to be sure—are emitted in large masses (but not in large fractions of the total inventory) in the upstream oil and gas sector in a densely populated urban area. In the sections below, we discuss the implications of these TAC emissions occurring in the Los Angeles Basin in close proximity to people in general and sensitive demographics in particular.

Given that benzene is known to be highly toxic (Lupo et al., 2011) and emissions from upstream oil and gas development in the Los Angeles Basin constitute more than 2,360 kg/year (9.6%) of the total stationary source emission inventory, we briefly review the public health literature and current exposures to benzene in the South Coast Region below. Benzene is generally not included in stimulation fluids, but rather is a compound that is co-produced (and co-emitted) with oil and gas during production, processing, and other processes.

4.3.3.4.6. Discussion of Benzene and Human Health Risks

Benzene is naturally occurring in hydrocarbon deposits and is released into the air throughout the oil and gas development process (Adgate et al., 2014; Werner et al., 2015; Shonkoff et al., 2014). Other large environmental sources of benzene emissions in the Los Angeles Basin are the burning and refining of oil and gasoline, environmental tobacco smoke (second-hand cigarette smoke), and vapors emitted from gas stations (Centers for Disease Control and Prevention (CDC), 2013). Active cigarette smoking exposes individuals to elevated dosages of benzene as well, but is not considered to be an environmental source as it is at an individual level. Comparing the mass of benzene and other TAC emissions among the largest sources in the South Coast, we see that in the south coast region, mobile emissions (gasoline and diesel vehicles) are the largest contributor in the total inventory (See Volume II, Chapter 3, Table 9). In our analysis of publicly available TAC inventories, we found that 2,361 kg/year of benzene is emitted by the stationary components of upstream oil and gas development in the Los Angeles Basin. This amount represents a significant proportion of stationary source (9.6%) and a small proportion of all benzene source emissions (including mobile source emissions) (0.14%) in the South Coast Air Basin.

With the exception of when diesel is used as an ingredient—and available data suggests that such use is rare in California, as noted in Volume II, Chapter 2 and Chapter 6—benzene is not found in well stimulation fluids. Thus, benzene is a hazard that is not specific to oil and gas development that is enabled or supported by well stimulation; rather, it is a compound intrinsic to the oil and gas development process in general.

There are no studies on benzene exposure attributed to oil and gas development in the Los Angeles Basin; however, adverse human health outcomes can occur through inhalation, oral, or dermal exposure, and benzene can volatilize into the air from water and soil (ATSDR, 2007; U.S. EPA, 2007). In the Los Angeles Basin context, however, potential exposures to benzene attributable to oil and gas development are likely to occur via inhalation. Benzene is a known carcinogen (Glass et al., 2003; Vlaanderen et al., 2010) and is associated with various other health outcomes associated with chronic and acute exposures, including birth defects (Lupo et al., 2011) and respiratory and neurological effects (ATSDR, 2007). Numerous studies on oil and gas development out of state have identified benzene as a potential health risk (Helmig et al., 2014; Macey et al., 2014; McKenzie et al., 2012, 2014; Pétron et al., 2014).

Acute effects of benzene inhalation exposure in humans include the following: (1) neurological symptoms such as drowsiness, vertigo, headaches, and loss of consciousness; (2) respiratory effects such as pulmonary edema, acute granular tracheitis, laryngitis, and bronchitis; and (3) dermal and ocular effects such as skin irritation or burns and eye irritation (ATSDR, 2007; U.S. EPA, 2012). While it is not known if children are more susceptible to benzene poisoning than adults, there has been some research to measure the effects of benzene exposure among children. For instance, an association has been shown between benzene exposure and respiratory effects in children such as bronchitis, asthma, and wheezing (Buchdahl et al., 2000; Rumchev et al., 2004).

Chronic (noncancerous) effects of benzene inhalation in humans include the following: (1) hematological effects such as reduced numbers of red blood cells, aplastic anemia, excessive bleeding, and adverse effects on bone marrow; (2) immunological and lymphoreticular effects such as damage to both humoral (antibody) and cellular (leukocyte) responses; and (3) possible reproductive effects such a neural tube defects and low birth weight (Lupo et al., 2011; U.S. EPA, 2012) there have been no studies assessing the association between environmental levels of hazardous air pollutants, such as benzene, and neural tube defects (NTDs).

Cancer risks include acute and chronic nonlymphocytic leukemia, acute myeloid leukemia, and chronic lymphocytic leukemia. Based on human and animal studies, benzene is classified by the U.S. EPA in Category A (known human carcinogen).

In June 2014, the California Environmental Protection Agency Office of Environmental Health Hazard Assessment (OEHHA) finalized updated benzene reference exposure limits (RELs) (OEHHA, 2014). RELs are airborne concentrations of a chemical that are anticipated to not result in adverse non–cancer health effects for specified exposure durations in the general population, including sensitive subpopulations. The three RELs that OEHHA adopted on 27 June 2014 cover three different types of exposure to benzene in air: infrequent 1-hour exposures, repeated 8-hour exposures, and continuous long term exposure. These three RELs are as follows:

- 1-hour REL: 27 mg/m^3 (0.008 ppm; 8 ppb)
- 8-hour REL: 3 mg/m^3 (0.001 ppm; 1 ppb)
- Chronic REL: 3 mg/m^3 (0.001 ppm; 1 ppb)

Table 4.3-8 shows benzene exposure levels at multiple locations in the South Coast Air Basin. Note that while the mean exposure levels do not exceed 1 ppb on annual averages, these data do not describe 1-hour or 8-hour benzene exposure values. It should also be noted that in both years of sampling, the maximum benzene exposure values exceeded the benzene 8-hour and chronic RELs in some cases up to 350%. Moreover, in some cases, these average exposures are within 0.5 ppb and 0.18 ppb of exceeding the 8-hour and the chronic RELs, which does not leave a large margin of safety. Additionally, the standard deviations indicate that exceedances do occur, in some cases frequently. Average exposure does not take into account potentially more elevated exposures that can occur in close proximity to emission sources where atmospheric concentrations are most elevated.

Table 4.3-8. Average benzene levels (parts per billion (ppb)) at 10 fixed sites in South Coast in 2004 – 2006.

	Year 1 (4/2004 - 3/2005)				Year 2 (4/2005 – 3/2006)			
Location	Mean	SD	N	Max	Mean	SD	N	Max
Anaheim	0.44	0.28	118	1.44	0.42	0.33	115	2.06
Burbank	0.73	0.42	118	2.16	0.69	0.44	122	1.85
Central Los Angeles	0.59	0.30	117	1.83	0.57	0.31	121	1.53
Compton	0.82	0.70	118	3.50	0.78	0.67	118	3.53
Inland Valley	0.49	0.24	115	1.26	0.49	0.24	116	1.24
Huntington Park	0.76	0.46	98	2.20	-	-	-	
North Long Beach	0.56	0.35	119	1.62	0.48	0.34	118	1.70
Pico Rivera	0.57	0.32	121	1.86	-	-	-	
Rubidoux	0.45	0.25	114	1.23	0.43	0.26	120	1.32
West Long Beach	0.57	0.44	114	1.95	0.50	0.38	120	1.77

Source: OEHHA (2014)

4.3.3.5. Screening Exposure Assessment Approach for Air Pollutant Emissions in the Los Angeles Basin

In this screening exposure assessment approach, we focus on the jurisdictional boundaries of the South Coast Air Basin (SoCAB), which includes Los Angeles County, Orange County, and parts of both Riverside and San Bernardino counties and includes the active oil and gas wells within the Los Angeles Basin. In order to assess the public health risks of air pollutant emissions from oil development operations in a region such as the Los Angeles and South Coast Air Basin (SoCAB), one needs information on three factors—pollutant emission rates (mass per time), a population exposure assessment (mass of pollutant inhaled per mass emitted), and toxicity (health impact per mass inhaled) (Bennett et al., 2002).

4.3.3.5.1. Intake Fraction Analysis

In previous sections of this case study, we compiled information on the emissions attributable to oil and gas development, as well as the fraction associated with those that have been fractured in the region. Here, we consider an exposure assessment that relates emissions mass to population intake. This analysis provides the basis for assessing health risks. With unlimited resources, we would identify the location of each emission, track the dispersion of these emissions as they spread out over the regional landscape, and then track population density and activity of the entire regional population to assess the magnitude and range of population intake. Unfortunately, for this report there is neither time nor resources for an analysis with this level of detail. Thus, we rely on the extensive body of analyses of source receptor relationships that has been compiled over the last decade for distributed pollutant emissions in the SoCAB. In particular, we rely on the extensive research and analysis of "intake fraction" relationships in the SoCAB as a of way of gaining important insights without carrying out extensive new analyses.

For air pollutant emissions, intake fraction (iF) is the mass of a pollutant inhaled by all potentially exposed populations divided by the mass of the pollutant emitted (Bennett et al., 2002). In other words, an intake fraction is the number of kilograms inhaled divided by the number of kilograms emitted, typically reported as "mg inhaled per kg released" or ppm. Intake fraction provides a transparent and parsimonious description of the complex atmospheric transport and human activity patterns that define exposure (Bennett et al., 2002). Because mass inhaled is a more reliable metric of potential adverse health impacts to populations than either mass emitted or airborne concentration, iF also provides key insights for assessing health risks. However, there are limitations to iF. As a measure of cumulative intake among a population over time, it lacks the ability to track exposure variation among individuals or exposure variations within populations over relatively short time periods, such as one hour or less.

Intake fraction is a metric, not a method. Values of the intake fraction for the South Coast Region have been determined from models and from measurements. Typical values for the intake fraction for pollutants released to outdoor air are as low as 0.1 per million (ppm) for air pollutant releases in remote rural areas, to 50 ppm or more for releases near ground level in urban areas. Three factors are dominant in determining the magnitude of the intake fraction for air pollutant emissions—(1) the size of the exposed population within reach of the pollutant emission, (2) the proximity between the emission source and the exposed population, and (3) the persistence of the pollutant in the atmosphere. A useful attribute of intake fraction is that it can be applied to groups of pollutants, rather than one pollutant at a time. When two pollutants are emitted from the same source, and have the same fate and transport characteristics, their intake fraction values will be the same, even if their chemical composition and mass emission rates differ.

The literature on intake fraction is diverse and growing. We identified multiple studies that address inhalation exposures of primary and secondary pollutants from a variety of sources, such as motor vehicles, power plants, and small-scale area sources. We identified five studies that provide detailed calculations on intake fraction for the Los Angeles region, and we make use of the results from these studies to estimate the intake fraction of oil and gas development in the Los Angeles Basin. Although these studies are not directed specifically at oil and gas development, they are well suited to the type of screening exposure assessment that is within our goal of assessing exposure potential of oil and gas.

In the first study considered, we examined the results of Marshall et al. (2003), who focused on the SoCAB as a case study and combined ambient monitoring data with time-activity patterns to estimate the population intake of carbon monoxide and benzene emitted from motor vehicles distributed throughout the SoCAB.

In the second study, we consider results from Heath et al. (2006), who assessed the exposure implications of a shift toward distributed petroleum-powered generation (DG) in California. For this, they combined Gaussian plume modeling and a GIS-based inhalation exposure assessment applied to existing and hypothetical power-generation facilities in California. To carry out this study, they assessed intake fraction for hypothetical DG emissions sources originating in the downtown areas of the eleven most populous cities in California.

In a third relevant study, Lobsheid et al. (2012) used source-receptor relationships derived from the U.S. EPA's AERMOD steady-state plume model to quantify the intake fraction of conserved pollutants (pollutants that are not strongly reactive in air or rapidly deposited to surfaces) emitted from on-road mobile sources. For this analysis, they used source-receptor relationships at census-block scale, and then aggregated and reported results for each of the 65,000 census tracts in the conterminous United States. Their study includes iF values for every census tract and county of California—thus providing useful information for the current case study.

In a fourth considered study, Apte et al. (2012) modeled intra-urban intake fraction (iF) values for distributed ground-level emissions in all 3,646 global cities with more than 100,000 inhabitants. Among all these cities, they found that for conserved primary pollutants, the population-weighted median, mean, and interquartile range iF values are 26, 39, and 14–52 ppm, respectively. They found that intake fractions vary among cities, owing to differences in population size, population density, and meteorology. Their reported iF value for Los Angeles is 43.

For the four studies noted above, Table 4.3-9 provides a summary of the best estimate (typically the median) value as well as the range of iF values that are relevant to the Los Angeles region. We see here that most of the studies converge toward a value of 40 ppm as most typical for this region. In the Lobsheid et al. (2012) study, which calculated iF for every census tract in Los Angeles and Orange counties, we also list ranges that reflect the 95% value interval for all census tracts for which iF is calculated. Lobsheid et al. (2012) also gives insight on variability with iF by census tract, varying from less than 1 ppm to slightly over 100 ppm.

Table 4.3-9. Published values of intake fraction relevant to the well stimulation-enabled oil and gas development emissions in the South Coast Air Basin.

Sources	Region	Pollutants	Method	Best estimate (range) ppm	Reference
Motor vehicles	South Coast air basin	Primary pollutants (CO, benzene)	Data analysis of tracers of opportunity	47 (34-85)	Marshall et al. (2003)
Distributed generators	Central locations in the 11 most populous cities of California	Primary pollutants ($PM_{2.5}$, formaldehyde)	Dispersion modeling	16 (7 – 30)	Heath et al. (2006)
Motor vehicles and distributed sources	Los Angeles county (2052 census tracts)	Primary conserved pollutants	Source-receptor air modeling for 65,000 US census tracks	38 (29 – 77)*	Lobsheid et al. (2012)
Motor vehicles and distributed sources	Orange county (577 census tracts)	Primary conserved pollutants	Source-receptor air modeling for 65,000 US census tracks	27 (19 – 50)*	Lobsheid et al. (2012)
Distributed ground level emissions	Los Angeles city	Conserved primary pollutants	High resolution dispersion model	43 (n/a)	Apte et al. (2012)

** This range reflects the 95% value range (that is 2.5% lower bound and 97.5% upper bound) of the iF for all census tracts in the county.*

Because of the lack of TAC emissions data on the census and local levels, we are unable to estimate the iF of oil and gas development at the census tract and local levels in the SoCAB context. This type of study is an important next step to understanding exposure to benzene and other TACs emitted by oil and gas development in the Los Angeles Basin. Nonetheless, below, we walk through some of the preliminary steps necessary to conduct such an analysis.

The intake fraction values provided above can be used to translate emissions in kg/d of any conserved pollutant into population exposures, and also into exposure concentration estimates. The intake fraction values above (for example, 38 ppm) provide an estimate of how many mg/day of a pollutant enters the lungs of the South Coast Population for every kg/d emitted. This is a cumulative intake obtained by identifying source locations and tracking exposures out to the limits of the South Coast Region—the cumulative integral of population intake. In the case of Marshall et al. (2003), the sources were roadways; for Heath et al. (2006), the sources were located at the commercial centers of large cities; and for Lobsheid et al. (2012), sources were located at the center of all census tracts, with dispersion followed out to all other census tracts in the region. In all three studies, the intake was obtained from concentrations using representative breathing rates (~14 m^3/d per individual). We note that the high spatial resolution of the Lobsheid et al. (2012) study allows us to consider not only the middle range iF for South Coast emissions, but also the effect of releases to areas with very high population density. In Lobsheid et al. (2012), the mean iF value is 38 ppm, with an upper bound of 77.

The next step of this assessment would be to take the regional emissions of air pollutants from oil and gas development, and multiply by the regional iF, to get an estimate of population intake. To get an estimate of health effects, we would need to divide the iF by the appropriate regional population to get the median (or mean) individual intake estimate, which can be compared to RELS, reference doses (RfDs), or reference concentrations (RfCs).

We could add more detail to this effort by calculating the iF for each census tract in the region and use the population impacted by emissions from that tract to do a bottom-up estimate of the range of iF values. As an example, we can use the Lobsheid et al. (2012) results to determine the types of concentrations that are associated with an iF in smaller regions. In L.A. County, with a median iF of 38 and assuming that the substantial amount of intake occurs within 3 km of the source (impacting some 50,000 people), the concentration imposed on this population from an additional 1 kg/day emissions is 0.05 $\mu g/m^3$. In Orange County, a similar calculation gives 0.04 $\mu g/m^3$ for each additional kg emitted to a representative census tract.

While we know the intake fraction potential at the census tract level, we are unable to estimate the iF of oil and gas development at the census tract and local levels in the SoCAB context, due to the lack of TAC emissions data on the census and local levels. But this would be an important next step to understanding exposure to benzene and other TACs emitted by oil and gas development in the Los Angeles Basin.

4.3.3.5.2. Summary of Screening Exposure Assessment for Air Pollutant Emissions in the Los Angeles Basin

The high population intake fractions that are possible in the SoCAB are primarily due to the high population density of the region. In other words a larger proportion of air pollutant emissions in the South Coast Air Basin enter human lungs compared to places with lower population density (fewer breathing lungs).

Those living in close proximity to emitting sources will likely be more exposed to these emissions than those that live further away. The reason that proximity to the source is important is that the contaminant in question will be at its highest atmospheric concentration at the source. The concentration generally falls off exponentially with distance from the source (via dilution), so that exposures near the source can be much larger than average regional exposures. So, for example, the regional contribution of the oil and gas production for benzene is 2,361 kg/year and is dispersed throughout the air basin. However, near emission sources, on or near active well pads, the atmospheric concentrations can be much higher than the regional average.

4.3.3.6. Proximity Analysis of Oil and Gas Development and Human Populations

In the previous sections, we have identified that TACs are emitted by oil and gas development in general, and that the concentrations of these emissions may be elevated near active oil and gas development. Wells are considered to be active if they are categorized as such in the Oil and Gas Well Database maintained by DOGGR. In this section, we quantify and locate all currently active oil and gas wells, and also the fraction that are stimulated. We then conduct an analysis of spatial relationships between currently active oil and gas wells and those that are hydraulically fractured and surrounding human populations and sensitive receptors.

4.3.3.6.1. Study Area

The geographic focus of this proximity analysis includes the California Air Resources Board (CARB) South Coast Air Basin (SoCAB), which includes Los Angeles County, Orange County, and parts of both Riverside and San Bernardino counties and the active oil and gas wells within this jurisdictional boundary. For a list of the methods we used to determine the number of active oil and gas wells—and the numbers and locations of those wells that have been hydraulically fractured, frac-packed, high-rate gravel packed, or acidized in the Los Angeles Basin—please see Appendix 4.A.

4.3.3.6.2. Numbers and Types of Active Oil and Gas Wells by Oil Field in the Los Angeles Basin

We used the methodology for calculating the number and proportion of stimulated wells as was used statewide in Volume I, with only minor modifications and focused specifically on the Los Angeles Basin (see Appendix 4.A). Our results indicate that there are approximately 5,256 wells that are currently active, according to DOGGR. Of these wells, 3,691 are located in oil and gas pools with estimated stimulation rates. When the stimulations rates for the pools are applied to the total number of wells in each pool, there are an estimated 1,341 wells that have been enabled or supported by hydraulic fracturing, frac-packing, or high-rate gravel packing (hereafter referred to as fracturing) (Table 4.3-10). The estimated number of wells that have been fractured thus represents approximately 26% of the 5,256 currently active wells listed as active by DOGGR as of July 2014, and 36% of the active wells in pools that were queried. These numbers should be considered conservative, given that we only have oil pool-level information on type of oil development (stimulation) for approximately 29% of the wells listed as active by DOGGR. As such, it is probable that more pools may have been hydraulically fractured, frac-packed, or high-rate gravel packed, but we do not have access to these data. While a report by Cardno ENTRIX (2012) found that as of 2012 there were 23 hydraulically fractured wells in the Inglewood Oil Field, as discussed in Volume I, DOGGR data suggest that this might be an underestimate, or that most of the other wells were supported or enabled by frac-packing and high rate gravel packing which was not included in the Cardno ENTRIX estimate. For a more detailed explanation of methods and approaches, please see Appendix 4.A. Please also refer to

Volume II, Appendix 5.E, for more information.

Table 4.3-10. Numbers of all currently active wells and the proportion that are supported by hydraulic fracturing, frac-packing, or high-rate gravel packing (HRGP) in the Los Angles Basin by oil field.

Oil Field	Total Active Wells	Total Wells Fractured	% Fractured
Brea-Olinda	551	551	100%
Inglewood	503	503	100%
Wilmington	1,716	179	10%
San Vicente	35	32	91%
Aliso Canyon	50	21	42%
Whittier	29	18	62%
Las Cienegas	60	10	17%
Esperanza	11	6	55%
Temescal	5	5	100%
Newhall-Potrero	45	4	9%
Tapia	30	3	10%
Del Valle	37	3	8%
Montebello	123	2	2%
Salt Lake	24	2	8%
Huntington Beach	306	1	0%
Wayside Canyon	10	1	10%
Playa Del Rey	28	0	0%
Torrance	128	0	0%
Total Assigned to Fields	**3,691**	**1,341**	**36%**
Unassigned to Fields	1,565	unavailable	
TOTAL	**5,256**	**1,341**	**26%**

4.3.3.6.3. New Wells and Wells Going Into First Production (2002-2012)

There are 1,403 oil and gas wells that were either new or went into first production between 2002 and 2012 in the SoCAB. Of these wells, 435 (31%) have been identified as having been hydraulically fractured (Table 4.3-11). Given the uncertainty in the data, this proportion (31%) is similar to the 26% of all active wells, and thus shows agreement with and corroboration of our data analysis.

Table 4.3-11. New wells or wells going into first production and the proportion that are hydraulically fractured, frac-packed, or high-rate gravel packed (HRGP) (2002-2012).

Oil Field	Total New Wells (2002-2012)	Total New Wells Fractured	% New Wells Fractured
Inglewood	219	219	100%
Brea-Olinda	29	29	100%
Wilmington	831	159	19%
Aliso Canyon	26	0	0%
Cascade	7	0	0%
Long Beach Airport	2	0	0%
Los Angeles Downtown	1	0	0%
Newhall-Potrero	12	1	8%
Richfield	1	0	0%
San Vicente	6	6	100%
Sansinena	7	0	0%
Santa Fe Springs	57	3	5%
Tapia	21	1	7%
Wayside Canyon	4	0	0%
Playa Del Rey	3	3	100%
Beverly Hills	83	0	0%
Las Cienegas	9	3	33%
Del Valle	5	0	0%
Montebello	21	0	0%
Huntington Beach	8	4	47%
Belmont Offshore	32	0	0%
Torrance	12	0	0%
Whittier	7	7	100%
TOTAL	**1403**	**435**	**31%**

4.3.3.6.4. Acidizing

Hydrofluoric and hydrochloric acid are frequently used in the development of oil in the Los Angeles Basin. Based upon the SCAQMD dataset, there are ~20 events per month that use hydrofluoric acid (SCAQMD, 2015). The SCAQMD reports a total of 22.5 events per month, including both acidization and hydraulic fracturing (excluding gravel packing). As described in Volume I, there is insufficient data in available datasets to distinguish matrix acidizing from maintenance acidizing, although operators were required to distinguish starting April 02, 2014.

4.3.3.6.5. Summary: Numbers and Types of Oil and Gas Wells in the Los Angeles Basin

Approximately 26% of currently active oil and gas wells (1,341/5,256) and 31% of wells that went into first production between 2002 and 2012 (435/1,403) are likely enabled or supported by hydraulic fracturing, frac-packing, and high-rate gravel packing.

Data from the SCAQMD mandated reporting suggest that the use of hydrofluoric and hydrochloric acid in oil production wells is common in the Los Angeles Basin (SCAQMD, 2015). However, the use of acid is supportive of current development and unlikely to be used to significantly increase expanded development.

4.3.3.7. Proximity of Human Populations to Oil and Gas Development

Our analysis of available state emission inventories indicates that 2,361 kg/year of benzene is emitted by upstream oil and gas development in the Los Angeles Basin. This amount represents a significant proportion of stationary source (9.6%) and <1% from all sources (including mobile source emissions) in the South Coast Air Basin. Our analysis of California emission inventories also indicates that 5,846 kg/year or 3.8% of the stationary source emissions and <1% of all source emissions (including mobile sources) of formaldehyde are attributable to the upstream oil and gas sector (Table 4.3-4). As a basis for understanding potential public health hazards attributable to upstream oil and gas development, we evaluated the spatial relationships of all active oil and gas wells, and then those that are stimulated, to the surrounding population, and selected sites considered to be “sensitive receptors.” We also characterized the demographics, vulnerability factors, and socioeconomic profiles of the communities in proximity to well stimulation events.

Our choice to include all oil and gas wells as opposed to only considering the fraction that are stimulated was based on our finding that benzene, a health-damaging indicator TAC as described above, is emitted from oil and gas development in general and is not specific to, or even related directly to, well stimulation. To evaluate proximity of populations within the Los Angeles Basin to only those wells that are stimulated is misleading and potentially would leave out communities that are potentially submitted to the same level of environmental public health hazard as those communities that live near stimulated wells.

For a complete description of our methods and approach to the spatial proximity analysis, please see Appendix 4.B.

4.3.3.7.1. Spatial Distribution of All Active Oil Wells and Active Stimulated Wells

Figure 4.3-3 shows the South Coast Air Basin with stimulated wells. As discussed in the methods above, we identified 4,487 active oil wells and 1,205 active wells that have been fractured, and at least 60 wells that have been supported by acidizing in the South Coast Air Basin that are still in production as of 14 December 2014. Figure 4.3-4 shows the density of active oil and gas wells in the SoCAB.

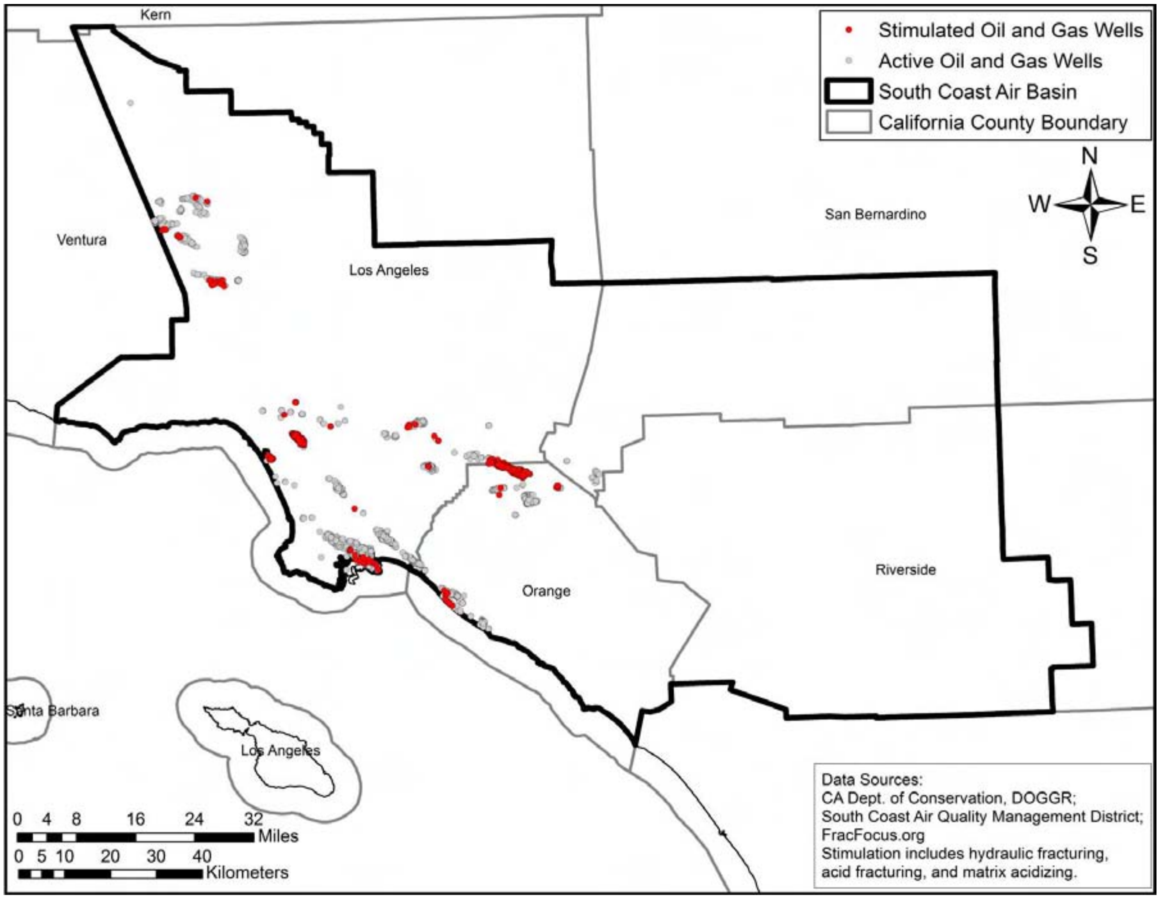
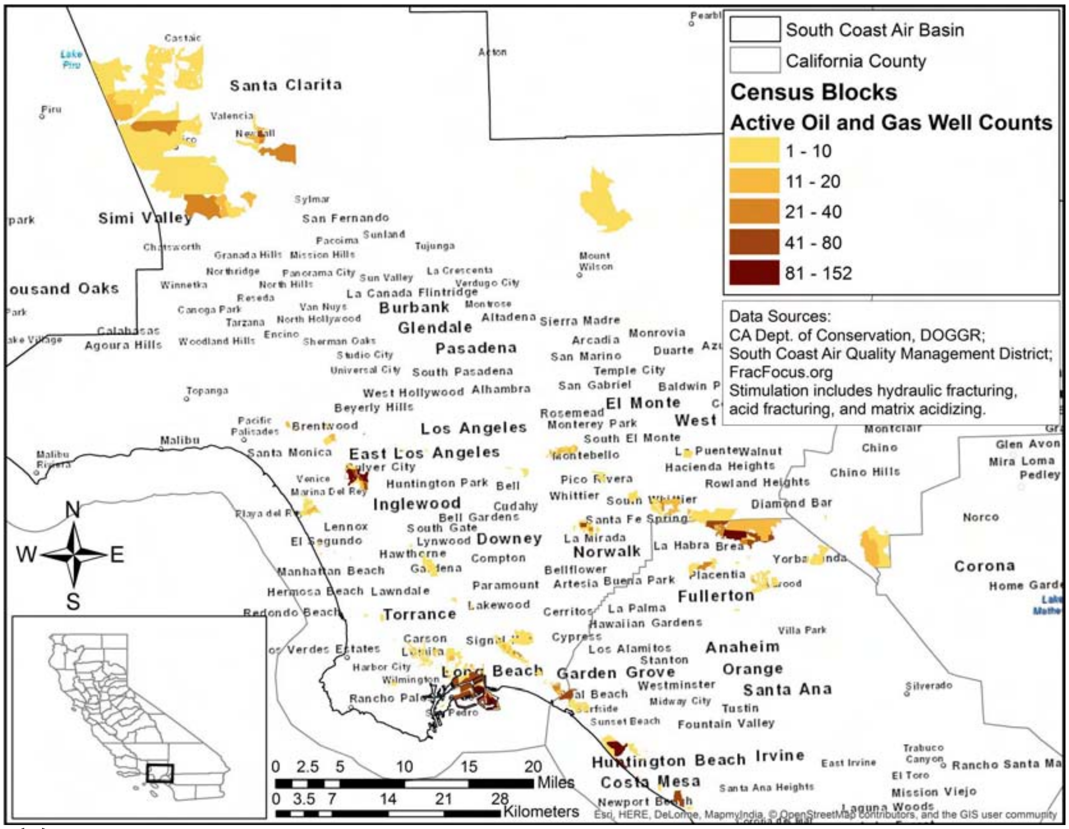


Figure 4.3-3. All active oil production wells in the South Coast Air Basin with those that are stimulated shown in red.



(B)

Figure 4.3-4. Density of active oil and gas well counts in the South Coast Air Basin.

4.3.3.7.2. Human Population Proximity Analysis

Figure 4.3-5 shows the population density in the Los Angeles Basin and the boundaries of 2,000 m (6,562 feet) distance from all active oil wells and the fraction of active oil wells that have been stimulated. It is evident that stimulated wells in the Los Angeles Basin exist both within and in close proximity to high population density areas. It is also evident that a slightly larger portion of the Los Angeles Basin population lives within 2,000 m (6,562 feet) of an active oil well than the population that lives within 2,000 m (6,562 feet) of a well that has been stimulated. This makes sense, because there are approximately 75% more oil wells that are not stimulated than those that are.

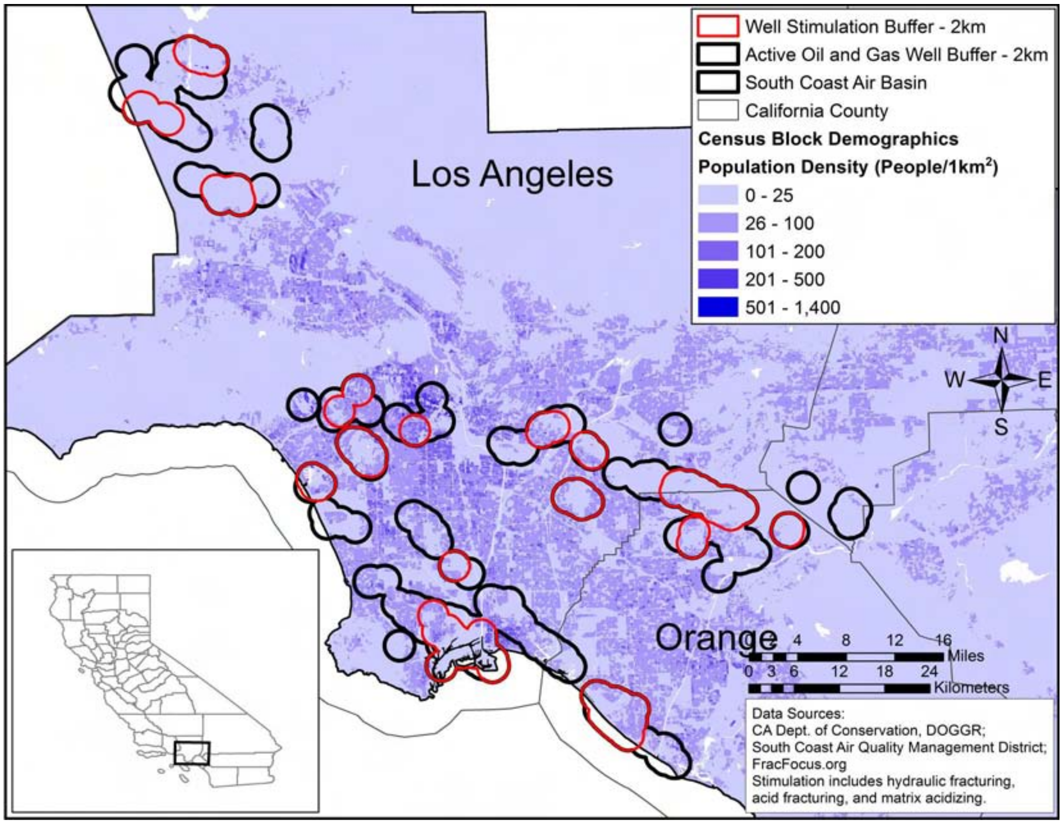


Figure 4.3-5. Population density within 2,000 m (6,562 feet) of currently active oil production wells and currently active wells that have been stimulated.

As summarized in Tables 4.3-12 and Table 4.3-13, a number of residents and sensitive receptors are in proximity to active oil development and the fraction of this development from wells that have been stimulated. Approximately 2,258,000 people (12% of the SoCAB population) live within 2,000 m (6,562 feet) of an active oil well. Additionally, there are 130 schools, 184 daycare facilities, 213 residential elderly homes and nearly 628,000 residents within 800 m (½ mile or 2,625 feet) of an active oil well. More than 50,000 children under the age of five, and over 43,500 people over the age of 75, live within 2,000 m (6,562 ft) of an active oil production well. Even within only 100 m (328 ft) of a well, there are more than 32,000 residents, nearly 2,300 of who are children under five (Table 4.3-12).

Fewer residents and sensitive receptors are located in close proximity to oil wells that have been stimulated in the SoCAB, largely because only a subset of the wells in this basin is stimulated. Approximately 760,000 people (4% of the SoCAB population) live within 2,000 m (6,562 feet) of a stimulated well. Additionally listed in Table 4.3-13 is the number of sensitive populations and facilities in proximity to stimulated wells. For instance, there are 20 schools, 39 daycare facilities, 27 residential elderly homes, and nearly 128,000 residents within 800 m (½ mile or 2,625 feet) of a stimulated well. More than 120,000 children under the age of five and over 90,000 people over the age of 75 live within a mile (1,600 m or 5,249 feet) of a stimulated well (Table 4.3-13).

Table 4.3-12. Proximity of human populations and sensitive human receptors to active oil wells in the South Coast Air Basin.

Buffer Distance (m)	Number of Residents	Number of Schools	Number of Children Attending Schools	Number of Elderly Facilities	Number of Daycare Facilities	Under 5	Over 75
100	32,071	4	3,290	12	5	2,295	1,664
400	233,102	50	34,819	94	72	16,685	14,005
800	627,546	130	89,241	213	184	45,050	35,189
1,000	866,299	180	135,797	258	262	62,547	47,759
1,600	1,677,594	348	242,833	429	524	122,321	91,452
2,000	2,257,933	470	332,855	582	718	164,992	122,737

Table 4.3-13. Proximity of human populations and sensitive human receptors to stimulated wells in the South Coast Air Basin.

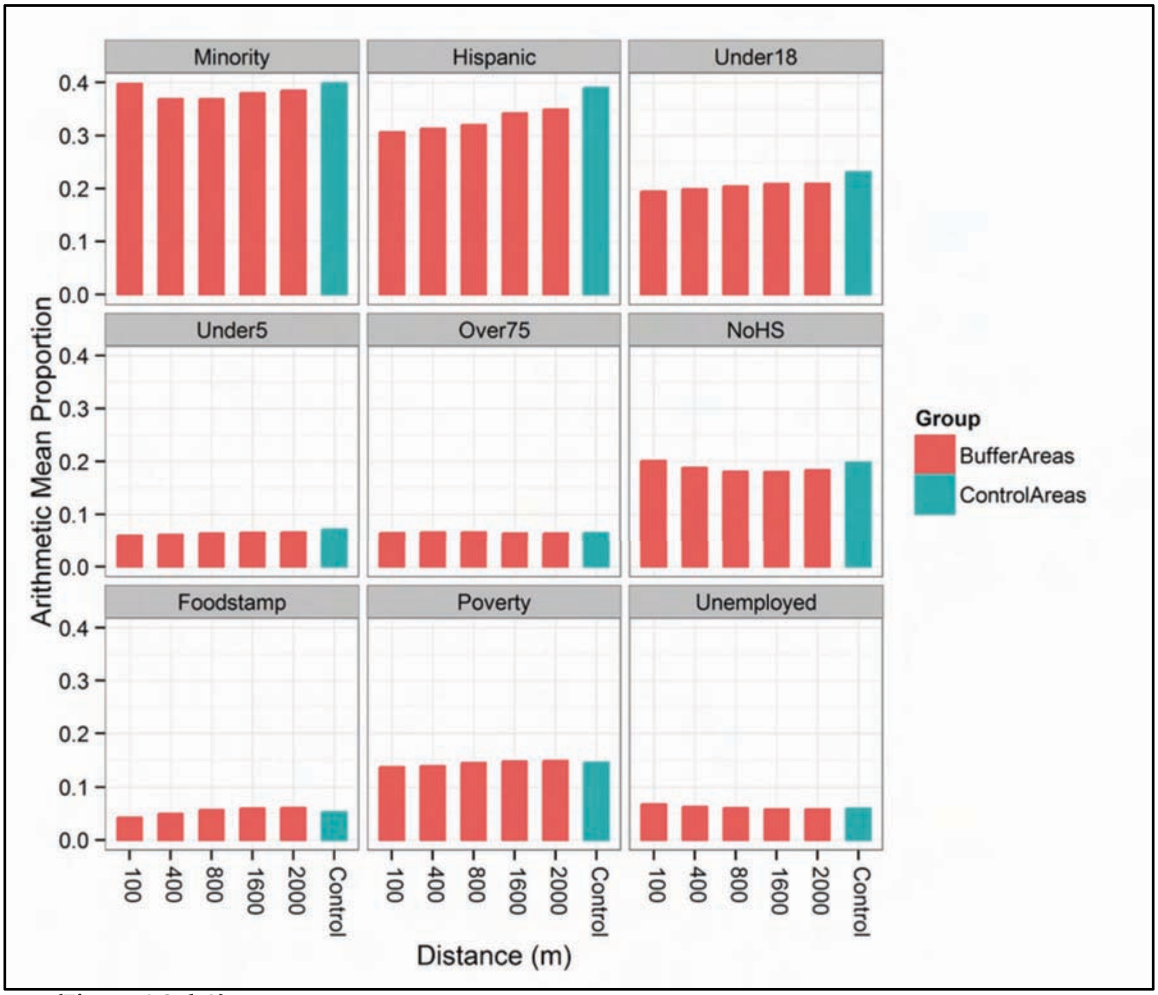
Buffer Distance (m)	Number of Residents	Number of Schools	Number of Children Attending Schools	Number of Elderly Facilities	Number of Daycare Facilities	Under 5	Over 75
100	3,661	2	2,135	1	0	285	163
400	33,928	7	3,738	4	8	2,170	2,301
800	127,896	20	12,302	27	39	7,653	8,849
1000	267,994	49	36,286	39	80	17,856	16,148
1600	494,831	125	91,585	111	181	31,199	29,827
2000	759,513	181	131,158	158	277	50,067	43,466

In summary, there are >65% more people that live within proximity of any active oil and gas well compared to those that live within proximity of only those active wells that are associated with well stimulation. As explained above, the TAC emissions of concern from a public health perspective do not differ between oil and gas wells that have been stimulated and those that have not, and the subsequent public health hazard associated with both are essentially the same as it pertains to TAC emissions.

4.3.3.7.3. Comparing Population Demographics Near vs. Far from Oil and Gas Wells

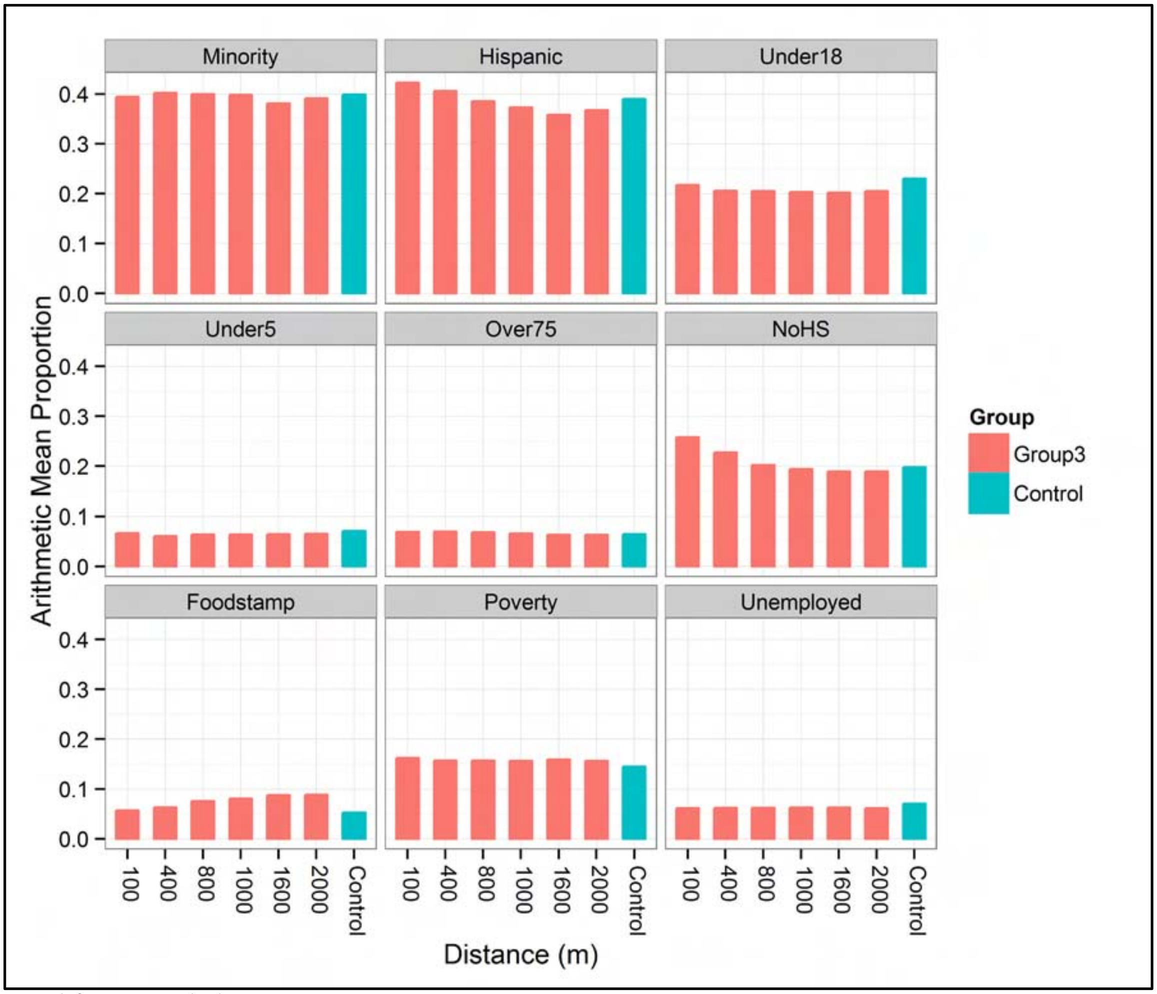
At the regional scale, demographic characteristics of populations were similar among all studied distances from active oil and gas development and stimulation-facilitated development (Figure 4.3-6.A and Figure 4.3-6.B). Moreover, the studied distances were also similar in demographics compared to the control population, those farther than

2,000 m (6,562 ft) distance from the closest active well. As such, while it is clear that oil and gas is being developed in low-income communities and communities of color, there does not appear to be a disproportionate burden of oil and gas development on any one demographic in the Los Angeles Basin. In other words, oil and gas wells are not located disproportionately near the rich, the poor, or any race/ethnicity more than any other. Differences in average proportions were less than 0.05 (i.e., 5%) across buffer distances from active oil and gas wells and versus control areas (Figure 4.3-6.A). The only exception to this was that at the 100-meter (328 ft) buffer distances, the proportion of residents without high school education was more than 5% greater than the population at 800 m (2,625 ft), 1,000 m (3,280 ft), 1,600 m (5,249 ft) , and 2,000 m (6,562 ft) buffer distances and the control population. The proportion of individual households that qualify for food stamps and the proportion under the poverty line were slightly more elevated among residents close to hydraulically fractured wells compared to control sites (Figure 4.3-6.B). Residents that are under 18 years of age and those that are unemployed are slightly lower, and the non-Hispanic minority, those less than 5 years of age, and those more than 75 years of age, were essentially the same as control sites. Proportions of Hispanic residents exhibited variations with buffer distance, such that those at 100-meter (328 ft) and 400-meter (1,312 ft) distances were higher, whereas those at 1,000, 1,600, and 2,000-meter (3,280; 5,249; and 6,562 ft) distances were lower than control areas (Figure 4.2-2). Arithmetic averages, medians, standard deviation, and empirical 90th percentile values were also similar. Density plots also indicated similar distributional shape among the groupings and control population, suggesting that they represent samples from a similar population overall.



Minority
Hispanic
Under18
Under5
Over75
NoHS
Foodstamp
Poverty
Unemployed
Arithmetic Mean Proportion
0.0
0.1
0.2
0.3
0.4
100
400
800
1600
2000
Control
Distance (m)
Group
BufferAreas
ControlAreas

(Figure 4.3-6.A)



(Figure 4.3-6.B)

Figure 4.3-6.A and 4.3-6.B. Proportion of demographic characteristics at studied geographic distance from (A) all active oil and gas wells; and (B) stimulated wells compared to the control (areas beyond 2,000 meter buffer distance). Minority = non-Hispanic minorities; NoHS = not completed high school education; Foodstamp = household income qualifies for food stamps (< $15,000); Poverty = below poverty; Under5=Children less than 5 years of age; Over75=adult more than 75 years of age; Foodstamp=receives food stamps.

4.3.4. Potential Risks to Ground Water Quality in the Los Angeles Basin

Most water delivered to homes and businesses in the Los Angeles Basin is delivered via pipelines and canals from distant water sources. Los Angeles' Department of Water and Power (LADWP) brings water to its 3.9 million residents from the Owens Valley via the Los Angeles Aqueduct (LADWP, 2013). The Metropolitan Water District of Southern

California (MWD) indirectly serves another 14 cities and 12 municipal water districts, indirectly providing water to 18 million people. MWD obtains water from the State Water Project, a system of dams and reservoirs in Northern California, and an aqueduct to the Colorado River on California's border with Arizona (MWD, 2012). These water sources are far removed from oil and gas development and are unlikely to be contaminated by such operations. However, groundwater makes up one-third of the water supply for the 4 million residents of the Los Angeles coastal plain (Hillhouse et al., 2002), and chemicals from oil and gas development, including well stimulation, could possibly contaminate some groundwater wells.

Potential pathways for contamination of groundwater from well stimulation activities are described in Volume II, Section 2.6.2 (Table 2.6.2). For example, potential risks to groundwater may be related to subsurface leakage via loss of wellbore integrity or hydraulic fractures intercepting an aquifer, accidental releases at the surface, and inappropriate disposal of recovered and produced water, as described in detail in Volume II, Chapter 2 of this report. Regarding subsurface leakage, the risk of water contamination from a hydraulic fracture intercepting a protected aquifer is minimal if the hydraulic fracturing operation is sufficiently deeper than the aquifer. However, as described below, some hydraulic fracturing in the Los Angeles Basin takes place in close vertical proximity to protected aquifers.

Much of the groundwater consumed by the cities of Santa Monica, Long Beach, and other nearby districts is extracted from the coastal plain aquifer system, which underlies much of the coastal area of Los Angeles and Orange Counties. The portion of the coastal plain aquifer system in Los Angeles County is shown in Figure 4.3-7.

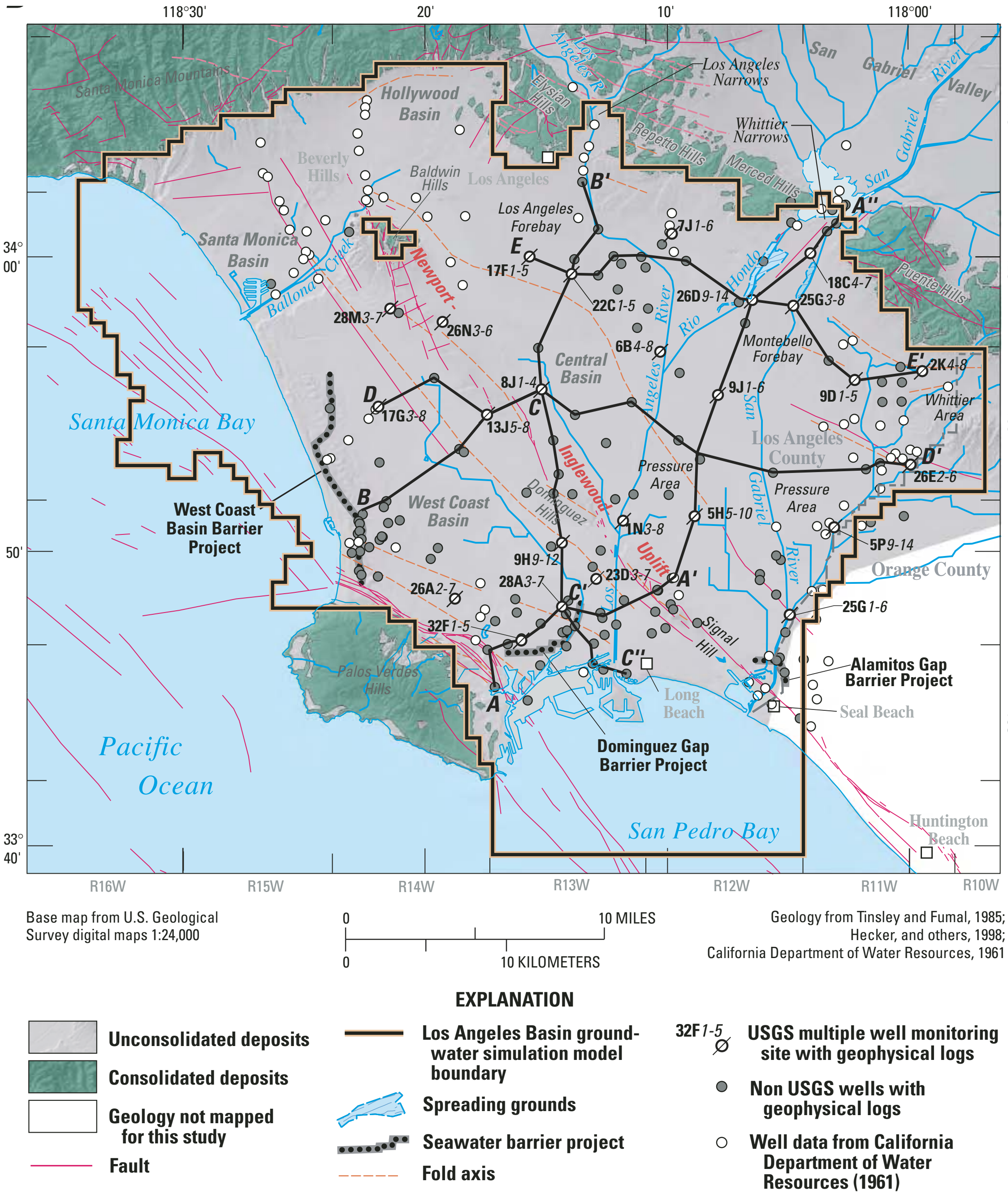
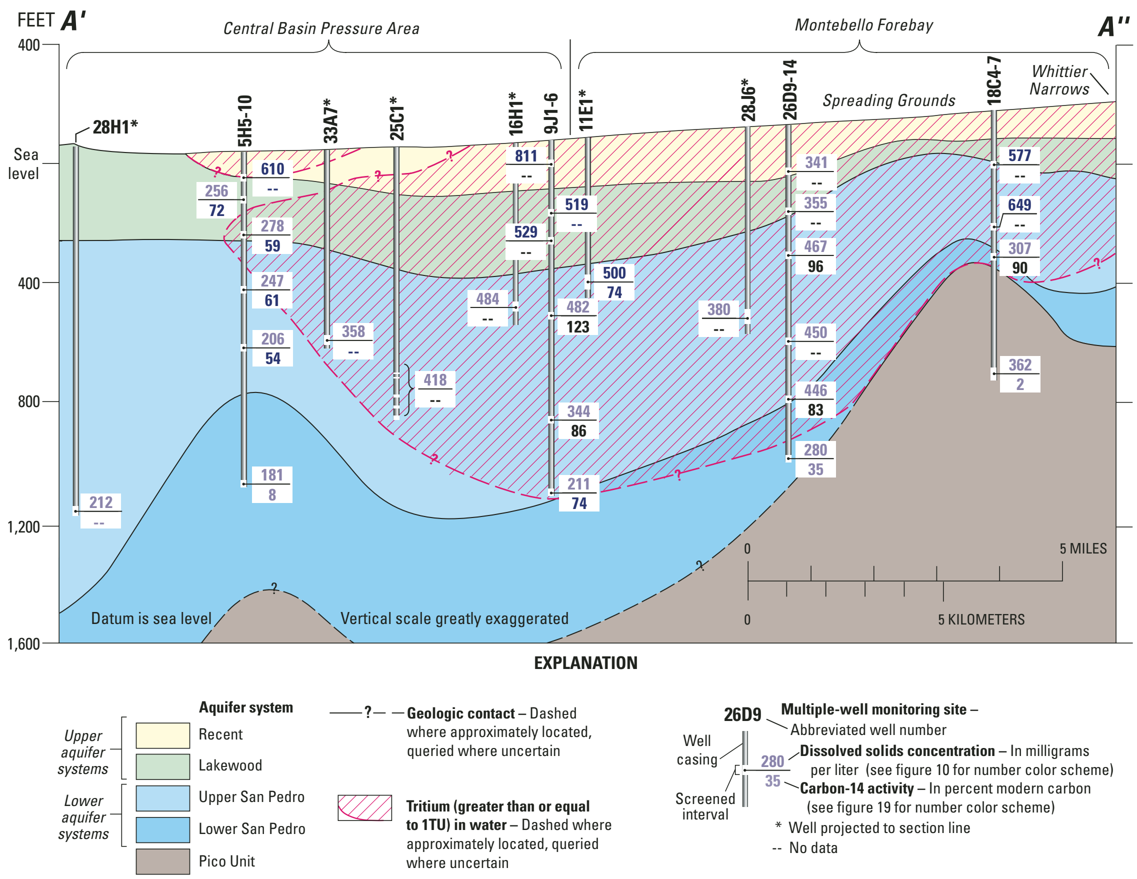


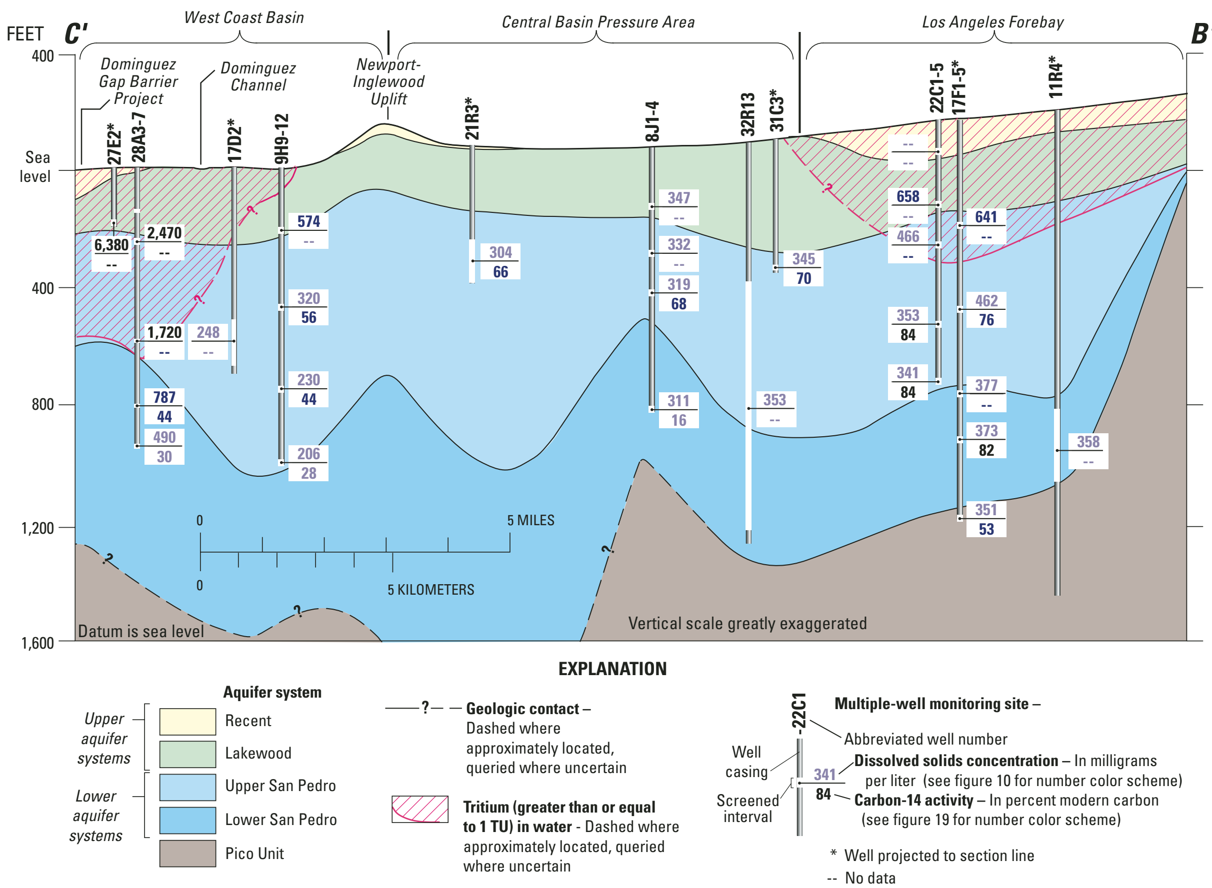
Figure 4.3-7. Coastal Plain of Los Angeles Groundwater Basin as defined by Department of Water Resources (DWR, 2012) consists of the contiguous unconsolidated deposits in the center of the figure. The unconsolidated deposits shown to the northeast are part of the San Gabriel Valley Groundwater Basin defined by DWR (2012). The geohydrologic sections shown on Figure 4.3-8 are located, along with some other sections not included in this report (Reichard et al., 2003).

Senate Bill 4 (SB 4) requires operators to monitor groundwater in aquifers in the vicinity of stimulated oil and gas wells. The main freshwater body of the coastal plain aquifer system extends from depths of less than 30 m up to 1,200 m (100 ft up to approximately 4,000 ft) (Planert and Williams, 1995). Two of the hydrologic sections located in Figure 4.3-7 are shown in Figure 4.3-8. Groundwater with less than 500 mg/L total dissolved solids (TDS) occurs at the lowest sampling points along the sections, which are typically 300 to 400 m (1,000 to 1,300 ft) deep. At many wells, the TDS concentration decreases with depth, indicating that water quality improves with increased depth. Most water supply wells in the Los Angeles coastal basin are drilled to depths of 155 to 348 m (510 to 1,145 ft) (Fram and Belitz, 2012), which accords with the TDS distribution on Figure 4.3-8 (Reichard et al., 2003).



a)

Figure 4.3-8. Dissolved-solids concentration, measurable tritium activity, and carbon-14 activity in ground water from wells sampled along geohydrologic sections A'–A'' (a) and C'–B' (b), Los Angeles County, California (Reichard et al., 2003).



b)

Figure 4.3-8. Continued.

Based on the hydraulic fracturing data for the last decade, we estimate about 40 to 80 fracturing operations are conducted each year on average in the Los Angeles Basin (see Volume I, Appendix K). Approximately three quarters of these are hydraulic fracturing operations, and one quarter are frac-packing operations (Volume I, Chapter 3). Volume I, Appendix M provides the well head locations for all wells where hydraulic fracturing operations were conducted, along with depths as available from the various data sets considered by this study. The appendix includes records of 314 fracturing operations in the Los Angeles Basin conducted from 2002 to mid-2014. Depths were available for 244 of these operations. All of these depths were either true vertical or measured total well depth. The shallowest well in these records was 401 m (1,320 ft), and 5% were shallower than 840 m (2,762 ft). This well depth distribution suggests that hydraulic fracturing may occur in close proximity to protected groundwater (defined as non-exempt groundwater with less than 10,000 TDS), and perhaps even in proximity to groundwater with less than 3,000 mg/L TDS. This is particularly the case, because the depth of the hydraulically fractured interval in an oil and gas well is less than the total well depth.

To assess the possibility that hydraulic fracturing is occurring at shallow depths, which may contaminate drinking water sources, we analyzed the spatial relationship between hydraulically fractured oil and gas wells and water wells in the Los Angeles Basin. The wellhead locations of hydraulically fractured wells were compared to the location of water wells in a database from the Department of Water Resources (DWR) provided by the United States Geological Survey (USGS) (Faunt, personal communication). The water well data are from well completion reports filed with the DWR.[1] These data are incomplete, and the California-wide dataset is missing at least 50,000 water wells drilled over the past 65 years plus wells drilled prior 1949 (Senter 2015, California Department of Water Resources, pers. comm.). However, the water well data does allow an initial screen for the proximity of hydraulically fractured wells.

The water well dataset indicates the purpose of the wells included in the set. For this study, we only included wells indicated as supply (“PROD”) or with no purpose listed. The remainder of the dataset consists of wells involved in seawater barriers, groundwater remediation, and observation.

All hydraulically fractured wells in Volume I, Appendix M with a wellhead located within 1 km (0.6 mi.) laterally of the water wells considered were selected for further analysis. The locations of these 18 wellheads are shown in Figure 4.3-9. The true vertical depth to the top of the hydraulically fractured interval in each was collected from their well record, and is also shown in Figure 4.3-9.

1. Since 1949, California law has required that landowners submit well completion reports to DWR, containing information on newly constructed, modified, or destroyed wells.

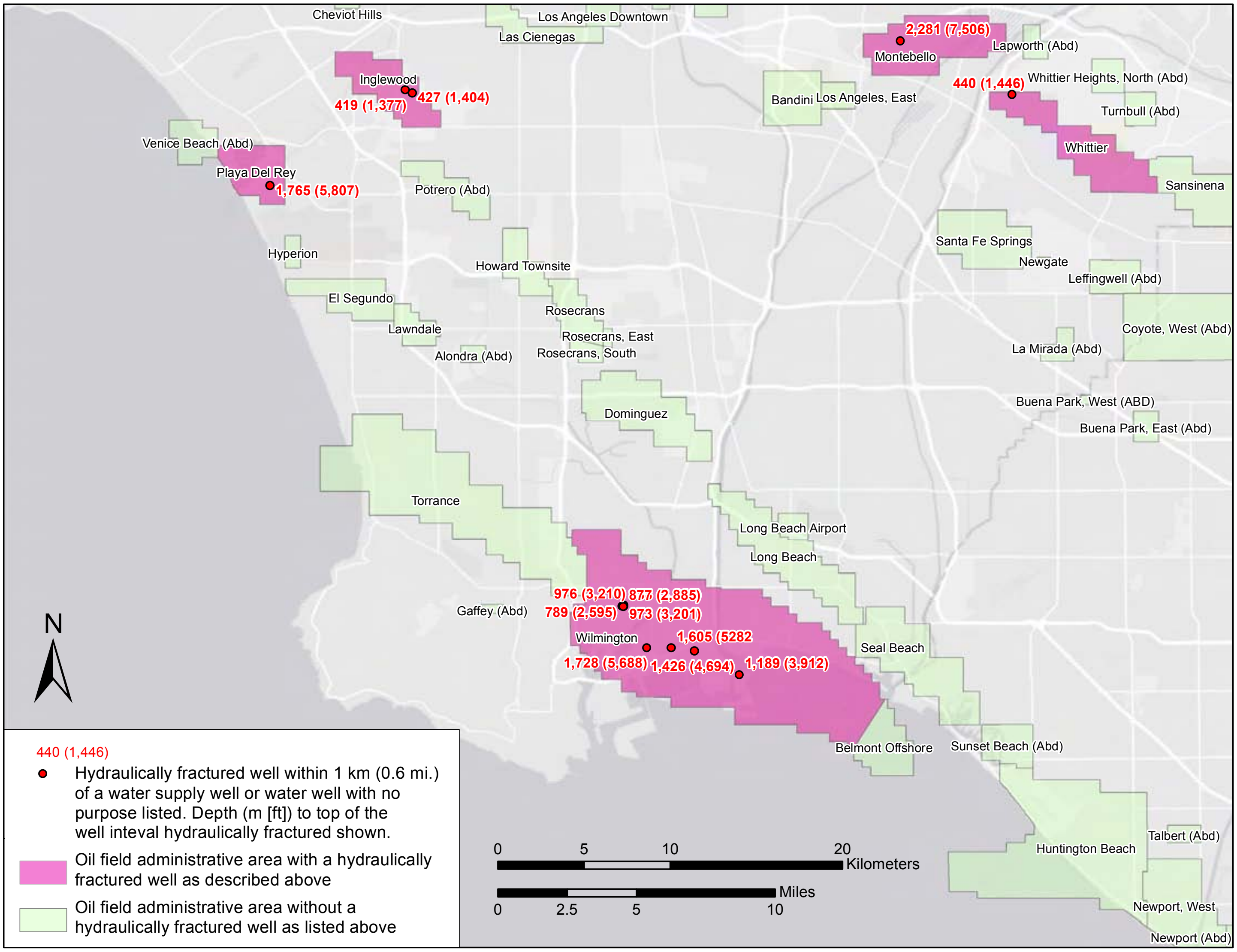


Figure 4.3-9. Depth in meters (and feet) to the top of the hydraulically fractured interval in each well in Volume I, Appendix M, with a wellhead within 1 km (0.6 mi.) laterally of a water supply well or a water well with no purpose stated. Note the depth to the top of the well interval hydraulically fractured is shown for 13 of the 18 wells assessed. The five wells without labels are in the northwestern-most cluster in the Wilmington field. Labels are shown for the four shallowest well interval tops in this cluster.

To assess the vertical separation between the hydraulic fracturing intervals and water wells, the depths of the water wells were subtracted from the depth to the top of each well interval hydraulically fractured for nearby wellheads. The depth to the base of the perforations were available for more than half of the water wells considered, and the total well depth was available for the rest. Figure 4.3-10 shows the depth separation between the base of the water well and the top of the well interval hydraulically fractured for each of the 18 wells stimulated, separated by the oil field in which they are located.

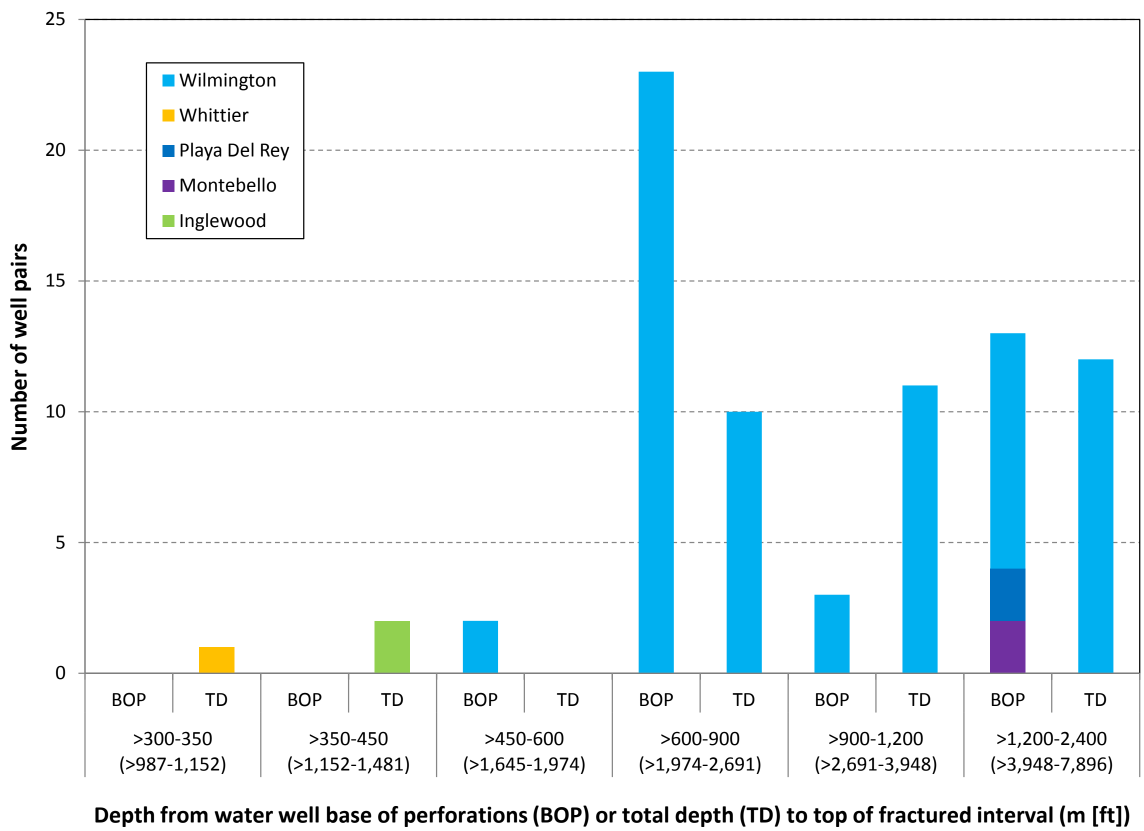


Figure 4.3-10. Depth separation between the base of each water well and the top of each well interval hydraulically fractured for wells with well heads within 1 km (0.6 mi.) of each other Note the bin intervals are not uniform in order to provide more detail for the smaller separations.

Figure 4.3-10 suggests that the vast majority of the selected hydraulic fracturing operations was conducted with large vertical separation to water wells between 600 m (1,974 ft) and 2,400 m (7,896 ft). The operations within four wells within the Wilmington and Inglewood oil fields had the vertical separation between 350 m (1,150 ft) and 600 m (1,974 ft). The operation in one well in the Whittier field has a vertical separation of

300 to 350 m (1,000 to 1,150 ft) from a water well. Given the small number of operations identified that are close to protected groundwater, and the relatively small overall number of hydraulic fracturing operations conducted in the basin, the risk of a hydraulic fracture impacting an existing water well is considered small, but does warrant further investigation (Volume II, Chapter 2).

Proximity to existing water wells is only one indicator of proximity to protected groundwater. Water supply wells typically only extend as deep as necessary to secure the desired supply of groundwater from aquifers that are reasonably secure from contamination by surface and near-surface releases. They typically do not necessarily extend to the base of protected groundwater (i.e., non-exempt groundwater with up to 10,000 mg/L TDS). For instance, most of the depths of the top of the fractured oil and gas well intervals are less than the maximum depth of the coastal plain aquifer of 1,200 m (3,900 ft). Some of these depths are also within 100 m (330 ft) of the deepest sampling intervals shown in Figure 4.3-8, which have water with <500 mg/L TDS, and deeper water supply wells.

A more detailed understanding of the depth to the base of protected water relative to the depth of the well intervals hydraulically fractured (Figure 4.3-9) is provided by the field rules from DOGGR, in combination with the reservoir water salinities listed in California Oil and Gas Field Volume II (DOGGR, 1992). Table 4.3-14 lists the TDS for each field indicated in Figure 4.3-9, along with the depth range of the top of the well interval hydraulically fractured from the 18 operations shown on Figure 4.3-9 for each field. The data in Table 4.3-14 are shown graphically on Figure 4.3-11.

The table and figure show that one fracturing operation in the Whittier field occurred within perhaps 300 m (1,000 ft) of water with <3,000 mg/L TDS, and actually within water with <10,000 mg/L TDS. Two fracturing operations occurred within 150 m (490 ft) of water with <10,000 mg/L TDS in the Inglewood field. The shallowest operation in the Wilmington field occurred within 200 to 350 m (660 to 1,100 ft) of water with <3,000 mg/L TDS. As these results are based on only 18 of the 341 known hydraulically fractured wells in the Los Angeles Basin, it is possible the minimum depth separation between well intervals hydraulically fractured and groundwater of these various qualities is even less.

Table 4.3-14. Groundwater TDS data compared to the depth to the top of select hydraulic fracturing well intervals (TDS data from field rules).

Field	Base of freshwater (<3,000 mg/L TDS) (m [ft])	Deepest reservoir with water <10,000 mg/L TDS (m [ft])	Shallowest reservoir listed with water >10,000 mg/L TDS (m [ft])	Top of stimulation well interval for selected operations (m [ft])
Inglewood	~90 (~300)	290 (950)	320 (1,050)	419-427 (1,377-1,404)
Montebello	490 (~1,600)	NA	670 (2,200)	2,281 (7,506)
Playa Del Rey	210 (~700)	NA	1,880 (6,200)	1,765 (5,807)
Whittier	46-200 (150-650)	490 (1,600)	1,230 (4,050)	440 (1,446)
Wilmington	~460-590 (~1,500-1,950)	NA	670 (2,200)	789-1,728 (2,595-5,688)

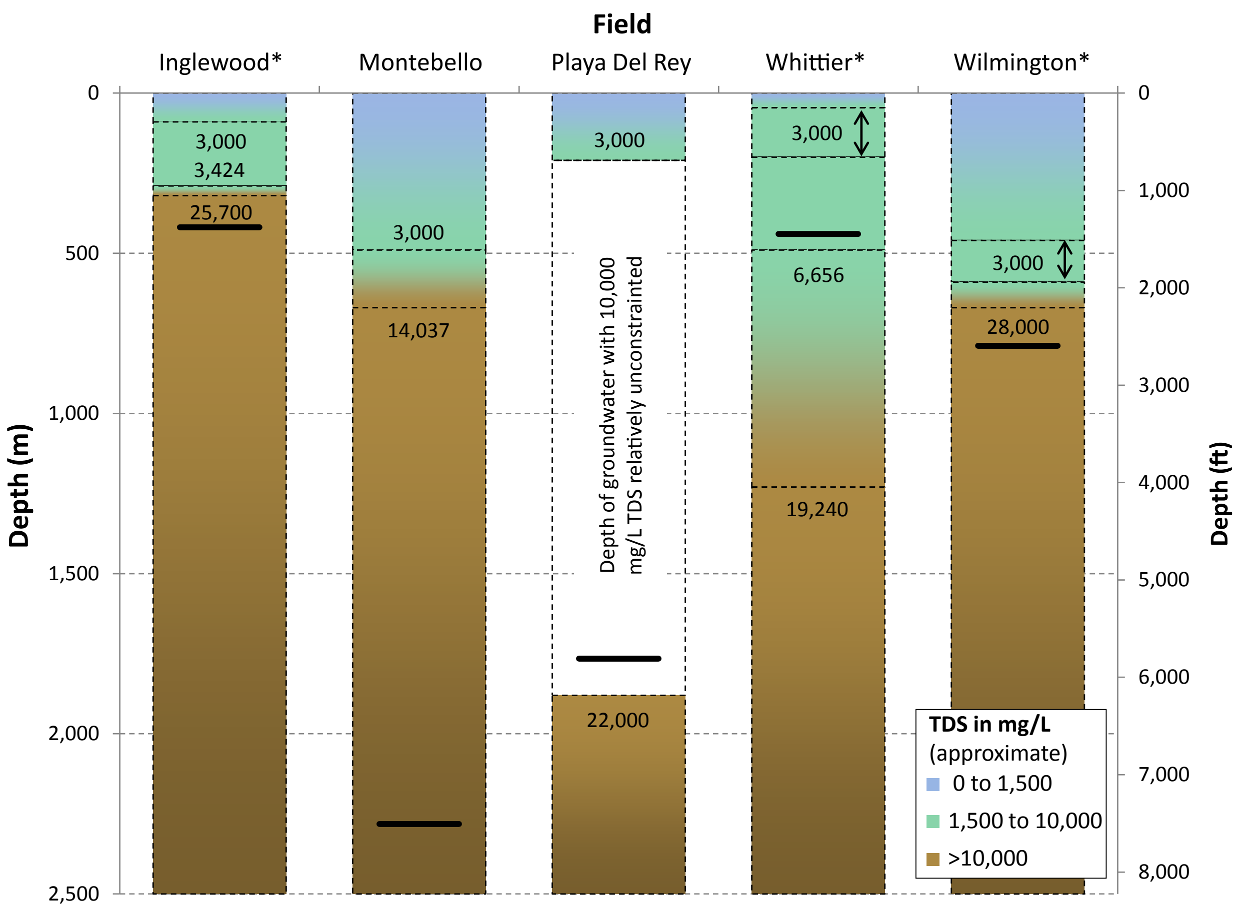


Figure 4.3-11. Depth of 3,000 mg/L TDS and data bracketing the depth of 10,000 mg/L TDS in each field with the hydraulically fractured wells selected for study (data from field rules and DOGGR (1992). The heavy black horizontal line indicates the shallowest well interval hydraulically fractured in each field.

4.3.4.1. Conclusion of Potential Risks to Ground Water Quality in the Los Angeles Basin and Potential Public Health Hazards

The results of our investigation, based upon the available data, indicate that a small amount of hydraulic fracturing in the Los Angeles Basin has occurred within groundwater with <10,000 mg/L TDS and in proximity to groundwater with <3,000 mg/L TDS, creating the risk of hydraulic fractures extending into or connecting with protected groundwater and contaminating aquifers with fracturing fluids and other compounds. If such contamination occurs, this could create an exposure pathway for people that rely on these water resources for drinking and other uses. As such, the recommendations regarding shallow fracturing near protected groundwater in Volume III, Chapter 5 should also be applied to such operations in the Los Angeles Basin if this practice continues. Among these recommendations we suggest there be special requirements to: 1) control fracturing stimulation design and reporting, 2) increase groundwater monitoring requirements; and 3) implement corrective action planning. Additionally, characterization of the base of the deepest groundwater with less than 10,000 mg/L TDS in the Los Angeles Basin is needed in some locations.

4.3.5. Conclusions of the Los Angeles Basin Public Health Case Study

In this case study, we investigated locations of currently active oil and gas development, the proportion of these wells that have been enabled or supported by well stimulation treatments, the emissions of criteria air pollutants and TACs from this development, and the numbers and demographics of residents and sensitive receptors that are in proximity to these operations. These components were discussed together in an effort to elucidate where and who might be exposed to emissions of air pollutants from the development of oil and gas in the Los Angeles Basin. We also examined the possibility that groundwater supplies in the Los Angeles Basin could become contaminated due to hydraulic fracturing-enabled oil and gas development. Our results, based upon available data, indicate that a small amount of hydraulic fracturing in the Los Angeles Basin has occurred within groundwater with <10,000 mg/L TDS, and in proximity to groundwater with <3,000 mg/L TDS. This creates a risk of hydraulic fractures extending into or connecting with protected groundwater, and could result in fracturing fluids mixing with these water resources, introducing a potential exposure hazard for populations that rely on these groundwater resources.

4.3.5.1. Air Pollutant Emissions and Potential Public Health Risks

Many of the constituents used in and emitted to the air by oil and gas development are known to be health damaging and pose risks to people if they are exposed—especially to sensitive populations, including children, the elderly, and those with pre-existing respiratory and cardiovascular conditions. We found that oil and gas development poses more elevated population health risks when conducted in areas of high population density, such as the Los Angeles Basin, because it results in larger population exposures to TACs (there are more breathing lungs nearby) than when conducted in areas of low population density (fewer breathing lungs nearby). Relatedly, emissions of TACs in close proximity to human populations often results in more elevated risks of exposures compared to those populations that are far from emission sources. Most of the documented public health risks associated with air pollutant emissions from oil and gas development are associated with oil and gas development in general, and are not unique to well stimulation.

Our emission inventory analysis found that 2,361 kg/year of benzene is emitted by the stationary components of upstream oil and gas development in the Los Angeles Basin. This amount represents a significant proportion of stationary source (9.6%) and a smaller proportion of benzene emissions from all sources (including mobile source emissions) (0.14%) in the South Coast Air Basin. Our state inventory analysis also indicates that 5,846 kg/year or 3.8% of the stationary source emissions of formaldehyde, and <1% of all source emissions (including mobile), are attributable to the upstream oil and gas sector. Smaller proportions of other indicator TAC species were identified. These indicator TAC species included in our assessment are not often used in well stimulation fluids, but rather are co-produced with oil and natural gas during development. Since only ~26% of the wells currently active in the Los Angeles Basin are hydraulically fractured and responsible for approximately 19% of oil production in the region, emissions of TACs and ROGs are a smaller subset of those emitted by the upstream oil and gas sector in general.

The proportion of the total TAC inventory (mobile and stationary sources) attributable to upstream oil and gas development is not high, and from a regional air quality perspective, these results seem to indicate that TAC emissions from the upstream oil and gas sector are unimportant. However, from a public health perspective, fractions of total emissions are not as important as the quantity or the mass of pollutants emitted at specific locations, as well as the proximity to humans where the emissions occur. Some of the TACs—especially benzene and formaldehyde and potentially hydrogen sulfide (but problems with the inventory do not allow us to be sure)—are emitted in large masses (but not in large fractions of the total inventory) in the upstream oil and gas sector in a densely populated urban area.

The Los Angeles Basin reservoirs have the highest concentrations of oil in the world, and Los Angeles is also a global megacity. Oil and gas development in Los Angeles occurs in close proximity to human populations. In the Los Angeles Basin, approximately 1.7 million people live, and large numbers of schools, elderly facilities, and daycare facilities are located within one mile of—and more than 32,000 people live within 100 m of—an active oil and gas well. The closer citizens are to these industrial facilities, the more likely they are to be exposed to TACs, and the more elevated their risk of associated health effects. Studies from outside of California indicate that community public health risks of exposures to TACs such as benzene and aliphatic hydrocarbons are most significant within 800 m (½ mile) from active oil and gas development. These risks will depend on local conditions and the type of petroleum being produced. California impacts may or may not be similar, but they have not been measured.

4.3.5.2. Potential Water Contamination Pathways in the Los Angeles Basin

Our assessment of hazards to groundwater by hydraulic-fracturing-enabled oil and gas development in the Los Angeles Basin indicates that while data is limited, a small amount of hydraulic fracturing in the Los Angeles Basin has occurred within a short vertical distance to potable aquifers. Given the small number of operations identified that are close to protected groundwater, and the relatively small overall number of hydraulic fracturing operations conducted in the basin, the overall risk of a hydraulic fracture impacting an existing water well is considered small, but the potential hazard to groundwater quality from shallow fracturing operations does warrant enhanced requirements to: 1) control fracturing stimulation design and reporting, 2) increase groundwater monitoring requirements; and 3) implement corrective action planning. No water contamination from well-stimulation-enabled oil and gas development has been noted in the Los Angeles Basin thus far, but this may be because there has been little to no systematic monitoring of aquifers in the vicinity of these oil production sites.

4.3.6. Data Gaps and Recommendations

An overarching recommendation from these analyses is to conduct studies in the Los Angeles Basin and throughout California to document public health risks and impacts as a function of proximity to all oil and gas development—not just those that are stimulated—and promptly develop policies that decrease potential exposures. Such policies might incorporate, for example, increased air pollutant emission control technologies, as well as science-based minimum surface setbacks between oil and gas development and places where people live, work, play and learn.

There are data gaps that contribute to uncertainty with regards to the environmental and public health dimensions of oil and gas development in the South Coast Air Basin. Below we have identified a number of important data gaps and recommendations that are pertinent to the issues explored in this case study:

- **Conduct epidemiological investigations designed to assess the association between proximity to producing wells and human health.** There has only been one epidemiological study that assessed the associations between oil and gas development (distance) and public health outcomes in the Los Angeles Basin, but this study was inappropriate for detecting statistical differences in disease outcomes between the population near the Inglewood Oil Field and Los Angeles County. Study designs—most likely longitudinal in nature and with good baseline environmental and public health measurements—are needed to understand the potential burden of adverse health outcomes associated with the development of oil and gas in the South Coast Air Basin, especially among groups in close proximity to these operations.

- **Study the numbers of residents with pre-existing respiratory and cardiovascular diseases in proximity to oil and gas development.** Populations with respiratory and cardiovascular diseases are disproportionately vulnerable to adverse health outcomes associated with exposures to criteria air pollutants and TACs. To date, no studies have investigated the numbers and concentrations of people with these conditions in close proximity to oil and gas development in the South Coast Air Basin or throughout California.

- **Conduct regional-scale field monitoring of VOC and TAC emission factors from oil and gas development in the South Coast Basin.** Top-down monitoring studies in the South Coast and throughout California have found oil and gas development-scale methane emissions to be potentially three to seven times greater than emissions reported in state inventories. There are no similar studies on the agreement or disagreement of state inventories (such as those analyzed for this case study) and field monitoring of TACs such as benzene (See Volume II, Chapter 3). Current state inventories on these TACs may agree with or be dwarfed by the findings of such field monitoring studies. Findings of such studies could hold policy implications for how VOC and TAC emissions are addressed in the South Coast Air Basin and throughout California.

- **Conduct community-scale monitoring of air pollutant emissions from oil and gas development.** Over the past two decades, the South Coast Region has made impressive strides in reducing criteria air pollutant and toxic air contaminant emissions, and the South Coast Air Basin has enjoyed cleaner air as a result. Nonetheless, the region still experiences severe non-attainment, especially with regards to tropospheric ozone and particulate matter concentrations, and only limited monitoring in close proximity to emitting facilities has been undertaken. Regional air pollutant concentrations, especially of toxic air contaminants and particulate matter, have limited relevance to public health assessments, largely due to the dilution of these air pollutants as they are transported in the atmosphere away from their sources. Exposures to air pollutants can increase with closer proximity to an emission source (e.g., active oil development operations). In order to more accurately understand the composition and magnitude of exposures to air pollutants emitted from the oil and gas development process, more community-scale monitoring activities and sufficient baseline environmental and public health measurements should be undertaken. Community-scaled air quality monitoring activities should be conducted collaboratively between air pollution researchers and community members to increase the relevance and representativeness of the sampling.

- **Investigate the emission and toxicological profiles of TACs associated with oil and gas development.** In this case study we examined the toxicological profiles and emission rates of only four indicator TACs, out of dozens that are known to be associated with oil and gas development. Investigations of emission and toxicological profiles of a larger subset of TACs associated with oil and gas development should be undertaken.

- **Conduct research on emission factors of TACs with no emission factors.** We identified more than 30 compounds known to be TACs that are added to hydraulic fracturing and acidizing fluids in the SoCAB in the SCAQMD oil and gas reporting dataset, yet none of them have known emission factors from oil and gas development processes. Research on the emission factors and the development of an emission inventory of these compounds should be a priority.

- **Require increased air pollutant emission reduction technologies on all processes and ancillary infrastructure.** All oil and gas development in the close proximity to human populations, especially in the dense urban context should be required to install air pollutant emission-reduction technologies, including but not limited to reduced emissions resulting from well completions. Emphasis should be placed on venting, flaring, and fugitive leakage that emit TACs and ROGs, given the non-attainment status and high population density of the Los Angeles Basin. Similar measures can be applied to limit emission of methane to reduce climate impacts.

- **Conduct research on the depth of hydraulic fracturing in relation to usable aquifers in the Los Angeles Basin, especially those used for drinking water.** Our research indicates that active oil and gas development is occurring in the same geographic extent as potable aquifers, such as the Coastal Plain aquifer, which underlies much of the coastal areas of Los Angles and Orange Counties. A full assessment of depth of fractures and the extent to which fractures intersecting aquifers in the Los Angeles Basin would inform regulators and the public as to whether this subsurface pathway presents a risk in this region.

- **Conduct research to identify exact locations of water wells, the use of their water, their geospatial relationship to active and historical oil and gas development, including that enabled by well stimulation, and potential for groundwater contamination.** Precise locations of water wells throughout California are not publicly available. As such, it is difficult to conduct accurate analyses on the potential risks posed by well-stimulation-enabled and other forms of oil and gas development to water quality used by human populations. Future research should identify locations of water wells and perform analyses on potential contamination pathways and potential contamination attributable to oil and gas development.

- **Implement the recommendations regarding shallow fracturing near protected groundwater from Volume III, Chapter 5 (San Joaquin Valley Case Study) should such operations in the Los Angeles Basin continue.** Among these recommendations and should this practice continue in the Los Angeles Basin we suggest there be special requirements to: 1) control fracturing stimulation design and reporting, 2) increase groundwater monitoring requirements; and 3) implement corrective action planning. Additionally, characterization of the base of the deepest groundwater with less than 10,000 mg/L TDS in the Los Angeles Basin is needed in some locations.

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Chapter Five

A Case Study of the Potential Risks Associated with Hydraulic Fracturing in Existing Oil Fields in the San Joaquin Basin

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5.1. Abstract

This case study discusses the conceivable future of hydraulic fracturing in the San Joaquin Basin and the potential consequent impacts on water and air resources, public health, and wildlife and vegetation. The rate of well stimulation in the San Joaquin Basin will likely continue over the next decade as it has over the last decade. Assessments have estimated large reserves in existing fields that have been the most productive historically, and the trends in past and current production patterns are quite likely to continue. In contrast, development of oil or gas production from source rock appears relatively unlikely. Additional production in predominantly hydraulically fractured pools can be delivered by installing new wells in existing fields, and there is sufficient remaining resource in those pools for production to continue in this manner for at least another decade.

Future oil production will continue to produce water. There are potential opportunities to reduce the amount of high-quality and low-salinity water consumed by production, and opportunities for beneficial reuse of the water produced along with the oil. One of the current methods for produced water disposal from pools with hydraulic fracturing in the San Joaquin Basin is discharge into evaporation-percolation pits. This presents a potential risk for contamination of potable groundwater resources and should be phased out in the future. Some produced water from pools with hydraulic fracturing has also been disposed of by injection into subsurface reservoirs with ground water resources that perhaps should not have been exempted from protection. Whether these injections can continue is currently undergoing review by California regulators. If it is determined

that the wastewater has been injected into protected groundwater, it is likely some of the water injected contained constituents due to stimulation that could contaminate the groundwater resources.

A general concern about hydraulic fracturing is that stimulation chemicals could leak into the environment, including drinking water wells, via potential subsurface leakage paths. The main concern identified by this investigation is the application of hydraulic fracturing at shallow depths in proximity to groundwater in some portions of the San Joaquin Basin. Most hydraulic fracturing in the San Joaquin Basin occurs shallower than 300 m (1,000 ft). This means that operators produce hydraulic fractures near the surface that can present a hazard if there is nearby protected groundwater. Two other concerns also arise. Reservoirs in the San Joaquin Basin have a high density of existing wells, which may provide potential pathways for leakage of stimulation fluids into groundwater. In addition, the density of faults in the San Joaquin Basin indicates that tens of shallow hydraulic fractures each year may intersect faults that are sufficiently large to potentially extend to protected groundwater. The presence of oil in close proximity to these faults indicates that they do not provide a leakage pathway in their natural state. However, it is unknown to what extent they might become a leakage pathway when intersected by a hydraulic fracture. No incidents of groundwater contamination due to stimulation have been found in the San Joaquin Basin to date, but there has also been no targeted monitoring of groundwater quality, nor have there been specific efforts to determine the extent of potentially compromised wellbore integrity. It is also noted that if leaks are relatively small, as can be expected for the majority of leaky wells, they are not easily detectable in the groundwater, even when dedicated monitoring is conducted.

Regarding potential air contamination, oil and gas production accounts for an appreciable portion of some air pollutants released in Kern County, but very little data have been collected to evaluate air emissions from oil and gas wells. Oil and gas production is the dominant source of hydrogen sulfide (96%) and a major contributor to emissions of benzene (9%), formaldehyde (26%), hexane (11%), and xylene (14%). Emissions from production involving well stimulation are a small portion (approximately 20%) of these emissions, but, for some pollutants, still an appreciable fraction of total emissions in Kern County (for instance nearly 20% for hydrogen sulfide and greater than 5% for formaldehyde).

The concentration of air contaminants is larger closer to the source of emissions, so those in close proximity to production wells could be exposed to higher than average concentrations. Of the population both within the San Joaquin Valley Air Pollution Control District and a county with more than one oil and gas field, 21% live within 2 km (1.2 mi.) of a well for oil and gas production. Of this population, 21% are estimated to be in such proximity to a hydraulically fractured well, which is 3.4 % of the total population. So, to the extent exposure to air contaminants from oil and gas wells is a concern, it is a concern for all wells, not just those that are hydraulically fractured.

In contrast to air-pollutant emissions, production-related greenhouse pollution per unit of oil from predominantly hydraulically fractured pools in the San Joaquin Basin is among the lowest in California. This is because most of the other oil production in the state involves energy-intensive water and steam injection, for which the energy is provided by combusting fossil fuels. Inventories indicate the production-related greenhouse pollution per unit of oil imported to California is also higher than the pollution from oil produced using hydraulic fracturing in the state. Consequently, a cessation in hydraulic fracturing could result in an increase in the use of oil produced using methods emitting more greenhouse pollution per unit of oil.

The viability of most species is inversely related to habitat fragmentation. As fragmentation increases, the population of a species increasingly consists of isolated subpopulations. Each of these subpopulations is at greater risk of complete mortality due to disease, as a consequence of less genetic diversity, or a change in environmental conditions, as a consequence of inability to migrate or change range. Habitat for wild species is largely available in some fields in the San Joaquin Basin where well stimulation is predominant. Additional development may not substantially increase fragmentation in some of these fields, because it would occur in already densely developed areas, such as in North and South Belridge. In other fields, such as Elk Hills, additional development would likely to increase fragmentation, reducing species population viability. At the landscape scale, there are currently some corridors between and through fields with predominantly fractured pools in the southwestern San Joaquin Basin that provide migration pathways between the surrounding areas. The impact of future development in these fields could be reduced by preventing the elimination of these corridors, such as by best management practices that would consolidate facilities to retain some percentage (to be tested) of undisturbed habitat in reserve areas and corridors.

5.2. Introduction

The goal of this case study is to develop an understanding of the risk from future well stimulation, with an emphasis on hydraulic fracturing, to water and air resources, public health, and wildlife and vegetation in the San Joaquin Basin. This assessment is conducted under the assumption that the future characteristics and magnitude of well stimulation are similar to what has been observed in the previous decade. Section 5.3 provides a summary of recent well stimulation trends in the San Joaquin Basin, with focus on hydraulic fracturing, and explains why these trends are expected to hold into the foreseeable future. Based on this assumption, Sections 5.4, 5.5, and 5.6 provide a brief assessment of the potential risks from hydraulic fracturing in the San Joaquin Basin to (respectively) water resources, air, and public health as possible using available sources and data.

Risk is the combination of the probability of an event occurring and the consequence of that event. This is in contrast to hazard, which only considers potential consequences without regard to the probability of occurrence. Given these definitions, a hazard may appear to present a problem, but in reality may have low risk because it is unlikely to occur. In the context of this report, risk can include both direct risk from hydraulic fracturing, such as spills of chemicals used in the process, and indirect risk from the oil and gas development enabled by hydraulic fracturing, such as air emissions from oil production from “pools” (geologically continuous zones containing oil) where a high proportion of wells are hydraulically fractured.

The possibility of hydraulic-fracturing-enabled oil and gas production from the source rocks of the Monterey Formation is not considered in this case study. Potential risks related to future source rock production, which is a highly uncertain scenario (see discussion in Volume I, Chapter 4), are considered in the Monterey Formation Case Study, provided in Chapter 3 in this volume.

The San Joaquin Basin Case Study focuses exclusively on hydraulic fracturing. Matrix acidizing and acid fracturing are not considered. No comprehensive data on the use of acid is available for the San Joaquin Basin, but existing data indicates that (1) operators use matrix acidizing one tenth as often as hydraulic fracturing, and (2) acid fracturing is hardly ever used and unlikely in the future, because it is not effective in the geologic conditions of the Basin.

5.3. Past and Future Oil and Gas Development Using Hydraulic Fracturing

This case study evaluates specific risks to water, air and public health associated with continued well stimulation in the San Joaquin Basin. The risks that may occur in the future will depend on how production in the basin develops. This section reviews well stimulation trends in the San Joaquin Basin during the last decade and defines a reasonable scenario of hydraulic-fracturing-enabled production over the next decade. This scenario forms the basis of the risk assessment.

Over 320 million m^3 (2 billion barrels) of oil were produced from the San Joaquin Basin between 2002 and 2014. This was more than three quarters of the oil produced in California during this period. A fifth of the oil produced in the San Joaquin Basin was from the predominantly hydraulically fractured pools in the four fields where 85% of the hydraulic fracturing occurs in the state: North and South Belridge, Elk Hills, and Lost Hills. Tennyson et al. (2012) assessed potential additional oil recovery from nine of the historically most productive oil fields in the San Joaquin Basin, indicated in Figure 5.3-1. These include the four fields mentioned where most hydraulic fracturing occurs. The results of the assessment indicated that 200 to 730 million m^3 (1.3 to 4.6 billion barrels (bbl)) with a mean of 410 million m^3 (2.6 billion bbl) of additional oil could be produced from these predominantly hydraulically fractured pools in the four main fields. Based on the estimated reserves and the production rates over the last decade, oil production from these pools could continue for another several decades to a century.

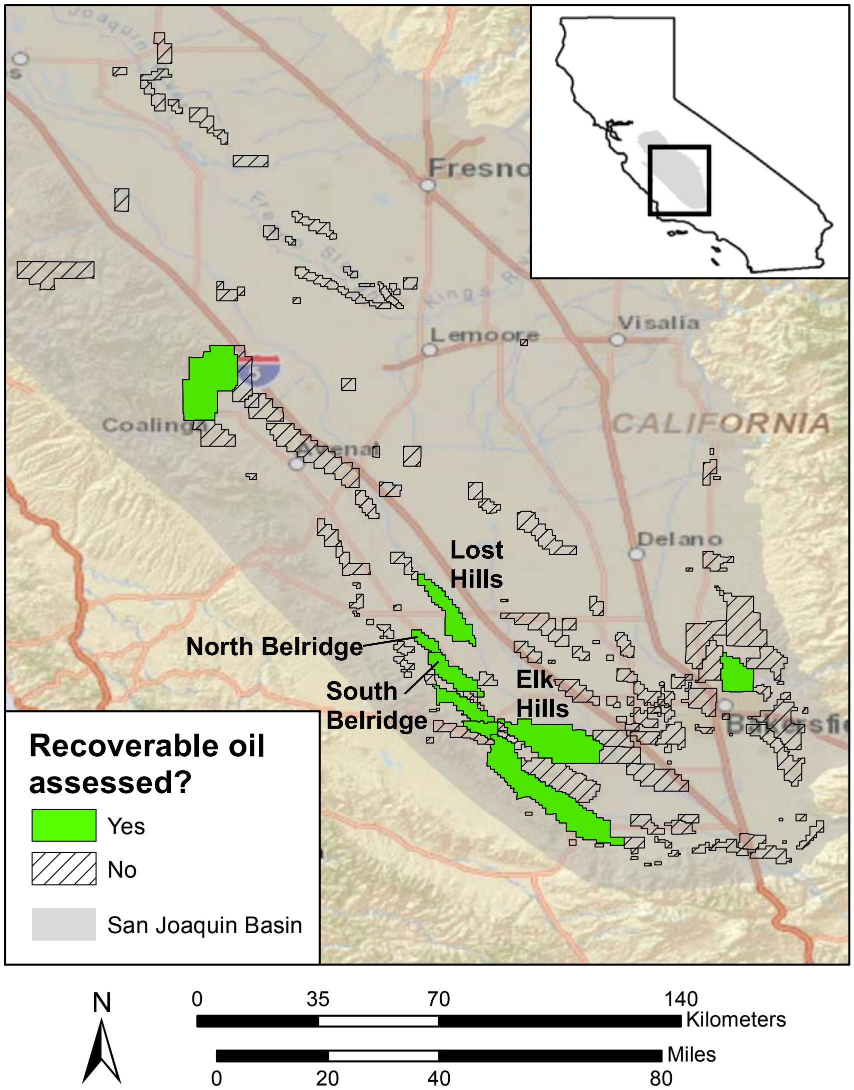


Figure 5.3-1. Oil fields assessed by Tennyson et al. (2012) for the remaining recoverable volume of oil.

The predominantly hydraulically fractured pools in the North and South Belridge fields, and in the Lost Hills field, consist of intervals of biogenic Opal A, a type of rock formed of the tests (skeletons) made of silica from single celled marine organisms, and Opal A diatomite recrystallized to Opal CT (cristobalite and tridymite) and quartz-phase, due to increased temperature and pressure resulting from deeper burial. The predominant hydraulically fractured pools in the Elk Hills field consist of sands, discussed further below.

Development of oil production from most of these reservoirs in California depends on hydraulic fracturing followed by waterflood, steam injection, or cyclic steam injection.

As such, the well stimulation within these reservoirs is different from that used in other parts of the country to develop oil and gas production from shale. In addition, about half of hydraulic fracturing in the San Joaquin Basin is shallower than 300 m (1,000 ft), which is shallower than hydraulic fracturing common in elsewhere in the country where it generally occurs at depths greater than 1,000 m (3,300 ft).

The number of hydraulic fracturing operations in the Elk Hills field each year is similar to the number in each of the North Belridge and Lost Hills fields (an operation consists of all the hydraulic fracturing stages occurring in a well with a relatively short time period, typically less than one week). Most of the Elks Hills operations occur in the Upper (Undifferentiated) pool, which includes the Scalez, Mulinia, Bittium, Wilhelm, Gusher, Calitroleum, and Olig sands in the San Joaquin, Etchegoin and Reef Ridge Formations (Division of Oil, Gas, and Geothermal Resources (DOGGR), 1998).

In addition to the prevalence of hydraulic fracturing in some pools in these fields, there are a number of other pools in the San Joaquin Basin where most of the wells are hydraulically fractured, as shown on Figure 5.3-2. Altogether, hydraulic fracturing in the San Joaquin Basin accounts for over 95% of hydraulic fracturing operations in California (Volume 1, Chapter 3).

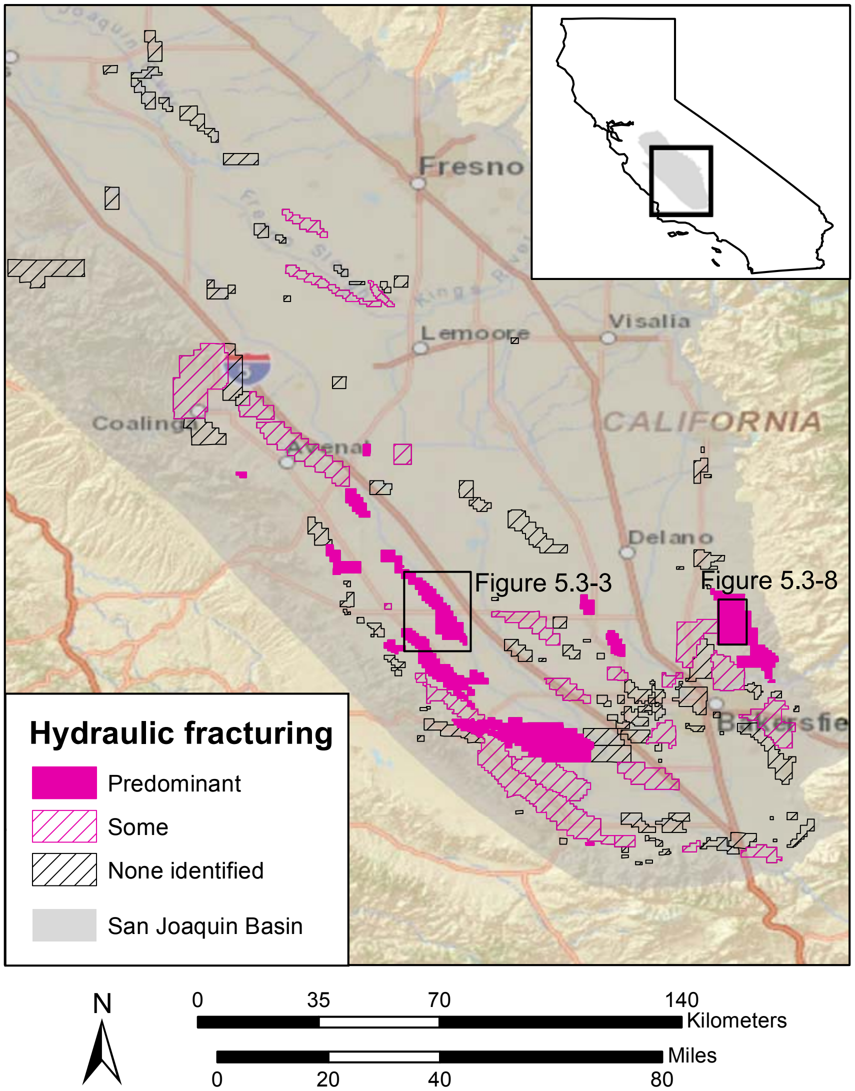


Figure 5.3-2. Oil fields containing one or more pools with where hydraulic fracturing has been conducted. "Predominant" indicates a field with at least one pool where most to all wells are estimated to have been hydraulically fractured.

Below, past and current production patterns in two fields are examined to substantiate the assessment of how hydraulic-fracturing-enabled production may continue over the next decade. Taking Lost Hills as the first example, Figure 5.3-3 shows the location of wells open to each of the two pools where hydraulic fracturing is prevalent in this field. The areal extents of the Etchegoin and Cahn pools overlap near the middle of the Lost Hills field. The Etchegoin pool consists of biogenic Opal A and recrystallized Opal CT diatomite, and the deeper Cahn pool consists of opal CT and quartz-phase developed from deeper burial of diatomite.

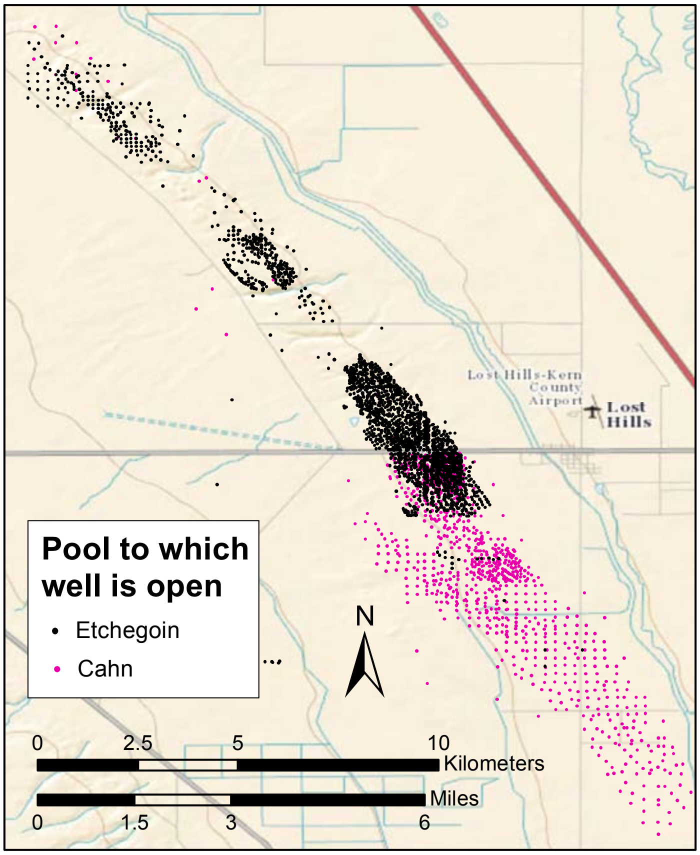


Figure 5.3-3. The location of wells open to the two pools in the Lost Hills field where most to all wells are estimated to have been hydraulically fractured. See Figure 5.3-2 for location.

Figure 5.3-4 shows the development of the Etchegoin pool in the Lost Hills field through time. There were almost no wells in this pool in 1977. Development proceeded steadily through 1989, at which time there was a grouping of oil production wells in one portion of the pool, but few injection wells for secondary recovery (water flooding). Through 1996, both the area with oil wells and the density of oil wells increased. Waterflood injection wells were also installed throughout the area with oil wells. In 1996, the east-west orientation of the northern edge of development, in combination with the sharp northwest and northeast corners of the developed area, suggests that development stopped at a survey boundary rather than a geologic boundary.

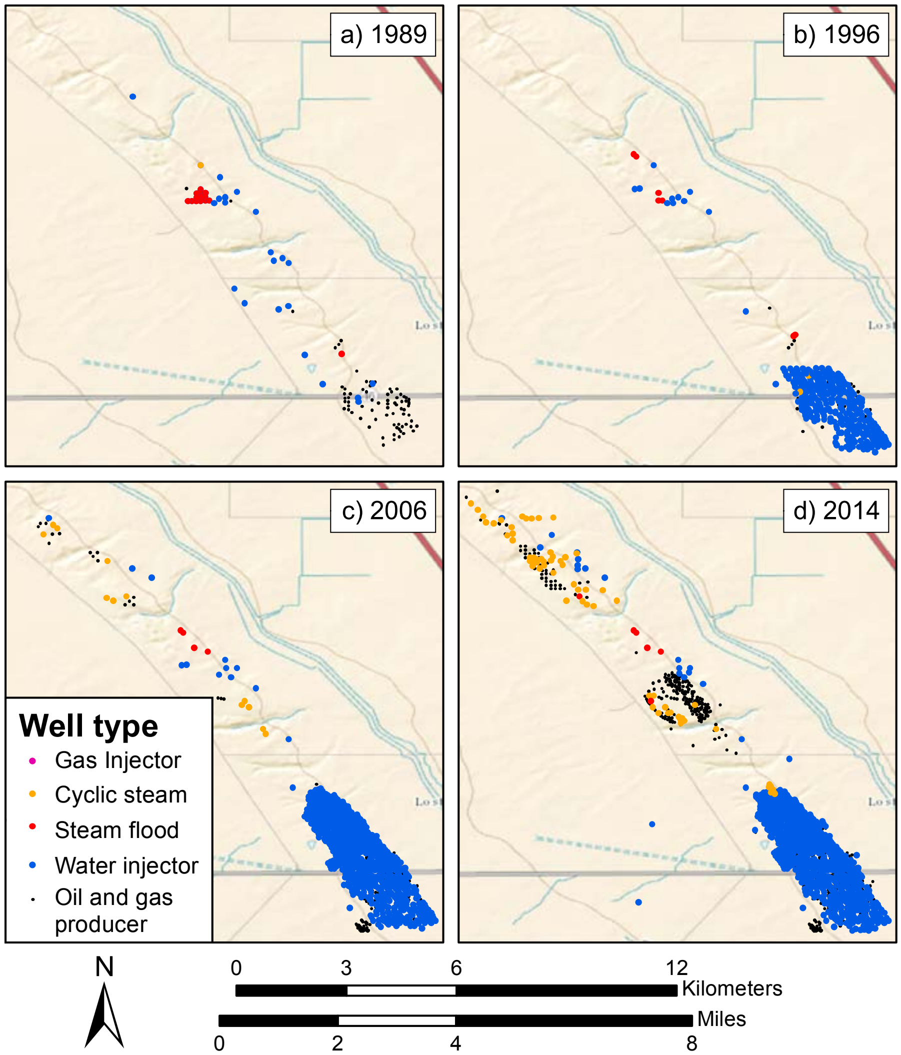


Figure 5.3-4. Wells in operation in the Etchegoin pool of the Lost Hills field in different years. Most to all of the wells shown have been hydraulically fractured.

By 2006, the dense development with oil production and waterflood wells in the southern portion of the pool shown in Figure 5.3-4 had extended further to the north. The curved northern margin of this development at this time suggests it stopped at a geologic rather than legal boundary. This is further suggested by the persistence of this development area boundary in that location through 2014. However, as of 2014, oil wells had been installed in two new areas of the pool to the northwest of the area of dense development at its southern extent. These consisted primarily of a mix of production wells and cyclic steam wells (through which steam injection alternates with oil production). The southern terminus of the northernmost pattern of oil and gas wells at this time is again east-west oriented, with sharp southwest and southeast corners, suggesting a survey rather than a geologic boundary. This in turn may suggest that development could continue to the southeast in the future.

Figure 5.3-5 shows the development of the deeper Cahn pool. A few oil wells were in operation in this pool in 1977. Development through 1986 consisted primarily of extending the productive area by installing oil wells. No injection wells were yet in operation. Through 1995, further development consisted primarily of increasing the well density in some areas and starting operation of some waterflood wells in those areas. The abrupt southern margin of the area of increased well density at that time suggested a lease rather than geologic boundary. This in turn indicates an increase in well density to the south could be productive.

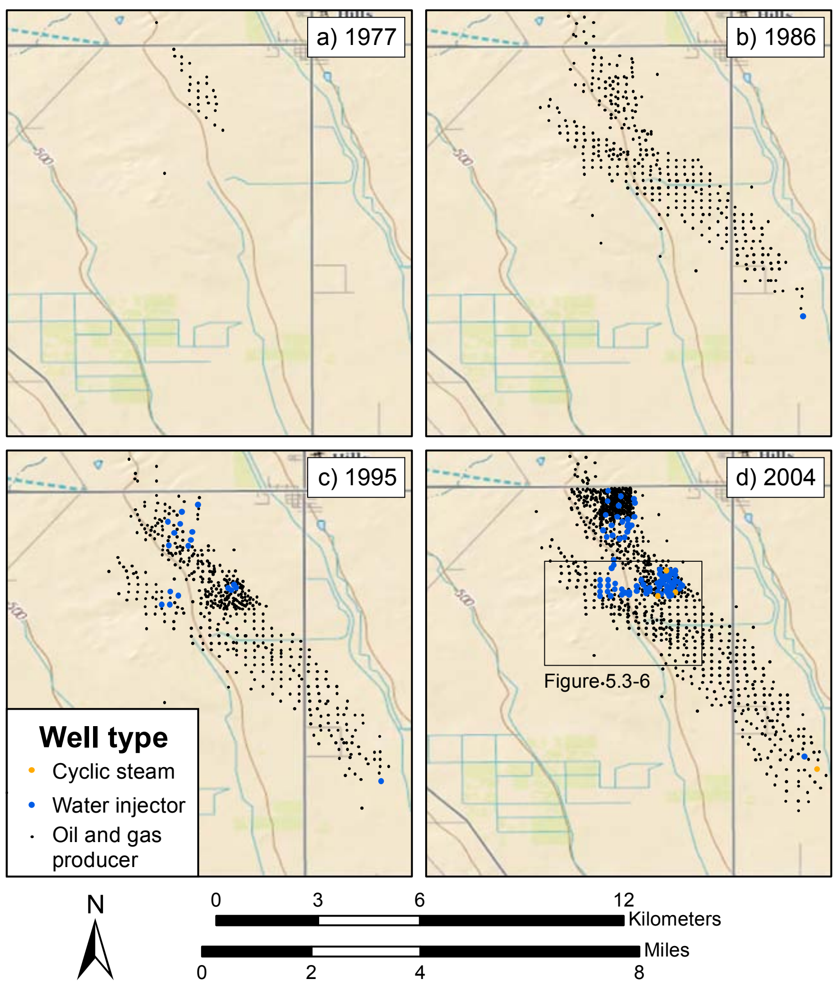


Figure 5.3-5. Wells in operation in the Cahn pool of the Lost Hills field in different years. Most to all of the wells shown have been hydraulically fractured.

By 2014, the well field in the Cahn pool had been extended north, with a relatively abrupt boundary at a highway suggesting a lease rather than geologic boundary. This abrupt boundary suggests further development to the north could be productive. In addition, far more injector wells were in operation for water flooding in the areas of greater well density.

In order to gain more quantitative insight into the likelihood and opportunity for further oil development utilizing hydraulic fracturing, past production was assessed from a region of the Cahn pool with wells in adjacent leases, as indicated by the box marked Figure 5.3-6 in Figure 5.3-5d. To provide an estimate of the productive area for each lease, the area closest to each well was assigned to the lease occupied by that well. Then, all the areas assigned to a lease were aggregated. Leases with aggregated areas relatively constrained to within the productive area of the pool were selected for study. The aggregated areas for these leases are shown in Figure 5.3-6.

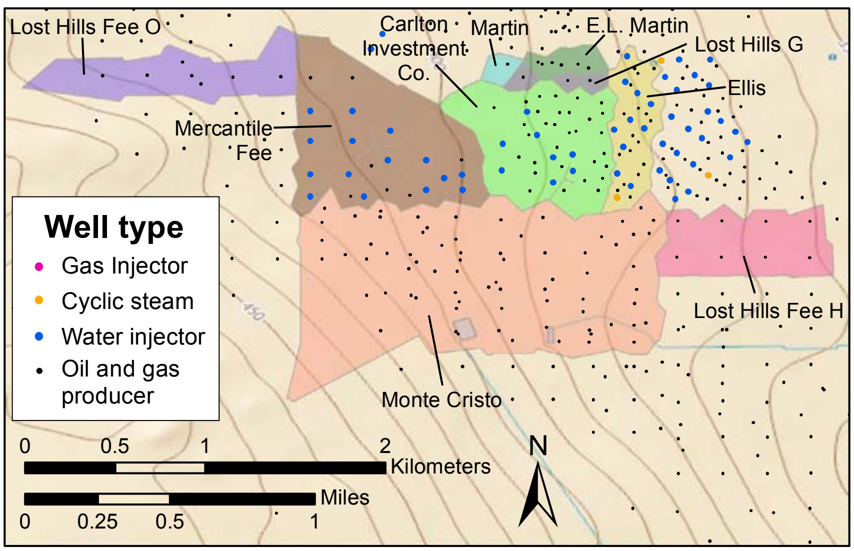


Figure 5.3-6. Lease study area in the Cahn pool of the Lost Hills field. See Figure 5.3-5d for location of figure relative to the entire Cahn pool.

The amount of oil and gas production from 1977 through May 2014 in each lease was summed from DOGGR's production database. Produced gas was converted to oil equivalent energy assuming 1,070 m^3 of gas per m^3 of oil (6,000 cubic feet/bbl), and the result was summed with the oil produced. This was divided by the aggregate area for each lease and the number of calendar years during which production occurred, to provide average equivalent oil energy produced per unit area per year in each lease. The average density of wells operating in 2013 in each lease was computed. Figure 5.3-7 shows production per area per year plotted against the well density for each lease.

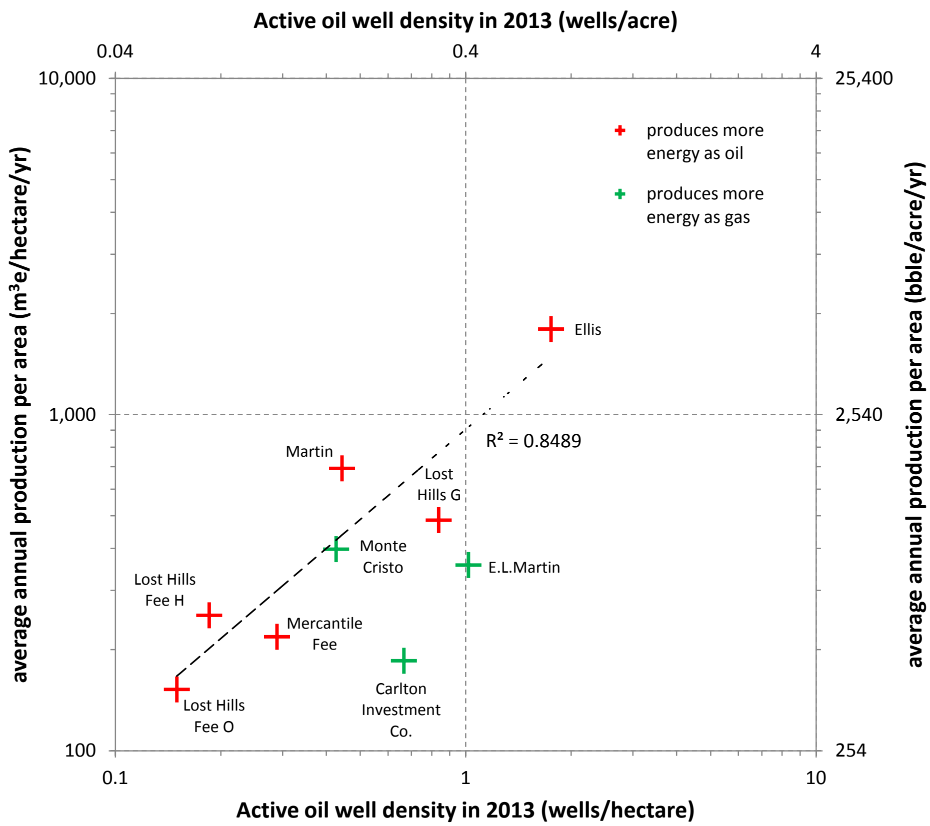


Figure 5.3-7. Scatter Plot depicting the relationship between annual equivalent oil production per area and well density across the study leases in the Cahn pool of the Lost Hills field. See Figure 5.3-6 for location of study leases. The dashed line indicates a least-squares regression line based upon the leases producing energy mostly as oil, with calculated coefficient of determination of $r^2 = 0.8489$.

Figure 5.3-7 shows how the average annual production per area is related to the well density for leases where production of energy is oil dominated. The regression line is based only on leases producing energy mostly as oil, because the energy density of gas per unit volume is substantially less. The scatter plot indicates that increasing well density by a factor of ten increases production per area per year by about a factor of ten. The pattern in the scatter plot extends to the highest well densities in Figure 5.3-7, suggesting that even at the closest spacing, production from one well is not likely interfering with production from adjacent wells. The average well spacing in the densest lease is about 75 m (250 ft). This is more than two times the average horizontal fracture length reported by hydraulic fracturing operators to the California Division of Oil, Gas, and Geothermal Resources (DOGGR; Volume II, Chapter 2), further indicating limited well interference.

The results in Figure 5.3-7 are consistent with the finding of Tennyson et al. (2012) that a considerable volume of oil can yet be produced from the assessed fields. Figure 5.3-5 suggests development over most of the Cahn pool has not progressed from the initial well pattern to infill drilling. Figure 5.3-4 indicates further increases in well density in the northern part of the Etchegoin pool are supportable. Consequently, there is opportunity for installing additional wells across both of these pools. This is further supported by the animation of wells in operation each year in the Cahn pool in Appendix 5.A.

The historical development of oil production in the smaller pools where most (to all) wells are estimated to have been hydraulically fractured (Volume I, Appendix N) provides further support and insight regarding how development will continue in the future. Figure 5.3-8 shows the wells in operation in the Pyramid Hill-Vedder pool of the Main area in the Mount Poso field. In the earlier period, production was from an initial pattern of wells enhanced with intervening steam flooding along the margins and cyclic steam focused on the Vedder portion of the pool. In the later period, production had shifted to the eastern portion of the pool with considerable infill well installation, cessation of most cyclic steaming and half of the steam flooding along that margin, and initiation of water flooding in the Pyramid Hill portion of the pool. This suggests water flooding may be initiated progressively to the south in the future, along with further infill installation of hydraulically fractured wells.

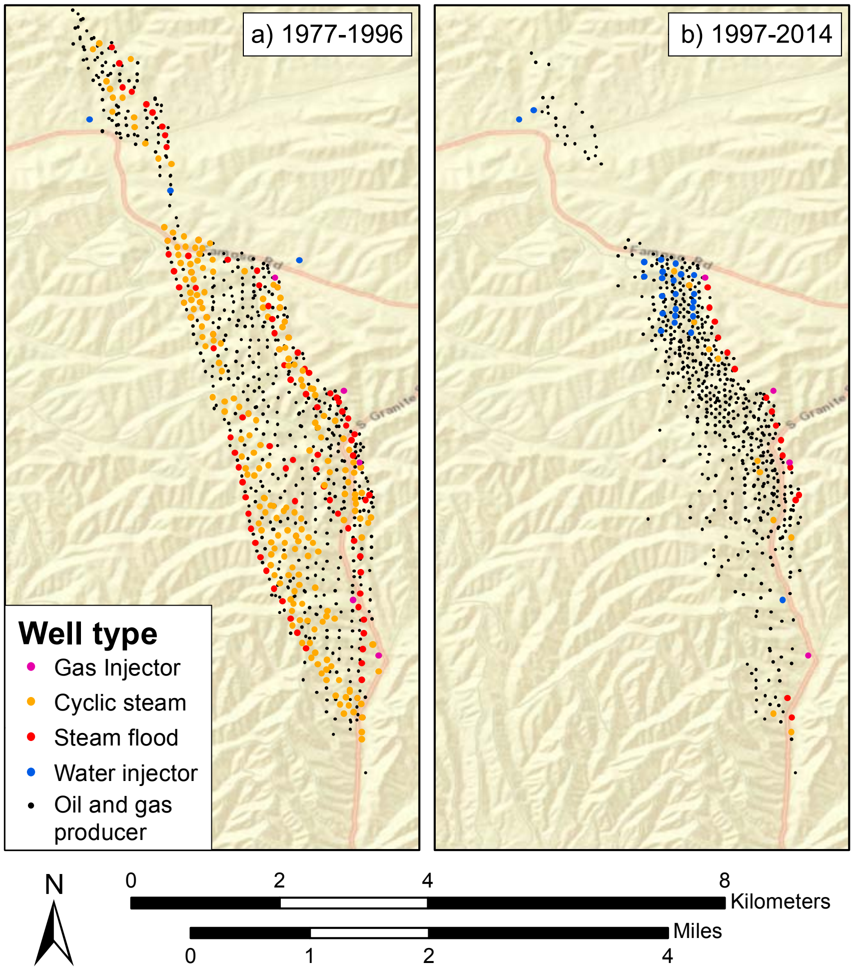


Figure 5.3-8. Wells in operation in the Pyramid Hill-Vedder pool of the Mount Poso field in different years. Most to all of the wells shown have been hydraulically fractured.

The three examples above indicate that additional production involving hydraulic fracturing can be achieved in part by installing additional wells in the existing fields, thereby increasing well density. More broadly, the baseline scenario assumed in this chapter is that the rate of well stimulation in the San Joaquin Basin will continue over the next decade as it has over the last decade, unless there is a substantial change in economic conditions. This assumption is based on (1) the large reserve estimates for existing fields that have been the most productive historically (Tennyson et al., 2012), (2) the analysis of trends in past and current production patterns in selected fields, and (3) the small likelihood of substantial, if any, development of oil or gas production from deeper shale source rock (Volume I, Chapter 4). In predominately hydraulically fractured pools, additional oil reserves and recovery in existing fields may be achieved with (a) infill well development, (b) the addition of new reservoir intervals to well completions, or (c) development area extensions (e.g., down the flanks into poorer quality rock). There is likely sufficient remaining resource in those pools for production to continue in this manner for several decades.

Given this continuation, the future risk of production enabled by hydraulic fracturing is likely to be similar to the present risk. The remainder of this case study primarily assesses this present risk.

5.4. Potential Risk to Water

Hydraulic fracturing can create risks to water supplies owing to competing demand for freshwater, and risks to water quality owing to potential releases of stimulation constituents, degradation products, mobilized natural constituents, and natural constituents in water associated with oil. Well stimulation requires water for making stimulation fluids. In some pools in the San Joaquin Basin, waterflooding or enhanced oil recovery (EOR) with steam is used after wells are hydraulically fractured, which requires additional water. (Such injection can push oil and/or, in the case of steam, reduce the viscosity of the oil, both of which results in more oil production.)

Hazards associated with well stimulation include degradation of water resources through the potential release of produced water (water that is produced along with oil and gas) that would not otherwise occur, as well as the potential release of well stimulation constituents via various potential release pathways. The potential pathways considered here are discharges of produced water to evaporation-percolation pits, disposal of produced water via injection into protected groundwater, beneficial reuse of produced water containing hazardous concentrations of stimulation constituents, and release of well stimulation constituents to groundwater via induced fractures, faults, and wells. In terms of potential subsurface pathways, the focus of this case study of the San Joaquin Basin is on induced fractures, wells, and faults. For the following reasons, the risk of leakage via natural fractures is judged to be lower than the other hazards considered in this report, and so is not further assessed. Natural fractures intersecting oil accumulations are not leakage pathways in their natural state, as evidenced by the presence of trapped oil. Natural fractures tend to be short relative to the distance between oil accumulations and protected groundwater, making them unlikely pathways even if a hydraulic fracture intersection props them open.

Some of these pathways also create risk to receptors other than water. For instance, a well blowout can release fluids to the surface that affect people, animals, and plants directly, rather than just through ingesting water contaminated with constituents used in stimulation that leak from the hydrocarbon-bearing zone into groundwater. (Note that this particular example is rare, in part because standard drilling and completion techniques require the use of a blowout preventer.)

5.4.1 Water Demand

Water used for making hydraulic fracturing fluids in the San Joaquin Basin is almost entirely high quality, meaning suitable for domestic or irrigation use (Volume II, Chapter 2). Therefore, one of the potential risks to public water availability is that the water demand for hydraulic fracturing could reduce valuable resources for other water uses. In some areas, produced water is treated, for example by reverse osmosis (RO), and then re-used for oil and gas operations, domestic purposes, or irrigation. Re-use of produced water is discussed in Section 5.4.2 below.

Some of the production enabled by hydraulic fracturing also uses “freshwater,” as coded in DOGGR records, for enhanced oil recovery (EOR), such as for water and steam flooding and cyclic steaming. Freshwater in this context in California is defined by DOGGR as water having less than 3,000 mg/L total dissolved solids (TDS) (Walker, 2011). This appears to reflect State Water Resources Control Board Resolution 88-63, as revised by Resolution 2006-0008, which defines water suitable, or potentially suitable, for domestic or municipal supply as, in part, water with less than 3,000 mg/L TDS.

The majority of solids dissolved in groundwater are generally salts. In other words, the water quality metric “total dissolved solids” is often equivalent to “salinity.” Water with low TDS has low salinity; water with high TDS has high salinity. In general, water with salinities exceeding 1,000 mg/L TDS is not considered suitable for drinking (Cal. Cod. Reg. § 64449) or for irrigating many crops, and so in this chapter, water with less than 3,000 mg/L TDS is referred to as low salinity rather than freshwater. Some portion of the water coded as low-salinity in DOGGR’s injection database may be high quality (i.e., appropriate for domestic or irrigation use), but DOGGR’s injection database does not make this distinction.

The use and potential use of low-salinity water in 2013 for EOR in hydraulic-fracturing-enabled production is broken out by pool in Table 5.4-1. This consists of water listed in DOGGR’s injection database as coming from sources other than an oil and gas well or the ocean, and consisting of other than salt water.

Table 5.4-1. Use and potential use of low-salinity water for EOR in 2013 in pools where most to all wells are hydraulically fractured. "Other" source is a designation in DOGGR's injection database. "Unknown" refers to water whose source code is not available in the database. "Maybe" low salinity includes water coded as c: "combined with chemicals", a: "another kind" beside salt, fresh, or with chemicals, and u: uncoded.

Field	Area	Pool	Source	Low salinity	Water volume	
					m^3	bbl
Belridge, North	Any	Diatomite	Other	Maybe-a	22,600	142,075
Elk Hills	Any	Stevens (31S)	Unknown	Maybe-u	368,000	2,314,947
Elk Hills	Any	Stevens (31S)	Water well	Maybe-u	39,100	245,752
Elk Hills	Any	Stevens (31S)	Water well	Yes	1,820,000	11,475,680
Elk Hills	Any	Stevens (31S)	Other	Maybe-a	95,800	602,296
Lost Hills	Any	Cahn	Other	Maybe-a	37,000	232,910
Lost Hills	Any	Etchegoin	Unknown	Maybe-c	2,210,000	13,887,373
Lost Hills	Any	Etchegoin	Other	Maybe-a	8,460	53,235
Mount Poso	Main	Pyramid Hill-Vedder	Unknown	Maybe-u	104,000	654,535
Total					4,710,000	29,608,803

Table 5.4-1 indicates that the 1.8 million m^3 (11.5 million bbl) of water from a groundwater well in one of the Elk Hills pool was definitely low-salinity and supplied to a pool with hydraulic-fracture-enabled production for EOR in 2013. For comparison, 13.4 million m^3 (84.3 million bbl) of such low-salinity water was used for EOR in all fields in the San Joaquin Basin in 2013. So 14% of the total volume of low-salinity water used for EOR in the Basin was used in pools where most to all wells are hydraulically fractured. This is less than the 22% of oil production in the San Joaquin Basin enabled by hydraulic fracturing (Volume II, Chapter 3). As obvious from Table 5.4-1, there are many entries with "Other" and "Maybe" classification, meaning that the water sources of several pools are unknown and could potentially be from high-quality water supplies.

The question arises whether the use of groundwater pumping for oil and gas production enabled by hydraulic fracturing has adversely affected groundwater levels. California's GeoTracker GAMA (Groundwater Ambient Monitoring & Assessment) provides access to water level data (http://geotracker.waterboards.ca.gov/gama/). There are no data for wells within the Elk Hills field to judge if pumping of low-salinity water in the area for EOR use in a hydraulic-fracture-enabled production pool has caused groundwater levels to decline. There is a cluster of monitoring wells in McKittrick to the east (Well ID L10008917084). Average annual water levels in these wells varied by two feet during the period covered (2006 to 2014). Levels declined in most wells and rose in some. The level in one well in Dustin Acres just south of the field rose 8 feet from 2001 through 2009 (ID 31S24E28Q002M), and rose by a few feet from 2000 through 2014 in another well in the area (ID 31S24E28B001M). Levels in three wells just east of the field near the Buena Vista Golf course varied by a couple feet or less from 2003 to 2009 (IDs 31S24E13P064M, 31S24E13K061M, 31S24E13J062M). Levels in the closest wells just north of the field have declined by more than 30 feet (ID 30S24E14M002M) and 20 feet (ID 30S24E06B002M) from 2011 to 2014.

The two wells north of the field with large water-level declines are in an area used for agriculture, while the wells to the west, south, and east with relatively stable water levels are not. This suggests that activities in the Elk Hills field are not affecting water levels in the surrounding shallow aquifers screened by these wells, but rather levels are more likely declining to the north due to groundwater withdrawal for irrigation during the drought.

Table 5.4-2 provides estimates of the total annual demand for low-salinity water in the San Joaquin Basin, which is the sum of demand for hydraulic fracturing fluids and for EOR in hydraulic fracturing-enabled production (modified from Volume II, Chapter 2, to account for only hydraulic fracturing and enabled EOR in the Basin). Note that only the demand that is coded as definitely low-salinity water supplied to the pool from Table 5.4-1 is shown in Table 5.4-2. In total, this demand is less than a thousandth of a percent of the high-quality water usage in the water resource Planning Areas in the San Joaquin Basin where hydraulic fracturing occurs, and is less than 0.2% in any individual Planning Area (total water use in each Planning Area from Department of Water Resources (2014)).

Table 5.4-2. The estimated annual volume of high-quality water demand for hydraulic fracturing and low-salinity water demand for hydraulic-fracturing-enabled EOR by water resources planning area in 2013.

Planning Area	Estimated annual hydraulic fracturing		Annual supply for enabled EOR (m^3)	Estimated annual water use		% of water use in Planning Area
	Operations	Water demand (m^3)		(m^3)	(acre-feet)	
Semitropic (Kern)	1,600	850,000	1,800,000	2,700,000	2,200	0.17
Kern Delta (Kern)	4	2,100		2,100	1.7	0.00011
Kern Valley Floor (Kern, Tulare)	34	18,000		18,000	15	0.0017
Uplands (Fresno, Tulare, Kern)	18	9,500		9,500	7.7	0.015
Western Uplands (San Benito, Fresno, Kings, Kern)	6	2,900		2,900	2.4	0.1
San Luis West Side (Fresno, Kings)	1	270		270	0.22	0.000017
Lower Kings-Tulare (Fresno, Kings)	1	740		740	0.6	0.00003
Total	1,700	880,000	2,000,000	3,000,000	2,500	0.0057

Table 5.4-2 shows that the volume of low-salinity water supplied to fields for hydraulic-fracturing-enabled EOR in the Semitropic Planning Area is about two times the volume of high-quality water needed for making hydraulic fracturing fluids in this area. Taking

the total volume of potential low-salinity water supplied to fields for hydraulic-fracturing-enabled EOR (i.e., 4,710,000 m^3, or 29.6 million bbl in Table 5.4-1) and comparing it to the total water demand for making hydraulic fracturing fluids in Table 5.4-2 (880,000 m^3, or 5.5 million bbl) gives a factor of roughly five. In other words, in the San Joaquin Basin, EOR enabled by hydraulic fracturing requires a larger volume of supplied low-salinity water than the actual stimulation requires high-quality water. While altogether the hydraulic fracturing-related demand in the Semitropic planning area is small relative to all demand, it occurs in an area of constrained supply.

As suggested in Section 5.4.2 below, it may be possible to reduce the use of high-quality water in hydraulic fracturing fluids by using brines higher in TDS, such as those available from produced water (Lebas et al., 2013; Kakadjian et al., 2013). However, it is not clear that the economic benefits would justify the cost in the San Joaquin Basin. Unlike in basins elsewhere in the country where hydraulic fracturing is conducted in, or near, source rock, and where there is typically less availability of pipeline infrastructure, hydraulic fracturing in California is conducted in migrated oil accumulations in fields with produced water pipelines to every well, and to nearby water supply pipelines. Consequently, water transport to and from the site is much less expensive than the longer distance transportation by truck common in production from source rock elsewhere.

5.4.2. Water Demand Reduction and Supply Increase

Oil production does not just use water; it also produces water along with the oil. There are potential opportunities to reduce the amount of water consumed by oil production and opportunities for beneficial reuse of the water produced along with the oil.

The volume of water produced with oil is more than ten times the volume of oil produced in California. For instance, DOGGR's production database indicates over 500 million m^3 (3 billion bbl) of water were produced along with over 30 million m^3 (200 million bbl) of oil in 2013, which is a ratio of 16 to 1. A total of 40% of this produced water is used for water flooding, steam flooding, and cyclic steam injection. The remainder of this water is disposed of via other means, mostly via subsurface injection into disposal wells.

At the same time, as indicated in the previous section, the largest demand for low-salinity water in hydraulic-fracturing-enabled production is not for making fracturing fluids, but rather for EOR. The source of this water is either low-salinity water produced along with oil within the field, or is supplied from other sources. Figure 5.4-1 shows the low-salinity supplied water for EOR in hydraulic-fracturing-enabled production, along with the amount of low-salinity produced water that is disposed of by injection in each field. More low-salinity produced water could be used to satisfy the water demand in other fields, thereby reducing the need for supply of potential high-quality water that could otherwise be used for municipal supplies or irrigation. After adequate treatment, such water is suitable for any domestic or irrigation use. If treatment with reverse osmosis (RO) is used, the higher-concentration brines that are generated as a waste fluid after RO treatment can be injected into disposal wells. The volume of this brine would be only a fraction of the total produced water volume, reducing impacts associated with injection wells.

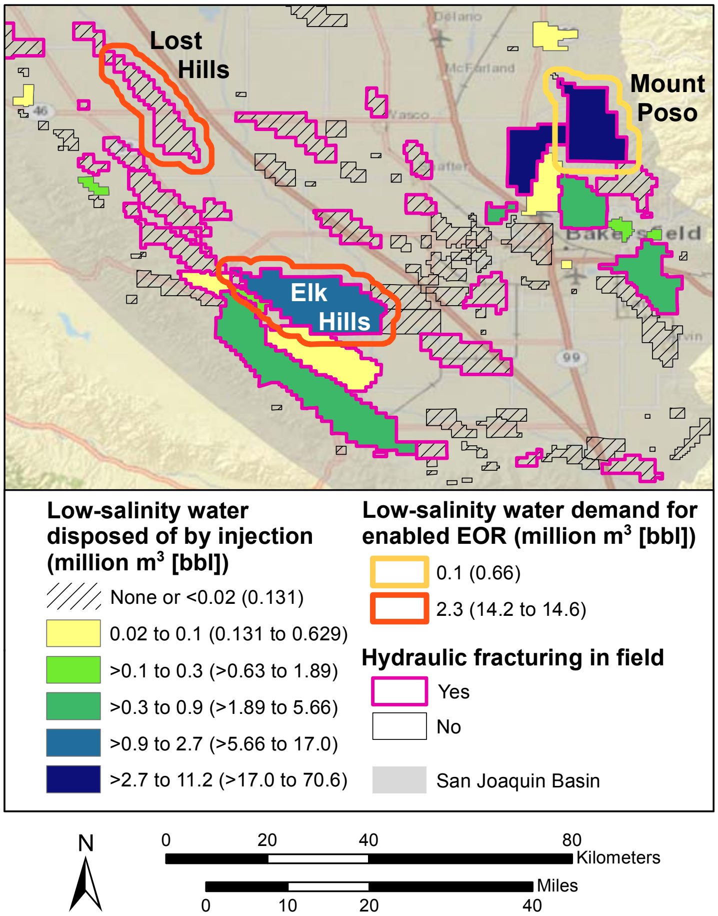


Figure 5.4-1. Produced low-salinity water disposed by injection in each field along with hydraulic fracture-enabled EOR demand for supplied low-salinity water in 2013

As an example, in the Elk Hills field, 1.1 million m^3 (7.0 million bbl) of low-salinity water was disposed of by injection in 2013. This was about half of the demand for low-salinity water of approximately 2.3 million m^3 (14.5 million bbl) supplied from outside oil and gas reservoirs for EOR in hydraulic-fracture-enabled pools. The simultaneous demand for supply of low-salinity water and disposal of low-salinity produced water in the same field may be because the quality of the low-salinity water that is disposed by injection is not sufficient for the EOR. If this is the case, it should be possible to treat the low-salinity water disposed of in Elk Hills so that it can instead be used for EOR. There is also low-salinity water disposed of in nearby fields that may be of sufficient quality to displace some of the demand for this water in Elk Hills.

The volume of low-salinity water disposed by injection in the Mount Poso field is much greater than demanded from supplies for EOR in the hydraulic-fracture-enabled pool. Again, this may result from a quality mismatch within the field. If so, and it is not practical to improve the water sufficiently with treatment, there is also a considerable amount of low-salinity water disposed by injection in surrounding fields that may be of sufficient quality for this use.

More generally, the total amount of low-salinity water disposed of by injection as shown in Figure 5.4-1 was 18.0 million m^3 (131 million bbl) in 2013. This is sufficient to meet the entire 2013 EOR demand for low-salinity water supply to fields of 13.4 million m^3 (84.3 million bbl), if the location and quality of sources can be matched to the location and quality of demand. If this were done, there would still be about 5 million m^3 (31 million bbl, 4,000 acre feet) of disposed low-salinity water that could be directed to other beneficial uses. However, because this water is presumably produced in the field in which it is disposed, and all the fields where larger volumes of this water are disposed also have a record of hydraulic fracturing, care would have to be taken to assure that the quality of the water is suitable for the beneficial use. Some perspective on this is offered below regarding use of this water for irrigation, for instance.

There may be additional low-salinity water resource opportunities in the San Joaquin Basin oil fields, because the quality of the water produced in each field is not coded in DOGGR's data, only the quality of the water disposed of by injection. Consequently, there may be low-salinity produced water disposed of by means other than injection, such as by percolation in unlined pits.

The disposal of low-salinity water suggests a detailed analysis of the spatial relationship and water quality between sources of this water and the location of supplied low-salinity water used for EOR would be useful. This could determine if the disposed water is suitable for EOR, or can be economically treated to make it suitable, and if it could economically be transferred to where it is needed for EOR. To the extent that this type of beneficial reuse could occur, it would reduce the demand for low-salinity water from sources outside oil pools. This would in turn make more water available for other uses in the San Joaquin Basin.

5.4.3. Produced Water Disposal

As discussed in Volume II, Chapter 2, there are various mechanisms by which produced water disposal can potentially degrade the quality of waters otherwise suitable for use, particularly groundwater. The risk from the two main methods of disposal of produced water from predominantly hydraulically fractured pools, percolation pits and injection, as well as from beneficial reuse of water at the surface from pools with some hydraulic fracturing, is discussed below.

5.4.3.1. Disposal to Percolation Pits

Hydraulic fracturing chemicals in the produced water may contaminate potable water supplies if not handled appropriately. According to DOGGR's production database, one of the methods currently used for produced water disposal in the San Joaquin Basin is discharge into evaporation-percolation pits (Volume I, Appendix N). These facilities vary from single, unlined pits to large complexes consisting of multiple pits. In the large complexes, the produced water enters smaller pits that provide for floatation and skimming of any remaining undissolved oil, with the water then flowing on to larger pits for evaporation and percolation. In practice, the year-round flow of water to these pits indicates most of it percolates, because evaporation rates in the winter are low. Figure 5.4-2 shows the location of percolation pits in the San Joaquin Basin relative to the minimum concentration of TDS in groundwater in 5 km by 5 km (3 mi. by 3 mi.) square areas. Most of the TDS data are from water supply wells. Consequently, the percolation of produced water into the shallow subsurface is a potential risk for contamination of potable groundwater resources.

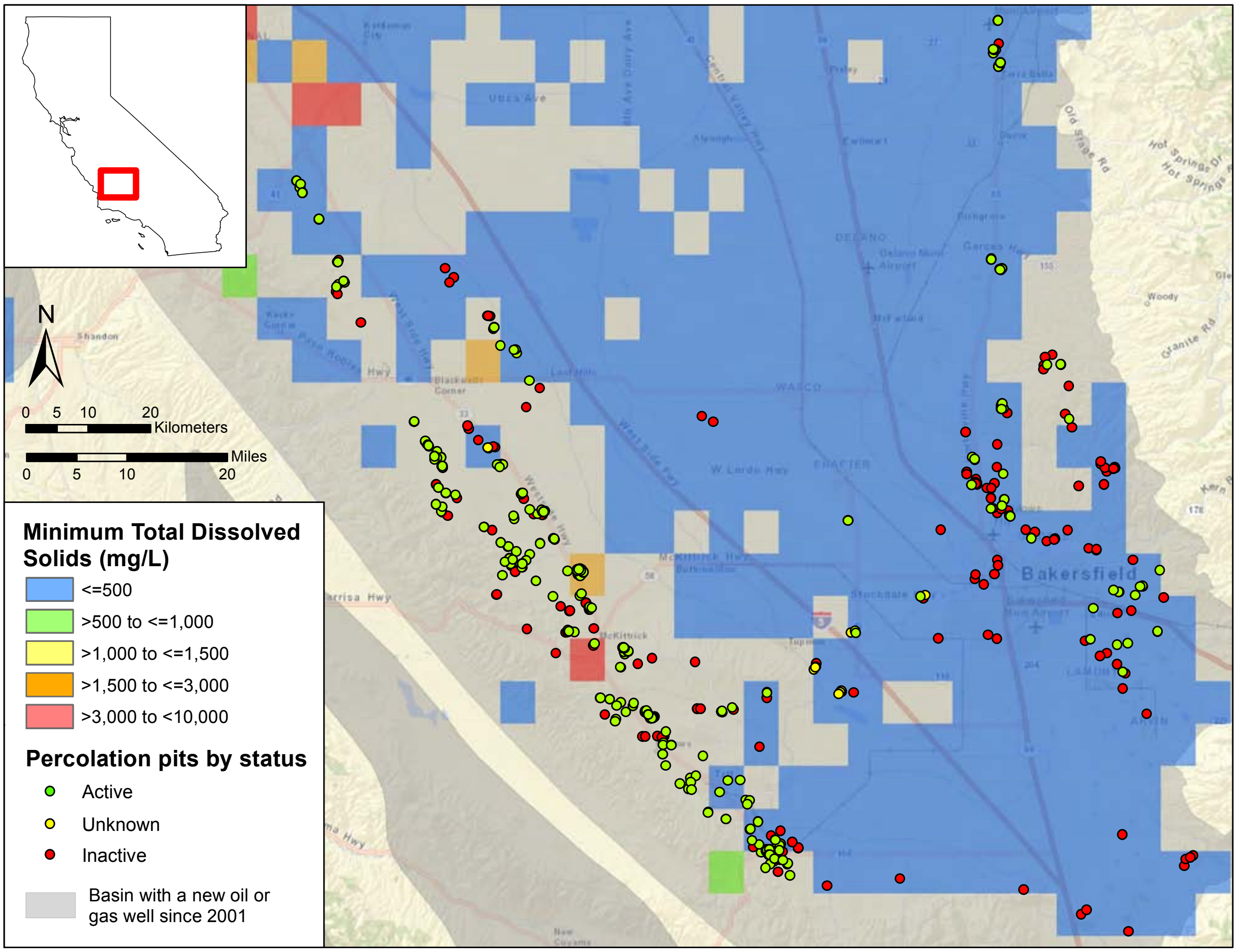


Figure 5.4-2. Minimum total dissolved solids concentration from GeoTracker GAMA[1] in 5 km by 5 km (3 mi.by 3 mi.) square areas in the southern San Joaquin Basin as of October 14, 2014, with the location of and location of percolation pits used for produced water disposal[2] overlain.

Table 5.4-3 provides the estimated number of hydraulic fracturing operations per year per pool in fields with more than 100 operations in total, and the percentage of produced water from each pool discharged to evaporation-percolation pits for disposal in 2013. The percentage of water from several of these pools discharged to pits is high. An important caveat, noted in Volume II, Chapter 2, is that some operators have communicated they no longer dispose of the water they produce in these fields in evaporation-percolation

1. http://geotracker.waterboards.ca.gov/gama/
2. http://www.waterboards.ca.gov/rwqcb5/water_issues/oil_fields/information/disposal_ponds/2015_0415_prod_pond_list.pdf

pits, but rather they dispose of the water by injection. The analysis in Table 5.4-3 is based upon the publicly available data, which in part is contradicted by the information communicated by some operators. The analysis below also assumes all the produced water from hydraulically fractured wells fully commingles with all the produced water from a field, and so is not specific to the method of disposal. This is because treatment of water produced in most fields is typically handled in central facilities, leading to the assumption that all the produced water from the stimulated pools is commingled with produced water from the entire field. For simplicity, the return of fracturing chemicals in produced water is also assumed constant, which is supported by the large number of hydraulic fracturing operations per month in the pools shown in Table 5.4-3.

Table 5.4-3. Estimated number of hydraulic fracturing operations per year per pool in fields with more than 100 estimated operations, and percentage of produced water from those pools discharged to evaporation-percolation pits for disposal in 2013.

Field	Pool	Estimated # of fracturing operations per year	% of produced water discharged to evaporation-percolation pond(s)
Belridge, North	Diatomite	139	83%
Belridge, South	Diatomite	996	90%
	Monterey (Undifferentiated)	1	0%
Elk Hills	Stevens (31S)	26	99%
	Upper (Undifferentiated)	129	98%
	Carneros	6	97%
Lost Hills	Etchegoin	179	59%
	Cahn	33	22%
	Antelope/McDonald	1	0%

Table 5.4-4 gives the estimated number of, and water volume used for, hydraulic fracturing operations per year in the four fields with the greatest number of operations. The estimated water volume for the hydraulic fracturing operations results from multiplying the estimated number of operations per year with the average water volume used for operations in that field from Volume I, Appendix O. As described in Volume II, Chapter 2, most stimulation-fluid returns are commingled and co-managed with water from the oil reservoir as produced water, so Table 5.4-4 also shows the water volume produced from each field in 2013. Finally, the table gives a dilution factor, calculated for each field as the ratio of the total produced water divided by the total water used for hydraulic fracturing. This "dilution" assumes as a conservative estimate that the entire volume of hydraulic fracturing fluid returns in the produced water.

Table 5.4-4. Estimated number of hydraulic fracturing operations and volume of water used per year per field with more than 100 estimated operations, water volume produced from each field in 2013, and dilution factor.

Field	Estimated fracturing operations per year			Water produced in 2013		Dilution factor (produced water/water for fracturing)
	#	Water volume				
		(m³)	(bbl)	(m³)	(bbl)	
Belridge, North	139	53,100	334,000	4,350,000	27,337,084	82
Belridge, South	997	347,000	2,180,000	49,300,000	310,278,910	140
Elk Hills	161	108,000	678,000	24,800,000	156,108,579	230
Lost Hills	213	107,000	675,000	21,100,000	132,840,719	200

The amount of each hydraulic fracturing fluid constituent, degradation product, and mobilized natural constituent subsequently produced with the water, oil, and gas from a well is not known in the San Joaquin Basin, because it is not reported in available databases, nor has it been determined from produced water analysis. In the absence of this information, the potential upper-limit concentration of each constituent in the produced water, excluding proppants, was estimated to provide some perspective on the potential risks (excluding proppant). The calculated total mass of each constituent injected was divided by the produced water mass for the field. This resulted in an approximate upper bound concentration of hydraulic fracturing fluid constituents in the produced water in each field as a whole, which are available in Appendix 5.B. The concentrations of degradation products and natural constituents mobilized by stimulation are obviously not considered in this first-order estimate approach.

The average mass of each chemical used recently in stimulations in the fields listed in Table 5.44 was calculated from the chemical dataset assembled from FracFocus (Volume II, Chapter 2). For each field, the mean mass of each constituent per record in the database was multiplied by the number of records in the database for that constituent, divided by the number of hydraulic fracturing operations in the database, to provide the mean mass per hydraulic fracturing operation. This accounted for the occurrence of more than one record for some constituents for some operations, such as if the same constituent was a component of more than one additive mixture. The mean mass per operation was multiplied by the estimated number of operations per year in Table 5.4-3, to provide the total estimated mass of each chemical injected per year.

The concentrations resulting from this approach are termed "potential upper-limit," for a number of reasons. The approach overestimates the concentration for constituents that react with each other or the water or rock in the reservoir, or are adsorbed onto the rock. It overestimates the concentration for constituents that are removed, in whole or part, by oil-water-gas separators and subsequent treatment systems. It may overestimate the concentration due to dilution with produced water from other fields disposed to the same percolation and evaporation pond. It overestimates or underestimates the concentration at any given time by assuming a uniform return of constituents with the produced water. The concentrations are highest when production begins after stimulation. It may underestimate concentrations in some produced water by erroneously assuming all produced water in a field is commingled, such as because there is more than one operator in a field, each with its own treatment plant.

With regard to concentration overestimation due to interaction with (including adsorption on) reservoir rock minerals, this seems likely to be less in California than other parts of the country. Fracturing fluids in California typically have the highest viscosity of fracturing fluid formulations available, and fracturing operations in California are designed to produce simple, bi-wing fractures with apertures at the largest end of the range for hydraulic fractures. Consequently, it is likely there is less interaction between hydraulic fracturing fluid and reservoir rock in California than elsewhere in the country on average, and consequently a higher fraction of the hydraulic fracturing fluid constituent mass returns in water produced after the hydraulic fracturing operation.

Figure 5.4-3 compares the potential upper limit concentrations in produced water to concentrations that are acutely toxic to half the individuals of three aquatic species during a two- to four-day exposure. Measures of these acutely toxic concentrations are only available for about a fourth to a third of the constituents for each of the three species, and only about two fifths of the constituents for one or more species.

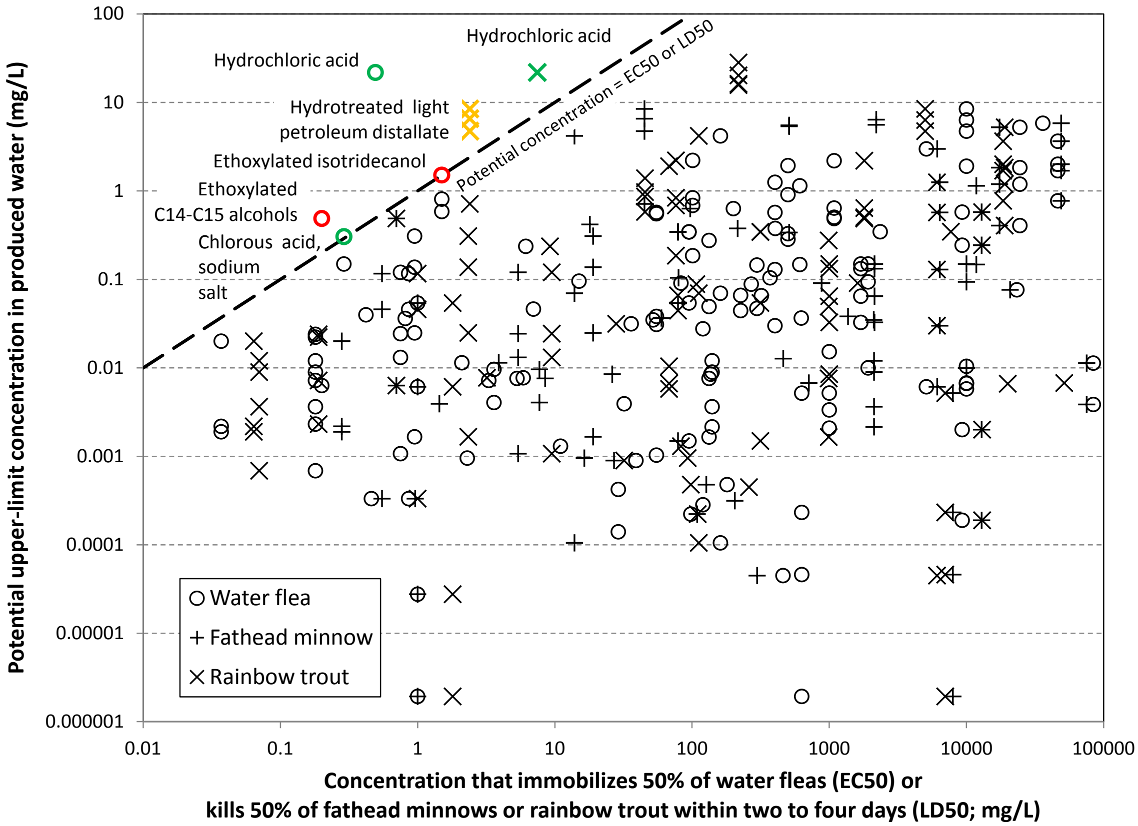


Figure 5.4-3. Comparison of potential hydraulic fracturing fluid constituent upper limit concentrations in produced water from the North and South Belridge, Elk Hills, and Lost Hills fields to the concentrations that are acutely toxic to more than half the individuals of a species during a two to four day exposure. Potential acutely toxic concentrations occur above the dashed line. See text for explanation of the symbol colors.

Some potential upper limit concentrations are acutely toxic to half the individuals of one or more of the three aquatic species. These concentrations consist of hydrochloric acid, hydrotreated light petroleum distillate, ethoxylated isotridecanol, and ethoxylated C14-C15 alcohols. Of these, hydrochloric acid almost certainly would not occur at a toxic concentration, because it would be neutralized by reactions with rock during stimulation. The concentrations of hydrotreated light petroleum distillate would likely be lower in the treatment plant effluent from a field, because it has low solubility. Consequently, it may be removed along with other hydrocarbon phases during oil-gas-water separation and subsequent water treatment. However, this may not occur, depending upon the interaction between this constituent and surfactants also typically added to hydraulic fracturing fluids. The ethoxylated constituents are miscible with water and not obviously reactive with rock, so these may occur at the potential upper-limit concentrations shown.

Assessing which, if any, concentrations have acute or chronic effects on terrestrial animals is more difficult. Acute toxicity measurements are available for rats, mice, or rabbits for many of the constituents. These measurements consist of a dose per body weight. Consequently, they are not readily comparable to potential upper-limit concentrations.

Regulatory agencies manage the deleterious health effects of water contamination for humans by proscribing maximum allowable concentrations of a contaminant, and a desirable concentration goal. The maximum allowable concentration is usually based upon limiting chronic health conditions, such as cancer, that some portion of individuals (such as one out of a million) will experience if they consume the water for a lifetime. In contrast, the desirable concentration goal is that at which no individuals are expected to experience health effects.

Agencies have established the maximum allowable concentration for only one of the hydraulic fracturing constituents disclosed (acrylamide), and a component of only one other has a concentration goal set by regulation (chloride). The Office of Environmental Health Hazard Assessment (OEHHA) provided screening criteria for additional constituents in Volume II, Appendix 6.B, but those are units relevant to inhalation and oral dosing, rather than the concentrations in water considered here. A comparison of the potential upper-limit concentrations of hydraulic fracturing fluid constituents to the maximum allowable concentrations in water for other constituents with similar acute toxicity in rats, rabbits, and mice suggests that some of the potential upper-limit concentrations would exceed the maximum allowable concentration for that concentration, if one were established. Further details of this analysis and its results are available in Appendix 5.C.

Ascertaining if any of the hydraulic fracturing fluid constituents actually occur at hazardous concentrations (for either acute or chronic effects) in produced water requires more detailed investigation via chemical analysis of produced waters from stimulated pools. In the absence of such data, given the comparison to concentrations acutely toxic to half the individuals in three aquatic species, and to maximum allowable concentrations for human consumption for similar acutely toxic constituents, it cannot be ruled out that some of the constituents would occur at concentrations of concern. Consequently, if usable groundwater is present, there is some likelihood that these constituents could percolate into the subsurface and eventually reach and degrade the groundwater resource. This evaluation of hazard does not account for the dilution of the constituents in groundwater and any chemical reactions that may occur.

Unless chemical analysis of produced water demonstrates low concentrations that pose no hazard, the most appropriate means to reduce the likelihood of groundwater degradation occurring due to the use of unlined pits in the future is to dispose of produced water from hydraulic fracturing pools by some other means, such as injection below the base of protected groundwater.

As mentioned in Volume II, Chapter 2, a means to reduce concern about release of stimulation constituents is to move toward the North Sea compact/OSPAR Convention (Oslo and Paris Convention) approach to constituent selection for stimulation fluids, which requires testing of chemicals for environmentally relevant parameters (such as acute toxicity and biodegradability) and meeting certain performance criteria prior to use. In California, a similar program could be built upon the U.S. Environmental Protection Agency's Designed for Environment program, which is voluntary at the national level (U.S. Environmental Protection Agency (U.S. EPA), 2011). This would result in utilization of constituents with among the lowest potential environmental impacts for each purpose (such as corrosion and bacterial growth inhibition).

As also mentioned in Volume II, Chapter 2, some operators have communicated that they have transitioned from produced water disposal in unlined pits to disposal by injection, despite data they have submitted to DOGGR to the contrary. So the risk from surface disposal appears to be less than indicated by the produced water disposition data available from DOGGR. However, there are other operators in these fields that have not been contacted whose produced water is also coded as being disposed of in unlined pits. In addition, there may still be a legacy risk of groundwater contamination from the past practice of operators who no longer discharge produced water to these facilities for disposal. Operators should be contacted and required to correct erroneous data submitted in the past. Even if disposal in unlined pits is phased out in the future, investigations should be conducted to determine if past disposal to such pits has impacted groundwater in the vicinity, and if so, site characterization and remediation should follow.

5.4.3.2. Injection Into Groundwater That Potentially Should Be Protected

Another common method for disposing of produced water in the San Joaquin Basin is injection into aquifers with low quality groundwater above 10,000 mg/L TDS. This is termed water disposal injection, in contrast to injection for EOR. Water disposal injection is regulated under the US Safe Drinking Water Act by DOGGR acting on behalf of the U.S. EPA, and can minimize the risk of contaminants entering protected water if carried out in compliance with the underground injection control regulations. In the San Joaquin Basin, water disposal injection is frequently being used for disposing of produced water. However, in June of 2014, DOGGR issued orders to cease water disposal injection in 11 wells that may have been inappropriately permitted for injection into protected groundwater. (Protected groundwater according to EPA has less than 10,000 mg/L TDS and is not in an exempt aquifer. Aquifers may be exempted for several reasons—for example, because they contain commercially producible minerals or hydrocarbons, or because they are too deep for economic water production.) Injection in some of these wells was subsequently determined allowable and restarted, while others remained closed. DOGGR is currently reviewing many more wells to determine if it inappropriately permitted injection into aquifers that should be protected (DOGGR and State Water Resources Control Board (SWRCB), 2015). Below, the wells in review are assessed to determine if they may have received wastewater from nearby stimulated production wells, in which case the injected water may also have contained stimulation chemicals at unknown concentrations.

The first component of the assessment is a statistical analysis regarding produced water disposed of by injection in pools where most wells are hydraulically fractured and where there are more than 100 fracturing operations per year. Table 5.4-5 shows the percentage of produced water from these pools disposed of by injection. The table indicates relatively little of the water is disposed of by injection; however, as mentioned in Section 5.4.3.1, some operators have indicated they do not dispose of produced water in the fields listed in Table 5.4-3 and 5.4-5 to evaporation-percolation pits any longer, despite submitting data to DOGGR to the contrary. They instead dispose of the produced water by injection (Volume II, Chapter 2). This is particularly true in the Elk Hills field, which Table 5.4-5 indicates has little produced water injection, but where the operator indicates that all produced water is now injected. In other words, the percentages of produced water disposed by injection given in Table 5.4-5 could be higher for more recent operational practices.

Table 5.4-5. Estimated number of hydraulic fracturing operations per year per pool in fields with more than 100 estimated operations, and percentage of produced water from those pools injected in 2013.

Field	Pool	Estimated # of fracturing operations per year	% of produced water injected in disposal wells
Belridge, North	Diatomite	139	16%
Belridge, South	Diatomite	996	8%
	Monterey (Undifferentiated)	1	0%
Elk Hills	Stevens (31S)	26	0%
	Upper (Undifferentiated)	129	0%
	Carneros	6	1%
Lost Hills	Etchegoin	179	13%
	Cahn	33	54%
	Antelope/McDonald	1	100%

The potential upper limit concentrations of hydraulic fracturing fluid constituents in produced water that were calculated in the previous section can also be used to evaluate potential concerns about inappropriate injection of produced water. DOGGR is currently reviewing if the zones into which wells have been injecting are exempt from protection, as required in order for injection of produced water to occur. Groundwater can be exempt from protection if the TDS concentration is greater 10,000 mg/L, the TDS concentration is over 3,000 mg/L and the water co-occurs with a quantity of oil or gas that is economical to produce, or if the TDS concentration is greater than 3,000 mg/L and the water is not economical to produce and treat to drinking water standards— such as due to location, depth, and/or naturally occurring contaminants in the water. As a result of this review, DOGGR has identified thousands of injection wells for more detailed consideration (DOGGR, 2015).

Of the 2,552 injection wells under review by DOGGR, 468 were active or idle water-disposal wells.[3] Figure 5.4-4 shows that many of the fields where hydraulic fracturing has occurred have a substantial percentage of water disposal wells under review. In particular, this is the case for three of the four main fields where these hydraulic fracturing operations take place: South Belridge, Lost Hills, and Elk Hills. To the extent these wells are determined to have been injecting into zones that should not have been exempted from protection, the estimated hydraulic fracturing constituent concentrations suggest such constituents could be detected, potentially at hazardous concentrations, in the zones.

3. DOGGR (2015) includes two lists of wells for review: one stated as water disposal wells and the other stated as EOR wells. Comparison of the water disposal well list to DOGGR's AllWells file (DOGGR, 2014) indicated some of the wells on the list are not water disposal wells. Consequently, the water disposal and EOR well review lists were combined in order to select all the wells under review that are water disposal wells according to DOGGR (2014). This determined there was one well included on both lists. One record was included for this well in the combined list.

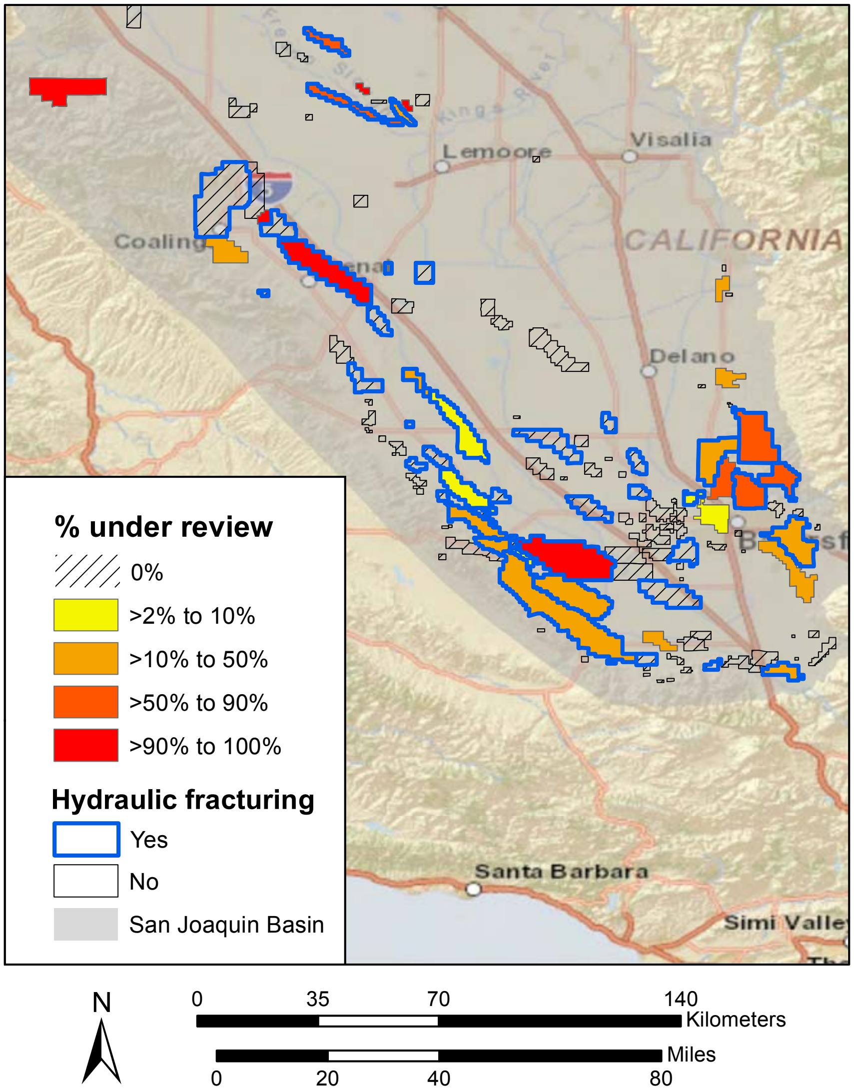


Figure 5.4-4. Percentage of water disposal wells in each field undergoing review by DOGGR for appropriateness of its permitting relative to the quality of the groundwater in the injection zone.

The percent of disposal wells under review in South Belridge and Lost Hills is relatively small, suggesting it might be possible to relatively rapidly redirect disposal to other wells in the event the wells under review are shut down. Almost all the disposal wells at Elk Hills are under review, indicating considerably more difficulty assessing potential impacts to the receiving zones if it is determined they contain groundwater that should be protected.

The Safe Drinking Water Act and the Underground Injection Control program provide a regulatory and technical basis for protecting underground sources of drinking water. As such, a more methodical system for permitting water disposal injections would arguably decrease the potential for disposal of contaminated produced water in protected groundwater. The state should establish the boundaries of water to be protected, and through the Underground Injection Control program, only allow injection into saline, non-potable aquifers that are sufficiently isolated from overlying groundwater resources to protect those resources. Currently, these boundaries are uncertain, because protected groundwater (for instance, water with TDS content up to 10,000 mg/L) has not been mapped systematically.

5.4.3.3. Beneficial Reuse Involving Release to the Surface

Some produced water is used for irrigation and groundwater recharge in parts of the San Joaquin Basin. After appropriate treatment, such reuse has benefits in areas with water scarcity. However, if this water is produced from fields that have applied well stimulation technologies, and if the treatment process is insufficient with regards to stimulation chemicals, then use for irrigation creates a potential pathway for humans to be exposed to chemicals in produced water from stimulated wells through agricultural products, as well as direct exposure of wildlife and vegetation. Where produced water has been used for irrigation and groundwater recharge, and how this relates to fields with hydraulic fracturing operations, is assessed below.

Produced water from two fields where hydraulic fracturing has occurred is permitted for agricultural usage: the Mount Poso and the Kern River fields (Volume II, Chapter 2). For the Mount Poso field, a search of the Central Valley Regional Water Quality Control Board (CVRWQCB) records suggests only water produced by SOC Resources, Inc., was permitted for irrigation (CVRWQCB, 2006). DOGGR's production database indicates that SOC Resources produced water in the Dominion area, but not the Main area, at the time and extending back to at least 2000. The integrated hydraulic fracturing data set (Volume I, Appendix M) does not include any operations in the Dominion area, nor are there any matrix acidizing operations listed in the CVRWQCB data set (described in Volume I, Chapter 3). Consequently, it is unlikely stimulation chemicals entered this water stream and ended up in irrigation water. However, water in the Vedder portion of the Pyramid Hill-Vedder pool has a TDS content of 1,000 to 1,500 mg/L (DOGGR, 1998), suggesting it could potentially be used for irrigation at some point in the future (it was primarily disposed by injection in 2013 according to DOGGR's production and injection database). The predominance of hydraulic fracturing in that pool suggests that hydraulic fracturing fluid constituents could be present in water produced from that pool.

In addition to irrigation, produced water from the Kern River field is used for groundwater recharge in the winter time when agricultural water demand is low. Prior to this, the water was released to Poso Creek (CVRWQCB, 2012). A search of CVRWQCB records indicates only Chevron USA, Inc. (Chevron), was permitted to discharge produced water for irrigation and groundwater recharge (CVRWQCB, 2012). Three of the wells identified as hydraulically fractured in the Kern River field in the integrated set (Volume I, Appendix M) are operated by Chevron. One of these was identified only from the well record search. Due to the small proportion of well records searched, this record suggests two hydraulic fracturing operations per year occur in the Kern River field on average. This is out of approximately 350 new wells per year from 2002 through 2013.

CVRWQCB (2012) indicates the facility operated by Chevron that treats produced water subsequently discharged for irrigation can process 143,000 m^3 (900,000 bbl) per day, but the average treated was 83,000 m^3 (520,000 bbl) per day. This is a significant fraction of the total water produced by Chevron in the Kern River field, which was 150,000 m^3 (950,000 bbl) per day on average from 1990 through 2013. The treatment facility uses the same components as the Kern Front No. 2 facility, which will not remove most stimulation fluid constituents (Volume II, Chapter 2).

Produced water from two of the three wells identified as hydraulically fractured operated by Chevron is disposed of by injection according to DOGGR's production database. The database has no disposition data for produced water from the third well. It is not known if produced water from this well is used for irrigation and groundwater recharge. Given the uncertainty regarding the accuracy of produced water disposition data in DOGGR's production database, it is not known if water from the other two wells is used for these purposes rather than disposed of by injection. It is also not known if water from unidentified hydraulically fractured wells operated by Chevron is used for these purposes. Given the high proportion of Chevron's produced water in this field that does go through the treatment facility, providing water for irrigation and groundwater recharge, it is likely that produced water from some well or wells goes to this facility. Further, and perhaps more importantly, there has been and is currently no regulatory control on produced water from hydraulically fractured wells being used for irrigation and groundwater recharge.

No data regarding stimulation fluid constituents for operations in the Kern River field are available. Of constituents that occur in more than 5% of the operations for which the constituents were disclosed (at least in part), the largest median mass for any single, soluble constituent with a Globally Harmonized System (GHS) acute aquatic toxicity category of 1 (the most toxic category) is 135 kg (ethoxylated C14-15 alcohols; GHS acute aquatic toxicity category 1 encompasses the most toxic constituents). This mass dissolved in the average daily volume of produced water used for irrigation would result in a concentration of 1.6 mg/L. This is several times the concentration that kills or disables 50% of the individuals of certain aquatic species in two to four days.

However, it is unlikely the entire mass of a stimulation chemical would be produced back from a hydraulically fractured well, and it is unlikely that whatever portion of the mass is ultimately produced back would be produced back in one day. Further, some downstream dilution with water from other sources does occur, although, according to information in CVRWQCB (2012), only minimal dilution appears to be necessary to meet the quality goals of the irrigation district receiving the water.

On the other hand, the concentration that would not have an acute effect on any individuals is less than that considered. In addition, acute aquatic toxicity measurements for the animals and algae considered are not available for more than half and a bit less than half of the constituents, respectively. The synergistic effects of exposure to the concentrations of multiple constituents at once are not accounted for in the acute toxicity measurements that are available. Other constituents in lower acute aquatic toxicity categories may be used in greater masses, also resulting in potentially acutely toxic concentration spikes in produced water.

The above reasoning indicates that the current practice of treatment and dilution of produced water utilized for irrigation may not be sufficient to reduce concentrations of all stimulation constituents to levels that are less than acutely toxic, or even to levels less than what can cause chronic effects for aquatic species on a continuous basis. In addition, the human exposure pathway involving consumption of food irrigated with produced water containing hydraulic fracturing fluid constituents is not considered. However, no known instances of such contamination have been observed. Further investigations are needed to ensure that environmental or human health concerns as a result of these practices can be ruled out. If risk of contamination is found to be unacceptably high, hydraulic fracturing in reservoirs that produce water used for irrigation or other beneficial purposes should be reconsidered until the produced waters are demonstrated to be safe for agricultural use. If concentrations are inconsistent with agricultural use, then treatment systems should be considered that remove stimulation fluid constituents or reduce their concentrations to acceptable levels, or use of the produced water for irrigation should cease. The latter would require determining what levels are acceptable, which is not known for almost all of the chemicals used in hydraulic fracturing.

5.4.4. Leakage Via Subsurface Pathways

Fluid leakage from an oilfield production interval into other zones can potentially occur via subsurface pathways, including induced and natural fractures, faults, and wells. A driving force is required for leakage via such pathways, whether preexisting or created by the stimulation. This can be provided by a vertical upward hydraulic gradient and/or buoyancy force due to fluids in the pool less dense than those overlying the pool.

Leakage of non-buoyant liquids, such as hydraulic fracturing fluids containing well stimulation chemicals, generally requires a pressure sufficient to cause them to flow upward towards protected groundwater resources. Gas leakage only requires a transmissive pathway, because gases are much less dense than water and migrate under buoyancy. Most oils are also less dense than water, and so could flow upward due to buoyancy. However, the buoyancy forces are smaller because oil is closer to the density of water than is gas, and the mobility of oil is much smaller than that of gas due to its much higher viscosity. As a result, leakage of oil is generally much less of a concern than leakage of gas, but it cannot be ruled out. Further, studies suggest leakage of buoyant fluids will be limited both by production in the reservoir and the capillary entry pressure to permeable features (Reagan et al., 2015).

This section focuses on the possibility of hydraulic fracturing fluids leaking into protected groundwater resources, which means the driving force of concern is the hydraulic gradient rather than buoyancy. In areas with oil and gas production, the natural hydraulic gradient can be strongly affected by production-related pressure changes in the reservoir rocks relative to the overlying fresh groundwater systems. This has certainly been the case in the San Joaquin Basin: In 2013, only about 3% of the oil produced from the 28 pools in the Basin where most to all wells are estimated as hydraulically fractured, flowed from the well due to reservoir pressure in 2013. About 90% is coded as produced using artificial-lift, mostly by rod-pump, with most of the rest coded as other or not coded. This is up from over 20% produced by artificial lift in 1980, early in the production from most of these pools, over 50% in 1990, and over 80% in 2000. In other words, past oil and gas production in the San Joaquin Basin has reduced the pressure in producing reservoirs to the extent that the driving force for potential leakage has diminished or reversed in most pools. Just a few of the 28 pools with hydraulic-fracture-enabled production continued to produce a significant portion of the oil by flow in 2013. All pools with more than 3% oil production by flow rather than lift are shown on Table 5.4-6.

General guidance to maximize production using pumping is to maintain the bottom-hole pressure at less than 10% of the static reservoir pressure (McCoy et al., 2003). This results in a large downward vertical head gradient from overlying aquifers to the pool. Due to this gradient, there is no driving force for upward leakage of liquids as dense as or denser than water during production, and thus little risk of fracturing fluids or formation water migrating upward from hydraulically fractured pools during production.

Table 5.4-6. Predominantly hydraulically fractured pools in the San Joaquin Basin with more than 3% of the oil flowed to the surface in 2013 rather being lifted, such as by a pump.

Field	Area	Pool	Oil produced		% flowing
			m^3	bbl	
Shafter, North	Any Area	McClure	150,000	940,893	66%
Lost Hills, Northwest	Any Area	Antelope Shale	420	2,642	27%
Rose	Any Area	McClure	73,700	463,643	19%
Kettleman Middle Dome	Any Area	Kreyenhagen	2,790	17,552	9%
Elk Hills	Any Area	Stevens (31S)	327,000	2,059,961	7%
Monument Junction	Main Area	Antelope	14,300	89,680	4%
McKittrick	Northeast Area	Point of Rocks	14,700	92,612	4%

While there is little risk of liquids leaking upward during production due to the general lack of a driving force, there may be some hazard of upward-leaking liquids during the hydraulic fracturing operations due to the pressure applied during fracturing. This possibility is analyzed below for the San Joaquin Basin regarding leakage of stimulation fluids via induced fractures, pre-existing natural fractures, wells, and fault pathways.

Aside from the risk of liquid leakage, the development of these pools does increase the probability of gas leakage via subsurface pathways due to buoyancy, as observed in several studies for various areas with and without hydraulic fracturing elsewhere in the country (Volume II, Chapter 2). The portion of these potential emissions that are caused by hydraulic-fracturing-enabled production is assessed in the section regarding risk to air in the San Joaquin Basin in this case study.

5.4.4.1. Shallow Fracturing

Most hydraulic fracturing in the San Joaquin Basin occurs shallower than 300 m (1,000 ft). This means that operators produce hydraulic fractures near the surface that can present a hazard if there is nearby protected groundwater. Hydraulic fracturing at these shallow depths has been permitted in at least one field where the California State Water Resources Control Board (SWRCB) has recently required a groundwater monitoring plan (Lost Hills), indicating the presence of protected groundwater (Volume I, Chapter 3, and Volume II, Chapter 2). Figure 5.4-5 shows the minimum depth of fracturing relative to the minimum TDS concentration in groundwater in 5 km by 5 km (3 mi. by 3 mi.) square areas, which suggests there are other fields with shallow hydraulic fracturing near protected groundwater. Consequently, the planned separation between the base of protected groundwater and the top of the shallowest induced fracture is in the tens to (at most) hundred meters. Given the uncertainty about the vertical extent of hydraulic fractures, this creates a potential for the induced fractures to encounter protected groundwater and release stimulation fluids as well as oil and gas into this groundwater. Further, because the TDS data were predominantly from water supply wells, Figure 5.4-5 also suggests that shallow fracturing creates a potential for release near existing sources of water supply.

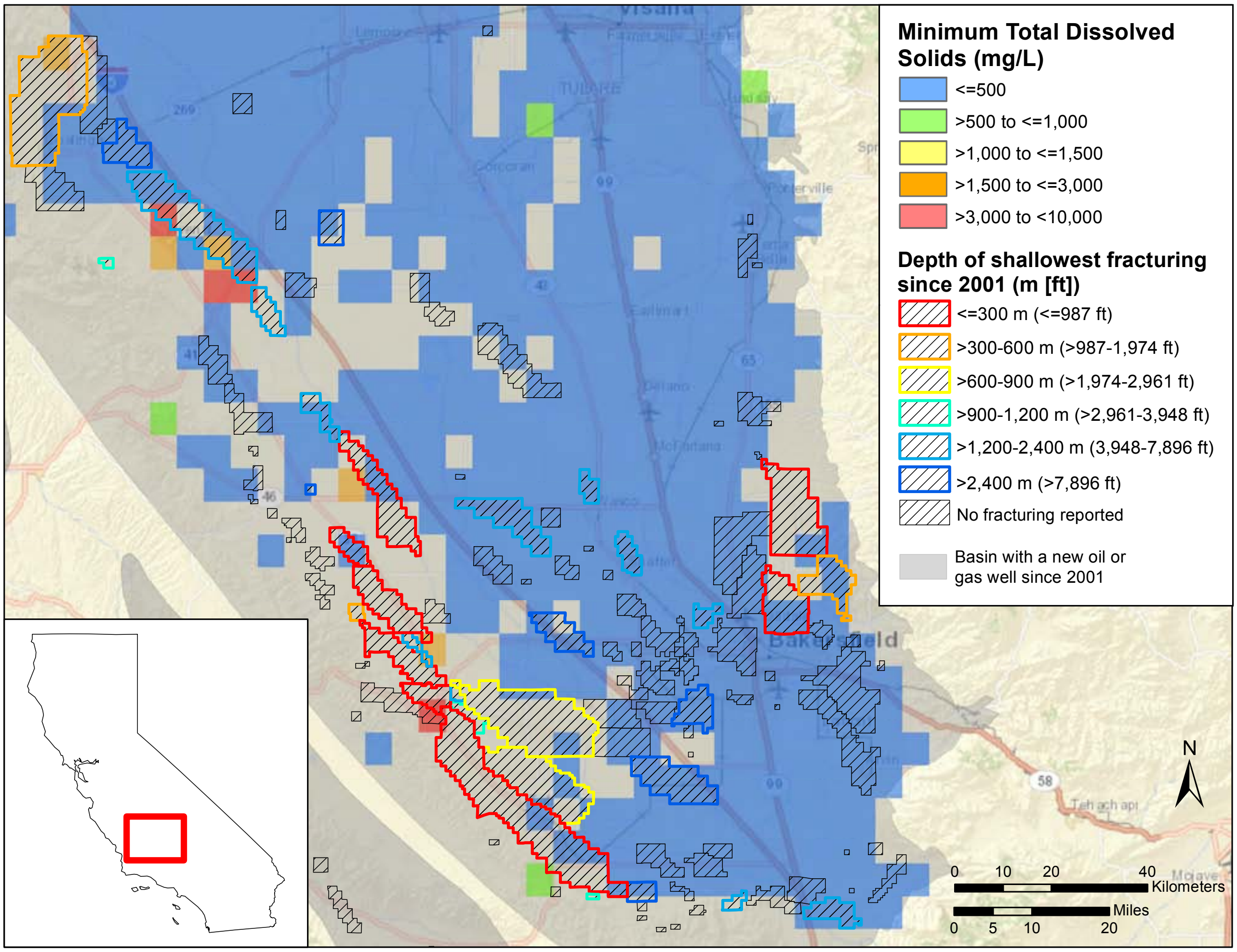


Figure 5.4-5. Minimum total dissolved solids concentration from GeoTracker GAMA[4] in 5 km by 5 km (3 mi.by 3 mi.) square areas in the southern San Joaquin Basin as of October 14, 2014, with the available minimum depth of hydraulic fracturing in each field available in Volume 1, Appendix M is shown. For most fields, this is the depth of a well in which hydraulic fracturing occurred, so the upper limit of the hydraulic fracture may be in a shallower category.

An important factor for the likelihood of induced fractures entering groundwater is their orientation, which in turn is a function of subsurface stress conditions and hydraulic fracturing operational choices. Flewelling and Sharma (2014) found that shallow formations are more likely to fracture horizontally rather than vertically; however, these results are from settings outside of California. Engineering of fractures from shallow

4. http://geotracker.waterboards.ca.gov/gama/

horizontal wells in California indicates they are typically vertical, at least in the southwest San Joaquin Basin, where most shallow fracturing occurs in the state, as discussed further in the next paragraph.

Emanuele et al. (1998) measured the orientation of fractures resulting from tens of stages in three horizontal wells in the Lost Hills field at a depth of ~600 m (2,000 ft), using surface tiltmeter measurements for each along with subsurface tiltmeter measurements for a few. The orientation of all the fractures was within 10 degrees of vertical. Hejl et al. (2007) reported vertical fracturing at depths as shallow as 425 m (1,400 ft) measured with downhole tiltmeters in the Lost Hills field. Allan et al. (2010) reported on testing of longitudinal versus transverse fracturing in horizontal wells at a depth of approximately 300 m (1,000 ft) in the South Belridge field. The tests determined wells oriented to create longitudinal fractures were considerably more productive. If fractures propagated horizontally, it would not be possible to create transverse fractures from a horizontal well, and the well orientation would be less relevant to the volume of oil it produced. In addition, Allan et al. (2010) reported that the fractures were vertical, as indicated by surface and downhole tiltmeter measurements. Figure 5.4-6 shows a representation of vertical fracturing from vertical wells in diatomite in the South Belridge field included in a history of the South Belridge field (Allan and Lalicata, 2007).

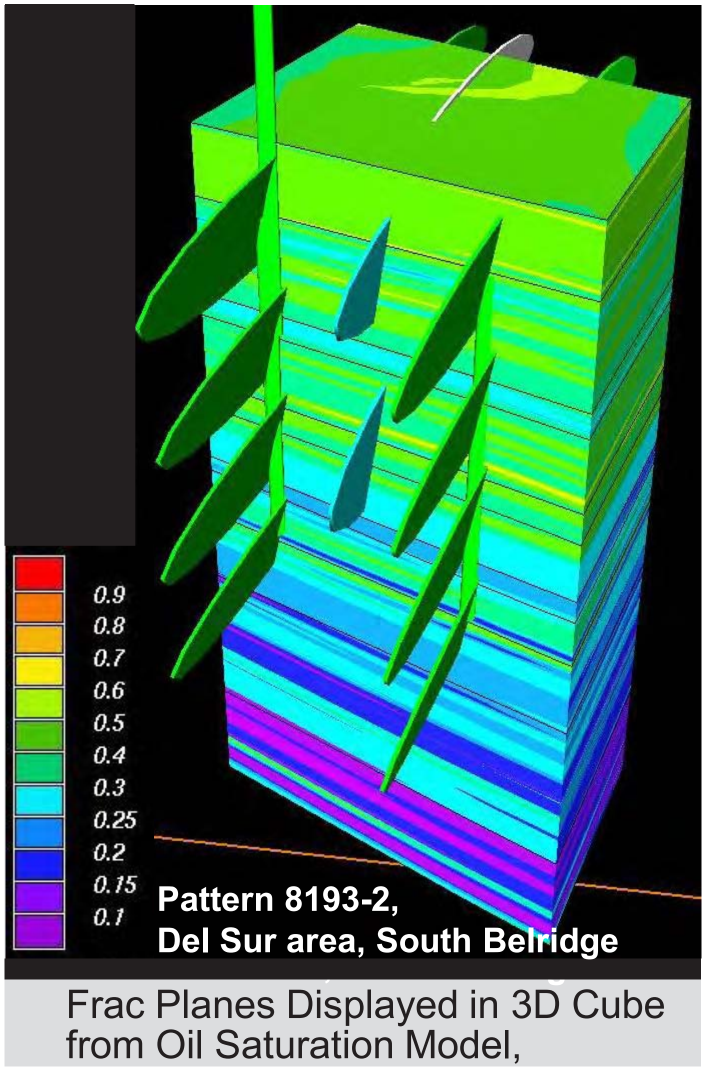


Figure 5.4-6. Representation of vertical fracturing from vertical wells in the diatomite in the South Belridge field (Allan and Lalicata, 2007).

Consequently, there are indications that fracturing at shallow depths in the San Joaquin Basin is predominantly vertical, which means fracturing is more likely to extend upward and encounter protected groundwater. Determining the probability of one of these fractures encountering protected groundwater requires a field-verified data set regarding the upward extent of induced shallow fractures, relative to the base of protected groundwater, which is sufficiently large to draw statistical inferences. Such a data set regarding upward extent is not known to exist in the public domain, although it may be available in hydraulic fracture completion reports prepared by the oil field service provider. Data sufficient to determine the position of protected groundwater may exist in the public domain. If so, it requires assembly and interpretation.

In the absence of such publicly available information, further investigation is recommended. A statistical understanding of the relationship of shallow fracturing to protected groundwater could provide the basis for judging if and what mitigation measures are needed in addition to standard practice. This analysis could be done with data already held by operators if this were made available. If the data cannot be made available, or turn out to be insufficient, then a field program monitoring the upward extent of shallow hydraulic fractures should be pursued to generate such data.

In the meantime, for operations with shallow fracturing near protected groundwater, additional recommendations to decrease the probability of groundwater resources being degraded by intersection with a hydraulic fracture include:

1. Detailed prediction of expected fracturing characteristics prior to starting the operation;

2. Minimum separation distance between expected fractures and protected groundwater, providing a sufficient safety margin with proper weighting of subsurface uncertainties;

3. Targeted monitoring of the fracturing operation to watch for and react to evidence (e.g., anomalous pressure transients, microseismic signals) indicative of fractures growing beyond their designed extent;

4. Ongoing monitoring of groundwater quality and levels (hydraulic head) to detect leaks and evidence of hydraulic connection to underlying reservoir;

5. Timely reporting of the measured or inferred fracture characteristics confirming whether or not the fractures have actually intersected or come close to intersecting groundwater;

6. Preparing corrective action and mitigation plans in case anomalous behavior is observed or contamination is detected;

7. Adapting groundwater monitoring plans as part of the corrective action, to improve the monitoring system and specifically look for contamination in close proximity to possible fracture extensions into groundwater.

5.4.4.2. Leakage Via Wells

Leakage of stimulation fluids during hydraulic fracturing could occur via well defects, including breaches in the casing and gaps in the cement sealing the space between the casing and the rock. Fluids migrating along this pathway could enter groundwater, the unsaturated soil zone above groundwater, and the atmosphere, and can spill onto the ground surface. The capacity of a well to prevent such migration is referred to as its integrity.

Well leakage can broadly be considered as acute or chronic. The difference is largely in how soon a leak is observed after it starts, and how soon mitigation commences. Leaks that are observed shortly after they commence (seconds to days) and for which mitigation activities start virtually immediately are acute. These are termed "well blowouts" in this study. They typically occur due to the sudden failure of vital well elements, such as well casing. In contrast, chronic leaks are typically caused by defects or deficiencies in well seals, such as incomplete cementing. Because the leakage rates are smaller, chronic leaks may not ever be observed, or, if observed, do not necessarily trigger immediate mitigation action in practice (e.g. Chilingar and Endres, 2005).

5.4.4.2.1. Injection Well Leakage

The wells undergoing hydraulic fracturing can provide a leakage path to the environment if the casing or cement of the well is flawed or breaks down, or if there is a breach in the casing. With regard to acute leakage, Jordan and Benson (2008) collated and assessed blowout data for oil, associated gas, and the small amount of non-associated gas operations in California Oil and Gas District 4. This district includes Kern County, where most of the hydraulic fracturing in the San Joaquin Basin and the state occurs. Analysis of the blowout data provided in Jordan and Benson (2008) for this case study finds that it does not contain any records of blowouts related to hydraulic fracturing during the period studied (1991 to 2005). The well-record search results reported in Volume I, Chapter 3, indicated 900 hydraulic fracturing operations per year from 2002 through 2006. Comparison to other data sets suggested that the actual number of operations per year is ~1,500, for a total of ~7,500 from 2002 through 2005. The literature review in Volume I, Chapter 3, also indicated that substantial hydraulic fracturing activity began in the early 1980s in the four fields where it is most common. Thus, even if the average number of operations per year from 1991 through 2001 was only half that from 2002 through 2005, the total number of operations during the 1991 through 2005 study period would have exceeded 15,000.

This suggests that the frequency of blowouts during hydraulic fracturing events is less than 1 per 15,000 operations, which is equivalent to about a decade of operations at the rate estimated in Volume I, Chapter 3. Consequently, even though the potential leakage flow rates during a blowout would be quite high, perhaps as high as the injection flow rates during the hydraulic fracturing operation, these events would occur infrequently. It is possible the total rate of well blowouts is somewhat higher than given in the database, because not all blowouts have surface expressions (i.e., they may be restricted to the subsurface). However, Jordan and Benson (2008) found that two thirds of the steam-injection-well blowouts were from the ground surface away from the well head, indicating a subsurface release that fractured to the surface due to the pressure. Consequently, at least some portion of subsurface blowouts of highly pressurized fluids would manifest themselves as surface blowouts, from which it can be concluded that the overall rate of well blowouts from hydraulic fracturing in California has been low.

The frequency and potential magnitude of chronic leakage of stimulation fluids from wells into the subsurface in the San Joaquin Basin, anywhere in California, and apparently anywhere in the world, is not well known. Kell (2011) suggests that no groundwater contamination incidents were reported from 16,000 multi-stage hydraulic fracturing operations in horizontal wells occurring in Texas from 1993 to 2008. Aside from this study, focused on the potential migration of stimulation fluids or brines into groundwater, most other analyses of well integrity have looked into the frequency of leakage along wells via monitoring of methane and other gases at the surface. A study conducted by Watson and Bachu (2009), in an area of Alberta where monitoring of gas leakage in the subsurface around each well was mandated, found 5.7% of these wells showed evidence of such leakage. Watson and Bachu (2009) furthermore found that 0.6% of wells across all of Alberta exhibited leaks to the subsurface. Davies et al. (2014), examining records from 2005 to 2013 for wells installed in the Marcellus shale in Pennsylvania from 1958 to 2013, found evidence that 1.27% had showed evidence of gas leakage to the ground surface. Vidic et al. (2013) is cited in Davies et al. (2014) as finding that 0.27% of wells whose borings drilled into the Marcellus Shale from 2008 to 2013 leaked to the surface.

There is a discrepancy between the finding of no groundwater contamination resulting from the hydraulic fracturing of 16,000 wells in Texas, and other studies finding 1 in 400 to 1 in 20 wells manifesting gas leakage at the surface from migration along wells. One reason for this is the difference in driving forces between non-buoyant subsurface fluids (such as stimulation fluids or deep reservoir brines) and buoyant gases such as natural gas, as previously mentioned.

Another reason for this discrepancy may be the difficulty of detecting subsurface leakage by monitoring groundwater quality. For instance, Carroll et al. (2014) presented the results of a risk assessment modeling study concerning geologic storage of carbon dioxide. The project assessed consisted of injecting 5 million metric tons (5.5 million tons) of carbon dioxide (CO^2) per year for 50 years. The resulting area with a pressure increase in the reservoir contained 48 legacy oil and gas wells with a 2% to 10% probability of chronic leakage. Groundwater monitoring was conducted for 200 years from one well per square kilometer over the entire pressure increase area. Given these conditions, the study found a less than 5% probability of detecting groundwater contamination when the location of leakage pathways into groundwater is unknown.

The findings of Carroll et al. (2014) indicate that it is not clear to what degree leakage causing an adverse impact to groundwater quality could be detected by monitoring. Theoretically any intrusion of contaminants, no matter how small, constitutes an impact to groundwater. As a practical matter, however, it is not possible to definitively measure and prove zero leakage. For instance, even if a sample of groundwater with quality altered by a leak is analyzed, natural variability in groundwater quality can mask that result. Only concentrations exceeding one of a variety of statistical thresholds of significance will be flagged for further investigation to determine if the concentration is due to leakage (Last et al., 2013).

Regulations recognize that assuring zero leakage is not possible, and consequently inherently find a certain amount of leakage acceptable. For instance, injection well casings in California are periodically pressure tested. The casing passes the test if the pressure declines less than 10% in fifteen minutes. The minimum final pressure is 1.4 MPa (200 psi), so the minimum acceptable pressure loss is 0.14 MPa (20 psi; Walker, 2011). A typically sized casing of a relatively shallow well (several hundred meters [a couple thousand feet] deep) can hold thousands of gallons. This combination of volume, size of acceptable pressure decline, test duration, and water compressibility indicates an allowable leak on the order of 3 L (1 gallon) per hour. At this rate, an injection well would leak 0.3 m^3 (2 bbl) within a week. Consequently, this amount of leakage is implicitly allowed by testing requirements in California.

Currently approved groundwater monitoring plans for some hydraulic fracturing operations in California provide another perspective. These plans specify monitoring for leakage via analysis of samples collected from groundwater supply wells or monitoring wells. The monitoring wells are typically located hundreds of meters from some of the hydraulically fractured wells they propose to monitor. For example, Figure 5.4-7 shows the location of 42 planned hydraulic fracture operations in relation to planned monitoring wells from one groundwater monitoring plan developed for operations in the Lost Hills field. The apparent average distance from a stimulated well to a monitoring well is 400 m (1/4 mi.). The monitoring well density is similar to that investigated by Carroll et al. (2014).

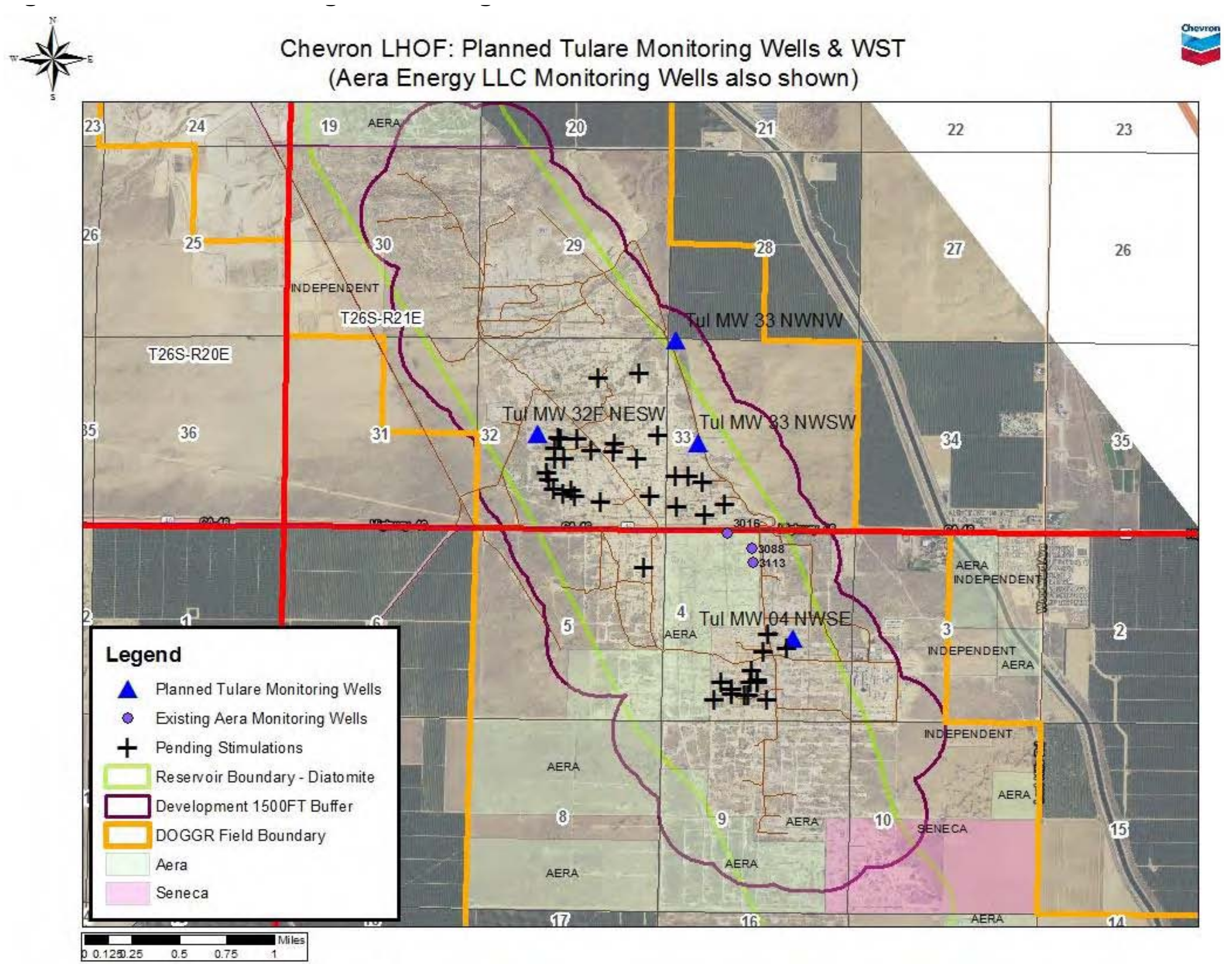


Figure 5.4-7. Location of planned hydraulic fracturing and monitoring wells in a portion of the Lost Hills field. The stimulation locations are shown by crosses and the planned monitoring wells by blue triangles (Chevron USA Inc., 2015).

Locating monitoring wells closer to stimulated wells would increase the likelihood of detection; however, this would require a geometrically larger increase in the number of monitoring wells. For instance, decreasing the average distance from a stimulated well to the nearest monitoring well by a factor of four would increase the number of monitoring wells by ~16. While this may be possible, the probability of detecting a leak would still depend on a monitoring well being in a zone into which a leak occurs, along a flow line from where leaking fluid entered the zone, and in sufficiently close proximity to where the leak entered the zone to allow its detection within a reasonable time of when the leak occurred. This is dependent upon proper prediction of the location of the leakage into the zone, and characterization of hydraulic gradients and the hydrogeological conditions in the zone, such as heterogeneity and anisotropy of the geologic materials. It is known that leakage pathways in the subsurface can be quite complex and irregular as a result of subsurface heterogeneities. For example, Jordan and Benson (2008) found that steam well blowouts can occur up to 200 m (600 ft) from the source well, presumably resulting from the steam fracturing through the subsurface from the well at some depth. It is not known how the extent of this horizontal spatial distribution shrinks at flow rates progressively less than blowout flow rates.

The above discussion, summarized as follows, illustrates the potential difficulty in developing appropriate groundwater monitoring plans that strike a balance between leakage detectability and the resources needed for multiple monitoring wells. The highest likelihood of detection is for the largest leaks, such as acute flow rates during well blowouts, which appear to occur in the San Joaquin Basin with a frequency of less than 1 per 15,000 hydraulic fracturing operations. Small leaks resulting from chronic flow along wells is considered more likely based on studies conducted elsewhere; however, these studies were mostly done for gas leakage and not for non-buoyant fluids. Groundwater contamination due to leakage of stimulation fluids or reservoir brines caused by hydraulic fracturing operations has rarely been reported. If leakage occurred, on the other hand, the leakage rates may be too low to be detected even with well-designed groundwater monitoring plans. It would be useful to conduct a study on leakage detectability like that reported by Carroll et al. (2014) to better inform the design of groundwater monitoring plans, so that they are as effective as possible. In addition, improved monitoring design could be achieved via dedicated field study areas where monitoring and data collection can be much more intense and ubiquitous than is possible in general industry operations. The field study areas would be monitored with more-than-usual resolution and frequency, which allows for testing of monitoring practices and provides for lessons learned in terms of what is useful or not.

It should be noted that the studies on chronic well leakage cited above are all from regions outside of California (e.g., Texas, Alberta, Pennsylvania); comparable studies have not been conducted in California. It is unknown if the well failure rates from elsewhere in the country provide reasonable approximations for the San Joaquin Basin. Such rates depend on factors like the regulations at the time of well construction, the degree to which those regulations were followed, the type of well (such as vertical versus horizontal), and the age of the well. For instance, land subsidence related to groundwater extraction and oil production in California might be more pronounced than where the studies have been conducted elsewhere, possibly resulting in a higher chronic leakage well leakage frequency in California. It is also possible the greater seismic activity in California and use of steam injection in pools overlying stimulated pools could also affect the chronic well leakage frequency. Thus, bounding this frequency in the state requires a California-specific study. It is important that further studies are conducted to assess the integrity of legacy wells and their susceptibility for chronic leakage.

5.4.4.2.2. Offset Well Leakage

Somewhat similar to leakage of stimulation fluid via wells that are themselves hydraulically fractured, leakage could also occur via an existing well, known as an offset well, that is intersected by a hydraulic fracture generated from a neighboring well. This intersection could result in leakage of fluids from the fracture via the well if the offset well is transmissive, or becomes transmissive as a result of the hydraulic fracture intersection. The hydraulic fracturing operations in the San Joaquin Basin are largely located in reservoirs with high well density that have been in production for a long time. For instance, the well density maps in Volume II, Chapter 5, indicate the average spacing between wells in the most of the North and South Belridge, and Lost Hills fields is about 100 m (330 ft) or less, and in the Elk Hills field is about 250 m (820 ft) or less. Thus, there may be many older offset wells in the vicinity of hydraulic fracturing operations, and these wells may not always be designed for, or have the integrity to withstand, the high pressures used in hydraulic fracturing. It is important in such conditions to assess the integrity and leakage risk of existing wells that might be encountered by a hydraulic fracture, and to remediate wells with a higher risk of leakage.

Jordan and Benson (2008) found that no blowouts occurred from offset wells during the minimum estimated 15,000 hydraulic fracturing operations conducted during the study period. Wright et al. (1997) stated that there were no offset wells intersected by hydraulic fractures observed prior to infilling with wells on a 1/4 hectare (5/8 acre) pattern in the South Belridge field. After about three years of infilling with 4 to 5 wells a week, 16 such intersections had been observed. This is a frequency of about one intersection per 50 hydraulically fractured wells. Applying this rate to the minimum number of estimated hydraulic fracturing operations during the study period considered by Jordan and Benson (2008) suggests that up to 300 offset wells were intersected by hydraulic fractures during this period. Jordan and Benson (2008) did not find any blowouts from such offset wells—this implies that the blowout frequency from offset wells intersected by a hydraulic fracture is certainly less than 1 per 300. Jordan and Benson (2008) found that the steam blowout rate from shut-in and abandoned wells was on the order of 1 per 100,000 well years, suggesting that the blowout rate from offset wells intersected by a hydraulic fracture is much less than 1 per 300.

5.4.4.2.3. Leakage Via Wells to Groundwater with 3,000 to 10,000 mg/L TDS

Per regulations, wells are constructed in the United States with surface casings extending beyond the base of groundwater aquifers that need to be protected. The annulus between the casing and the well-bore surface is filled with cement prior to deeper drilling. This increases protection of the groundwater by assuring there is a cement seal isolating it from fluids deeper in the boring, such as oil, and providing an additional layer of casing isolating it from fluids in the well.

In California, DOGGR's groundwater protection program has been oriented to fresh groundwater, defined as having TDS of 3,000 mg/L or less (Walker, 2011). However, another classification of groundwater that is typically found deeper than fresh groundwater, called underground sources of drinking water (USDWs), has not received the same regulatory protection in California as elsewhere in the country. This leads to increased risk of contamination of USDWs compared with fresh groundwater as defined by DOGGR. As mentioned before, USDWs are defined by the U.S. Environmental Protection Agency, with some exceptions, as groundwater having TDS of 10,000 mg/L or less. Consequently, wells in California have not been constructed to be protective of groundwater that is of USDW quality but above the 3,000 mg/L TDS limit. In other words, surface casings have been set and cemented below the 3,000 mg/L TDS limit rather than below the 10,000 mg/L TDS limit, which may create a leakage hazard.

As an example, the field rules for the Lost Hills field diatomite (Etchegoin) pool indicate there is no low-salinity ("fresh") groundwater (DOGGR, 2007b). The surface casing is only required to extend to 10% of the total well depth, which is only about 30 m (100 ft) given the 300 m (1,000 ft) depth of the pool (DOGGR, 1998). As mentioned above, a groundwater monitoring plan has been required for hydraulic fracturing in this pool under the new requirements imposed by California Senate Bill 4 (SB 4). This indicates a USDW with between 3,000 and 10,000 mg/L TDS is considered to be present. The field rules for this pool require cementing all casing, including the production casing, to the surface. The field rules for the deeper Cahn pool require cementing 150 m (500 ft) above all oil, gas, and anomalous pressure zones (DOGGR, 2007a). So the likelihood of a hydraulic fracture encountering an open annulus in an offset well is low. However, these wells do not have the additional layer of surface casing and cement protecting typically required to protect all USDW. The lack of this layer suggests the chronic leakage volume frequency to USDW may be higher than the 5% of wells discussed in the previous section, because there are fewer barriers in some wells between the fractured interval and the USDW.

The risk of leakage via wells to groundwater above the 3,000 mg/L TDS limit can be decreased in the future via a number of actions. Future wells should be constructed with casings extending through USDWs. This may require the addition of an intermediate casing, depending upon the depth separation between the base of groundwater with less than 3,000 mg/L TDS and groundwater with less than 10,000 mg/L TDS. Past wells within the search area around a stimulated well should be reviewed to determine if they are protective of USDWs. This determination likely requires research regarding the permeability distribution along wells from fractured pools to USDWs. One approach would be to install monitoring wells screened near the base of USDWs near offset wells known to have been encountered by hydraulic fractures. Another would be to hydraulically test well cement via ports cored through production casings to determine well seal permeability, such as just prior to well abandonment.

5.4.4.3. Leakage via Faults

The San Joaquin Basin has abundant faults, which present potential paths for leakage out of hydraulically fractured pools. The probability of leakage via faults has two components: first, the probability that a hydraulic fracture will encounter a fault; second, the probability that fluids can migrate via the fault from the hydraulic fracture to a USDW. Most faults in the oil reservoirs do not act as permeable conduits; they are sealing and often function as hydrocarbon traps.

The probability of a hydraulic fracture intersecting a fault can be roughly estimated from an assessment of fault density and typical hydraulic fracture geometry (Jordan et al., 2012). Figure 5.4-8 shows the fault density measured for a portion of the eastern San Joaquin Basin from Jordan et al. (2012). Fault density is typically found to be a power function of throw truncation. This is the density of faults with a vertical displacement across the fault greater than a particular value. Structure maps of some of the oil fields in the eastern portion of the San Joaquin Basin provided the data from which the correlation in Figure 5.4-8 was developed. Fault throw in turn has been demonstrated to correlate with fault height. These correlations are used below to explore the relationship between fault density, fault size, and the likelihood of hydraulic fractures encountering faults in the western portion of the San Joaquin Basin, where most of the hydraulic fracturing operations take place.

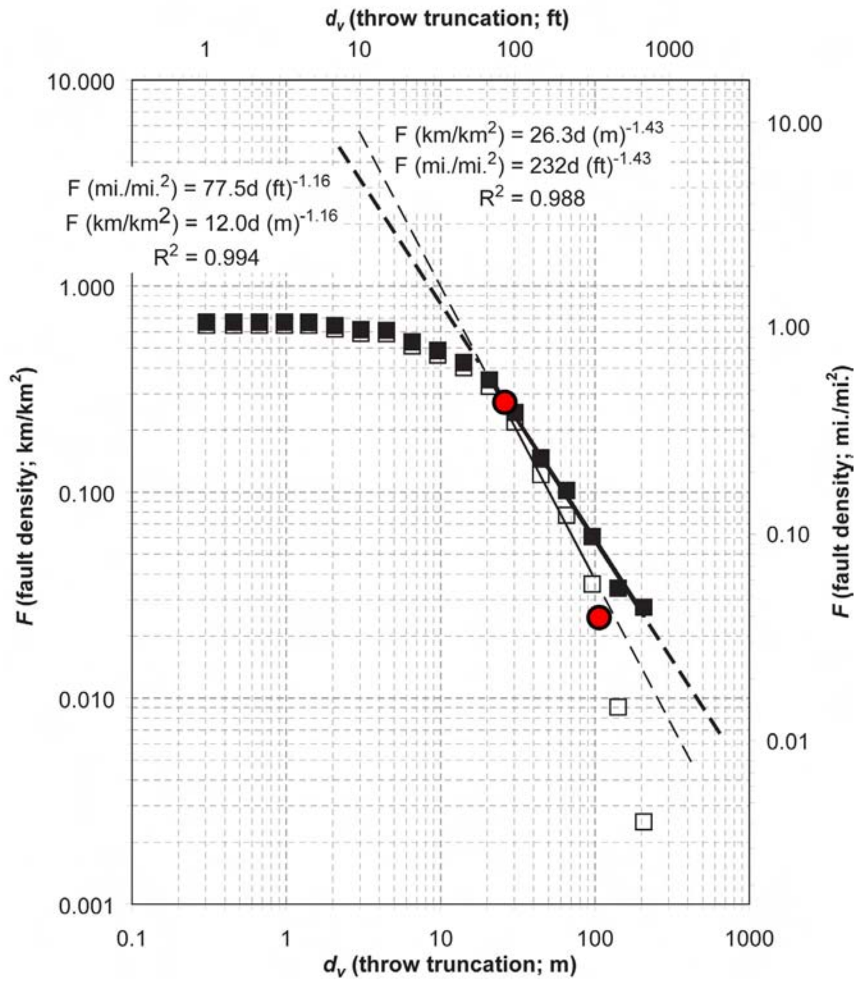


Figure 5.4-8. The red dots are fault densities measured by this study from structure maps for the four fields in the western San Joaquin Basin where 85% of the hydraulic fracturing in the state occurs: North and South Belridge, and Lost and Elk Hills (DOGGR, 1998).These match the underlying raw data from a portion of the eastern San Joaquin Basin, indicating the heavy line is the best estimate of the density of faults with throw (vertical displacement) greater than the throw truncation value (Jordan et al., 2012). The heavy line adjusts the raw data for censoring caused by map edges (Pickering et al. 1995).

Because nearly 90% of the hydraulic fracturing in the San Joaquin Basin occurs in four fields in the western Basin (North and South Belridge, and Lost and Elk Hills), the fault density analysis conducted for the eastern Basin (Jordan et al., 2012) needed to be extended to the western Basin. The length of faults in these four western fields was measured from the structure maps in DOGGR (1998), the area covered by each map was measured, and the fault length was divided by the map area to arrive at the fault density.

The resulting fault densities measured for these fields are plotted as two points on Figure 5.4-8. In the earlier study, Jordan et al. (2012) found that all faults with a throw (vertical displacement) greater than two thirds of the structure map contour interval typically are mapped. So the measured fault densities are plotted at these values. The red point shown on Figure 5.4-8 with a throw truncation of about 100 m (330 feet) is from the Elk Hills field alone, because it had a much larger structure contour interval than the maps for the other fields. The red point shown on Figure 5.4-8 at a throw truncation of about 25 m (80 ft) is from the other three fields combined, their maps having similar structure contour intervals.

The fault densities measured for the western San Joaquin Basin fields lie on the raw data trend from the eastern Basin. Consequently, the heavy line in Figure 5.4-8 (which was developed from the raw data in the eastern San Joaquin Basin) is also considered a good estimate of the fault density in the portion of the western Basin where the fields are located. Fault height worldwide averages about 100 times the maximum displacement on a fault. This ratio ranges from 20 to 1,000 (Cowie and Scholz, 1992). Thus, faults with 4 m (13 ft) of throw encountered by hydraulic fractures are likely to extend at least 200 m (660 ft) vertically above the point of encounter (ignoring possible mechanical heterogeneity and the absence of some overlying strata at the time of fault movement). At the shallow depths where most hydraulic fracturing is conducted, a fault of this height is likely to intersect a USDW.

From Figure 5.4-8, the density of faults with at least 4 m (13 ft) of throw is 2 km/km^2 (3 mi/mi^2). The probability of a hydraulic fracture with an average length of 30 m (100 ft; Volume II, Chapter 2) encountering a fault with at least this much throw is 6% (presuming the fracture is perpendicular to the fault). However, operators are likely to make an effort to avoid having hydraulic fractures encounter faults where they are known to exist. Presuming operators are able to map all faults where they have at least 10 m (30 ft) of throw, the probability of a hydraulic fracture encountering faults with at least 10 m (30 ft) of throw should be subtracted. From Figure 5.4-8, the density of these faults is 0.8 km/km^2 (1 mi./mi^2), which gives an encounter probability of 2.4%. Subtracting this from the previous probability gives a 3.6% probability of a hydraulic fracture encountering an unknown fault with sufficient extent to encounter a USDW. With over 1,500 wells hydraulically fractured each year in the western San Joaquin Basin, it is possible that tens of hydraulic fractures encounter such a fault each year.

How far stimulation fluids may propagate along such a fault once it is encountered is unknown. As mentioned above, faults in oil pools generally do not provide a pathway for fluids to migrate upward; otherwise the oil would have leaked out of the pool due to its buoyancy. However, the hydraulic fracturing process itself could cause the fault to open (Rutqvist et al., 2013). In addition, there is the possibility that once stimulation fluid starts opening a fault, it might cause slip beyond the stimulation fluid extent, which can increase fault permeability and provide a pathway for the stimulation fluid to migrate further. This could also provide a pathway for migration of gases after cessation of fracturing that would not otherwise exist. More research is needed to better understand fault permeabilities and how they might be affected by high fluid pressure if intersected by a hydraulic fracture. Given these uncertainties, it is important to ensure that site characterization efforts are designed to ensure a reasonable chance of detecting existing faults of a given size before a hydraulic fracturing operation is conducted.

5.5. Potential Risk to Air

Air emissions in the San Joaquin Basin were discussed in Volume II, Chapter 3, of this report. In that volume, emissions of criteria air pollutants, toxic air contaminants (TACs), and greenhouse gases were discussed. All emissions were assessed statewide, and the pollutant emissions were also assessed by air district. Emissions can be even more localized, resulting in more localized impacts. This section assesses emissions in Kern County, the western portion of which has the vast majority of the population and emissions in the county and is part of the San Joaquin Valley Air Pollution Control District. Because most of the oil and gas production in the San Joaquin Valley is in Kern County rather than spread out more uniformly across the air district, assessing emissions at the county level allows more detailed understanding of emissions from oil and gas production in the local context. The next section, which concerns potential risk to human health (Section 5.6), regards emissions at the scale of a single well, which is relevant to single households, facilities, and neighborhoods.

5.5.1. Air Pollutants

This analysis takes a more detailed look at the pools where most to all wells within the San Joaquin Basin are hydraulically fractured, aligning datasets from DOGGR with California Air Resources Board (CARB) air-pollution inventories. Because DOGGR regional jurisdictions do not align with CARB air districts, the analysis was performed using counties as the regions of interest. For this reason, only emissions in Kern County were considered, since 71% of all statewide production and most of the production in the San Joaquin Basin occurred there.

Total criteria air pollutants in the San Joaquin region are shown in Table 5.5-1. TAC emissions for four indicator TACs that are released by oil and gas operations are shown in Table 5.5-2.

Table 5.5-1. Anthropogenic emissions of criteria air pollutants and reactive organic gases in Kern County (San Joaquin Basin), 2012.

Pollutant	Metric tonnes/day	Tons/day
Reactive organic gases (ROG)	82.4	90.6
Nitrogen oxides (NO_x)	98.0	107.8
Sulfur oxides (SO_x)	4.8	5.3
PM_{10}	53.8	59.2
$PM_{2.5}$	17.8	19.6

Table 5.5-2. Emissions of toxic air contaminants from all sources in Kern County (San Joaquin Basin), 2010. Data from California Toxics Inventory.

Species	Emissions (kg/y)	Emissions (lb/yr)
1,3-Butadiene	30,575	67,326
Acetaldehyde	2,802,503	6,171,112
Benzene	267,163	588,293
Carbonyl sulfide	0	0
Ethyl Benzene	70,974	156,285
Formaldehyde	486,080	1,070,348
Hexane	423,110	931,688
Hydrogen Sulfide	146,942	323,566
Toluene	550,514	1,212,232
Xylenes (mixed)	117,249	258,182

The portion of these emissions due to the portion of oil and gas production enabled by hydraulic fracturing in Kern County was estimated. A variety of sources in the criteria pollutants inventory and facility-level toxics database can be linked to the oil and gas industry. In order to estimate criteria pollutant emissions from the oil and gas sector in Kern County, emissions from the following sectors were summed (see Volume II, Chapter 3, for more detail):

1. Stationary sources > Petroleum production and marketing > Oil and gas production > All subsectors and sources

2. Stationary sources > Fuel combustion > Oil and gas production (combustion) > All subsectors and sources

3. Mobile sources > Other mobile sources > Off-road equipment > Oil drilling and workover

The oil and gas sector will also have some use of on-road light and heavy-duty trucks in non-drilling operations. These are not able to be differentiated using reported inventory results (on-road vehicles are classified by weight class rather than industry using them). Table 5.5-3 below shows the result of summing oil and gas sources in Kern County. As shown, oil and gas production emits a significant fraction of criteria pollutants in the San Joaquin region, especially reactive organic gases (ROG), which are involved in ground level ozone formation, and sulfur oxides (SO_x). This is because most of the oil production in the state occurs in Kern County, and there is a lack of other heavy industry in the area. These results differ from results presented in Volume II, Chapter 3 due to their being compiled for Kern County rather than San Joaquin Unified Air Pollution Control District. This was done because most of the oil and gas production in the San Joaquin Basin, and well stimulation in particular, is located in Kern County at the south end of the basin.

Table 5.5-3. Emissions of criteria air pollutants from oil and gas production in metric tonnes/day, and these emissions as a percent of total emissions in Kern County in 2012. ROG = reactive organic gases; NO_x = nitrogen oxides; SO_x = sulfur oxides; PM_{10} = particulates smaller than 10 microns; $PM_{2.5}$ = particulates smaller than 2.5 microns.

	ROG	NO_x	SO_x	PM_{10}	$PM_{2.5}$
Stationary oil and gas	22.5	1.80	0.96	1.48	1.48
Mobile oil and gas	0.02	0.17	0.00	0.01	0.01
Total anthropogenic	82.4	98.0	4.8	53.8	17.8
Percentage	27.3%	2.0%	19.8%	2.8%	8.3%

The contribution of oil and gas sources to TAC emissions was estimated by searching for facility-level emissions by Standard Industrial Classification (SIC) codes. Using the five SIC codes identified as comprising the upstream oil and gas sector (Volume II, Chapter 3), it is possible to compute the fraction of TAC emissions for select pollutants that are due to the oil and gas industries. Because total TAC emissions from all sources are only available from 2010, this table compares TAC emissions by oil and gas facility in 2010 to overall TACs reported in 2010. Table 5.5-4 below shows the oil and gas contribution to select TACs in the San Joaquin region. As shown on the table, oil and gas production is the dominant source of hydrogen sulfide (96%) and a major contributor to emissions of benzene (9%), formaldehyde (26%), hexane (11%), and xylene (14%).

Table 5.5-4. Emissions of toxic air contaminants from oil and gas production in kg/yr, and these emissions as a percent of total emissions in Kern County in 2010.

	Total: Stationary oil and gas	Total: All stationary	Total: All sources	Fraction stationary oil and gas
1,3-Butadiene	67	133	30,575	0.2%
Acetaldehyde	10,605	15,651	2,802,503	0.4%
Benzene	23,765	28,177	267,163	8.9%
Carbonyl sulfide	0	1	1	0.0%
Ethyl Benzene	2,266	6,280	70,974	3.2%
Formaldehyde	124,708	139,499	486,080	25.7%
Hexane	46,777	140,030	423,110	11.1%
Hydrogen Sulfide	141,662	143,565	146,942	96.4%
Toluene	17,173	54,679	550,514	3.1%
Xylenes (mixed)	16,832	42,475	117,249	14.4%

A comparison of Tables 5.5-3 and 5.5-5 indicates that criteria air-pollutant emissions from mobile sources involved in oil and gas production is accounted for, but TACs emissions are not. While stationary and mobile emissions sources in oil and gas operations can be separated for criteria pollutants, this is not the case for TACs inventories. TACs reporting for stationary sources is available in detailed databases that can be queried by economic sector. In contrast, TACs emissions from mobile sources are presented in aggregate form and are not able to be separated into oil and gas and other sources. Because most criteria pollutants from oil and gas sources come from stationary sources, it is likely that the majority of TACs from oil and gas sources are also counted in the stationary source inventory. For further discussion, see Volume II, Chapter 3.

The pools in Kern County where most or all of the wells are hydraulically fractured, as listed in Volume I, Appendix N, produced 23.2% of the oil in the county in 2013—and 30.0% of the wells starting production that year accessed those pools. These activity factors were used to scale the stationary source and mobile source emissions from the oil and gas sector as a whole to capture those emissions enabled or facilitated by well stimulation. All stationary source emissions (combustion and non-combustion) were scaled by the fraction of oil production from the hydraulic-fracturing-enabled pools, and mobile source off-road emissions were scaled by the fraction of wells commencing production in enabled pools. The results are shown in Tables 5.5-5 and 5.5-6. These results do not take into account differences in emissions from heavy oil production facilitated by steam injection, and lighter oil production enabled by hydraulic fracturing. The first involves production of more viscous oil with lower volatile hydrocarbon concentrations at higher temperatures compared to second, which involves production of less viscous oil with higher volatile hydrocarbon content at lower temperatures. Based on the differences in temperature and volatile content, it is not clear which would have the higher relative emissions.

Table 5.5-5. Percent of criteria air pollutant and reactive organic gases emissions from hydraulic fracturing enabled production in Kern County in 2012.

ROG	NO_x	SO_x	PM_{10}	$PM_{2.5}$
6.3%	0.5%	4.6%	0.6%	1.9%

Table 5.5-6. Toxic air contaminant emissions from hydraulic fracturing enabled production as a percent of total emissions in Kern County in 2010.

TAC species	Percentage Well Stimulation (WS)-related
1,3-Butadiene	0.1%
Acetaldehyde	0.1%
Benzene	2.1%
Carbonyl sulfide	0.0%
Ethyl Benzene	0.7%
Formaldehyde	6.0%
Hexane	2.6%
Hydrogen Sulfide	22.4%
Toluene	0.7%
Xylenes (mixed)	3.3%

Table 5.5-5 shows about a fifteenth of the ROG emissions in Kern County are from oil and gas production enabled by hydraulic fracturing. As mentioned, ROG is involved in the formation of ground-level ozone (as opposed to ozone in the troposphere). Due to regular high ozone concentrations, the portion of Kern County in the San Joaquin Valley is designated by the EPA as extremely out of compliance with the 8-hour ozone standards, meaning ozone concentrations regularly exceed health standards (U.S. Environmental Protection Agency (U.S. EPA), 2012). In this context, the portion of ROG emissions due to hydraulic-fracturing-enabled oil and gas production is substantial, although obviously not uniquely so compared to other sources.

Table 5.5-6 shows that a substantial percentage of some TAC species emissions in Kern County are caused by hydraulic-fracturing-enabled production, especially hydrogen sulfide. This is because oil and gas production as a whole is responsible for the majority of these emissions, as shown in Table 5.5-4. Consequently, measures that can reduce these emissions should be considered.

5.5.2. Greenhouse Pollutants

CARB also issues annual inventories of the greenhouse pollution emitted during oil production and transportation to a refinery on a field-by-field basis for the more productive fields. This does not include greenhouse pollution from refining the oil or combusting the final product.

The amount of pollution is expressed as units of carbon equivalent emissions per unit of energy produced, which is termed carbon intensity (CI). Figure 5.5-1 shows all the CIs available in the 2013 inventory versus the volume of oil produced 2013 from DOGGR's production database (CARB, 2014). Each symbol indicates whether the field had water flooding or steam injection, and whether it had a pool with hydraulic-fracturing-enabled production. If it did have such a pool, the shading of the symbol indicates the fraction of the field's production coming from such a pool (or pools), with darker shading indicating a higher fraction.

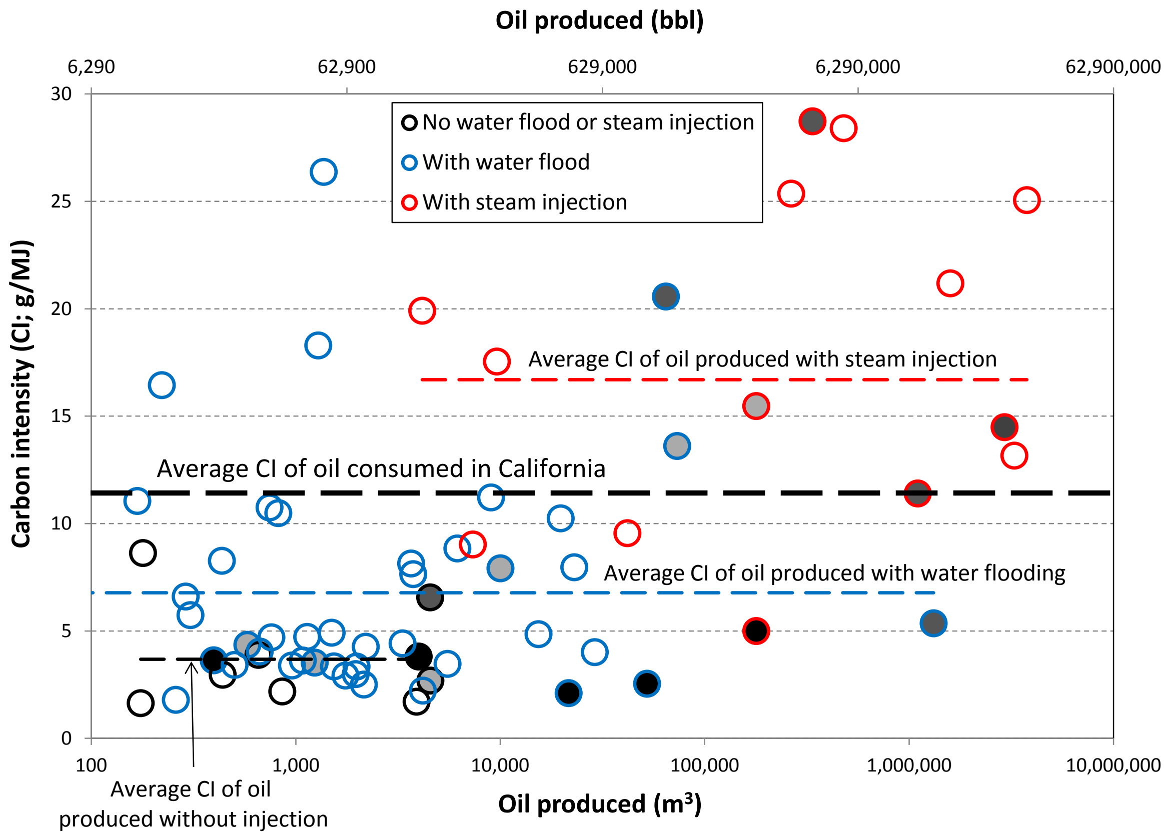


Figure 5.5-1. Greenhouse pollution, as carbon intensity (CI), from producing and transporting a unit of oil from California fields to a refinery (CARB, 2014) versus oil production in 2013 from DOGGR. Open symbols indicate no hydraulically fracture-enabled production. Black indicates more than two thirds of the production was enabled. Averages are weighted by production in each field.

Figure 5.5-1 indicates the CI of oil from fields with hydraulic-fracturing-enabled production is generally less than from fields without such production. The average CI for oil from fields with hydraulic-fracturing enabled production, but without water flooding or steam injection, are near the average CI for all fields without water flooding or steam injection. For fields with water flooding and steam injection, the greater the production fraction from predominantly hydraulically fractured pools, the lower the CI in general. Most of the fields with higher fractions of production from such pools have CIs below the average for all fields with either water flooding or steam injection. This is presumably because in those fields, stimulation requires additional effort to produce a unit of oil, whereas in fields with water or steam injection, stimulation reduces this effort.

CARB (2014) indicates the average CI of oil used in California is 11.39 g/MJ. Figure 5.5-1 indicates the average CI for oil produced in California using hydraulic fracturing is less than this value. This analysis indicates that if hydraulic fracturing were disallowed, the average greenhouse pollution per unit of oil consumed in California due to production and transportation could actually increase if well stimulation was stopped. If stimulation was stopped and consumption remained constant, more oil would be required from non-stimulated California fields or regions outside of California, greenhouse pollution due to oil consumption in California could increase.

5.6. Potential Risk to Public Health From Proximity to Oil Production

Many features, events, and processes associated with oil production can create risk to public health, such as air-pollutant emissions, water quality degradation, and light and noise pollution. This section focuses on the potential risk from air-pollutant emissions in the San Joaquin Basin. Other health risks are assessed in Volume II, Chapter 6.

The concentration of air contaminants is largest at the source emitting those contaminants. The concentration declines rapidly with distance from the source. Consequently, risk to public health due to air pollution from production wells is sensitive to a population's proximity to the well. Studies of the distribution of air pollutant concentrations around other point sources indicate that these typically decline to background at a distance of one to two km (0.6 to 1.2 mi.) from the source (references and further discussion are available in Volume II, Chapter 6).

The only air-pollutant emission data available is the aggregate total for all oil and gas production in a given area. Statistics for air-pollutant emissions from a single well in California are not available. In addition, most pollutants emitted during oil and gas production are not associated with well stimulation chemicals. Rather they are due to production of petroleum, whether or not that production is enabled by well stimulation (full discussion available in Chapter 4 of this volume). Exposure to these chemicals will be a function of the proximity of the population to any production well, although without statistics on the emission per well, the consequence of this exposure cannot be determined.

Below, the proximity of population to all production wells and the subset in proximity to hydraulically fractured wells is assessed, to emphasize the point that the health impact is only indirectly related to hydraulic fracturing. It is production in general aside from well stimulation that may cause an impact. These points, with supporting data and citations, are elaborated on in Appendix 4.B to Chapter 4 of this volume. The analysis calculates the size and character of the population, as well as sensitive receptor sites such as schools and senior care facilities, occurring within various distances of a production well. Details on the analysis approach are available in Appendix 4.B to Chapter 4 of this volume.

The extent of this analysis was limited to the CARB San Joaquin Valley Air Basin (SJVAB) without Merced, San Joaquin, and Stanislaus Counties, as shown in Figure 5.6-1 (CARB, 2009). Merced and Stanislaus Counties were removed because little to no oil and gas production occurs in them. San Joaquin County was removed because it actually resides outside of the San Joaquin geologic basin, and no well stimulations are reported to have occurred there.

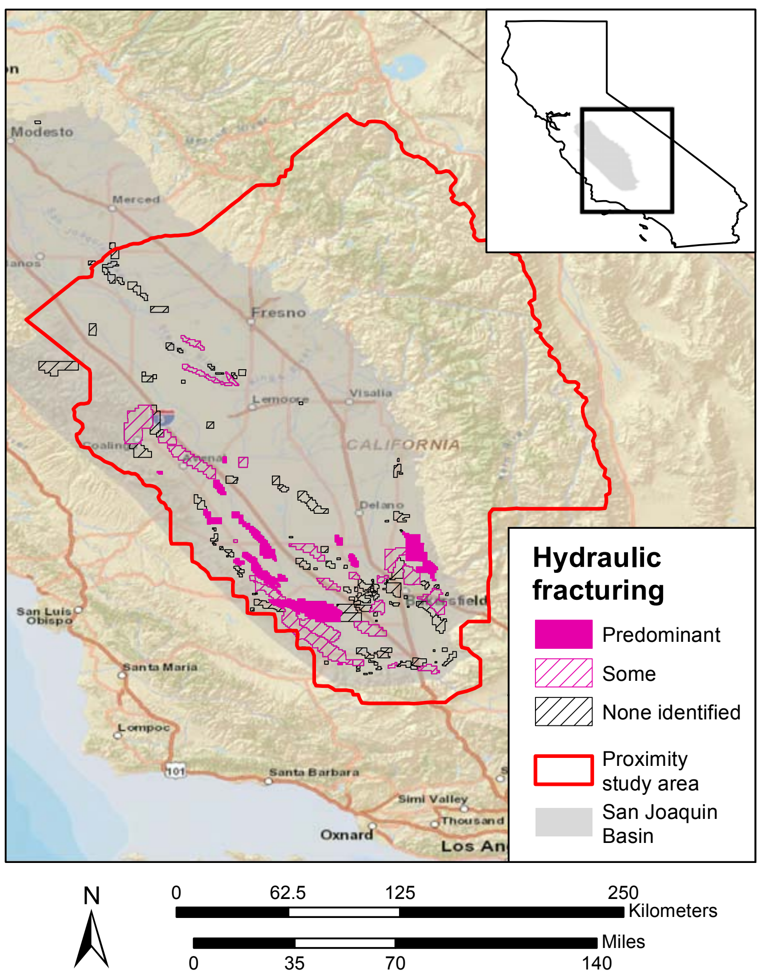


Figure 5.6-1. Study area for analysis of population and households in proximity to hydraulically fractured wells and all active wells.

Decennial census data was downloaded from American Fact Finder via Census.gov for the entire state of California at the census block and block group level (U.S. Census Bureau, 2012). The demographic data found in Summary File 1 for the 2010 census were used, including details collected from every household, such as “sex, age, race, Hispanic or Latino origin, household relationship, household type, household size, family type, family size, and group quarters.” Data on housing included occupancy status, vacancy status, and tenure (whether a housing unit is owner-occupied or renter-occupied; U.S. Census Bureau, 2012).”

In addition to demographic profiles, the spatial analysis included four types of facilities frequented or inhabited by more sensitive members of the population. The proximity of residential elderly care homes, schools, permitted daycare facilities, and playgrounds in the San Joaquin Basin were included to provide additional perspective on the population of elderly and children in proximity to stimulated wells.

The analysis used data regarding residential care homes from the California Health Care Facility Dataset (HLTHFAC, undated); a dataset of over 4,000 facilities in California. The dataset was limited to only residential elderly care facilities. Student enrollment demographics data was downloaded from the California Department of Education web site. The location of schools was downloaded from a California Department of Education Portal (California Department of Education, undated), cleaned, and the locations verified for elementary, secondary, and unified school districts. Then, 2013/2014 enrollment demographic data for each school were taken from the United States Census Bureau’s 2014 TIGER file (U.S. Census Bureau, 2014). Schools with no student enrollment were removed from the dataset. Quality control techniques identified enrollment demographics for schools that did not match the schools listed in the Geographic Information Systems (GIS) files, which were eliminated from the analysis. The location of licensed childcare, preschool, and day care facilities was extracted from a larger dataset of all childcare facilities, which also included child group homes (California Department of Social Services, undated).

The results of the proximity analysis of this data in the SJVAB are shown in Table 5.6-1. The proximity of facilities with sensitive populations (such as schools and elder care) and other demographics, including low education populations, unemployed populations, and low-income households, are listed in tables in Appendix 5.D.

Table 5.6-1. Total and percent of population, population by age, Hispanic, and Non-Hispanic minority in proximity to hydraulically fractured (HF) wells and all wells in the study area (based on the Census block level).

Proximity to a well (m; ft)	All active or HF wells?	Metric	Category population	Under 18 years of age	5 years of age and younger	Over 75 years of age	Minority (Non-Hispanic)	Hispanic
100 (330)	HF	Population.	76	20	6	4	14	20
		% of total pop..	<0.01%	<0.01%	<0.01%	<0.01%	<0.01%	<0.01%
	All	Population	3,640	985	341	214	953	1,499
		% of total pop..	0.15%	0.13%	0.14%	0.21%	0.10%	0.12%
		HF pop % of total pop.	2.1%	2.0%	1.8%	1.9%	1.5%	1.4%
400 (1,300)	HF	Population.	1,542	472	159	75	411	533
		% of total pop..	0.06%	0.06%	0.06%	0.07%	0.04%	0.04%
	All	Population	32,917	9,631	3,220	1,378	9,708	14,498
		% of total pop..	1.4%	1.3%	1.3%	1.4%	1.1%	1.1%
		HF pop % of total pop.	4.7%	4.9%	4.9%	5.4%	4.2%	3.7%
800 (2,600)	HF	Population.	9,908	2,984	1,011	413	3,194	3,819
		% of total pop..	0.42%	0.41%	0.40%	0.41%	0.35%	0.30%
	All	Population	101,103	29,906	10,128	3,952	31,815	44,896
		% of total pop..	4.2%	4.1%	4.1%	4.0%	3.5%	3.5%
		HF pop % of total pop.	9.8%	10%	10%	10%	10%	8.5%
1,600 (5,300)	HF	Population.	51,689	16,368	5,546	1,776	16,432	19,970
		% of total pop..	2.17%	2.24%	2.22%	1.78%	1.79%	1.56%
	All	Population	289,112	87,311	29,449	10,707	96,132	130,687
		% of total pop..	12.1%	12.0%	11.8%	10.7%	10.4%	10.2%
		HF pop % of total pop.	18%	19%	19%	17%	17%	15%
2,000 (6,600)	HF	Population.	81,153	26,017	8,877	2,415	27,227	32,846
		% of total pop..	3.4%	3.6%	3.5%	2.4%	3.0%	2.6%
	All	Population	381,665	116,772	39,693	14,055	129,723	175,000
		% of total pop..	16%	16%	16%	14%	14%	14%
		HF pop % of total pop.	21%	22%	22%	17%	21%	19%
		Total population	2,386,959	730,050	250,065	99,957	920,404	1,278,020

Table 5.6-1 and those in Appendix 5.D show that about 4% or less of the population in general, and subpopulations assessed (e.g., all households, household types, and daycare centers and schools), are estimated to reside within 2 km (1.2 mi.) of a hydraulically fractured well in the San Joaquin Basin. For these same groupings, 17% or less are estimated to reside within 2 km (1.2 mi.) of an active oil or gas well. Consequently, a bit less than about a fifth of the populations, households, and schools that are in proximity to an active oil and gas well are in proximity to a hydraulically fractured well. This is about the same as hydraulic-fracture-enabled production as a fraction of all production in the

San Joaquin Basin, and suggests to the extent air emissions due to hydraulic fracturing are small compared to all other emissions to install and produce a well, the majority of exposure in the Basin is not due to hydraulically fractured wells, but rather to other wells.

Table 5.6-1 and those in Appendix 5.D show that the percentage of almost every selected demographic and household group in proximity to both hydraulically fractured and all active wells is smaller than the percentage of the general population and households. In other words, people and households in proximity to a hydraulically fractured well and all active oil wells are on average more young adult to middle aged, better educated, and have higher incomes than populations away from these wells.

However, because the density of hydraulically fractured wells is typically high where they do occur, people and households that are in proximity are likely in proximity to a large number of such wells. This is shown for the town of Shafter in Figure 5.6-2. Consequently, the threshold of emissions for any single well to have an acceptable impact is smaller than the threshold for a well among a grouping of wells. For instance, in the Shafter area the threshold for a well among the group would be about one hundredth of the threshold for a single well, based on a proximity of 1.6 km.

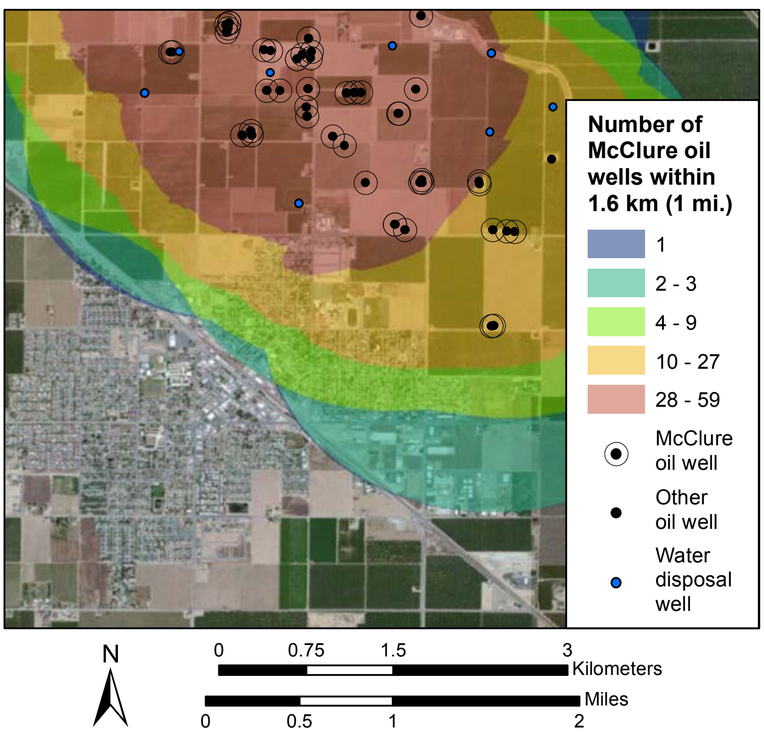


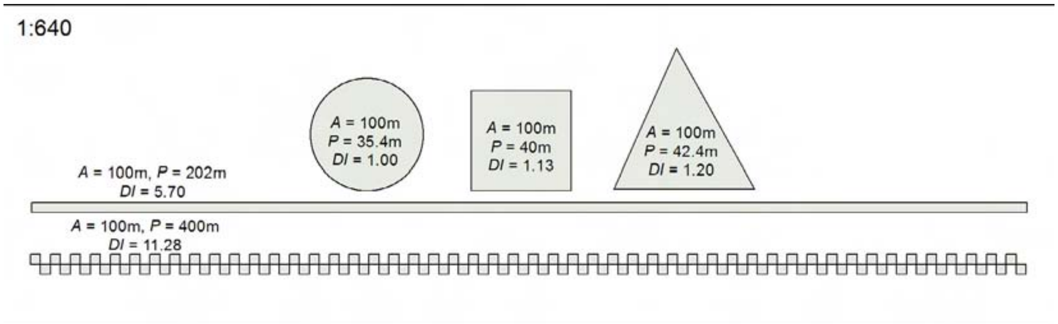
Figure 5.6-2. Number of oil wells in the McClure pool in proximity to a location in the town of Shafter. Oil wells in this pool are generally hydraulically fractured. Other wells in this area are generally not hydraulically fractured. The well type during 2014 is shown.

5.7 Potential Risk to Wildlife and Vegetation From Habitat

While habitat loss, as discussed in Volume II, Chapter 5, denotes a decrease in the total area of suitable habitat, fragmentation is a change in configuration of that habitat. The two are related, but fragmentation has distinct aspects: an increase in the proportion of perimeter to interior, and the change from one large to many small areas, as shown on Figure 5.7-1. An increase in the ratio of perimeter to interior results in increased exposure to disturbance at the fringe of the habitat, commonly referred to as "edge effects." A change from one large to many small areas of habitat, also referred to as loss of connectivity or corridors, splits populations of an organism from one large population into many smaller subpopulations. It is important to maintain connectivity between subpopulations to prevent inbreeding and enable recolonization after local extinctions (Pimm and Gilpin, 1989). These two aspects of fragmentation are referred to simply as edge effects and loss of connectivity in the following discussion.

Most of the hydraulic-fracturing-enabled production in the San Joaquin Basin takes place against a backdrop of rangeland habitat, mostly saltbush scrub and non-native grasslands (Volume II, Chapter 5). Almost 90% of the hydraulic fracturing reported in the state is concentrated in six fields clustered in the southwestern portion of the valley: North and South Belridge, Lost Hills, Elk Hills, Midway-Sunset, and Buena Vista fields (Volume I, Chapter 3, Table 3-1). The southwestern San Joaquin also happens to be one of the largest locales of remaining saltbush scrub habitat in the state and is a high regional priority for conservation (Volume II, Chapter 5).

Many populations of native species in the San Joaquin Valley are endangered because of habitat loss and fragmentation (Kelly et al., 2005; Kucera et al., 1995). While the main drivers of habitat loss in the valley as a whole are agriculture and urbanization, in the southwestern portion, a large proportion of land is occupied by oil fields (see Volume II, Chapter 5's section on "Kern County: Ecology, Oil and Gas Development, and Well Stimulation"). Maintaining linkages between small, fragmented populations is important for survival of native species, such as the San Joaquin Kit Fox (Cypher et al., 2007; Harrison et al., 2011).



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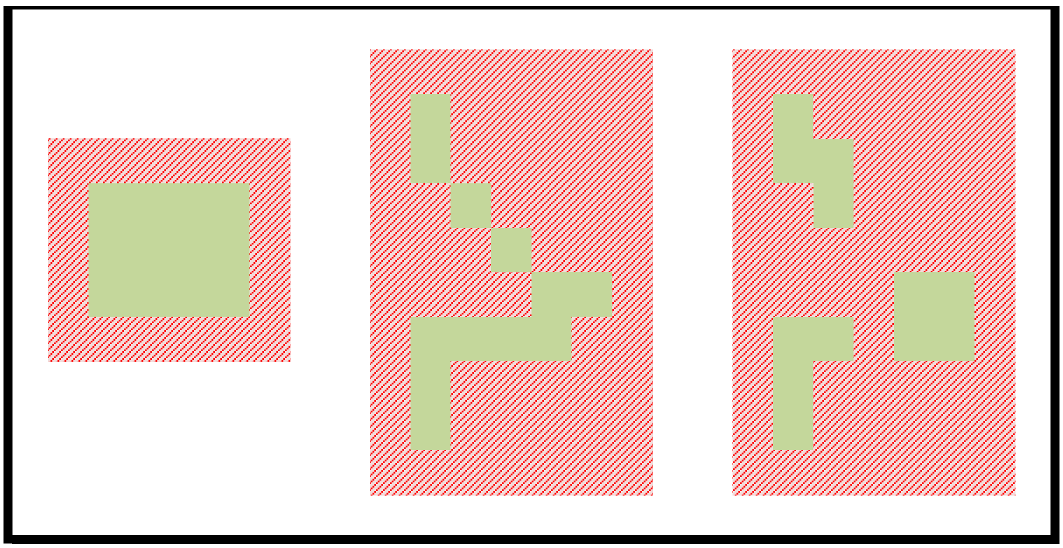

b)

Figure 5.7-1. Fragmentation. a) Edge effects: a comparison of five shapes with low to high edge effects. The shapes have the same area but different configurations, progressing from the shape with the lowest ratio of perimeter to area (the circle) to a shape with a very high ratio of perimeter to area (a string of many small squares). The DI metric increases as the ratio of perimeter to area increases. b) Loss of connectivity: a comparison of connected and disconnected areas. Green represents suitable habitat and red hatching represents unsuitable habitat. The portion marked in green is the same total area in all three, but progressing from greatest connectivity on the left (one continuous block), through reduced connectivity (minimal connection points between habitat), to loss of connectivity (three isolated patches with no corridors).

5.7.2. Fragmentation Analysis Methodology

Two approaches were taken to assess fragmentation in the San Joaquin Valley. First, a metric for edge effects called the Diversity Index (DI) was used (Patton, 1975). As illustrated in Figure 5.7-1a, an area with a higher DI is more fragmented. Details on the calculation of DI are provided in Appendix 5.E.

DI was calculated for six fields: North Belridge, South Belridge, Mount Poso, Elk Hills, Midway-Sunset, and Buena Vista. It was calculated from three categories of land use: barren/highly disturbed oil field, other developed (urban or agriculture), and vegetated. The vegetated areas are habitat (nearly all non-native grasslands and Valley saltbush scrub). The DI was calculated for the perimeter of the vegetated area, which includes the edges between vegetated area and the two other land-use categories, as well as the perimeter of the field. Data was acquired from the Geographical Information Center (2014).

Second, corridors in the southwestern San Joaquin Valley were identified, and whether they could be lost due to expanding oil and gas development was assessed. Four criteria were used to identify a viable corridor. First, a corridor needed to have a well density no greater than 77 wells per square kilometer, based on studies showing that most native organisms do not use areas at higher well densities[5] (Fiehler and Cypher, 2011). Second, corridors needed to be more than 2 (1 mi.) wide to be viable, based on expert opinion (Garcia and Associates, 2006). Corridors needed to connect areas of shrubland/grassland (as opposed to urban or agricultural areas). Finally, while areas that are extremely wide do allow migration, they are not “corridors” in the sense that they are not relatively narrow pathways connecting patches of habitat. Our fourth criteria for identifying an area as a corridor was that it be less than 3 km (2 mi.) wide, in order to identify relatively narrow pathways that could be eliminated by relatively small geographic expansions or intensifications of oil development.

5.7.2. Fragmentation Analysis Results

The six fields assessed had different degrees of fragmentation. Elk Hills had the highest DI, followed by Midway-Sunset, then Mount Poso, Buena Vista, South Belridge and North Belridge, as shown in Table 5.7-1. Figure 5.7-2 shows the land use types and fragmentation in each field. Note that DI is calculated based on the length of contact between vegetation and developed areas, including oil and gas, urban, and agriculture areas. Only a portion of the oil and gas development can be attributed to hydraulic-fracturing-enabled production (column A/B).

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5. Well density is highly predictive of habitat disturbance from all infrastructure in an area. See Volume II, Chapter 5, Appendix 5.C for details.

Table 5.7-1. Edge effects in six southern San Joaquin Basin oil fields, ranked from greatest to least DI. Note that DI is calculated based on the length of contact between vegetation and developed areas, including oil and gas, urban and agriculture areas. Only a proportion of the oil and gas development can be attributed to hydraulic fracturing-enabled production (column A/B).

	A	B	A/B			
Field	**Hydraulic Fracturing-Enabled Alteration to Habitat (km^2)**	**All Oil & Gas Alteration to Habitat (km^2)**	**Proportion of Alteration to Habitat Due to Hydraulic Fracturing (%)**	**Vegetated Area (km^2)**	**Vegetated Perimeter (km)**	**DI**
Elk Hills	53	146	36%	160	1836	40.88
Midway - Sunset	7	181	4%	201	1595	31.75
Mount Poso	18	48	37%	112	506	13.51
Buena Vista	10	90	11%	112	506	13.51
Belridge, South	5	46	10%	27	172	9.41
Belridge, North	4	15	30%	18	107	7.08

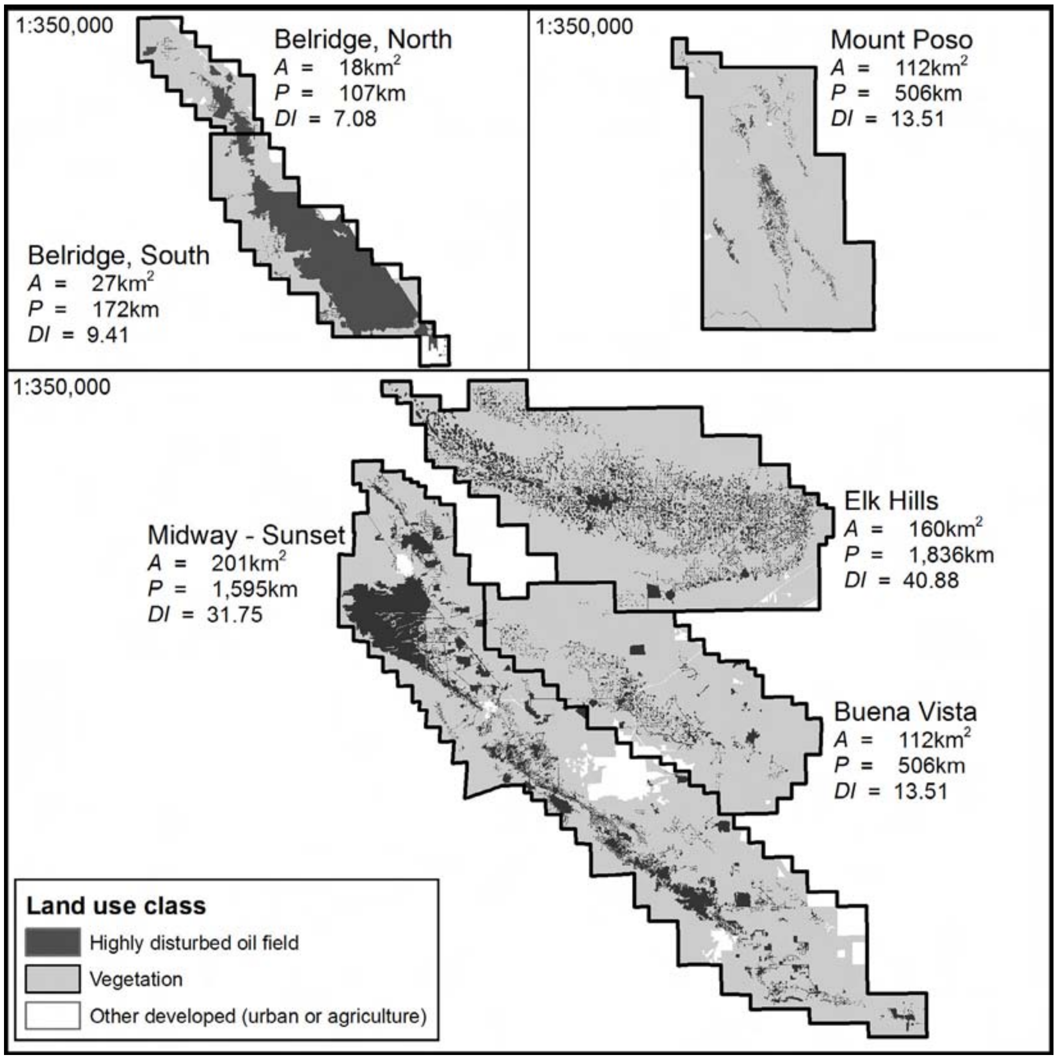

Figure 5.7-2. Land use categories and fragmentation in six oil fields in the San Joaquin Basin with the greatest number of hydraulic fractures.

Different patterns of development have very different impacts on habitat loss and fragmentation; for example, while North and South Belridge have a much smaller amount of vegetated area remaining than Elk Hills, that area is much less fragmented, because development in the Belridge fields is highly clustered. It is also worth noting that while North and South Belridge have much higher numbers of reported hydraulic fractures than Elk Hills, the newly drilled and stimulated wells in the Belridge fields are generally located in areas that have already been intensively developed. It is also important to note that the analysis of fragmentation did not attempt to parse out the impact of hydraulic-fracturing-enabled development. Column “A/B” in Table 5.7-1 gives the proportion of habitat altered due to hydraulic-fracturing-enabled development compared to all oil and gas development in each field. Only a portion of the fragmentation of habitat by oil and gas production can be attributed to development enabled by hydraulic fracturing. In some fields in particular, such as Midway-Sunset, this portion is likely quite small, although the exact contribution to fragmentation will depend on the location of the altered habitat.

The ratio of edge to interior habitat can be minimized by clustering facilities as much as possible: for example, building a network of main roads, pipelines, and powerlines rather than many small ones; using centralized staging and storage equipment; and placing multiple directionally drilled wells on one well pad rather than placing individual vertical wells on each well pad (Getches-Wilkinson Center for Natural Resources, Energy, and the Environment, 2015).

Eight locations were identified in the southwest San Joaquin Basin that met the definition of a corridor. These are shown in Figure 5.7-3. These connected the relatively small islands of habitat that lie between the vast expanses of agricultural fields and the highly developed oil and gas areas with the open land to the south and west of the oil fields. These eight corridors lie between areas of high-density oil patches in the Midway Sunset field (3 corridors), McKittrick/Elk Hills field (2), Elk Hills (2), and South Belridge/Cymric (1). All of these fields except the McKittrick were identified as having pools where production is predominantly facilitated by hydraulic fracturing (Volume I Appendix N). These corridors are high-value areas that should be targets for conservation and implementation of best management practices, habitat thresholds, and/or regulated mitigation measures that maintain sustainable populations of rare species within the oil field landscape.

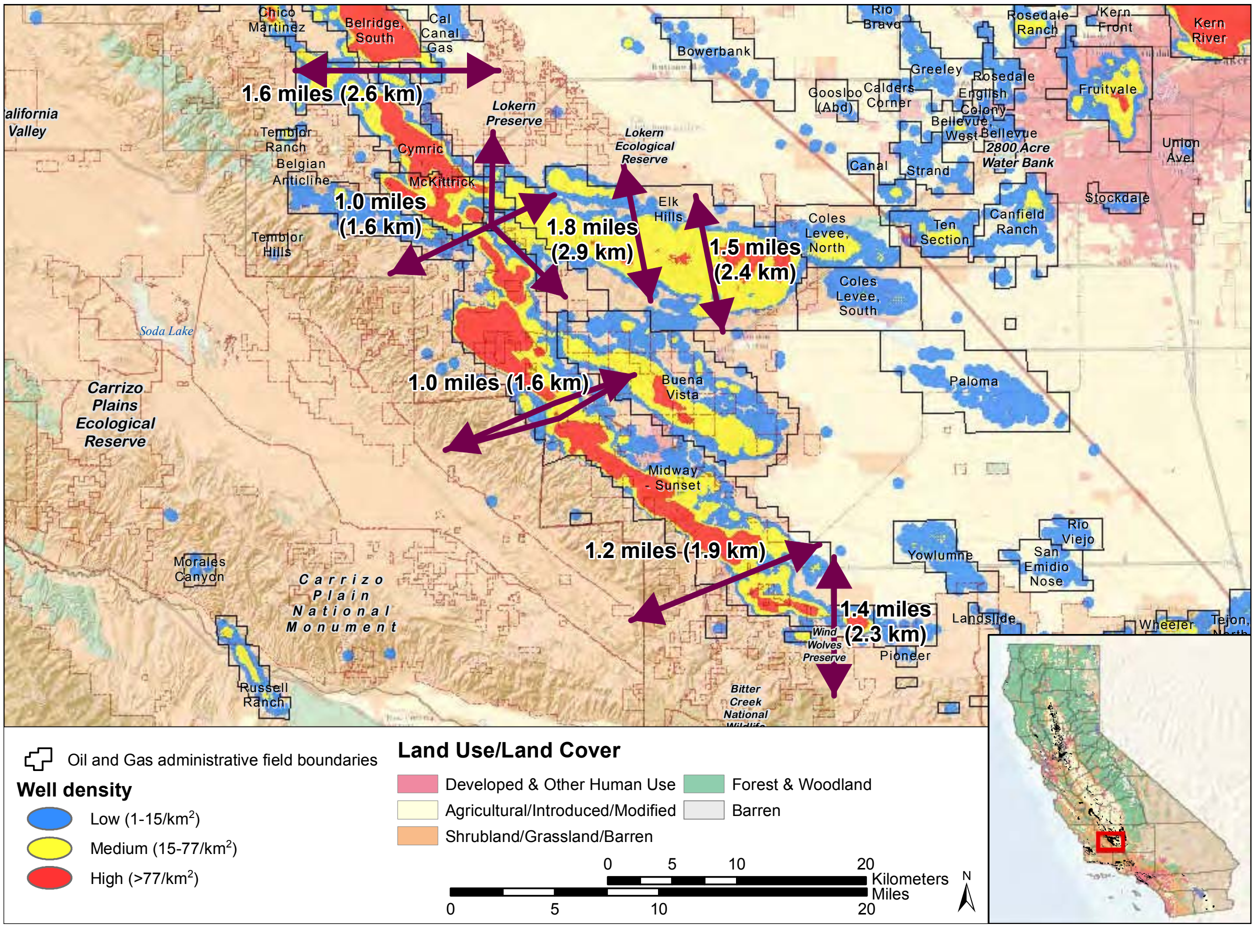

Figure 5.7-3. Corridors between high-density oil developments in the southwestern San Joaquin Valley.

From the standpoint of habitat conservation, how much new development is enabled by well stimulation is less important than where that new development occurs. Well stimulation in California has enabled production from pools that were formerly uneconomical to produce (Volume I, Chapter 3). In some cases, these pools underlie regions at the surface that have already been intensively developed for human use—either for oil and gas production tapping into other pools, or for agriculture or cites. If well stimulation spurs development of pools that underlie habitat, it results in loss and fragmentation of that habitat. When well stimulation enables new development in pools that underlie already developed areas, the marginal impact to habitat loss and fragmentation is much smaller. It is possible that the co-occurring unstimulated pools could cease production before the stimulated ones, in which case stimulation could extend the duration of an impact to the field. However, in the limited number of studies of long-term habitat impacts after a well is abandoned, the habitat did not reconverge to pre-disturbance quality within the timeframe of the studies (on the scale of a few to approximately ten years after a well was abandoned) (Hinshaw et al., 1998). This suggests that while extending the duration of production at a site may have some ecological impacts, the major impact is in the initial development.

Oil and gas production as a whole has contributed to habitat fragmentation in California, although the proportion of fragmentation caused specifically by hydraulic-fracturing-enabled production is most likely fairly minor, in line with the proportion of habitat loss it has caused. However, in certain key areas, particularly the southwestern San Joaquin Basin, hydraulic-fracturing–enabled production is an important contributor to fragmentation in an ecologically sensitive area. In particular, there are only a few corridors connecting the islands of habitat remaining between farmland and oil fields to each other and the habitat to the south and west of the oil fields. These relatively small areas are vulnerable to expanded production, given that most native species do not generally use high-density oil fields. Fragmentation from future development can be minimized by focusing on infill areas, and minimizing new development in corridors can reduce the impacts of fragmentation resulting from future oil and gas development.

5.8. Data Gaps

Many of the sections above have identified data gaps regarding each assessment, which are summarized below together with recommendations for assessing and collecting additional data.

- The disposal method for water produced from the fields with the most hydraulic fracturing is uncertain. Data submitted to the public database by at least some operators disagree with statements from them regarding how they dispose of water. In order to understand the historic disposition of these waters, an effort should be made to correct this data set. Aside from providing an accurate understanding of current practice, this is relevant to characterizing potential legacy contamination, discussed below in the conclusions. Going forward, adequate reporting procedures should be implemented with data quality assurance and control to increase data integrity.

- The concentration of well stimulation chemicals, their degradation products, and natural constituents mobilized by stimulation in produced water streams from central treatment plants is unknown. This is particularly a concern for produced water from pools with hydraulic fracturing operations that is disposed of in percolation pits or potentially injected into protected groundwater. The composition of produced water should be analyzed in order to characterize this possible source of contamination. Even if the recommendations above to phase out such disposal are implemented, this source characterization is needed to inform the recommended next step of investigating potential legacy contamination at and beneath percolation pits and around disposal wells injecting into groundwater that is determined to require protection.

- The statistical likelihood of shallow hydraulic fractures encountering protected groundwater resources is currently unknown, or at least not estimable from publicly available data. It may well be that operators have data sufficient to develop this understanding if it is released, perhaps in response to a regulatory request. If these data do not exist, cannot be released, or are insufficient, field research is recommended to develop these statistics. In addition, a theoretical basis should be developed for limiting the likely maximum size of shallow hydraulic fractures to support appropriate regulations to prevent intersecting protected water.

- The frequency of chronic well leakage in California is not known. This information is critical to estimating the frequency of fluid volumes leaking from wells. While information regarding this frequency exists for other parts of North America, the frequency in California could be different for a variety of reasons (such as sedimentary consolidation and ground settlement, use of thermal recovery methods, and seismic activity). If an understanding of the chronic well-leakage frequency in California cannot be developed from existing public data sources, this understanding should be developed through new field research, such as soil gas monitoring around statistical samples of existing wells, and testing of behind-casing well permeability as part of plugging orphaned wells.

- Data regarding the concentration of TACs and criteria pollutants in the vicinity of stimulated wells, and oil and gas wells in general in the San Joaquin Basin, appears to be lacking. Air quality data should be collected in the vicinity of such wells, particularly where communities are located in proximity to high well densities, given the high percentage of criteria pollutant emissions in the San Joaquin Basin by oil production.

- Assessments of greenhouse gas pollution from oil production, transportation, and refining from pools where most wells are hydraulically fractured versus pools developed using other technologies are not available. Consequently, understanding the amount of pollution from different production methods, with greatly varying greenhouse pollution profiles, is difficult. Assessments of greenhouse gas pollution should be conducted for individual pools, at least some that are representative of different production methods used in California, because production methods are more consistent across a pool than they are within a field consisting of multiple pools.

- Our understanding of key parameters for conservation in the southwestern San Joaquin Basin is limited. Key questions for further research are: what is the minimum width for a viable corridor? What level of human disturbance can the native species tolerate in a corridor, and in viable habitat? What is the minimum amount of area and degree of connectivity that must be maintained in order for native species to sustain their populations? How will continuing changes in the region—such as from oil field development, agriculture, urbanization, and climate change—affect native species? These are classic questions in conservation biology, but relatively little research has been done on these issues for the suite of species that inhabit the southwestern San Joaquin Basin.

5.9. Conclusions and Recommendations

The following summarizes the conclusions from each potential risk assessed in this case study. Recommendations to reduce some risks in the San Joaquin Basin are also included, along with some additional general recommendations.

Water Supply: In the San Joaquin Basin, high-quality water is used for hydraulic fracturing, and low-salinity supplied water is used for EOR in some fields, while produced low-salinity water is disposed of in other fields. There may be opportunities for switching from using supplied water to low-salinity produced water that is currently disposed of in the same or nearby fields. This could both reduce demand for supplied low-salinity and high-quality water and reduce subsurface disposal volumes, which in turn would reduce the induced-seismicity risk created by disposing of produced water by injection. It is currently unknown what barriers exist to using produced water for this purpose. They may be technical, such as a mismatch between the quality of the produced water and the water quality needed for hydraulic fracturing and EOR. It might be possible to address such a barrier, for instance with incentives to apply an appropriate treatment technology to improve the quality of the produced low-salinity water. The barriers may be legal, such as restrictions on operators cooperating on transfers of produced water between them within the same field or between different fields, or the liability associated with such transfers. These could potentially be addressed through legislation.

Disposal of Produced Water in Percolation Pits: Analysis of available data suggests the concentrations of hydraulic fracturing fluid constituents in produced water from fields with substantial hydraulic fracturing are sufficiently high that it should not be disposed of by percolation, because of the risk of groundwater contamination this creates.

Produced Water Used for Irrigation: Analysis of available data suggests occasional hydraulic fracturing in fields from which produced water is used for irrigation. While there are central treatment facilities for produced water, these may not be designed to remove or reduce stimulation-fluid constituents, their degradation products, and any natural constituents mobilized by stimulation or reduce the concentration of those constituents to acceptable levels. Thus, there is a possibility that hydraulic fracturing fluid constituents could be at concentrations of concern in the produced water stream from central treatment facilities, in particular shortly after a well is put on production after stimulation. In the absence of appropriate treatment systems and a determination of what are acceptable concentrations, which are unknown for many possible constituents, hydraulic fracturing should not be allowed in fields that supply produced water for use in the environment, such as irrigation. Alternatively, use of produced water for irrigation from fields with hydraulic fracturing should be prohibited.

Constituents Used for Stimulation: One means of reducing concerns about the release of stimulation constituents is to move to a constituent selection approach similar to that of the North Sea compact/OSPAR Convention. In California, a similar program could be built upon the U.S. Environmental Protection Agency's Designed for Environment program, which is voluntary at the national level (U.S. EPA, 2011). This would result in utilization of constituents with among the lowest potential environmental impacts, and would allay the current situation involving use of numerous chemicals without a complete environmental profile, which precludes a complete assessment of risk to the environment and human health. In the meantime, a risk assessment regarding those constituents for which OEHHA provided screening criteria in Volume II, Appendix 6.B should be carried out, ideally based upon measurements of constituent concentrations in produced water at the point of disposal. But if those are unlikely to be collected in the near term, it is advised to use the potential upper-bound concentrations derived in this report in the meantime.

Site Characterization: Site characterization is needed in order to assess the risk of leakage to groundwater via subsurface pathways. This includes characterizing the extent and quality of groundwater with less than 10,000 mg/L TDS, horizontal hydraulic gradients and flow directions in this zone, vertical gradients through the section from the reservoir to the ground surface, and hydrostratigraphy throughout the section in the vicinity of a hydraulic fracturing operation, as well as potential leakage paths (such as wells and faults). A particular focus for the San Joaquin Basin is determining the extent of and hydraulic head distribution within groundwater with less than 10,000 mg/L TDS, which has not historically been methodically determined and mapped. This information is necessary to designing monitoring for all protected groundwater.

Shallow Hydraulic Fracturing Operations: Most hydraulic fracturing in the San Joaquin Basin occurs in relatively shallow subsurface reservoirs, which increases the potential for created fractures encountering protect groundwater. Shallow fracturing should only be permitted if (1) there is a detailed prediction of the expected fracturing extent, (2) the separation distance between this extent and protected groundwater provides a sufficient safety margin given appropriate weighting of uncertainties, (3) operations are monitored to infer if the fracture has intersected or come near groundwater, (4) a corrective action plan is in place if this occurs, and (5) the groundwater monitoring plan includes appropriate adjustments to monitor groundwater in close proximity to any possible fracture extensions into or near groundwater.

Leakage Detection and Groundwater Monitoring: SB 4 now requires operators to implement appropriate monitoring near well stimulation operations. However, groundwater monitoring will not necessarily detect contamination should it occur, in particular if leakage frequencies are low and rates are small. It would be beneficial to conduct further studies on leakage detectability specific to the conditions in the San Joaquin Basin to assess the cost versus the benefit of different monitoring approaches, and to optimize monitoring strategies to adequately account for potential higher risk stimulations, such as hydraulic fracturing in close proximity to protected groundwater.

While similar studies have been conducted in other settings, the depth of stimulation in the San Joaquin Basin is one unique feature that warrants studies specific to the practice in the state. In addition, improved monitoring design could be achieved via dedicated field study areas where monitoring and data collection can be much more intense and ubiquitous than is possible in general industry operations. The field study areas would be monitored with more-than-usual resolution and frequency, which allows for testing of monitoring practices and provides for lessons learned in terms of what types of monitoring is useful.

Well Construction: Current well construction requirements in the San Joaquin Basin are not designed to protect groundwater with 3,000 to 10,000 mg/L TDS that is not otherwise exempt from protection. These requirements should be modified to protect this water, such as by requiring full-length cementing of casing into an aquitard below the base of the deepest water with <10,000 mg/L TDS. A statistical understanding of the existing wells relative to protecting this groundwater from potential migration of stimulation fluids should be developed, both through an assessment of available well construction records and field research in the vicinity of selected legacy wells of concern. Wells that do not have seals behind casing positioned to protect groundwater with less than 10,000 mg/L TDS should be remediated with cement squeeze operations.

Faults as Leakage Pathways: The San Joaquin Basin has a high density of faults, which present potential paths for leakage out of hydraulically fractured pools. The presence of oil generally suggests that faults intersecting oil reservoirs do not provide leakage paths. However, the likelihood of leakage of stimulation fluids or reservoir gases via faults opened during hydraulic fracturing is not known. This likelihood should be investigated further, perhaps in simulation assessments and/or dedicated field studies. In the meantime, it is important to ensure that site characterization efforts conducted will detect existing faults of a size sufficient to connect the reservoir to protected groundwater before a hydraulic fracturing operation is conducted.

Proximity Analysis: About 3 to 4% of the total population in the San Joaquin Basin lives within 2 km (1.2 mi.) of a hydraulically fractured well, and about 16% live within this distance from an active oil and gas production well. Consequently, about a fifth of people in proximity to an active oil production well are in proximity to a hydraulically fractured well. This is about the same as the portion of oil production that is enabled by hydraulic fracturing. The population within the vicinity of both hydraulically fractured wells and all active wells is younger, more educated, and has higher incomes than populations further away.

Habitat Fragmentation: Habitat fragmentation is related to both an increase in the proportion of edge to interior habitat, and a loss of connectivity between areas of high-quality habitat. An increase in edge habitat tends to be deleterious for species that are intolerant of human disturbance. Loss of connectivity tends to reduce the long-term viability of populations of native species. Conserving large patches of habitat with a relatively low ratio of edge to interior, and preserving corridors for connectivity between patches of habitat, are important for conservation of native species. Edge effects can be minimized by clustering facilities as much as possible: for example, building a network of main roads, pipelines, and power lines rather than many small ones; using centralized staging and storage equipment; and placing multiple wells on one well pad. Connectivity can be preserved by maintaining corridors between patches of habitat. Eight major corridors were identified in the vicinity of the oil fields with the most hydraulic fracturing in the San Joaquin Basin. These should be preserved by focusing development elsewhere or by drilling directional and horizontal wells from well pads outside these corridors to reach locations beneath the corridors. The agencies of jurisdiction should identify quantifiable objectives for habitat conservation (in terms of minimum width of corridors, maximum disturbance levels, total area conserved and configuration) that could be applied in high priority reserves and corridors in the southwestern San Joaquin Basin to maintain sustainable populations of special status species in the corridors and oil field landscape.

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