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. (See Box 1.1-1 for a short history of oil and gas production in California.) This scientific assessment addresses well stimulation used in oil and gas production both on land and offshore 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, the present volume, 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, also issued in July 2015, presents case studies that assess environmental issues and qualitative risks for specific geographic regions. A final Summary Report summarizes key findings, conclusions and recommendations of all three volumes.

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.

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

Hydraulic Fracturing Stimulation Common feature: All treatments create sufficient pressure in the well to induce fractures in the reservoir.		
Proppant Fracturing: Uses proppant to retain fracture permeability		**Acid Fracturing:** Uses acid instead of proppant
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	**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	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

Acidizing Stimulation Common feature: All treatments use acid to dissolve materials impeding flow	
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	
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	**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

Box 1.1-1. The 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. For example, Long Beach oil field, in the Los Angeles Basin, once contained about ~ 5 billion m3 (3 billion barrels) of oil within an area of less than 7 km2 (2,000 acres). Four of the ten largest conventional U.S. oil fields are in California: Midway-Sunset, Kern River, and South Belridge in the San Joaquin Basin and Wilmington-Belmont in the Los Angeles Basin. According to the Division of Oil, Gas, and Geothermal Resources (DOGGR) there are 52 giant oil fields in the state, each with more than 16 million m3 (100 million barrels) of known recoverable oil, and many other fields of various sizes. California's oil production ranks third in the nation, behind Texas and North Dakota and provides about 20,000 jobs.

Oil has been exploited since prehistoric times, first by Native Americans and later by Spanish colonists and Mexican residents, who routinely collected “brea” from the numerous natural oil seeps. Commercial production started in the middle of the nineteenth century from hand-dug pits and shallow wells. Exploratory drilling began in the 1860s and 1870s and boomed in the first half of the Twentieth Century. 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, 1993). California’s oil production reached an all-time high of almost 64 million m3 (400 million barrels) in 1985 and has generally declined since then. By 1940 all but four of the giant onshore fields had been discovered. San Ardo, South Cuyama, and Round Mountain were discovered in the 1940s, and the last, Yowlumne field, was discovered in1974. 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 m3, or 198 million barrels produced in the state out of a total of about 98.7 million m3, or 621 million barrels consumed). Californian’s mainly made up the shortfall of about 67.3 million m3 (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. Water flooding involves injecting water into a reservoir, causing additional oil to flow to production wells. Water flooding was first used in the Los Angeles Basin in 1956 at Wilmington-Belmont field to mitigate subsidence, with the incidental benefit of increased oil recovery. By the 1960s the method had been widely deployed in many fields around the state as an effective means of augmenting production.

California has substantial heavy oil that must be liquefied with heat to make it flow to a well. Steam injection (steam flooding and soak), the most commonly used “thermal recovery” method, involves injecting steam into wells interspersed among production wells. Nearly all production at Kern River field and much of the production from Midway Sunset and many other California fields is heavy oil produced by thermal recovery. Since 1989, when DOGGR first reported oil recovered by water flooding and steam injection, over 70% of production can be attributed to these energy-intensive techniques (DOGGR, 1990; DOGGR, 2010).

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).

The first offshore oil production in the United States began in 1897 on piers in Santa Barbara County. The first Federal Outer Continental Shelf (OCS) lease sale was held in 1966 and production began from a platform in 1969. That same year a well failure on Union Oil Platform A in Dos Cuadras field, not far from the Santa Barbara Coast, spilled

15,899 m3 (100,000 barrels) in ten days and made a deep negative impression on public opinion that has constrained offshore development ever since. In 1984 a moratorium on development in the Federal OCS went into effect. Billions of barrels of recoverable oil probably remain in the federal offshore, but with no new leases, OCS production has been steadily declining since 1996.

California's oil production reached an all-time high of almost 64 million m3 (400 million barrels) in 1985 and has generally declined since then. In 1960, almost as much oil was produced in California as was consumed, but by 2012 Californians used about 67.3 million m3 (423 million barrels) more than they produced (Figure 1.1-1) with the shortfall mainly delivered by tanker from Alaska, Saudi Arabia, Ecuador, Iraq, Colombia and other countries.

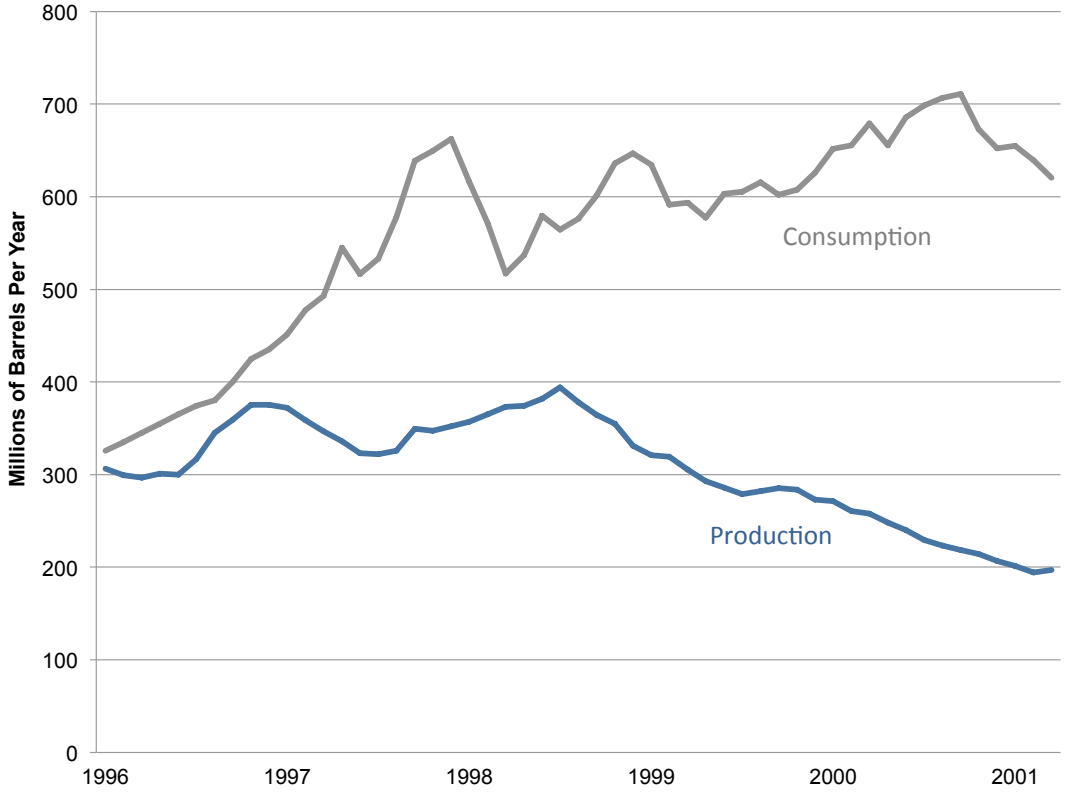


Figure 1.1-1. Total oil production (blue line) and consumption (grey line) from all sources in California from 1960 to 2012 (Data: US EIA, 2014a and b).

Natural gas is much less abundant than oil in California and most of the state's natural gas production is a co-product of oil development, referred to as "associated" gas production. Only the Sacramento Basin has significant non-associated natural gas production, but about three quarters of the gas production in the state is not from dry gas wells, but from wells that primarily produce oil, mostly in the San Joaquin Valley.

1.1.1. California Council on Science and Technology (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. (Volume II, 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. Volume II, 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 Volume II, 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.

1.1.2. Data and Literature Used in the Report

This assessment reviews and analyzes both existing data and scientific literature, with preference given to findings 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 Volume I, Appendix E, "Review of Information Sources." The science team did not collect any new data, but did do original analysis of available data.

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 allowed the authors to present the factual basis of well stimulation in California. With a few exceptions, the existing data was sufficient to identify the technologies used, where and how often they are used, and where they are likely to be used in the future (see Volume I Chapter 3). This volume, Volume II, faces the challenge of 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. 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 this volume)-- that warrant a closer look and perhaps regulatory attention. We believe 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.

The SB 4 completion reports provide reliable data to assess certain potential environmental and health impacts such as the use of fresh water for hydraulic fracturing. For most potential impacts, however, only incomplete information and data exist. Few scientific studies of the health and environmental impacts of well stimulation have been conducted to date, and the ones that have been done focus on 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 targeted studies have been conducted to look for such contamination. Data describing the quality of groundwater near hydraulic fracturing sites is 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 in locations that have no nearby

protected groundwater have been exempted from groundwater monitoring. Consequently information is now being gathered about the quality of water near proposed hydraulic fracturing sites, but the SB 4 requirements have only been in place since 2013.

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.

1.2. Assessing Impacts of Hydraulic Fracturing in California

This scientific assessment of hydraulic fracturing and acid stimulation impacts covers the application of hydraulic fracturing and acid stimulation technology and resulting oil and gas production activities. The report considers impacts and potential impacts resulting from the development of a well pad and support infrastructure required to drill the well, hydraulic fracturing or acid stimulation and completion, production of oil and/or natural gas, and disposal or reuse of produced water. Figure 1.2-1 shows the parts of the oil and gas system included in this assessment and examples of impacts for each.

This report excludes other stages in the development, production, refining, and use life cycle of oil and gas, including impacts of manufacturing of materials or equipment used in stimulation, impacts of transport of produced oil and gas to refineries or providers, impacts of refining, or impacts of combustion of hydrocarbons as fuel.

Existing California regulations, including the state's new well stimulation regulations effective July 1, cover many of the areas of potential concern or risk raised in this study, 2015. This study does not address the effectiveness of the current regulatory framework in mitigating any potential risks associated with well stimulation technologies, but recommends that the state conduct such assessments in the future.

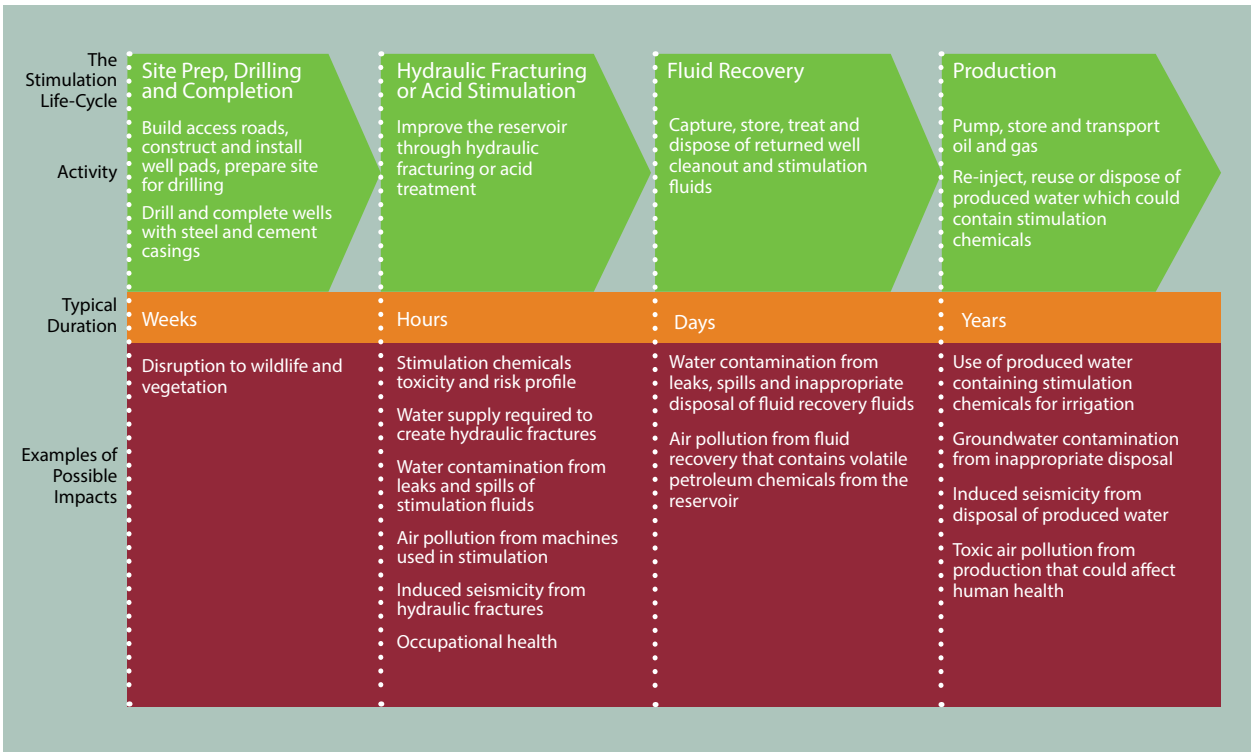


Figure 1.2-1. The sequential parts of the well stimulation system considered in this report.

1.2.1. Direct and Indirect Impacts of Hydraulic Fracturing and Acid Stimulation.

Hydraulic fracturing or acid stimulation can cause direct impacts. Potential direct impacts might include 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 hydraulic fracturing chemicals. These direct impacts do not occur in oil and gas production unless hydraulic fracturing or acid stimulation has occurred. This study covers potential direct impacts of hydraulic fracturing or acid stimulation.

Hydraulic fracturing or acid stimulation can also incur indirect impacts, i.e., those not directly attributable to the activity itself. Some reservoirs require hydraulic fracturing for economic production. All activities associated with oil and gas production enabled by hydraulic fracturing or acid stimulation can bring about indirect impacts. Indirect impacts of hydraulic-fracturing-enabled oil and gas development usually occur in all oil and gas development, whether or not the wells are stimulated.

In some cases, we cannot separate direct and indirect impacts. For example, the inventory of emissions of hazardous air pollutants is for all oil and gas production and does not differentiate between hydraulically fractured and unfractured wells, so the data do not

support differentiating direct and indirect impacts. However, as illustrated in the following examples, differentiating direct and indirect impacts can be important for framing investigations and policy.

An indirect impact common to all production, not just production enabled by hydraulic fracturing, means the impacts incurred by just the hydraulically fractured wells represent a small subset of the problem. For example, disposal of produced water through underground injection may carry the risk of inducing an earthquake. If this produced water comes from a hydraulically fractured reservoir, this potential impact would be an indirect impact. In California, about 20% of all produced waters come from stimulated reservoirs. Understanding induced seismicity requires looking at all the wastewater injections, not just those generated by hydraulically fractured wells. In this case, the indirect impact attributed to hydraulically fractured wells represents a small part of a larger problem.

As another example, studies show elevated health risks near hydraulically fractured reservoirs attributable to benzene (Volume II, Chapter 6). But benzene use has been phased out in hydraulic fracturing fluids. These health risks probably occur due to processes associated with oil production, because oil contains benzene naturally. In this case, the health impacts do not occur because of hydraulic fracturing itself; they are indirect impacts that occur because of production. So the same health impacts could occur near any production, whether the wells have been fractured or not. Research that focuses only on benzene impacts near hydraulically fractured wells will likely result in a very poor understanding of both the extent of this problem and the possible mitigation measures. Concern about hydraulic fracturing might lead to studying health effects near fractured wells, but concern about the health effects from benzene should lead to study of all types of oil and gas production, not just hydraulically fractured wells.

As a final example, the activities associated with hydraulic fracturing or acid stimulation can add some new direct occupational hazards to a business that already has substantial occupational hazards. The drilling, completion, and production phases common to all oil and gas production incur significant risk of exposure to many toxic substances and accidents. In general, oil and gas production has significant occupational health issues, but these impacts are not directly attributable to well stimulation activity. In hydraulic fracturing, silica sand used for the proppant in hydraulic fracturing presents an additional occupational health hazard for serious lung disease (silicosis). Potential exposure to silica is a direct impact of hydraulic fracturing and a relatively small part of the total hazard profile for oil and gas development.

While this project was not tasked with a full assessment of the impacts of all oil and gas development in California, we have described indirect impacts in the context of all oil and gas production where the issue and associated data either allows or requires this. This report does include some recommendations for assessment of certain impacts for all oil and gas development in the future.

Table 1.2-1 describes the potential direct impacts of hydraulic fracturing and acid stimulation, plus potential indirect impacts of hydraulic-fracturing-enabled oil and gas development covered in this report.[1] The table includes issues of concern named in the SB 4 legislation or issues that have been raised by the public in the various forums around California and the U.S. regarding well stimulation or were identified by expert judgment. A long list of features, events, and processes related to well stimulation and production could possibly lead to harmful impacts, but these are not all likely or equally likely. A long list of plausible hazards have been described in Volume II, but the reader is cautioned to treat these as a "checklist" of possible impacts, not at all a list of impacts that are generally occurring. Existing regulations prevent or mitigate many of these risks; however, an evaluation of the effectiveness of this regulatory framework was beyond the scope of this study.

Out of the possible plausible hazards, some emerge as especially relevant potential risk factors worthy of further attention through additional data collection or increased scrutiny. Chapter 6 presents a table of these risk issues, which are also the basis of the conclusions and recommendations in this chapter.

1. We do not include indirect impacts of acid stimulation because based on existing data, we did not find reservoirs that required acid stimulation for production.

Table 1.2-1. Examples of direct and indirect impacts considered in this study.

Issue	Possible Direct Impact	Possible Indirect Impact of Hydraulic-Fracturing-Enabled Oil and Gas Development
Stimulation Chemicals	Chemicals used in stimulation create the potential for introduction of hazardous materials into the environment.	N/A
Water Use	Stimulation uses California fresh water supply.	Freshwater is sometimes used to produce oil in a previously stimulated reservoir, e.g., enhanced oil recovery via injection of water or steam.
Water Supply	Stimulation chemicals could enter produced water that is otherwise of sufficient quality for beneficial uses, such as irrigation, making treatment more complicated.	Additional production enabled by hydraulic fracturing can lead to additional produced water, which, with appropriate treatment, may be of sufficient quality for beneficial uses.
Water Contamination	Intentional or accidental releases of stimulation chemicals and their reaction products could lead to contamination of fresh water supply. Risk of hydraulic fractures acting as conduit for accidental releases of fluids; and risk of high-pressure injection affecting integrity of existing wells.	N/A
Air pollution	Equipment used in stimulation emits pollutants and greenhouse gases (GHGs). Retention ponds and tanks used to store stimulation fluids could contain off-gassing volatile organic compounds (VOC).	Oil and gas development activities cause emissions including VOC emissions from produced water.
Induced Seismicity	Hydraulic fracturing could cause earthquakes.	Disposal of wastewater from hydraulic fracture-enabled production in disposal wells classified by the EPA's Underground Injection Control (UIC) program as "Class II"[1] could cause earthquakes.
Human Health	Releases of stimulation chemicals that pollute water and air, as well as noise and light pollution from the stimulation operation could affect public health.	Proximity to any oil production, including stimulation-enabled production, could result in hazardous emissions to air and water, and noise and light pollution that could affect public health.
Wildlife and Vegetation	Introduction of invasive species; contamination of habitat or food web by stimulation chemicals; and water use for stimulation fluids could impact wildlife and vegetation.	Habitat loss and fragmentation, introduction of invasive species, and water use for enabled enhanced oil recovery could impact wildlife and vegetation.

1. Class II wells are underground injection wells that inject fluids associated with oil and natural gas production. There are three types of Class II wells: enhanced recovery, wastewater disposal, and hydrocarbon storage. For more information, see http://water.epa.gov/type/groundwater/uic/class2/index.cfm.

1.2.2. Impacts Covered in this Volume

The chapters of this volume assess, to the extent possible, the potential impacts of well stimulation on water, air, seismicity, habitat and human health.

Chapter 2 analyzes the hazards and potential impacts of well stimulation on California's water resources including water use in well stimulation, the volumes, chemical compositions, and potential hazards of stimulation fluids, and the characteristics of wastewater including production, management, and the potential release mechanisms and transport pathways by which well stimulation chemicals enter the water environment. The chapter addresses the following questions and for each evaluates the available data, identifies data gaps and ways to mitigate or avoid potential impacts:

- What are the volumes of fresh water used for well stimulation in California, and what are the sources of these supplies (e.g., domestic water supplies, private groundwater wells, irrigation sources)? How does water use for well stimulation compare with other uses in California and in the regions where well stimulation is occurring?

- What are the volumes and chemical compositions—including types of chemicals and quantities—of stimulation fluids? What are the physical, chemical, and toxicological properties of the stimulation chemicals used? To what extent does this chemical use create hazards for and potential impacts on water resources in California?

- What volumes of recovered fluids and produced water are generated from stimulated wells and what are the chemical compositions of those waters? Are volumes of produced water generated from stimulated wells and non-stimulated wells different? Does the chemical composition of produced water from stimulated wells differ from that of non-stimulated wells? What techniques are used to recover fluids and manage produced water (e.g., deep well injection, unlined sumps)? Could existing treatment technologies remove well stimulation chemicals that are being used in California?

- What are the release mechanisms and transport pathways by which well stimulation chemicals could enter surface water and groundwater aquifers? Could the introduction of stimulation chemicals into the environment affect ecosystems and human health (through contamination of aquifers, spills, inappropriate uses of wastewater, etc.)?

Chapter 3 assesses the potential of well stimulation to emit greenhouse gases (GHGs), volatile organic compounds (VOCs), oxides of nitrogen (NO_x), toxic air contaminants (TACs), and particulate matter (PM). Because oil and gas development in general can also have these impacts, the purpose of this chapter is to evaluate what is known about the contribution of well stimulation to general impacts from oil and gas development.

Well stimulation could impact air quality via emission of a large variety of chemical species. These species can have local, regional, or global impacts, mediated by the regional atmospheric transport mechanisms and the natural removal mechanisms relevant for that species. For clarity, this report groups species into four categories of interest, each with unique potential impacts.

1. Greenhouse gases (GHGs);

2. Reactive organic gases (ROGs), and oxides of nitrogen (NO_x) that cause photochemical smog generation;

3. Toxic air contaminants (TACs, a California-specific designation similar to federal designation of hazardous air pollutants (HAPs); and

4. Particulate matter (PM), including dust.

The chapter describes methods of classifying well-stimulation-related air impacts, and the major sources and types of emissions from oil and gas activities. The chapter also describes the treatment of well-stimulation-related emissions in current California emissions inventories. Then, the chapter evaluates the California regions likely to be affected by the use of well-stimulation technology, current best practices for managing air quality impacts of well stimulation, and gaps in data and scientific understanding surrounding well-stimulation-related air impacts.

Chapter 4 assesses the potential for induced seismicity in California caused by injection of fluids into the subsurface. The vast majority of earthquakes induced by fluid injection are too small to be felt at the ground surface. However, induced seismicity can produce felt or, in rare cases, damaging ground motions. Large volumes of water injected over long time periods (i.e. months to years) into zones in or near potentially active earthquake sources can induce earthquakes. This chapter reviews the current state of knowledge about induced seismicity, and the data and research required to determine the potential for induced seismicity in California, including along the San Andreas Fault. The chapter also discusses how existing protocols could be improved to lower the risk from induced seismicity in California.

Chapter 5 evaluates the potential impact of well stimulation on wildlife and vegetation, and how these impacts depend on the density of oil and gas wells and other human land uses in the area. The chapter describes how the impacts of oil and gas production to native wildlife and vegetation depend on the prevailing land use. In some regions, well stimulation takes place in areas where wild habitat has already been displaced by near-continuous well pads or agricultural and urban development. However, in oil fields with little other development and a relatively low density of oil wells, oil and gas development could more directly impact valuable native habitat. Because habitat loss and fragmentation is likely to have the greatest impact on wildlife and vegetation, the chapter explores

this topic in greater depth by quantifying habitat loss and fragmentation attributable to well-stimulation-enabled hydrocarbon production. Other potential impacts, such as the introduction of invasive species, releases of harmful fluids to the environment, diversion of water from waterways, noise and light pollution, vehicle collisions, ingestion of litter by wildlife, and the possible release of well stimulation chemicals into the environment are described. Then the chapter reviews regulation of the oil and gas industry with respect to impacts on wildlife and vegetation. The chapter describes measures to mitigate oil field impacts on terrestrial species and their habitats, and major data gaps and ways to remedy the gaps.

Chapter 6 addresses health hazards associated with community and occupational environmental exposures *directly* attributable to well stimulation and *indirect* exposures due to oil and gas development that were facilitated by stimulation in California. The chapter evaluates hazards directly attributable to well stimulation stemming from the chemicals used in stimulation that might contact humans through contaminated water (described in Chapter 2) and air pollution hazards associated with oil and gas development described in Chapter 3 for human health.

1.3. Conclusions and Recommendations

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. For the sake of consistency, some conclusions include information from other volumes as noted.

1.3.1. Direct and Indirect Impacts of Hydraulic Fracturing and Acid Stimulation

Conclusion 3.1. Direct impacts of hydraulic fracturing appear small but have not been investigated.

Available evidence indicates that impacts caused directly by hydraulic fracturing or acid stimulation or by activities directly supporting these operations appear smaller than the indirect impacts associated with hydraulic-fracturing-enabled oil and gas development, or limited data precludes adequate assessment of these impacts. Good management and mitigation measures can address the vast majority of potential direct impacts of well stimulation.

Hydraulic fracturing in California lasts a relatively short amount of time near the beginning of production—less than a day—and requires relatively small fluid volumes. In contrast, the subsequent oil and gas production phase lasts for years and involves very large volumes of fluid, with potential for long-term perturbations of the environment. Consequently, the production phase following well stimulation can have a much larger impact than the stimulation phase.

This study identifies a number of possible pathways for direct impacts from hydraulic fracturing and acid stimulation, such as accidental spills or leaks of hydraulic fracturing or acid fluids or emissions of volatile organic compounds (VOCs) from hydraulic fracturing fluids. Many, if not all, of these potential direct impacts can be addressed with good management practices or mitigation measures. These are described in Volumes II and III.

The recommendations below provide specific measures that could eliminate, avoid, or ameliorate direct impacts. These measures include limiting the use of toxic chemicals, avoiding inappropriate disposal, managing beneficial use of produced water containing stimulation chemicals, providing extra due diligence for shallow fracturing near protected groundwater, and using "green completions" to control emissions in oil and gas wells.

In California, existing or pending regulation already addresses many of these direct impacts. The state's new well stimulation regulations, going into effect on July 1, 2015, will likely avoid or reduce many, but not all, of the impacts described in this report. The scope of this study did not include judging the adequacy of existing regulation, but this would make sense at some later time when significant experience can be assessed.

Recommendation 3.1. Assess adequacy of regulations to control direct impacts of hydraulic fracturing and acid stimulations.

Over the next several years, relevant agencies should assess the adequacy and effectiveness of existing and pending regulations to mitigate direct impacts of hydraulic fracturing and acid stimulations, such as to: (1) reduce the use of highly toxic or harmful chemicals, or those with unknown environmental profiles in hydraulic fracturing and acid fluids; (2) devise adequate treatment and testing for any produced waters intended for beneficial reuse that may include hydraulic fracturing and acid fluids or disallow this practice; (3) prevent shallow hydraulic fractures from intersecting protected groundwater (Volume II); (4) dispose of produced waters that contain stimulation chemicals appropriately; and (5) control emissions, leaks and spills.

Conclusion 3.2. Operators have unrestricted use of many hazardous and uncharacterized chemicals in hydraulic fracturing.

The California oil and gas industry uses a large number of hazardous chemicals during hydraulic fracturing and acid treatments. The use of these chemicals underlies all significant potential direct impacts of well stimulation in California. This assessment did not find recorded negative impacts from hydraulic fracturing chemical use in California, but no agency has systematically investigated possible impacts. A few classes of chemicals used in hydraulic fracturing (e.g., biocides, quaternary ammonium compounds, etc.) present larger hazards because of their relatively high toxicity, frequent use, or use in large amounts. The environmental characteristics of many chemicals remain unknown. We lack information to determine if these chemicals would present a threat to human health or the environment if released to groundwater or other environmental media. Application of green chemistry principles, including reduction of hazardous chemical use and substitution of less hazardous chemicals, would reduce potential risk to the environment or human health.

Operators have few, if any, restrictions on the chemicals used for hydraulic fracturing and acid treatments. The state's regulations address hazards from chemical use and eliminate or minimize many, but not necessarily all risks. Some of the chemicals used present hazards in the workplace or locally, such as silica dust or hydrofluoric acid. Other chemicals present potential hazards for the environment, such as biocides and surfactants that, if released, can harm fish and other wildlife. Many of the chemicals used can harm human health. If well stimulation did not use hazardous chemicals, hydraulic fracturing would pose a much smaller risk to humans and the environment. Even so, hazardous chemicals only present a risk to humans or the environment if they are released in hazardous concentrations or amounts, persist in the environment, and actually reach and affect a human, animal or plant. Even a very toxic or otherwise harmful chemical presents no risk if no person, animal or plant receives a dose of the chemical. Characterization of the risk posed by chemical use requires information on both the hazards posed by the chemicals and information about exposure to the chemicals (in other words, risk = hazard x exposure).

We have established a list of chemicals used in California based on voluntary disclosures by industry. In California, oil and gas production operators have voluntarily reported the use of over 300 chemical additives. New state regulations under SB 4 will eventually reveal all chemical use. However, knowledge of the hazards and risks associated with all the chemicals remains incomplete for almost two-thirds of the chemicals (Table 1.3-1). The toxicity and biodegradability of more than half the chemicals used in hydraulic fracturing remains uninvestigated, unmeasured, and unknown. Basic information about how these chemicals would move through the environment does not exist. Although the probability of human and environmental exposure is estimated to be low, no direct studies of environmental or health impacts from hydraulic fracturing and acid stimulation chemicals have been completed in California. To the extent that any hydraulic fracturing and acid stimulation fluids can get into the environment, reduction or elimination of the use of the most hazardous chemicals will reduce risk.

Table 1.3-1. Availability of information for characterizing the hazard of stimulation chemicals used in hydraulic fracturing. The Chemical Abstracts Service Registry Number (CASRN) is a unique numerical identifier assigned to chemical substances. Operators do not provide CASRN numbers for proprietary chemicals.

Number of chemicals	Proportion of all chemicals	Identified by unique CASRN	Impact or toxicity	Quantity of use or emissions
172	55%	Available	Available	Available
17	5%	Available	Available	Unavailable
6	2%	Available	Unavailable	Available
121	38%	Unavailable	Unavailable	Available

For this study, we sorted the extensive list of chemicals reported in California to identify those of most concern or interest and created tables identifying selected chemicals for each category contributing to hazard (see Summary Report, Appendix H, and Volume II, Chapters 2 and 6). Chemicals used most frequently or in high concentrations rise to a higher level of concern, as do chemicals known to be acutely toxic to aquatic life or mammals. The assessment included chemicals used in hydraulic fracturing that can be found on the Toxic Air Contaminant Identification List, the Proposition 65 list of chemicals known to the State of California to cause cancer and reproductive harm, and the OEHHA list of chemicals with published reference exposure limits. Additional hazards considered include, flammability, corrosivity, and reactivity. These various criteria allow identification of priority chemicals to consider when reducing potential hazards from chemical use during well stimulation.

Strong acids, strong bases, silica, biocides, quaternary ammonium compounds, nonionic surfactants, and a variety of solvents are used frequently and in high concentrations in hydraulic fracturing and acid stimulation. Strong acids, strong bases, silica, and many solvents present potential exposure hazards to humans, particularly during handling, and of are of particular concern to workers and nearby residents. Use of appropriate procedures minimizes the risk of exposure and few incidences of the release of these materials during oil and gas development have been reported in California.

Biocides, quaternary ammonium compounds, nonionic surfactants, and some solvents present a significant hazard to aquatic species and other wildlife, particularly when released into surface water. The study found no releases of hazardous hydraulic fracturing chemicals to surface waters in California and no direct impacts to fish or wildlife. However, there is concern that well stimulation chemicals might have been released and potentially contaminated groundwater through a variety of mechanisms (see Conclusions 4.1, 4.3, 4.4, 5.1, 5.2 below). Many of the chemicals used in well stimulation, such as surfactants, are more harmful to the environment than to human health, but all of these chemicals are undesirable in drinking water. Determining whether chemicals that have been released pose an actual risk to human health or the environment requires further study, including a better understanding of the amounts of chemicals released and persistence of those chemicals in the environment.

Green Chemistry principles attempt to maintain an equivalent function while using less toxic chemicals and smaller amounts of toxic chemicals. It may be possible to forego or reduce the use of the most hazardous chemicals without losing much in the way of functionality. Chemical substitutions can present complications and can also introduce a new set of hazards and require a careful adaptive approach. For example, the use of guar in hydraulic fracturing fluids introduces food to bacteria in the reservoir, and this increases the need for biocides to prevent the buildup of toxic gases generated by bacterial growth. Operators moving to a less toxic but less effective biocide might also need to move away from guar to a less-digestible substitute. Then this choice could introduce new hazards instead of old hazards. For these reasons, the American Chemical Society currently sponsors a Green Chemistry Roundtable on the topic of hydraulic fracturing.

The state could also limit the chemicals used in hydraulic fracturing by disallowing certain chemicals or limiting chemicals to those on an approved list where approval depends on the chemical having an acceptable environmental profile. The latter approach reverses the usual practice, whereby an industry is permitted to use a chemical until a regulatory body proves that the chemical is harmful. Oil and gas production in the environmentally sensitive North Sea uses this pre-approval approach and might provide a model for limiting chemical risk in California. The EPA Designed for the Environment (DFE) list of chemicals may also be useful. Of course, any of these approaches requires that the operators report the unique identifier (CASRN number) of all chemicals.

Recommendation 3.2. Limit the use of hazardous and poorly understood chemicals.

Operators should report the unique CASRN identification for all chemicals used in hydraulic fracturing and acid stimulation, and the use of chemicals with unknown environmental profiles should be disallowed. The overall number of different chemicals should be reduced, and the use of more hazardous chemicals and chemicals with poor environmental profiles should be reduced, avoided, or disallowed. The chemicals used in hydraulic fracturing could be limited to those on an approved list that would consist only of those chemicals with known and acceptable environmental hazard profiles. Operators should apply Green Chemistry principles to the formulation of hydraulic fracturing fluids, particularly for biocides, surfactants, and quaternary ammonium compounds, which have widely differing potential for environmental harm. Relevant state agencies, including DOGGR, should as soon as practical engage in discussion of technical issues involved in restricting chemical use with a group representing environmental and health scientists and industry practitioners, either through existing roundtable discussions or independently (Volume II, Chapters 2 and 6).

Conclusion 3.3. The majority of impacts associated with hydraulic fracturing are caused by the indirect impacts of oil and gas production enabled by the hydraulic fracturing.

Impacts caused by additional oil and gas development enabled by well stimulation (i.e. indirect impacts) account for the majority of environmental impacts associated with hydraulic fracturing. A corollary of this conclusion is that all oil and gas development causes similar impacts whether the oil is produced with well stimulation or not. If indirect impacts caused by additional oil and gas development enabled by hydraulic fracturing cause concern, these concerns in most cases extend to any oil and gas development. As hydraulic fracturing enables only 20% of production in California, only about 20% of any given indirect impact is likely attributable to hydraulically fractured reservoirs.

Without hydraulic fracturing, oil and gas production from certain reservoirs would not be possible. If this oil and gas development did not occur, then the impacts of this development would not occur. Well stimulation is a relatively brief operation done after a well is installed, but oil and gas development goes on for years, involving construction of infrastructure and disruption of the landscape. Operators build roads, ponds, and well pads, and install pumps, field separators, tanks, and treatment systems in reservoirs that are stimulated and in those that are not. Surface spills and subsurface leakage may lead to impacts on groundwater quality as an impact of production. The life of a production well involves production of many millions of gallons of water that must be treated or disposed of properly. Production with or without stimulation can cause emission of pollutants over many years, often in proximity to places where people live, work, and go to school. Whereas the short-term injection of fluids for the purpose of hydraulic fracturing is unlikely to cause a felt or damaging earthquake (a direct impact), the subsurface disposal of millions of gallons of water produced along with oil over the life of a well can present a seismic hazard. The inappropriate disposal of produced water can contaminate protected groundwater, whether this water contains stimulation chemicals or not. All oil and gas development potentially incurs impacts similar to the indirect impacts of hydraulic fracturing.

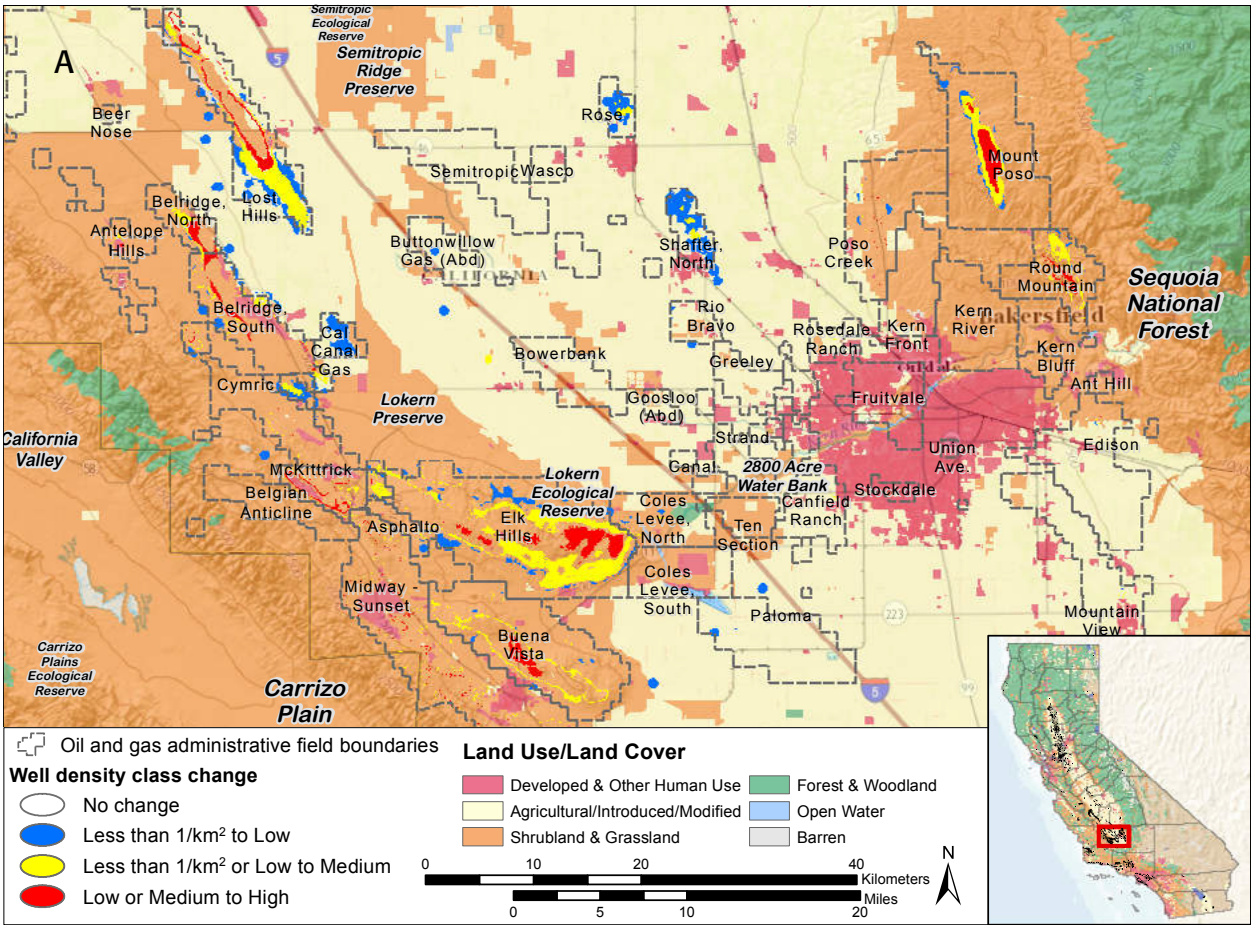
> **Recommendation 3.3. Evaluate impacts of production for <u>all</u> oil and gas development, rather than just the portion of production enabled by well stimulation.**
>
> *Concern about hydraulic fracturing might cause focus on impacts associated with production from fractured wells, but concern about these indirect impacts should lead to study of all types of oil and gas production, not just production enabled by hydraulic fracturing. Agencies with jurisdiction should evaluate impacts of concern for all oil and gas development, rather than just the portion of development enabled by well stimulation. As appropriate, many of the rules and regulations aimed at mitigating indirect impacts of hydraulic fracturing and acid stimulation should also be applied to all oil and gas wells (Volume II, Chapter 6).*

Conclusion 3.4. Oil and gas development causes habitat loss and fragmentation.

Any oil and gas development, including that enabled by hydraulic fracturing, can cause habitat loss and fragmentation. The location of hydraulic fracturing-enabled development coincides with ecologically sensitive areas in Kern and Ventura Counties.

The impact to habitat for native wildlife and vegetation caused by increases in well density depends on the background land use. Some California oil and gas fields are already so densely filled with well pads that other human land uses and native species habitat cannot coexist. Other oil and gas fields have relatively sparse infrastructure interspersed with cities, farms, and natural habitat. The impact caused by increases in well density depends on the background land use. Oil wells installed into agricultural land (such as Rose and Shafter oil fields), or urban areas such as Los Angeles, create only minor impacts to native species. Increases in well density and habitat disturbance from well pads, roads, and facilities cause substantial loss and fragmentation of valuable habitat in those oil and gas fields inhabited by native wildlife and vegetation.

Elk Hills, Mt. Poso, Buena Vista, and Lost Hills fields in Kern County and the Sespe, Ojai, and Ventura fields in Ventura County host substantial amounts of hydraulic fracturing-enabled development as well as rare habitat types and associated endangered species. Portions of oil fields in Kern County are essential to support resident populations of rare species and serve as corridors for maintaining connectivity between remaining areas of natural habitat (including protected areas), and these are vulnerable to expanded production (Figure 1.3-1).


A
Semitropic Ecological Reserve
Semitropic Ridge Preserve
Beer Nose
Rose
Semitropic
Wasco
Mount Poso
Belridge, North
Lost Hills
Antelope Hills
Buttonwillow Gas (Abd)
Shafter, North
Poso Creek
Round Mountain
Sequoia National Forest
Belridge, South
Rio Bravo
Rosedale Ranch
Kern Front
Kern River
Bakersfield
Kern Bluff
Cal Canal Gas
Bowerbank
Greeley
Ant Hill
Cymric
Lokern Preserve
Goosloo (Abd)
Fruitvale
California Valley
Strand
Union Ave.
Edison
McKittrick
Canal
2800 Acre Water Bank
Stockdale
Belgian Anticline
Lokern Ecological Reserve
Coles Levee, North
Canfield Ranch
Asphalto
Elk Hills
Ten Section
Coles Levee, South
Midway - Sunset
Paloma
Mountain View
Buena Vista
Carrizo Plains Ecological Reserve
Carrizo Plain
Oil and gas administrative field boundaries
Well density class change
No change
Less than 1/km² to Low
Less than 1/km² or Low to Medium
Low or Medium to High
Land Use/Land Cover
Developed & Other Human Use
Agricultural/Introduced/Modified
Shrubland & Grassland
Forest & Woodland
Open Water
Barren
0 10 20 40 Kilometers
0 5 10 20 Miles
N

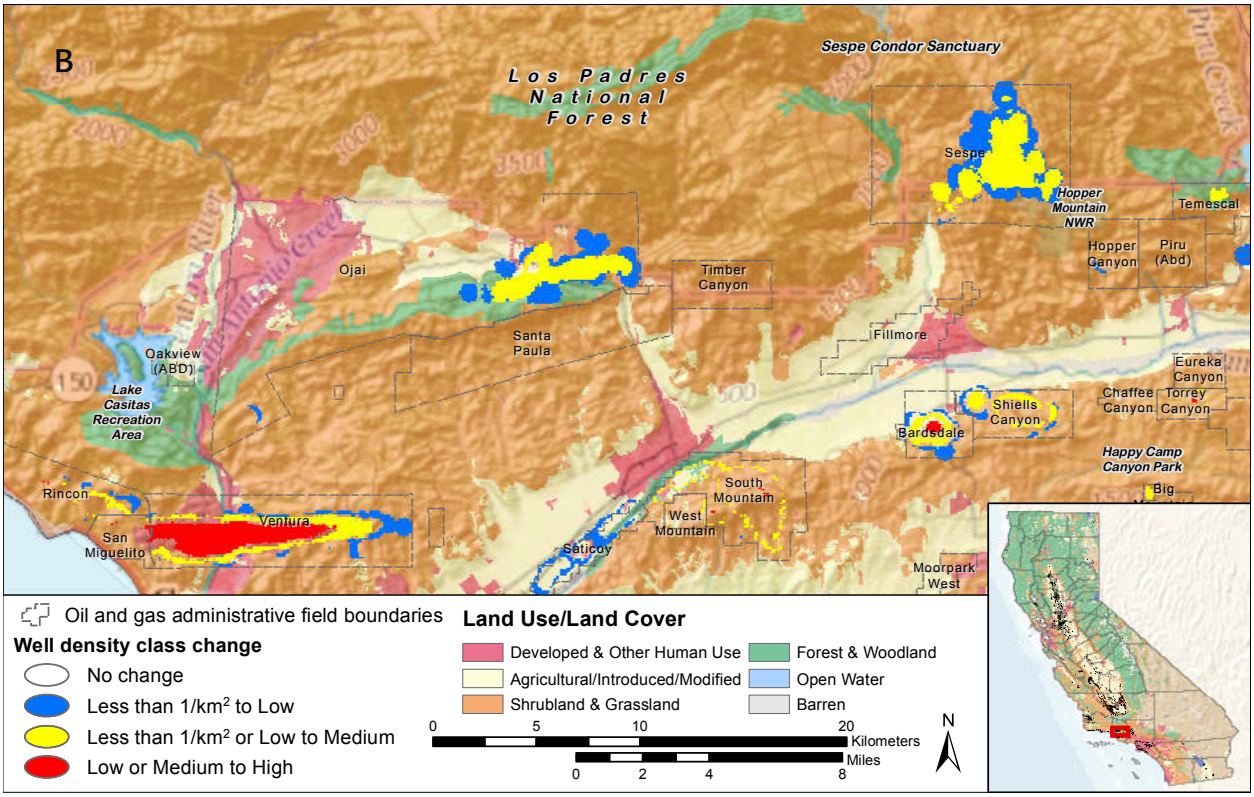

B
Los Padres National Forest
Sespe Condor Sanctuary
Sespe
Hopper Mountain NWR
Temescal
Hopper Canyon
Piru (Abd)
Ojai
Timber Canyon
Santa Paula
Fillmore
Oakview (ABD)
Lake Casitas Recreation Area
Eureka Canyon
Chaffee Canyon
Torrey Canyon
Shiells Canyon
Bardsdale
Happy Camp Canyon Park
Big
Rincon
Ventura
San Miguelito
South Mountain
West Mountain
Seticoy
Moorpark West
Oil and gas administrative field boundaries
Well density class change
No change
Less than 1/km² to Low
Less than 1/km² or Low to Medium
Low or Medium to High
Land Use/Land Cover
Developed & Other Human Use
Agricultural/Introduced/Modified
Shrubland & Grassland
Forest & Woodland
Open Water
Barren
0 5 10 20 Kilometers
0 2 4 8 Miles
N

Figure 1.3-1. Maps of (a) Kern and (b) Ventura Counties showing the increase in well density attributable to hydraulic fracturing-enabled development and land use/land cover between 1977 and 2014. We compared two scenarios for well density in California: actual well density, with all wells present; and a theoretical well density, without hydraulically fractured wells. Foreground colors show areas that have a higher well density with hydraulic fracturing-enabled production. Background shading shows land use/land cover. Kern and Ventura Counties each had oil fields where a substantial proportion of wells were enabled by hydraulic fracturing and where the underlying land use was undeveloped, open land (figure modified from Volume II, Chapter 5).

Ecologically sensitive areas require the conservation of habitat to compensate for new oil and gas development. Currently, no regional planning strategy exists to coordinate habitat conservation efforts in a manner that would ensure continued viable populations of rare species. While possible to compensate only for habitat loss caused by hydraulic fracturing-enabled development, a more logical approach would account for habitat loss from oil and gas production as a whole. Maintaining habitat connectivity in the southwestern San Joaquin will likely require slowing or halting increases in well pad density in dispersal corridors. This type of planning, such as the Kern County Valley Floor Habitat Restoration Plan, has not succeeded in the past, but a renewed effort would safeguard the survival of threatened and endangered species.

Recommendation 3.4. Minimize habitat loss and fragmentation in oil and gas producing regions.

Enact regional plans to conserve essential habitat and dispersal corridors for native species in Kern and Ventura Counties. The plans should identify top-priority habitat and restrict development of those areas. The plan should also define and require those practices, such as clustering multiple wells on a pad and using centralized networks of roads and pipes, which will minimize future surface disturbances. A program to set aside compensatory habitat in reserve areas when oil and gas development causes habitat loss and fragmentation should be developed and implemented (Volume II, Chapter 5; Volume III, Chapter 5 [San Joaquin Basin Case Study]).

1.3.2. Management of Produced Water from Hydraulically Fractured or Acid Stimulated Wells

Large volumes of water of various salinities and qualities get produced along with the oil. Oil reservoirs tend to yield increasing quantities of water over time, and most of California's oil reservoirs have been in production for several decades to over a century. For 2013, more than .48 billion m3 (3 billion barrels) of water came along with some .032 billion m3 (0.2 billion barrels) of oil in California. Operators re-inject some produced water back into the oil and gas reservoirs to help recover more petroleum and mitigate land subsidence. In other cases, farmers use this water for irrigation; often blending treated produced water with higher-quality water to reduce salinity. Disposal or reuse of produced water without proper precautions can cause contamination of groundwater and

more so, if this water contains chemicals from hydraulic fracturing and acid stimulation. Underground injection of produced water can cause earthquakes.

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 1.3-2. 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.

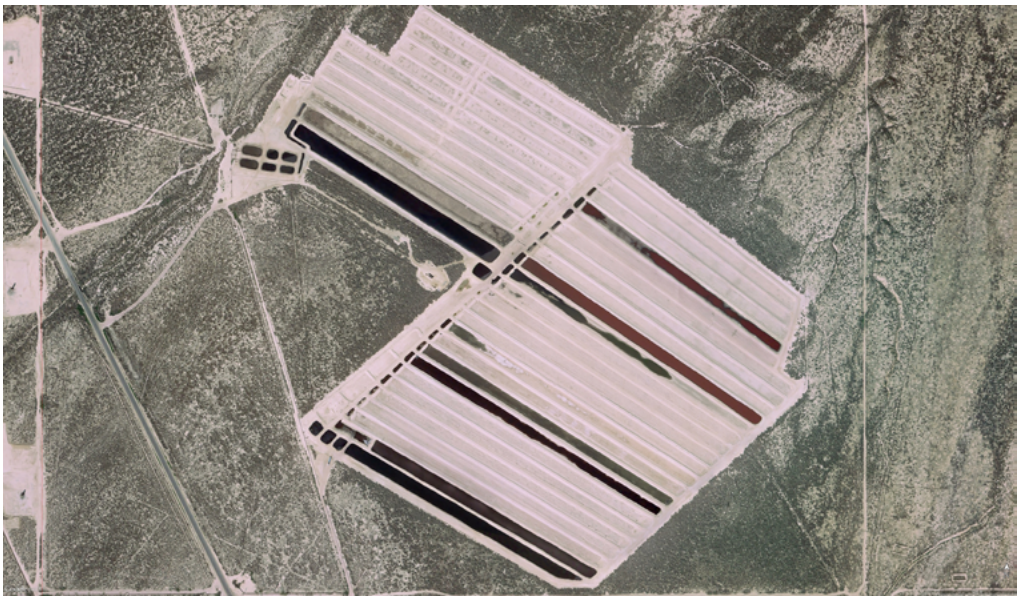


Figure 1.3-2. Percolation pits in Kern County used for produced water disposal (figure modified from Volume II, Chapter 1). Image courtesy of Google Earth.

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 Central Valley Regional Water Quality Control Board (CVRWQCB) ordered the closure of percolation pits at Lost Hills in 2009.[2]

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 1.3-3 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.[3]

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

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

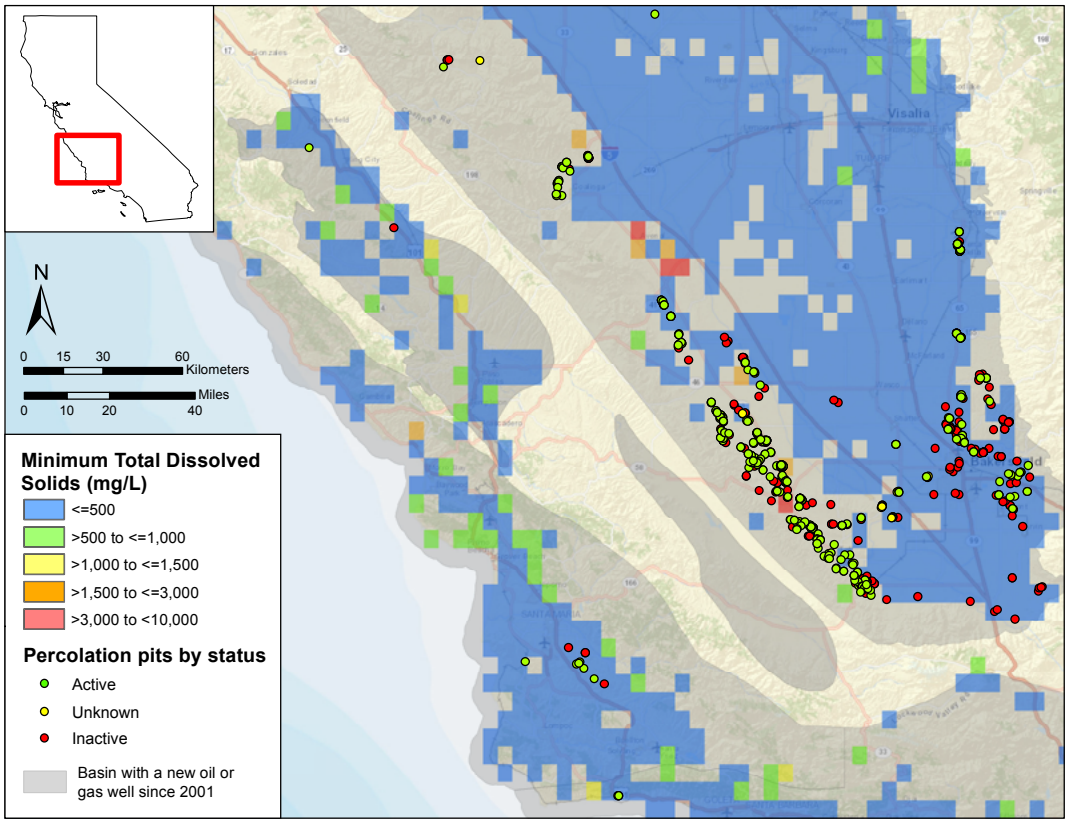


Figure 1.3-3. Location of percolation pits in the Central Valley and Central Coast used for produced water disposal and the location of groundwater of varying quality showing that many percolation pits are located in regions that have potentially protected groundwater shown in color (figure from Volume 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 4.2. The chemistry of produced water from hydraulically fractured or acid stimulated wells has not been measured.

Chemicals used in each hydraulic fracturing operation can react with each other and react with the rocks and fluids of the oil and gas reservoirs. When a well is stimulated with acid, the reaction of the acid with the rock minerals, petroleum, and other injected chemicals can release contaminants of concern in the oil reservoirs, such as metals or fluoride ions that have not been characterized or quantified. These contaminants may be present in recovered and produced water.

An average of about 25 different chemicals are used in each hydraulic fracturing operation. As discussed in Conclusion 3.2, some of these can be quite hazardous alone and chemical reactions can results in new constituents. Acids used in well treatments quickly react with rock minerals and become neutralized. But acids can dissolve and mobilize naturally occurring heavy metals and other pollutants in the oil-bearing formation. Neutralized hydrofluoric acid can release toxic fluoride ions into groundwater. Assessment of the environmental risks posed by hydraulic fracturing and acid use along with commonly associated chemicals, such as corrosion inhibitors, requires more complete disclosure of chemical use and a better understanding of the chemistry of treatment fluids and produced water returning to the surface. We found no characterization of the chemistry of produced water from wells that have been hydraulically fractured or stimulated with acid.

> **Recommendation 4.2. Evaluate and report produced water chemistry from hydraulically fractured or acid stimulated wells.**
>
> *Evaluate the chemistry of produced water from hydraulically fractured and acid stimulated wells, and the potential consequences of that chemistry for the environment. Determine how this chemistry changes over time. Require reporting of all significant chemical use, including acids, for oil and gas development (Volume II, Chapters 2 and 6).*

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 occured and farmers use the produced water for irrigation. In the Kern River field in the San Joaquin Basin, hydraulic fracturing operations occasionally occured, and a fraction of the produced water goes to irrigation (for example, Figure 1.3-4). But we did not find policies or procedures that would necessarily exclude produced water from hydraulically fractured wells from use in irrigation.

Figure 1.3-4. 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 1.3-5 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.

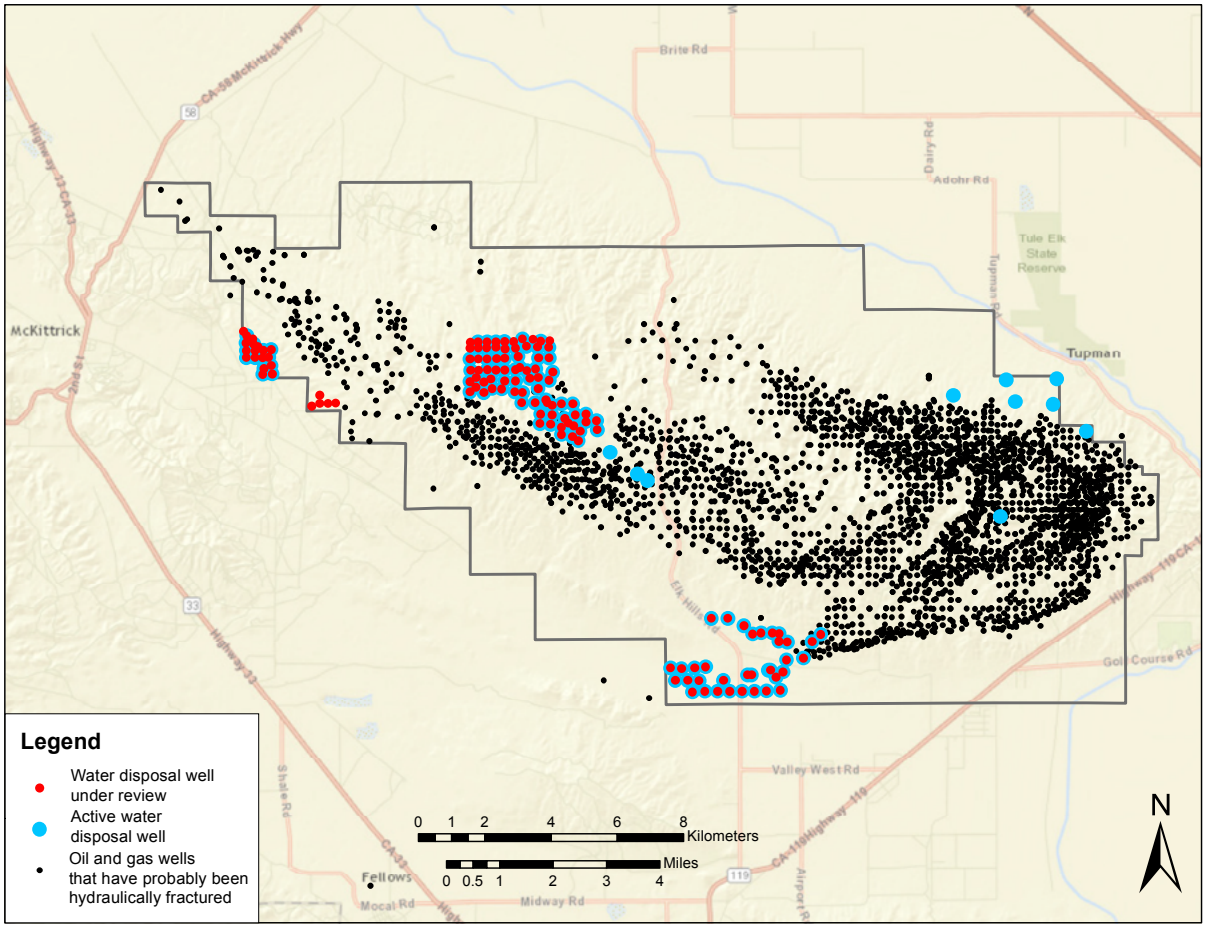


Figure 1.3-5. A map of the Elk Hills field in the San Joaquin Basin showing the location of wells that have probably been hydraulically fractured (black dots). Blue dots are the location of active water disposal wells, and blue dots with a red center are the location of disposal wells under review for 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 4.5. Disposal of wastewater by underground injection has caused earthquakes elsewhere.

Fluid injected in the process of hydraulic fracturing will not likely cause earthquakes of concern. In contrast, disposal of produced water by underground injection could cause felt or damaging earthquakes. To date, there have been no reported cases of induced seismicity associated with produced water injection in California. However, it can be very difficult to distinguish California's frequent natural earthquakes from those possibly caused by water injection into the subsurface.

Hydraulic fracturing causes a pressure increase for a short amount of time and affects relatively small volumes of rock. For this reason, hydraulic fracturing has a small likelihood of producing felt (*i.e.*, sensed), let alone damaging, earthquakes. In California, only one small earthquake (which occurred in 1991) has been linked to hydraulic fracturing to date (Volume II, Chapter 4).

Disposal into deep injection wells of water produced from oil and gas operations has caused felt seismic events in several states, but there have been no reported cases of induced seismicity associated with wastewater injection in California. The volume of produced water destined for underground injection could increase for a number of reasons, and disposal of increased volumes by injection underground could increase seismic hazards.

California has frequent naturally occurring earthquakes—so many that seismologists have a hard time determining if any of these earthquakes were actually induced by fluid injection. In areas like Kansas that do not have frequent earthquakes, it is much easier to find correlations between an earthquake and human activity. In the future, the amount of fluid requiring underground injection in California could increase locally due to expanded production or a change in disposal practice. Such change in practice might incur an unacceptable seismic risk, but understanding this possible risk requires a better understanding of the current correlation between injection and earthquakes, if any.

California also has many geologic faults. Figure 1.3-6 shows a map of California earthquake epicenters, the location of wastewater disposal wells active since 1981 and faults in the United States Geological Survey (USGS) database in central and southern California. Across all six oil-producing basins, over 1,000 wells are located within 2.5 km (1.5 miles) of a mapped active fault, and more than 150 within 200 m (650 ft).

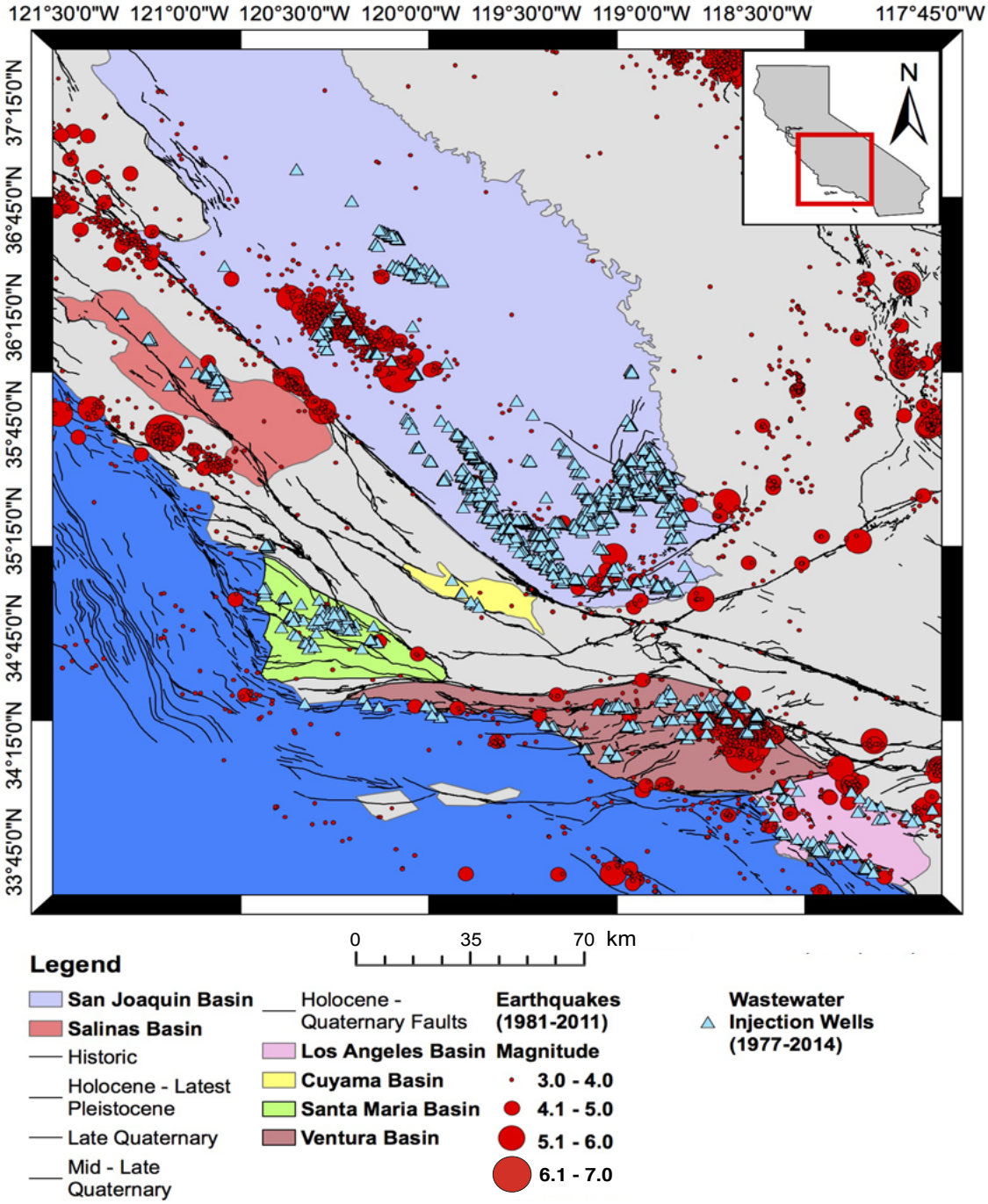


Figure 1.3-6. High-precision locations for earthquakes M≥3 in central and southern California during the period 1981-2011, and active and previously active water disposal wells from DOGGR (figure from Volume II, Chapter 4).

A systematic regional-scale analysis of earthquake occurrence in relation to water injection would help identify if induced seismicity exists in California. This study should include statistical characterizations and geomechanical analysis for induced seismicity and will require more detailed data than that currently reported by industry on injection depth, variations in fluid injection rate, and pressure over time. Currently, operators report the volume of injected water and wellhead pressures only as monthly averages. Analysts will need to know more about exactly when, how, how much, where injection occurred to identify a potential relationship between earthquakes and injection patterns. A systematic study will also require geophysical characterization of oil field test sites, detailed seismic monitoring, and modeling of the subsurface pressure changes produced by injection in the vicinity of the well.

The state could likely manage and mitigate potential induced seismicity, by adopting protocols to modify an injection operation when and if seismic activity is detected. The protocol could require reductions in injection flow rate and pressure, and shutting down the well altogether if the risk of an earthquake rises above some threshold. Currently, ad hoc protocols exist for this purpose. Better protocols would require monitoring the reservoir and local seismic activity, and formal calculation of the probability of inducing earthquakes of concern.

Recommendation 4.5. Determine if there is a relationship between wastewater injection and earthquakes in California.

Conduct a comprehensive multi-year study to determine if there is a relationship between oil and gas-related fluid injection and any of California's numerous earthquakes. In parallel, develop and apply protocols for monitoring, analyzing, and managing produced water injection operations to mitigate the risk of induced seismicity. Investigate whether future changes in disposal volumes or injection depth could affect potential for induced seismicity (Volume II, Chapter 4).

Conclusion 4.6. Changing the method of wastewater disposal will incur tradeoffs in potential impacts.

Based on publicly available data, operators dispose of much of the produced water from stimulated wells in percolation pits (evaporation-percolation ponds), about a quarter by underground injection (in Class II wells), and less than one percent to surface bodies of water. Changing the method of produced water disposal could decrease some potential impacts while increasing others.

Figure 1.3-7 shows the results of an analysis of disposal methods of produced water from known stimulated wells in the first full month after stimulation during the period from 2011 to 2014. As much as 60% of the water was sent to percolation pits, also known as evaporation-percolation ponds, as discussed in Conclusion 4.1 Second to this, produced

water from stimulated wells was injected into Class II wells for disposal or enhanced oil recovery. With proper regulation, siting, construction, and maintenance, subsurface injection is less likely to result in groundwater contamination than disposal in percolation pits.

However, increasing injection volumes could increase the risk of induced seismicity, discussed in Conclusion 4.5. Also, concerns have recently emerged about whether California's Class II underground injection control (UIC) program provides adequate protection for underground sources of drinking water (USDWs), as discussed in Conclusion 4.4, USDWs are defined as groundwater aquifers that currently or could one day supply water for human consumption. The least common method of dealing with wastewater, disposal to surface bodies of water, can, for example, augment stream flows, but requires careful testing and treatment to ensure the water is safe, especially if stimulation chemicals could be present.

The DOGGR monthly production data either do not specify the disposal method or report as "other" for 17% of the produced water from known stimulated wells. This reporting category could include subsurface injection, disposal to a surface body of water, sewer disposal, or water not disposed of but reused for irrigation or another beneficial purpose, as described in Conclusion 4.3.

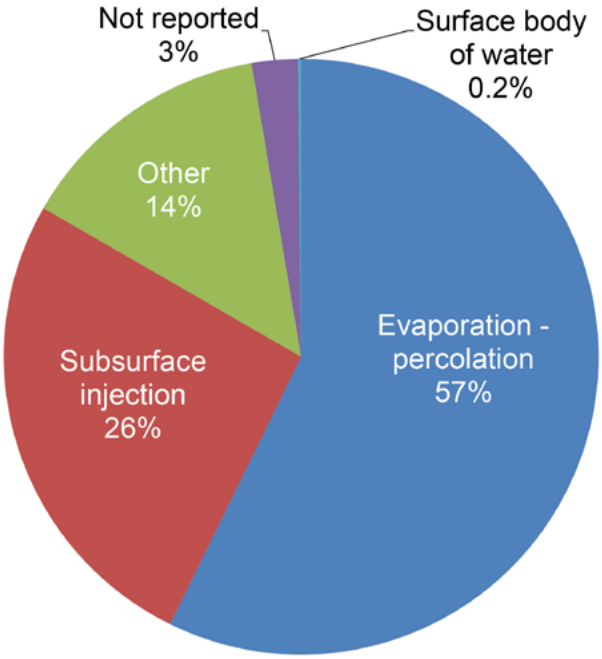


Figure 1.3-7. Disposal method for produced water from hydraulically fractured wells during the first full month after stimulation for the time period 2011-2014 based on data from DOGGR monthly production database. Note: Subsurface injection includes any injection into Class II wells, which include disposal wells as well as enhanced recovery wells used for water flooding and steam flooding (figure from Volume II, Chapter 2).

Changing the method of produced water disposal or reuse will incur tradeoffs. Any attempt to reduce one disposal method must consider the likely outcome that other disposal methods will increase. For example, eliminating disposal in evaporation–percolation pits can lead to an increase in other disposal methods to make up the difference. In particular, closure of percolation pits or injection wells found to be contaminating protected aquifers would increase the use of other disposal methods, and this will require careful planning and management on a regional basis.

Recommendation 4.6. Evaluate tradeoffs in wastewater disposal practices.

As California moves to change disposal practices, for example by phasing out percolation pits or stopping injection into protected aquifers, agencies with jurisdiction should assess the consequences of modifying or increasing disposal via other methods (Volume II, Chapter 2; Volume II, Chapter 4).

1.3.3. Protections to Avoid Groundwater Contamination by Hydraulic Fracturing

Hydraulic fracturing operations could contaminate groundwater through a variety of pathways. We found no documented instances of hydraulic fracturing or acid stimulations directly causing groundwater contamination in California. However, we did find that fracturing in California tends to be in shallow wells and in mature reservoirs that have many existing boreholes. These practices warrant more attention to ensure that they have not and will not cause contamination.

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 1.3-8). A few instances

of shallow fracturing have also been reported in the Los Angeles Basin (Figure 1.3-9), 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.

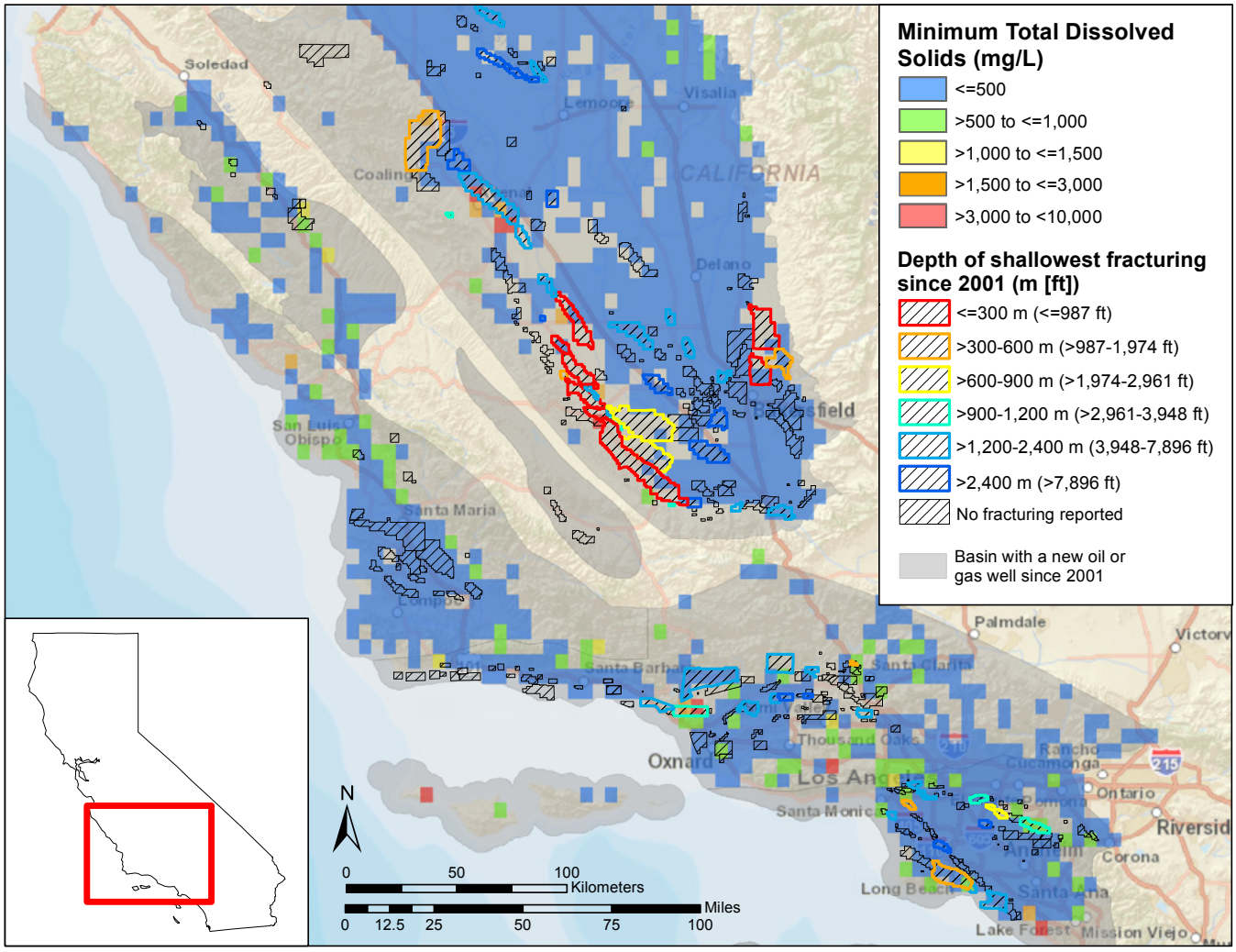


Figure 1.3-8. Shallow fracturing locations and groundwater quality in the San Joaquin and Los Angeles Basins. Some high quality water exists in fields that have shallow fractured wells (figure from Volume II, Chapter 2).

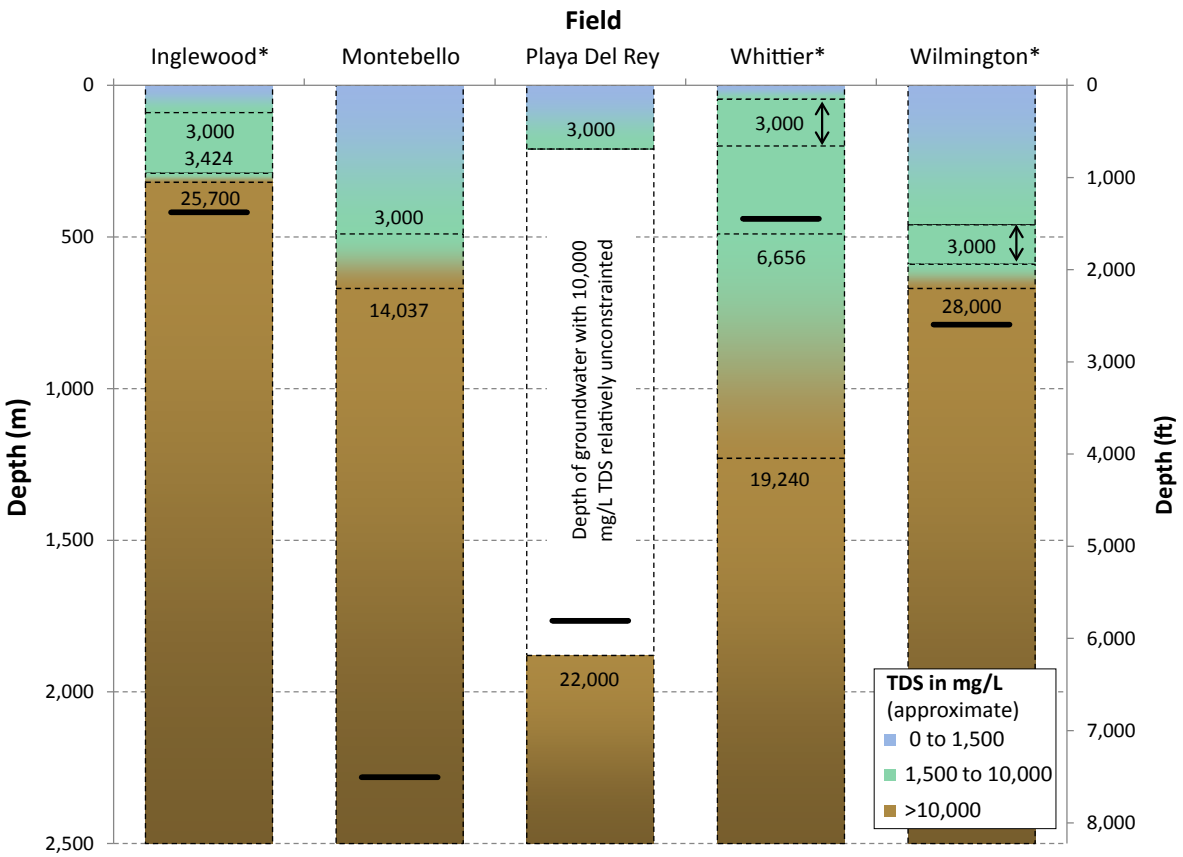


Figure 1.3-9. Depths of groundwater total dissolved solids (TDS) in mg/L in five oil fields in the Los Angeles Basin. The numbers indicate specific TDS data and the colors represent approximate interpolation. The depth of 3,000 mg/L TDS is labeled on all five fields. Blue (<3,000 mg/L) and aqua (between 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,[4] 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 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

4. 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.

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 Studies]).

1.3.4. Emissions and their Impact on Environmental and Human Health

Gaseous emissions and particulates associated with hydraulic fracturing can arise from the use of fossil fuel in engines, outgassing from fluids, leaks, or proppant, which have potential environmental or health impacts.

Conclusion 6.1. Oil and gas production from hydraulically fractured reservoirs emits less greenhouse gas per barrel of oil than other forms of oil production in California.

Burning fossil fuel to run vehicles, make electricity, and provide heat accounts for the vast majority of California's greenhouse gas emissions. In comparison, publicly available California state emission inventories indicate that oil and gas production operations emit about 4% of California total greenhouse gas emissions. Oil and gas production from hydraulically fractured reservoirs emits less greenhouse gas per barrel of oil than production using steam injection. Oil produced in California using hydraulic fracturing also emits less greenhouse gas per barrel than the average barrel imported to California. If the oil and gas derived from stimulated reservoirs were no longer available, and demand for oil remained constant, the replacement fuel could have larger greenhouse emissions.

Most oil-related greenhouse gas (GHG) emissions in the state come from the consumption of fossil fuels such as gasoline and diesel, not the extraction of oil. According to state emission inventories, GHG emissions from oil and gas production processes equal about four percent of total GHG emissions in California, although some studies conclude these emission inventories may underestimate true emissions. Fields with lighter oil result in low emissions per barrel of crude produced, while fields with heavier oil have higher emissions because of the need for steam injection during production as well as more intensive refining needed to produce useful fuels such as gasoline. Well stimulation generally applies to reservoirs with lighter oil and consequently smaller greenhouse gas burdens per unit of oil. Oil and gas from San Joaquin Basin reservoirs using hydraulic fracturing have a relatively smaller carbon footprint than oil and gas from reservoirs such as those in the Kern River field that use steam flooding (Figure 1.3-10).

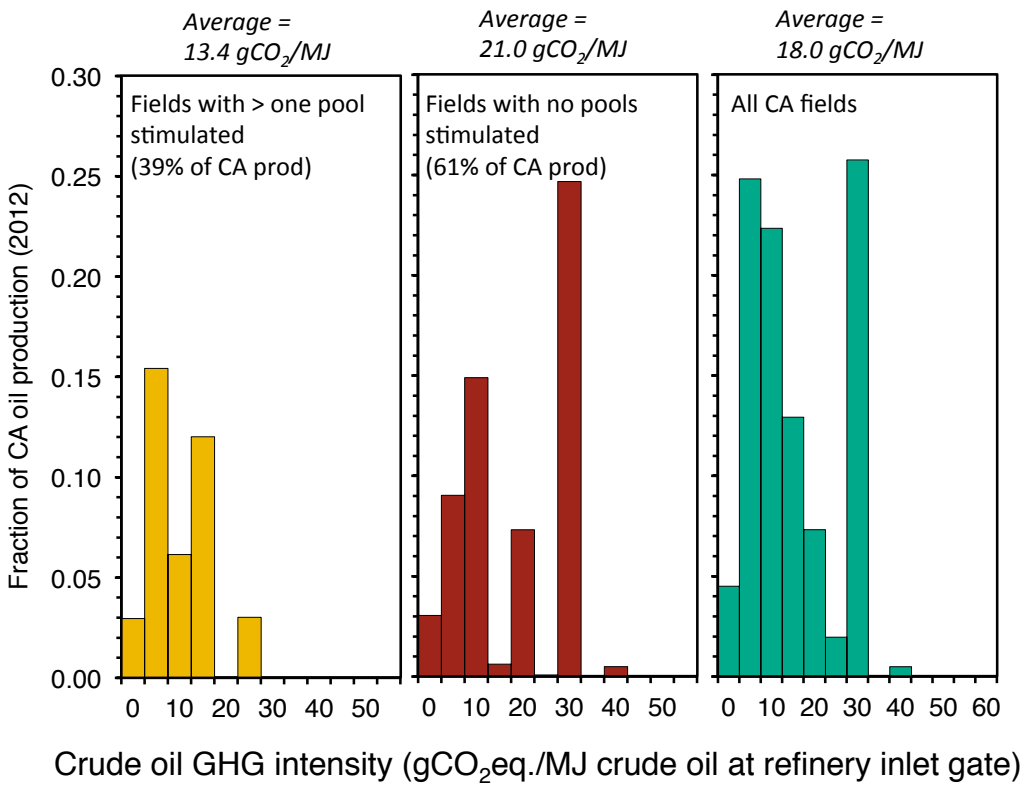


Figure 1.3-10. Distribution of crude oil greenhouse gas intensity for fields containing well-stimulation-enabled pools (left), those that are not stimulated (middle) and all California oilfields (right) (figure from Volume II, Chapter 3).

If well stimulation were disallowed and consumption of oil and gas in California did not decline, more oil and gas would be required from non-stimulated California fields or regions outside of California, possibly with higher emissions per barrel. Consequently, overall greenhouse gas emissions due to production could increase if well stimulation were stopped in California. The net greenhouse gas change associated with the use of hydraulic fracturing requires knowing the carbon footprint of both in-state and out-of-state production, and understanding the scale of impact requires a market-informed life cycle analysis.

Recommendation 6.1. Assess and compare greenhouse gas signatures of different types of oil and gas production in California.

Conduct rigorous market-informed life-cycle analyses of emissions impacts of different oil and gas production to better understand GHG impacts of well stimulation (Volume II, Chapter 3).

Conclusion 6.2. Air pollutants and toxic air emissions[5] from hydraulic fracturing are mostly a small part of total emissions, but pollutants can be concentrated near production wells.

According to publicly available California state emission inventories, oil and gas production in the San Joaquin Valley air district likely accounts for significant emissions of sulfur oxides (SO_x), volatile organic compounds (VOC), and some air toxics, notably hydrogen sulfide (H_2S). In other oil and gas production regions, production as a whole accounts for a small proportion of total emissions. Hydraulic fracturing facilitates about 20% of California production, and so emissions associated with this production also represent about 20% of all emissions from the oil and gas production in California. Even where the proportion of air pollutants and toxic emissions caused directly or indirectly by well simulation is small, atmospheric concentrations of pollutants near production sites can be much larger than basin or regional averages, and could potentially cause health impacts.

In the San Joaquin Valley oil and gas production as a whole accounts for about 30% of sulfur oxides and 8% of anthropogenic volatile organic compound (VOC) emissions. VOCs in turn react with nitrogen oxides (NO_x) to create ozone. Eliminating emissions from oil and gas production would reduce, but not eliminate the difficult air pollution problems in the San Joaquin Valley. Oil and gas facilities also emit significant air toxics in the San Joaquin Valley. They are responsible for a large fraction (>70%) of total hydrogen sulfide emissions and small fractions (2-6%) of total benzene, xylene, hexane, and formaldehyde emissions (Figure 1.3-11). Dust ($PM_{2.5}$ and PM_{10}) is a major air quality concern in the San Joaquin Valley, and agriculture is the dominant source of dust in the region. The amount of dust generated by oil and gas activities (including hydraulic fracturing) is comparatively very small.

5. Toxic air pollutants, also known as hazardous air pollutants, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental effects. Criteria air contaminants (CAC), or criteria pollutants, are a set of air pollutants that cause smog, acid rain, and other health hazards.

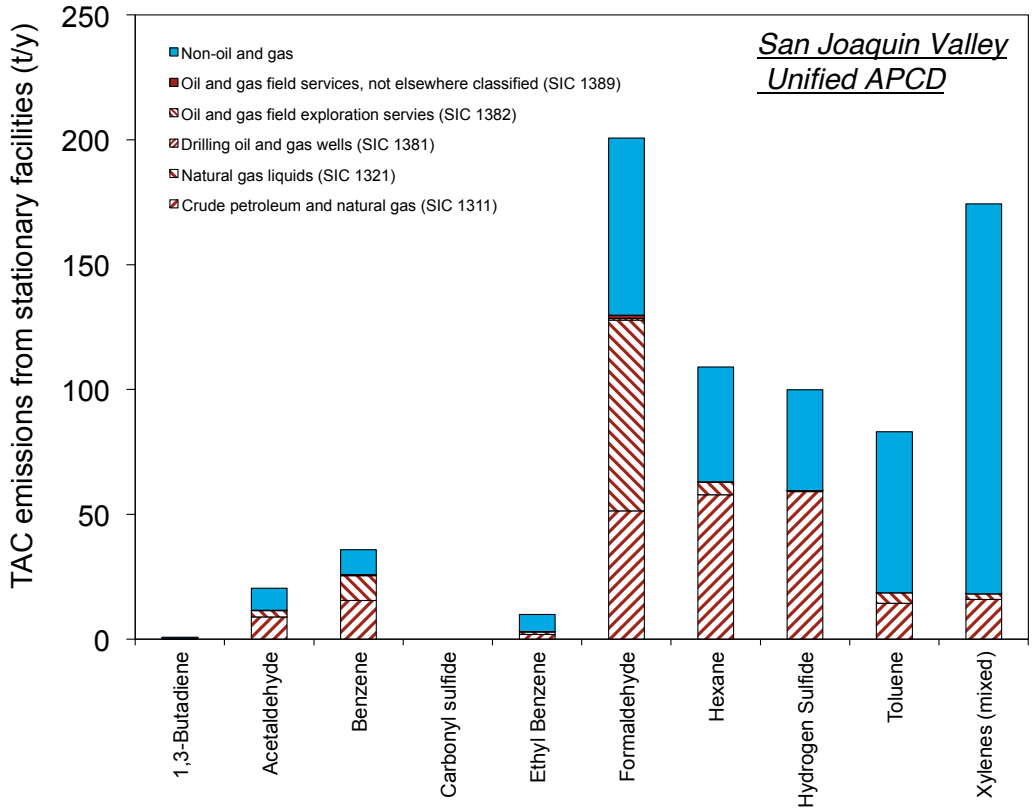


Figure 1.3-11. Summed facility-level toxic air contaminant (TAC) emissions in San Joaquin Valley air district). Facility-level emissions derived from a California Air Resources Board (CARB) facility emissions tool. Total emissions are emissions from all oil and gas facilities in the air district, including gasoline fueling stations (Volume II, Chapter 3) (figure from Volume II, Chapter 3).

In the South Coast Air District (including all of Orange County, the non-desert regions of Los Angeles and Los Angeles County, San Bernardino County, and Riverside County), upstream oil and gas sources represent small proportions (<1%) of criteria air pollutant and toxic air contaminant emissions due to large quantities of emissions from other sources in a highly urbanized area.

> *Produced gas can be emitted during recovery of hydraulic fracturing liquids and therefore be a possible source of direct air emissions from well stimulation. Regulation and control technologies can address these emissions with proper implementation and enforcement. Federal regulations already control emissions during fluid recovery from new gas wells using "green completions," and California is developing similar regulations for oil wells.*

Public data sources provide information about the emissions from all upstream oil and gas production, but do not include information that would allow separating out the

contribution of emissions from hydraulically fractured wells. Because well stimulation facilitates or enables about 20% of California's oil recovery, indirect air impacts from well stimulation are likely on the order of one-fifth of total upstream oil and gas air impacts.

Even if upstream oil and gas operations are not a large part of basin-wide air pollution load, at the scale of counties, cities or neighborhoods, oil and gas development can have larger proportional impacts. Even in regions where well stimulation-related emissions represent a small part of overall emissions, local air toxic concentrations near drilling and production sites may be elevated. This could result in health impacts in densely populated areas such as Los Angeles, where production wells are in close proximity to homes, schools, and businesses. Public datasets do not provide specific enough temporal and spatial data on air toxics emissions that would allow any realistic assessment of these impacts.

Recommendation 6.2. Control toxic air emissions from oil and gas production wells and measure their concentrations near productions wells.

Apply reduced-air-emission completion technologies to production wells, including stimulated wells, to limit direct emissions of air pollutants, as planned. Reassess opportunities for emission controls in general oil and gas operations to limit emissions. Improve specificity of inventories to allow better understanding of oil and gas emissions sources. Conduct studies to improve our understanding of toxics concentrations near stimulated and un-stimulated wells (Volume II, Chapter 3; Volume III, Chapter 4 [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 1.3-12). 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.

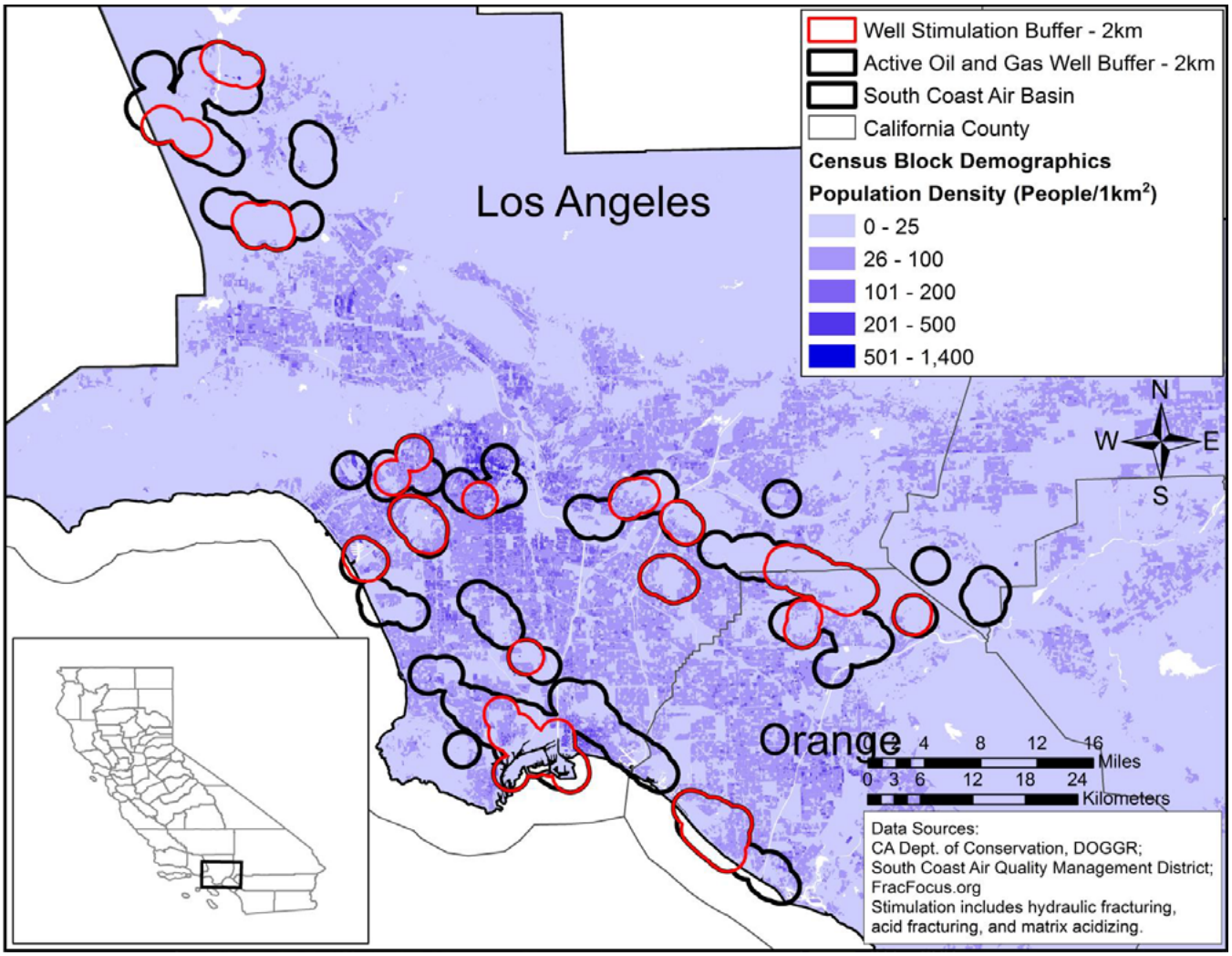


Figure 1.3-12. Population density within 2,000 m (6,562 ft) of currently active oil production wells and currently active wells that have been stimulated (figure from Volume III, Chapter 4 [Los Angeles Basin Case Study]).

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]).

Conclusion 6.4. Hydraulic fracturing and acid stimulation operations add some occupational hazards to an already hazardous industry.

Studies done outside of California found workers in hydraulic fracturing operations were exposed to respirable silica and VOCs, especially benzene, above recommended occupational levels. The oil and gas industry commonly uses acid along with other toxic substances for both routine maintenance and well stimulation. Well-established procedures exist for safe handling of dangerous acids.

Occupational hazards for workers who are involved in oil and gas operations include exposure to chemical and physical hazards, some of which are specific to well stimulation activities and many of which are general to the industry. Our review identified studies confirming occupational hazards directly related to well stimulation in states outside of California. The National Institute for Occupational Safety and Health (NIOSH) has conducted two peer-reviewed studies of occupational exposures attributable to hydraulic fracturing across multiple states (not including California) and times of year. One of the studies found that respirable silica (silica sand is used as a proppant to hold open fractures formed in hydraulic fracturing) was in concentrations well in excess of occupational health and safety standards (in this case permissible exposure limits or PELs) by factors of as much as ten. Exposures exceeded PELs even when workers reported use of personal protective equipment. The second study found exposure to VOCs, especially benzene, above recommended occupational levels. The NIOSH studies are relevant for identifying hazards that could be significant for California workers, but no study to date has addressed occupational hazards associated with hydraulic fracturing and other forms of well stimulation in California.

While both hydrochloric acid and hydrofluoric acid are highly corrosive, hydrofluoric acid can be a greater health risk than hydrochloric acid in some exposure pathways because of its higher rate of absorption. State and federal agencies regulate spills of acids and other hazardous chemicals, and existing industry standards dictate safety protocols for handling acids. The Office of Emergency Services (OES) reported nine spills of acid that can be attributed to oil and gas development between January 2009 and December 2014. Reports also indicate that the spills did not involve any injuries or deaths. These acid spill reports represent less than 1% of all reported spills of any kind attributed to the oil and gas development sector in the same period, and suggest that spills of acid associated with oil and gas development are infrequent, and industry protocols for handling acids protect workers.

Employers in the oil and gas industry must comply with existing California occupational safety and health regulations, and follow best practices to reduce and eliminate illness and injury risk to their employees. Employers can and often do implement comprehensive worker protection programs that substantially reduce worker exposure and likelihood of illness and injury. However, the effectiveness of these programs in California has not been evaluated. Engineering controls that reduce emissions could protect workers involved in well stimulation operations from chemical exposures and potentially reduce the likelihood of chemical exposure to the surrounding community.

Recommendation 6.4. Assess occupational health hazards from proppant use and emission of volatile organic compounds.

Conduct California-based studies focused on silica and volatile organic compounds exposures to workers engaged in hydraulic-fracturing-enabled oil and gas development processes based on the NIOSH occupational health findings and protocols.

1.4. References

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