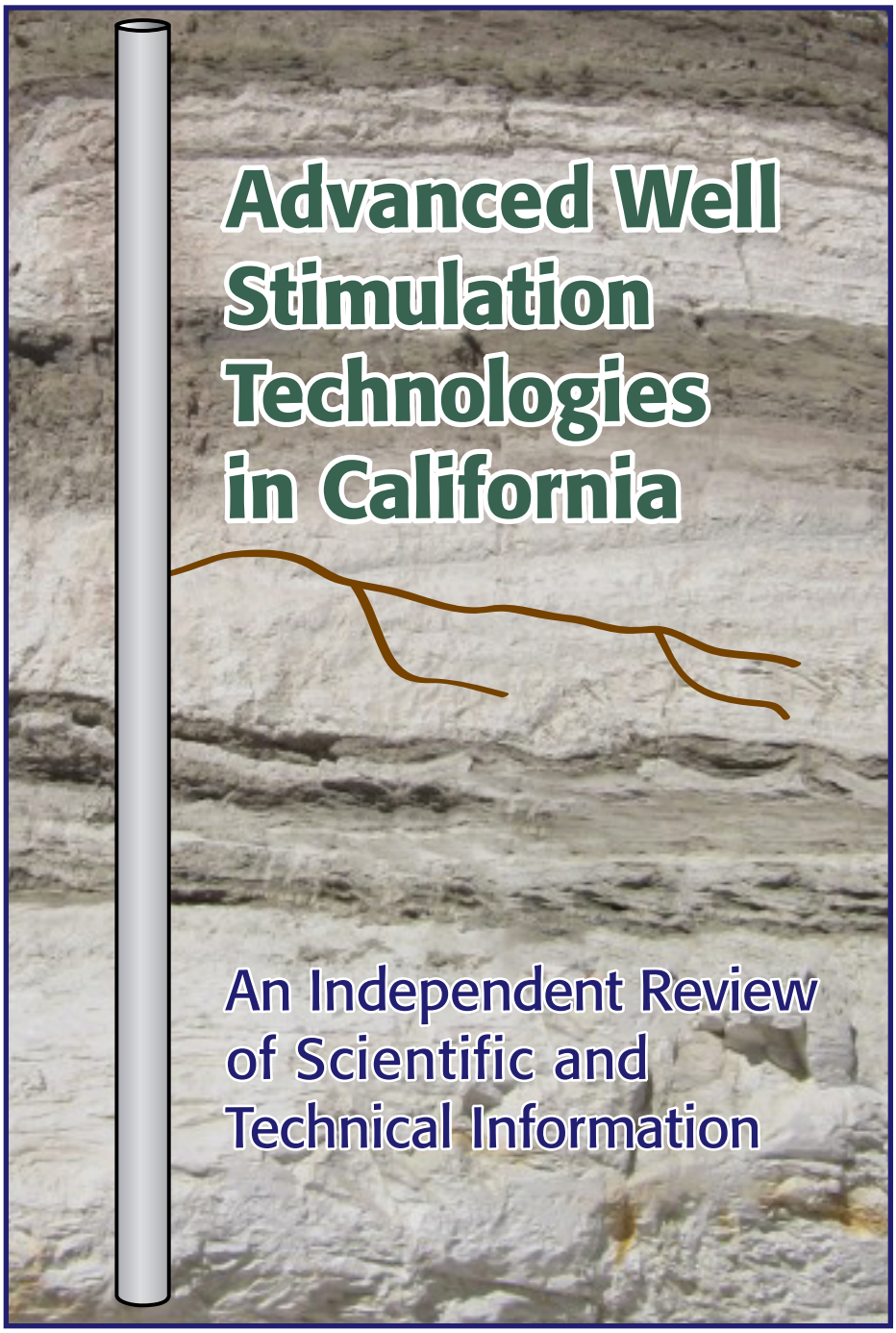

Advanced Well Stimulation Technologies in California

An Independent Review of Scientific and Technical Information

California Council on Science and Technology
Lawrence Berkeley National Laboratory
Pacific Institute

July 2016

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About CCST

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

Note

The California Council on Science and Technology (CCST) has made every reasonable effort to assure the accuracy of the information in this publication. However, the contents of this publication are subject to changes, omissions, and errors, and CCST does not accept responsibility for any inaccuracies that may occur.

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Acronym List

API Number	American Petroleum Institute Number
BWSD	Belridge Water Storage District
BLM	Bureau of Land Management
BTEX	Benzene, toluene, ethylbenzene, and xylenes
CARB	California Air Resource Board
CAS	Chemical Abstract Service
CCST	California Council on Science and Technology
CEMA	California Emergency Management Agency
cp	Centipoise
CSU	California State University
CVRWQCB	Central Valley Regional Water Quality Control Board
dBA	Decibels
DFW	Dallas-Fort Worth
DOC	(California) Department of Conservation
DOC	Dissolved organic carbon
DOE	United States Department of Energy
DOGGR	California Division of Oil, Gas and Geothermal Resources
EC	Electrical conductivity
EDTA	Ethylenediaminetetraacetic acid
EGMBE	Ethylene glycol monobutyl ether
EGS	Enhanced geothermal system
EPS	Explosive propellant systems
ERCB	Energy Resources Conservation Board
FWS	Fish and Wildlife Service
GAMA	Groundwater ambient monitoring and assessment
GAO	Government Accountability Office
GHG	Greenhouse gas
GHS	Globally Harmonized System
GIS	Geographic information system
GPa	Gigapascal
GWP	Global warming potential
HCl	Hydrochloric acid
HF	Hydrofluoric acid
ICoTA	International Coiled Tubing Association
IUC	Underground injection control
KCl	Potassium chloride
LBNL	Lawrence Berkeley National Laboratory
LPG	Liquid propane
Ma	Million years ago
MAPDIR	Maximum pressure differential and injection rate
MCLs	Maximum contaminant levels
MPT	Mud pulse telemetry

MWD	Measurement while drilling
NEPA	National Environmental Policy Act
NORM	Naturally occurring radioactive materials
NOx	Nitrogen oxides
NPDES	National Pollution Discharge Elimination System
NRC	National Research Council
NTA	Nitrilotriacetic acid
NYSDEC	New York State Department of Environmental Conservation
OandG	Oil and gas
PAHs	Polycyclic aromatic hydrocarbons
PCBs	Polychlorinated biphenyls
PI	Pacific Institute
PM	Particulate matter
SB	Senate Bill
SCP	Sustained casing pressure
SJVAPCD	San Joaquin Valley Air Pollution Control District
SVOCs	Semi-volatile organic compounds
TDS	Total dissolved solids
TOC	Total organic carbon
TSS	Total suspended solids
TVD	True vertical depth
UC	University of California
USGS	United States Geological Survey
US DOE	United States Department of Energy
US EIA	United States Energy Information Administration
US EPA	United States Environmental Protection Agency
VOCs	Volatile organic compounds
WET	Whole effluent toxicity
WSA	World shale average
WSPA	Western States Petroleum Association
WST	Well stimulation technologies
WWTPs	Wastewater treatment plants

Introduction

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Jens Birkholzer, Preston Jordan, James Houseworth (LBNL)

Background and Key Objectives

In the context of rapidly increasing oil production from low-permeability rocks, including hydrocarbon source rocks, elsewhere in the country, the Bureau of Land Management (BLM) as an owner of federal lands with potential for expanded oil exploration
and production in California was interested in an up-to-date independent technical assessment of well stimulation technologies (WST), with a focus on hydraulic fracturing, employed in this state. WST increase the permeability of rocks around a well to allow or increase oil production. The three WST considered in this report include hydraulic fracturing, acid fracturing, and matrix acid stimulation as practiced in California.

The purpose of this report, commissioned in September 2013, is to provide BLM with the required independent technical assessment. (Appendix A provides BLM's charge to the California Council on Science and Technology (CCST).) This information will be used in future planning, leasing, and development decisions regarding oil and gas issues on the Federal mineral estate in California. The report provides a synthesis and assessment of the available scientific and engineering information available up to February 2014 associated with hydraulic fracturing and other WST in onshore oil reservoirs in California.

This report addresses three key questions posed by BLM:

- **Key Question 1:** What are the past, current and potential future practices in well stimulation technologies including hydraulic fracturing, acid fracturing, and matrix acidizing in California?

- **Key Question 2:** Where will well stimulation technologies allow expanded production of oil onshore in California?

- **Key Question 3:** What are the potential environmental hazards of well stimulation technologies in California?

The History of Oil Production in California

The Midway-Sunset field, which is the largest in California in terms of expected total oil production, was discovered in 1894. The twelve largest onshore or partially onshore oil fields were discovered by 1932 and the 43 largest by 1949. All 45 onshore or partially onshore oil fields termed "giant" by DOGGR (more than 16 million m^3 (100 million barrels) of expected total oil production) were discovered by 1975 (DOGGR, 2010).

More oil was produced in California in 2013 than in any other state except Texas and North Dakota. California has produced the third most oil of all the states since at least the 1980s. The volume of oil produced in California peaked in 1985 and had declined by approximately half as of 2013 (US EIA, 2014).

Oil production in California has been enhanced by application of a number of technologies through time. Wide deployment of water flooding commenced in the mid-1950s. This technique involves injecting water into the oil reservoir via one set of wells, which causes more oil to flow to the production wells. Wide deployment of cyclic steaming and steam flooding commenced in the mid-1960s (Division of Oil and Gas, 1966). Injection of steam heats highly viscous ("heavy") oil resulting in more flowing to the production well. In cyclic steaming, injection of steam alternates with oil production in the same well. Steam flooding involves continuous steam injection into wells interspersed among the production wells. Intensive deployment of hydraulic fracturing commenced in the 1980s (see Chapter 3).

DOGGR first attributed the portion of oil production due to water flooding and steam injection for production in 1989. It attributed 71% of oil production in that year to these techniques (DOGGR, 1990). A total of 76% of production in 2009, the most recent year with attribution, was due to these techniques (DOGGR, 2010). The portion of production involving hydraulic fracturing was not listed.

In addition to steam injection, fire flooding and downhole heating were tested for heating viscous oil in the subsurface in the early 1960s. Fire flooding involved injecting air into the reservoir to sustain combustion of part of the oil. Downhole heating involved placing pipe loops into wells that circulated hot water or oil. Fire flooding was found to be generally uneconomical. Downhole heating resulted in more modest, and less economic, production increases than steam injection (Rintoul, 1990).

CCST Committee Process

A WST steering committee was assembled and vetted by CCST. Members were appointed based on technical expertise and a balance of technical viewpoints. (Appendix A provides information about CCST's steering committee.) In parallel, BLM contracted with Lawrence Berkeley National Laboratory to support the analysis and develop the findings based on the literature review and analyses. Appendix B provides information about the LBNL review team which authored Sections 2, 3, 4, and 5 of this report.

For each of the three key questions asked by the BLM, investigations conducted by LBNL and their contractors led to a series of findings, and based on these findings, the steering committee reached a series of consensus conclusions. These findings and conclusions are included below. The literature and analyses are described in the bulk of this report in Section 2, 3, 4, and 5.

This report has also undergone extensive peer review. (Peer reviewers are listed in Appendix H, "California Council on Science and Technology Study Process"). Reviewers were chosen for their relevant technical expertise. Following the receipt of peer review comments in May 2014, this report was revised.

Method and Data Sets Available for the Report

This assessment is based on review and analysis of existing data and scientific literature. Preference is given to using the findings in peer-reviewed scientific literature. Peer-reviewed scientific literature is principally found in peer-reviewed scholarly journals. Certain institutions such as the National Academies of Sciences and United States federal regulatory agencies such as the United States Geological Survey also self-publish scientific papers that undergo a rigorous peer review process. Scientific papers that undergo independent peer review by a panel of experts are considered to provide information that is more likely to be accurate than non-peer reviewed literature. Peer review entails experts not involved in the work assessing the thoroughness, accuracy and relevance of the work. If the reviewers find omissions or errors in the work, they provide comments describing these to the authors of the paper and the editor of the publication. In order for the paper to be published, the authors must address these to the satisfaction of the editor. Because of this process, such papers are referred to as "peer-reviewed scientific literature."

During the conduct of this review, it was found that the body of relevant peer-reviewed literature — the source that meets the highest standard of scientific quality control — is very limited. For instance there is little information on water demand in California for hydraulic fracturing. Consequently other material was considered, such as government data and reports including well records collected by the Division of Oil, Gas and Geothermal Resources (DOGGR) and recent notices submitted pursuant to California Senate Bill 4 (SB 4, Pavley, Chapter 313, Statutes of 2013), and so-called "grey literature" if this

literature was topically relevant and met scientific standards for inclusion. We also accessed and analyzed voluntary web-based databases such as FracFocus. In some cases where specific data on California were not available, analogues from other locations were used, while recognizing the limitations of the analogues. Much of the data available to analyze current practice come from voluntary sources plus six weeks of data from well stimulation notices required by SB4. Data from well stimulation notices submitted through January 15th, 2014, were considered. Data through the end of 2013 were considered from the other sources. Relevant scientific literature available as of February, 2014, was reviewed. A reference to a report from US EIA published in June 2014 was added during the peer review process because the updated assessment had a substantial bearing on our findings and conclusions.

Extensive efforts were made to survey all information relevant to this report, including peer-reviewed scientific literature, government-collected data, voluntary reporting by industry, and non-peer reviewed literature. Categories of non-peer reviewed literature considered admissible to the report were government reports, studies issued by universities and non-government organizations, textbooks, and papers from technical conferences. To be considered admissible to the report, literature needed to be based on data that drew traceable conclusions clearly supported by the data. Opinion-based materials were not included in the assessment.

Avenues for finding relevant literature and data included:

1. Keyword searches in databases of scientific literature;

2. Finding literature and data, regardless of peer-review status, referenced in other literature;

3. Soliciting data and literature submissions from the public via two webinars, a website, and a press release;

4. Discussions with outside experts in the field, consisting of informal dialogues and organized technical meetings;

5. Data mining of voluntary industry reporting to FracFocus.org;

6. Data mining of government-collected data; and

7. Internet keyword searches.

Further details on the process for reviewing data and literature for the report can be found in Appendix E, “Bibliography of Submitted Literature.”

We caution that official government records were not necessarily designed to answer all the questions posed by BLM to CCST. Records filed with DOGGR in the past do not comprehensively record well stimulation events. Voluntarily submitted data, such as those available on FracFocus, although very useful, are not required to be either complete or accurate. We describe the challenges with the quality of the data in order to transparently qualify the limitations in our conclusions.

More information pertinent to this assessment may exist, but was unavailable at the time of writing. This is particularly the case for research and development and exploration results. Oil companies and their service providers spend billions of dollars per year on research and development (IHS, 2013). This compares to hundreds of millions of dollars per year in Federal government funding for all research related to fossil fuels, including coal (US Department of Energy, 2013). The resulting disparity in private versus publicly available information makes it particularly difficult to assess the prospects for further application of well stimulation in California in the future.

Furthermore, due to the timing of this report, the mandatory reporting requirements pursuant to California Senate Bill 4 (SB 4, Pavley, Chapter 313, Statutes of 2013) were only just becoming available for analysis in this study. Effective January 1, 2014, SB4 required that notices have to be submitted at least 30 days prior to each well stimulation operation, and that well stimulation records have to be filed within 60 days after stimulation. These well records will provide information on well stimulation locations, fluid volumes, and constituents, as well as the composition and disposition of flowback fluids. Such information will in the future allow a much improved assessment of potential hazards specific to California associated with well stimulation, including material and equipment supply for stimulation, disposal of stimulation fluids, and land-use changes. For our study, however, no well records had yet been submitted, and only a limited amount of well stimulation notices projecting future activity could be considered, submitted during a 6-week period between November 1, 2013 and January 15, 2014.

In future months, more disclosures required by SB4 will be filed, and the picture we obtained from the limited data available for this report may change. Some important data gaps will likely remain, for example: (1) the depth of the base of groundwater in the vicinity of well stimulations (which varies depending upon the definition of groundwater, the location, and other factors); (2) the means of delivery of stimulation fluids to and removal from well stimulation sites; (3) emissions from venting and flaring of gases from flowback fluids; and (4) the number of oil and gas wells that show indications of structural integrity impairment. Lack of data on structural integrity impairment of oil and gas well casing and cement limits the ability to identify the extent of the sub-surface migratory mechanisms through which fluids and gases can move from the well and the well bore into the environment.

Well Stimulation Technologies

Hydraulic fracturing creates fractures in reservoir rocks in order to enhance the flow of petroleum or natural gases to the well. This is accomplished by pumping fluids into a zone of the well until the fluid pressure is sufficient to break the rock. Then, small particles called "proppant" are pumped into the fracture to keep it from closing back down when the fluid pressure is reduced, e.g., during subsequent fluid production. The hydraulic fracturing fluid that returns up the well bore is called "flowback" fluid. Fluid removed from the well gradually changes from flowback fluid to "produced water" and the time at which a well changes from the hydraulic fracturing process to the production process is not precisely defined

Acid fracturing accomplishes the same goal as hydraulic fracturing by injecting low pH fluids instead of proppants into a created fracture. This process is not intended to create new fractures via high fluid pressures. The acid is intended to non-uniformly etch the walls of the fracture so that some fracture conductivity is maintained after the fracture closes.

Matrix acidizing is the process of injecting strong acids into the formations around a well at pressures below the fracturing pressure of the rock. The most common acid systems used are hydrochloric acid (HCl) in carbonate formations, and hydrofluoric/hydrochloric acid (HF/HCl) mixtures in sandstone formations. Matrix acidizing in carbonates can create small channels or tubes called wormholes that can propagate as much as 20 feet into the formation. This can provide a true stimulation of a well, analogous to that of a small hydraulic fracturing treatment. Because of much smaller reaction rates, the acid dissolution in sandstones is limited to a much smaller distance, of less than one to perhaps two feet into the formation. Because of this limited penetration distance, the benefit of matrix acidizing in sandstones comes primarily from removing damaging solids that have reduced the near-well permeability. However, there are some instances of matrix acidizing using HF/HCl reported in the Monterey Formation in California that may have greater penetration because of the presence of natural fractures.

Report Structure and Content Overview

Section 1 below gives the major findings and conclusions of this study that were developed in a consensus process by members of the steering committee. The detailed technical information in the remainder of this report is presented in four sections. Section 2 covers WST in general, subject to the constraint that the stimulation is used to increase the permeability of the oil reservoir. Section 3 presents information on the past, current and potential future use of WST in California. Section 4 presents information on the petroleum geology of California. Section 5 covers a wide range of items all linked to potential adverse impacts caused by the use of WST in California.

Section 2 presents information on the general types and applications of WST in general, starting with the techniques for drilling and constructing the well. Well drilling methods for vertical and directional drilling are covered and the associated installation of casing and cement are presented. Section 2 also defines and presents well stimulation methods, including the typical types of materials and procedures, and how these methods are applied for different geologic conditions. The stimulation methods described are hydraulic fracturing, acid fracturing, and matrix acidizing.

Section 3 describes the application of the WST for onshore oil production in California. These are discussed in terms of how the horizontal wells and well stimulation technologies have been used in the past along with information about current applications in California. An assessment is provided of the current level of activity for each well stimulation method including the types and quantities of well stimulation fluids currently in use.

Section 4 provides background on the geologic components and processes that affect the development of petroleum systems. The important reservoir rock types currently being produced using well stimulation technologies in California are described and their rock properties are summarized. These rock types and properties are compared with the Bakken shale, an unconventional shale reservoir found in North Dakota, Montana and Canada, that has been extensively developed using WST. The California oil reservoirs are then described in terms of the major sedimentary basins in which they occur, including deeper petroleum source rocks that have not been subject to significant petroleum resource development. Some general observations are provided about the potential application of advanced well stimulation technologies, as currently used elsewhere for petroleum production from unconventional shale reservoirs, to oil-bearing shales in California.

Section 5 brings together all the potential environmental impacts of using well stimulation technologies in California. The section begins with a discussion impacts in terms of the quantities of water being used for well stimulation activities in the state. Water quality are discussed in terms of chemicals used for well stimulation fluids and the composition of fluids recovered at the end of the stimulation during flowback. The potential contamination pathways are then summarized for various types of surface discharge and subsurface pathway formation and fluid migration. Information on known or suspected contamination episodes in California and elsewhere that have occurred as a result of well stimulation activities are presented for both surface and subsurface sources of contamination. The potential effects of well stimulation activities on air quality using information from various US locations are reviewed and put into context for California. In addition, atmospheric emissions of greenhouse gases (CO_2 and methane) are also estimated and compared with emission related to overall energy use. The impacts on wildlife and vegetation are discussed in the context of the typical petroleum recovery infrastructure and from which effects of well stimulation activities are inferred. The potential for induced seismic activity as a result of the injection of hydraulic fracturing fluids and injection of flowback for waste disposal are reviewed. Other impacts of increased vehicular traffic and noise as a result of well stimulation activities are also discussed. There is very little definitive

information on the direct environmental impacts of WST in California. Most of the available information addresses indirect impacts from oil and gas production, or direct impacts in other states, or provides some partial information on direct impacts in California, but fails to provide complete answers to the question at hand. As a result, the authors surveyed a wide range of literature that offers relevant information but few conclusive answers.

Major Findings And Conclusions

Authored by
CCST Steering Committee

Key Question 1: What are the past, current and potential future practices in well stimulation technologies including hydraulic fracturing, acid fracturing, and matrix acidizing in California?

Many of the concerns about WST and hydraulic fracturing in particular arise because practices in other states have come under scrutiny and criticism. Over the last decade, application of horizontal drilling and hydraulic fracturing has allowed a substantial increase in production of oil from low-permeability rocks containing this resource, such as the Bakken Formation in Montana and North Dakota (Pearson et al., 2013; Hughes, 2013). This report critically evaluates the practices in California and the differences between the practice in California and the major hydraulic fracturing practice in other states. In the Bakken and the Eagle Ford, for example, oil is found in thin, but very extensive layers that have very low permeability because they are lacking many natural fractures in the rock. Producers drill long, horizontal wells and create permeability by creating networks of connected fractures. In California, reservoirs that are produced using hydraulic fracturing tend to be thick and not laterally extensive and they typically have higher initial permeability than the shale oil formations mentioned above. Consequently the practice in our state is significantly different than elsewhere.

Conclusion 1: Available data suggests that present day well stimulation practices in California differ significantly from practices used for unconventional shale reservoirs in states such as North Dakota and Texas. For example, California hydraulic fractures tend to use less water, the hydraulic fracturing fluids tend to have higher chemical concentrations, the wells tend to be shallower and more vertical, and the target geologies present different challenges. Therefore the impacts of hydraulic fracturing observed in other states are not necessarily applicable to current hydraulic fracturing practices in California.

Hydraulic fracturing in a variety of forms has been widely applied over many decades in California with records of application in at least 69 onshore oil fields identified through well-record searches in central and southern California out of more than 300 fields in the state. The vast majority (85%) of past and current recorded fracturing activities occur in the North and South Belridge, Lost Hills, and Elk Hills fields, located in the southwestern portion of the San Joaquin Valley, in Kern County. Data from FracFocus, Division of Oil,

Gas and Geothermal Resources' (DOGGR's) well records, well stimulation notices filed from December 1, 2013 to January 15, 2014 pursuant to SB 4 requirements, and well-record searches suggest hydraulic fracturing is conducted in 100 to 150 wells per month. Well-record searches indicate that this rate has increased since the end of the most recent recession, but is the same as before the recession. For comparison, over one million hydraulic fracturing operations are estimated to have occurred throughout the United States, with over 100,000 of these in recent years. *(Sections 3.2.1, Historical Use of Hydraulic Fracturing, and 3.2.2, Current Use of Hydraulic Fracturing)*

Large-scale application of high-fluid-volume hydraulic fracturing has not found much application in California, apparently because it has not been successful, and for reasons discussed below is unlikely in the future (see Conclusion 3). The majority of the oil produced from fields in California is not in the low-permeability shale source rock (i.e., shale in the Monterey Formation), but rather from other more permeable geologic formations that often contain oil that has migrated from source rocks. These reservoirs do not resemble the low-permeability extensive, and continuous shale layers that are amenable to production with high volume hydraulic fracturing from long-reach horizontal wells. *(Section 4, Prospective Application of Well-Stimulation Technologies in California)*

According to DOGGR well data and SB 4 stimulation notices, most of the hydraulically fractured wells in California are vertical or near vertical. These shorter wells require less fluid for hydraulic fracturing applications than wells that have long lateral (i.e., horizontal) legs. More than 95% of the hydraulic fracture events in California employ a gel for the stimulation fluid as opposed to applications of "slickwater." Slickwater includes a friction reducer to allow injection of more stimulation fluid volume in a given time period. This is useful where the goal is to create a new network of fractures in rocks that are relatively brittle with low permeability. Gel is used in California because the main rocks targeted for stimulation are less brittle and more permeable than areas where slickwater is used. Additionally, gel is capable of carrying more proppant than slickwater to hold existing fractures open. Because of the predominance of stimulation in vertical and near-vertical wells, and the use of gel, the volumes of water used in hydraulic fracturing in California are much smaller than in oil source rock plays elsewhere.

The average amount of reported water used in the recent past and currently in California for each hydraulic fracturing operation is 490 to 790 m^3 (130,000 to 210,000 gallons) per well. These volumes are similar to the annual water use of 580 m^3 (153,000 gallons) in an average household in California over the last decade and are significantly less than the average 16,100 m^3 of water per well (4.25 million gallons) reported for the Eagle Ford shale tight oil play in Texas. Further, the volume per treatment length in California is 2.3 to 3.0 m^3/m (188 to 244 gallons per ft) based on FracFocus and notice data. This is much less than the 9.5 m^3/m (770 gallons per foot) used in the Eagle Ford formation. It is slightly below the 3.4 m^3/m (277 gallons/ft) for cross-linked gel used in the Bakken formation, in North Dakota, but considerably below the 13.2 m^3/m (1,063 gallons/ft) for slickwater used in that location. *(Section 3.2.3, Fluid Volume, and 3.2.4, Fluid Type)*

Conclusion 2: Acid fracturing is a small fraction of reported WST to date in California. Acid fracturing is usually applied in carbonate reservoirs, and these are rare in California. Matrix acidizing has been used successfully but rarely in California. These technologies are not expected to lead to major increases in oil and gas development in the state.

Acid fracturing is commonly limited to carbonate reservoirs, because the acid-mineral reaction rates in in a sandstone or siliceous shale rock as found in California are too slow to create significant etching of the fracture walls. For the process to work in such rocks as it does in carbonates, the acid-rock reaction rates would have to be increased by many orders of magnitude (4-8 orders). It is not reasonable to expect any innovation that would accomplish this. A few instances of acid fracturing in siliceous rock in California were reported in SB 4 well stimulation notices. However, given that acid fracturing of siliceous rocks is otherwise unknown, these may be cases of misreported matrix acidization.

As mentioned above, acid fracturing is generally applied only to carbonate reservoirs, which include those consisting of dolomite. The only onshore carbonate oil reservoirs identified in California are in the Santa Maria and possibly the Los Angeles basins. The carbonate reservoirs occurring in a few fields in the Santa Maria Basin consist of naturally fractured dolomite. Reports of the use of acid fracturing in these reservoirs in California were not identified in the literature.

Hydrochloric acid mixed with hydrofluoric acid is generally reported as used for matrix acidizing of siliclastic reservoirs, which predominate in California. In these reservoirs, matrix acidizing is typically used to overcome the effects of formation damage (reduction in the rock permeability near the wellbore) that occurs during drilling and completion operations in conventional reservoirs. In the absence of formation damage, matrix acidizing can increase well productivity by only about 20%. In a very-low-permeability reservoir, this limited increase in productivity is far less than the stimulation level necessary to make oil or gas recovery economic.

By comparison, the large-scale fracturing treatments being applied in shale formations like the Eagle Ford or the Bakken increase well productivity by orders of magnitudes above the productivity of an unstimulated well. Thus, matrix acidizing technology is not expected to lead to dramatic increases in oil and gas development as has hydraulic fracturing technology in many shale formations.

Use of matrix acidizing is only reported in three onshore oil fields in California, which contrasts with the tens of fields identified where hydraulic fracturing has been used. Stimulation notices submitted to the State to date indicate matrix acidizing only in the Elk Hills Field. There were 26 matrix acid notices submitted and not withdrawn in the first six weeks of SB 4 permitting, as compared to 208 hydraulic fracture notifications.

All the notices specify use of "mud" acid, either by combining HCl and HF acids directly or by producing an HCl-HF acid mixture by reacting NH_4HF_2 (ammonium bifluoride) with an excess of HCl. The notices indicate an average matrix acidizing water volume per well of 109 m^3 (40,000 gallons), which represents a fraction of that needed for hydraulic fracturing. The average volume per treatment length implied by the notices is 1.7 m^3/m (137 gallons per ft). *(Section 3.3, Acid Fracturing, and 3.4, Matrix Acidizing)*

Key Question 2: Where will well stimulation technologies allow expanded production of oil onshore in California?

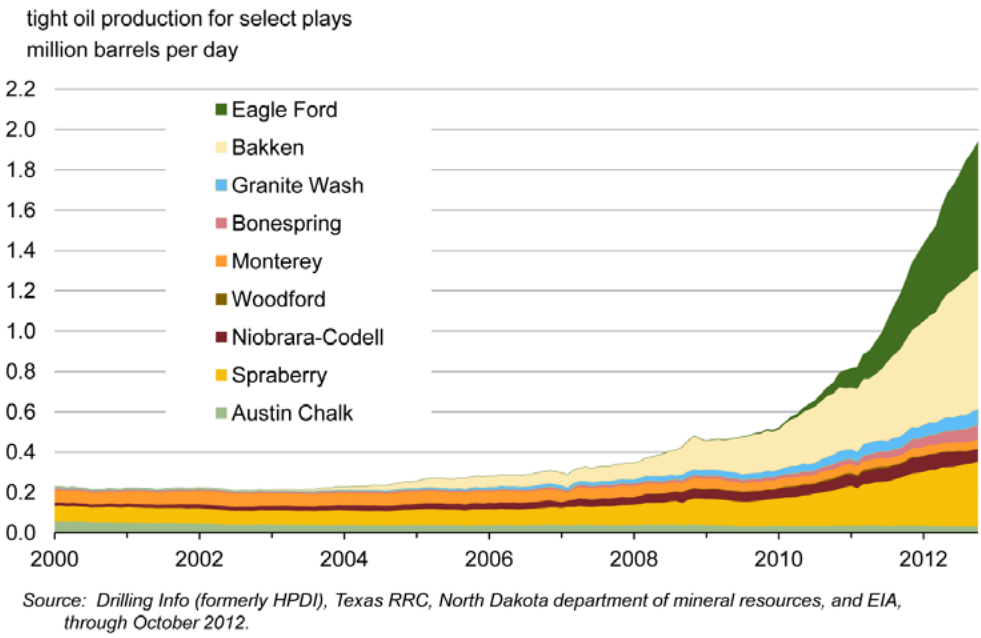

Figure 1-1. Oil production through time from selected low permeability ("tight") oil plays in the United States US EIA (2013).

As shown in Figure 1-1, the current production from low-permeability portions of the Monterey Formation in California is modest compared to production from other low-permeability strata in the United States. Furthermore, the Monterey production level has remained fairly constant between 2000 and 2012, a trend quite different from oil shales such as the Eagle Ford and the Bakken formations. However, in 2011 the United States Energy Information Administration (US EIA) estimated the Monterey Formation contains 2.45 billion cubic meters (m^3; 15.4 billion barrels) of recoverable tight oil. The report estimated this to be 64% of the recoverable oil from low-permeability rocks in the United

States (US EIA, 2011). This estimate of recoverable tight oil in the Monterey Formation gained broad attention and raised the question whether California might experience the same type of rapid increase in oil production and development of associated infrastructure as has occurred elsewhere in the country, such as in Montana and North Dakota (e.g. Garthwaite, 2013). Our report examined the assumptions in the original EIA estimate and the likelihood for WST technology to expand production in California. We found the original EIA estimate to be based on a series of highly skewed assumptions that resulted in a very high estimate for the amount of recoverable oil in the Monterey. Notably, since this report was prepared, the EIA has revised their estimate of recoverable oil in the Monterey Formation downward to about one thirtieth of the original estimate (US EIA, 2014).

Conclusion 3. The most likely scenario for expanded onshore oil production using WST in California is production in and near reservoirs that are currently using WST. Thus, existing and likely future production is expected to come from reservoirs containing oil migrated from source rocks, not from the Monterey Formation source rock. Credible estimates of the potential for oil recovery in and near 19 existing giant fields (> 1 billion barrels of oil) in the San Joaquin and Los Angeles basins indicate that almost 10 billion barrels of additional oil might be produced but would require unrestricted application of current best-practice technology, including, but not restricted to WST. In 2011 the EIA estimated about 15 billion barrels of technically recoverable oil from new plays in the Monterey Formation source rock, but these estimates have been revised in 2014 to a value of 0.6 billion barrels. Neither of these estimates of unconventional oil resources in California source rocks are well constrained.

There are significant resources in existing oil fields, and estimates of these resources are relatively consistent. The United States Geological Survey (USGS) estimates that an additional 6.5 billion barrels and 3.2 billion barrels can be recovered from the largest fields in the San Joaquin and Los Angeles basins, respectively, using existing oil production technology (see Figures 1-2(a) and (b)). Figures 1-2(a), (b) and (c) show existing oil and gas fields in California and locations where expanded production might occur in the San Joaquin and Los Angeles basins, respectively. Some but not all of this expanded production requires WST. In California today, WST enables production in the diatomite reservoirs of the San Joaquin Valley and expanded production in similar reservoirs would likely also be enabled by WST. In contrast, WST may not be required to expand production in the Los Angeles Basin where its use is not common today.

New oil and gas production in regions removed from existing fields is more uncertain than increased production in existing oil and gas fields. There is a considerable amount of source rock, including the Monterey Formation and other geologic units within the deeper portions of major basins, which could potentially contain oil that has not migrated ("source" oil), and could perhaps be extracted using WST. However, there is little published information on these deep sedimentary sections, so it is difficult to estimate the potential recoverable reserves associated with these rocks. No reports of significant production of source oil from these rocks were identified.

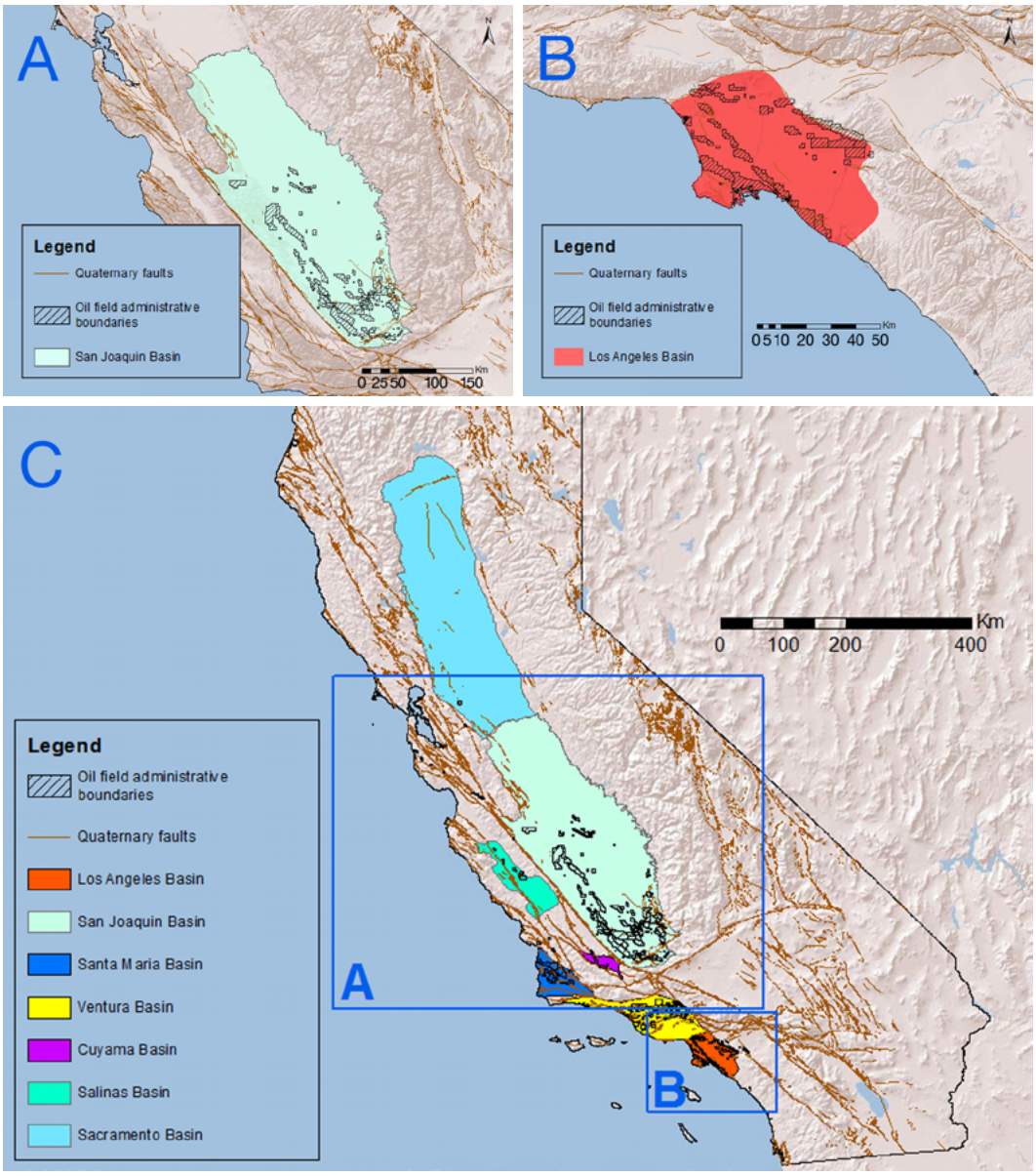

Figure 1-2. Maps of major sedimentary basins and associated oil fields in California.
(a) The San Joaquin Basin with outlines of producing oil fields. USGS estimates an additional 6.5 billion barrels of oil could be recovered from existing fields in the San Joaquin Basin.
(b) The Los Angeles Basin with outlines of producing oil fields. USGS estimates an additional 3.2 billion barrels of oil could be recovered from existing fields in the Los Angeles Basin.
(c) All major sedimentary basins and associated oil fields in California.
Data from DOGGR, Wright (1991), and Gautier (2014).

The US EIA 2011 INTEK report has garnered considerable attention because of its large estimate of 2.45 billion m^3 (15.4 billion barrels) of technically recoverable oil in Monterey Formation source rock. Very little empirical data is available to support this analysis and the assumptions used to make this estimate appear to be consistently on the high side. INTEK estimated that the average well in low-permeability source rock in the Monterey Formation would produce 87.5 thousand m^3 (550 thousand barrels) of oil. This amount greatly exceeds the production that has occurred to date from low-permeability rocks in known oil accumulations in this formation, with single-well oil production of only 10.7 and 22.4 thousand m^3 (67 and 141 thousand barrels) in the San Joaquin and Santa Maria basins, respectively. Consequently the INTEK estimate requires a four- to five-fold increase in productivity per well from an essentially unproven resource.

In addition, the Monterey Formation was formed by complex depositional processes and subsequently deformed in many tectonic events, resulting in highly heterogeneous as well as folded and faulted rocks that are difficult to characterize. INTEK posited production over an area of 4,538 km^2 (1,752 square miles), but this is almost the entire source rock area estimated in this report. (Note that the updated US EIA (2014b) report has reduced this areal extent significantly to 497 km^2 (192 square miles). There has not been enough exploration to know how much of the Monterey source rock has retained oil, or if the oil has largely migrated away, but it is unlikely the entire source rock area will be productive, given the extreme heterogeneity in the Monterey Formation. Finally, even if significant amounts of oil do remain in the Monterey Shale, and wells reach this oil, it still remains to be determined if hydraulic fracturing of Monterey source rock will result in economically viable production. For all these reasons, the INTEK estimate of recoverable oil in Monterey Formation source rock warranted skepticism. The EIA has recently issued a revised estimate (0.6 billion barrels) of this unconventional oil resource (US EIA, 2014b); this decrease is mainly due to a nine-fold reduction in the estimated potential resource area. The information and understanding necessary to develop a meaningful forecast, or even a suite of scenarios about possible recoverable unconventional oil in the Monterey shale, are not available.

While major production increases from oil shale source rock are considered highly uncertain, they are not impossible. High-volume proppant fracturing is the enabling technology for significant increases in development of low permeability reservoirs. If large-scale proppant fracturing can be shown to work in source rocks in California as it has in other low permeability plays in the United States, it would change the outlook for oil and gas production in the state. The oil and gas industry is constantly innovating, and research and development could improve the utility of proppant fracturing in the future. Deep test wells in source rock-shale plays have been drilled in California that with research and development may eventually prove successful. *(Section 4.5, Oil-Producing Sedimentary Basins in California, and 4.7, Review of the US EIA Estimate of Monterey Source Rock Oil)*

Key Question 3: What are the potential environmental hazards of well stimulation technologies in California?

This report focuses on what we refer to as the "direct" environmental impacts caused by application of WST. We define direct impacts as the impacts incurred by the act of using WST themselves, either a single application or the additive impacts of many applications. Direct impacts include, for example, those that might arise from the use of large volumes of water for stimulation, from the addition of chemicals in the WST fluids that may be toxic, or those related to injecting at high pressures into the subsurface to break the rock. Each well stimulation treatment requires the use of water, incurs transportation of materials, can cause emission of pollutants or greenhouse gases, and pumps chemically loaded water underground.

In this report we attempted to carefully assess the direct environmental, climate, and public health impacts of WST within the limits of data availability. The direct impacts in general have not been monitored, but some can be inferred from operations data and California practice. In other cases, it is not possible to make inferences and all that can be done is to review and summarize what has been observed in other states or the published literature. This information should be taken as background material, which can direct further monitoring and observation in California. We do not claim that what has been observed in other states is happening in California or directly applicable to California. The vast majority of California hydraulic fractures are conducted in shallower wells that tend to be vertical rather than horizontal, and use a relatively small amount of water that is more highly concentrated in chemicals in geologic settings that differ significantly from those in other states. Regulations are different in California and some practices in other states are not allowed in California.

WST applications can slow the decline of production in existing fields or increase that production. WST may allow production in new greenfield sites that could not be produced with more conventional technologies. We refer to all of this collectively as "WST-enabled production." Because WST can enable oil production, WST can have indirect environmental impacts in addition to the direct impacts of well stimulation. If well stimulation enables greater oil and gas production[1], which has additional environmental impacts, we refer to these as "indirect" impacts. The report identifies issues and impacts that may arise because of well stimulation-enabled production. Indirect impacts arise because oil and gas production involves building, supplying, and managing oil and gas well operations, including land clearing and construction, general truck traffic to bring and remove materials, energy operations at the wellheads, and wastewater management. The report identifies

[1] *Although the focus of the report is on oil production, the fact is that oil contains natural gas in solution which can vaporize from the oil, and therefore we cannot avoid consideration of this "associated gas" along with oil.*

indirect issues and impacts that may arise because of well stimulation-enabled production; however, they receive only cursory treatment in the synthesis and assessment conducted here. As noted in the conclusions and the assessments below, there is evidence that the indirect impacts of WST-enabled oil and gas production may be significant, and we recommend that a more detailed analysis should be undertaken. The scientific literature indicates that indirect impacts should not be dismissed and will be the focus of future work. Indirect effects are beyond the scope of this study, but we provide key issues for future study at the end of this summary.

WST-enabled oil and gas production presents environmental, health and safety impacts that can be very different depending on the history of land use where it takes place. For example, environmental impacts of oil and gas production depend on whether it occurs in an existing oil and gas field versus a greenfield location, or if the surrounding area is urban, agricultural, or undeveloped. Local conditions also affect the environmental impacts of expanded production, such as the depth and quality of the local groundwater, availability of surface water, local air quality, distance to human population centers, and the proximity of sensitive species and habitats.

Important conditions that affect impacts associated with expanded production include:

- Quality and depth of groundwater;
- Local air quality;
- Proximity to population centers;
- Proximity to species and habitats;
- Volume of fluids requiring disposal; and
- Proximity to active faults.

In some cases, the line between direct and indirect effects is not absolutely clear. Wastewater disposal presents an illustrative example of an indirect impact, but some assessment was made in this report. Wastewater includes “flowback water,” which is the water used in a hydraulic fracturing operation that returns to the surface, as well as “produced water,” which comes up with the produced oil and gas and is subsequently separated and disposed of. Flowback water is directly attributable to WST, whereas produced water is an indirect effect of WST enabled production. After a hydraulic fracturing event, the fluid that comes out of the well changes gradually from flowback water to produced water. There is no formal distinction between the two fluids. In California, the volumes of water used in WST applications are currently a very small fraction of the total

volume of produced water. We refer to this fluid as flowback/produced water, to make it clear we are discussing the combined direct and indirect issues. Produced water disposal in dedicated injection wells (Class II wells according to EPA's regulation for underground injection) presents the possibility of triggering earthquakes. Given concerns about this issue, we briefly address some issues with flowback/produced water disposal.

Although the focus of this report is primarily on the direct impacts of WST, rather than the lifetime processes and environmental hazards of oil and gas production as a whole as enabled by the technologies, it seems likely that the major environmental effects of WST are not from the WST itself, but rather from new or expanded production enabled by WST. Direct impacts represent a very narrowly defined marginal change in risks associated only with actual conduct of the WST itself. The impacts associated with these technologies exist within the overall context of environmental risks associated with oil and gas development in general. For example, dozens of chemical constituents may be present in hydraulic fracturing fluids, but operators typically combine fluids associated with hydraulic fracturing with produced water streams, which, by themselves typically contain high concentrations of salt, trace elements, and hydrocarbons. The volumes of flowback water are extremely small relative to the volume of water produced along with the oil. The emissions associated with WST operations are a small fraction of emissions from the highly energy-intensive oil production industry.

A large number of other impacts associated with WST in California were not covered in this report including local and state economic and employment impacts; local, state, and federal tax and royalty payment impacts; increased industry research and technology investments resulting from expanded WST applications; and of particular importance to Californian, the impact of increased WST-driven production on the level of imported crude to the state from non-U.S. sources. The CCST steering committee recognizes the importance of these impacts which have had material effects in other states, but notes that they were not within the defined scope of the of this report.

Direct impacts on water supply, water quality, air quality, greenhouse gas emissions and induced seismicity are described below.

Water Supply

Conclusion 4: While current water demand for WST operations is a small fraction of statewide water use, it can contribute to local constraints on water availability, especially during droughts.

The upper estimate of current annual water demand for WST in California is 1.4 million m^3 (1,200 acre-feet), based on estimates of water use from notices filed with DOGGR; the lower estimate is 560 thousand m^3 (450 acre-feet) based on water volumes reported voluntarily to FracFocus. Ninety-five percent of water currently used is fresh water; the remainder is produced water. Most of this demand is in the southwestern San Joaquin

Valley. Stimulation notices indicate the Belridge Water Storage District, supplied by the State Water Project, meets most of the demand in this area. The demand indicated by the notices represents less than 1% of this District's allocation. However, their allocation from the State Water Project can be cut in average and in drier years. The notices indicate use of well water for stimulation fluid as an alternative to supply from the District, but it is unclear under which conditions this would occur. If well water is used, it could draw down the groundwater table. *(Section 5.1.1, Quantities and Sources of Water Used for Well Stimulation in California)*

Water Quality

Conclusion 5: Of the chemicals reported for WST treatments in California for which toxicity information is available (compiled from the voluntary industry database, FracFocus), most are considered to be of low toxicity or non-toxic. However, a few reported chemicals present concerns for acute toxicity. These include biocides (e.g., tetrakis (hydroxymethyl) phosphonium sulfate; 2,2-dibromo-3-nitrilopropionamide; and glutaraldehyde), corrosion inhibitors (e.g. propargyl alcohol), and mineral acids (e.g. hydrofluoric acid and hydrochloric acid). Potential risks posed by chronic exposure to most chemicals used in WST are unknown at this time.

A list of chemicals used for hydraulic fracturing was developed from disclosures in FracFocus. These data are not required to be either complete or accurate. For matrix acidization, a list of chemicals used was developed from stimulation notices, which did not indicate any undisclosed chemicals. Information on acute oral toxicity was available for some of these chemicals. This toxicological assessment is limited, because it considers only oral toxicity as an indicator of potential impacts to human health, and does not consider other effects such as biological responses to acute and chronic exposure to many of the stimulation chemicals, eco-toxicological effects of fluid constituents, overall toxicological effects of fluids as a mixture of compounds (compared to single-chemical exposure), and potential time-dependent changes in toxicological impacts of fluid constituents, due to their potential degradation or transformations in the environment. Thus, further review of the constituents of injection fluids used in well stimulation jobs in California is needed, which additionally considers information that is now required to be submitted to DOGGR by operators, and some of the above mentioned toxicological effects.

After hydraulic fracturing fluids are injected, they return along with some formation water as flowback water and are subsequently either disposed off or sometimes used for other purposes (see Conclusion 7). At this time, it is not possible to evaluate flowback contaminants in California, because there is very limited information regarding the concentrations of these substances in flowback/produced waters from well stimulation operations in California. Flowback and produced water compositions vary considerably across regions, and their characteristics can change according to the fluids injected during well stimulation, the amount of fluids recovered at the surface, and over the duration of the flowback period. The chemistry of produced waters from unconventional oil production

could potentially differ from that of conventional oil production due to differences in the target formations and interactions of fracturing fluids with formation rocks and water, although this does not generally appear to be the case based on the limited data that is available. More California-specific data will become available starting in 2014 as operators are now required to report the composition of waters recovered from well stimulation operations to DOGGR. *(Section 5.1.2, Chemistry of Fluids Related to Well Stimulation Operations)*

Conclusion 6: There are no publicly recorded instances of subsurface release of contaminated fluids into potable groundwater in California, but a lack of studies, consistent and transparent data collection, and reporting makes it difficult to evaluate the extent to which this may have occurred. Existing wells are generally considered as the most likely pathway for subsurface transport of WST and subsurface fluids (water, brines, gas). California needs to characterize this potential hazard in order to evaluate risk to groundwater resources. In California, hydraulic fracturing is occurring at relatively shallow depths and presents an inherent risk for fractures to intersect nearby aquifers if they contain usable water. Fracturing has occurred in many fields at a depth less than 600 m (2000 ft). Available research indicates 600 m is likely the maximum distance for vertical propagation of hydraulic fractures, although the maximum vertical length of a fracture may be less than 600 m for fracturing in shallow formations because of the different stress conditions. California needs to develop an accurate understanding about the location, depth, and quality of groundwater in oil and gas producing regions in order to evaluate the risks of WST operations to groundwater. This information on groundwater must be integrated with additional information to map the actual extent of hydraulic fractures to assess whether and where water contamination from WST activities has been or will be a problem.

More complete information about the quality and location of groundwater resources relative to the depth at which hydraulic fracturing is occurring would make it possible to identify inherently hazardous situations that could and should be avoided. Data on the location and quality of groundwater must be obtained in order to assess risks from proposed hydraulic fracturing.

Hydraulic fracturing at shallow depths poses a greater potential risk to water resources because of its proximity to groundwater and the potential for fractures to intersect nearby aquifers. Geomechanical studies conducted for WST in other states have indicated that fracturing directly from the stimulated reservoir into groundwater is unlikely when well stimulation is applied in formations that are sufficiently far below overlying aquifers. However, according to FracFocus and DOGGR's GIS well data files, the depth of roughly half of the wells in California that have been stimulated using hydraulic fracturing lie within 610 m (2,000 feet) of the ground surface, where 600 m (1,969 feet) has been identified as a threshold for vertical disturbance by hydraulic fracturing. Based on well stimulation notices filed to date with DOGGR, much of the current and planned hydraulic

fracturing operations in California occur at depths of less than 305 m (1,000 feet) below the ground surface. Because of the shallow depth of well stimulation and the typically lower injection volumes in California, the stress and damage behavior is very different from high-volume hydraulic fracturing elsewhere, meaning the separation distance of 600 m suggested may not be applicable to the conditions in this state. However, the potential for hydraulic fractures to intercept groundwater in these conditions warrants more careful investigation and monitoring (see Figure 1-3), including geomechanical studies and surveys of fracture extent relative to groundwater location, depth, and quality.

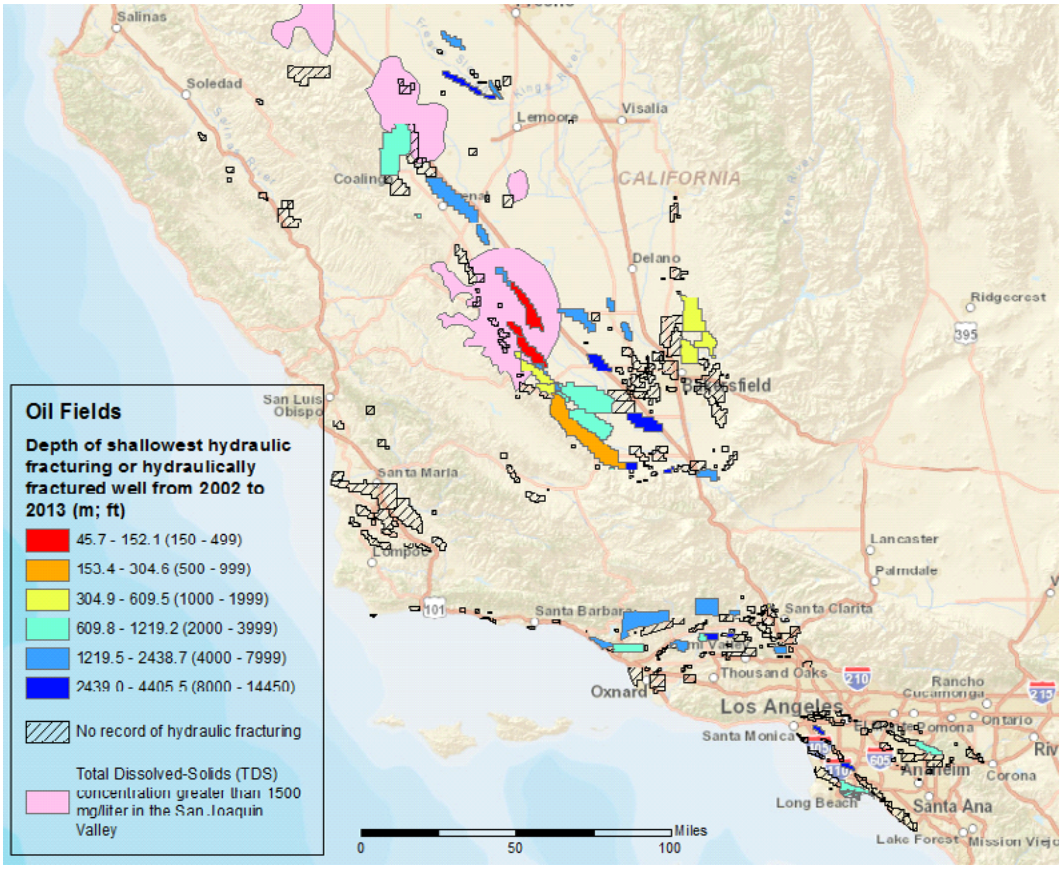

Figure 1-3. A map showing the shallowest hydraulic fracturing depth from the well stimulation notices or hydraulically fractured well total depth (measured depth from DOGGR for wells drilled after 2001 or true vertical depth from FracFocus) in each field. Pink areas show regions in the San Joaquin Valley where the shallow groundwater has total dissolved solids above California's short-term secondary maximum contaminant level for drinking water of 1,500 mg/L. Note the oil fields colored orange and yellow in the San Joaquin Valley, indicating shallow hydraulic fracturing, that are located in areas with better groundwater quality. Data from DOGGR 2014(a), DOGGR 2014(b), FracFocus (2013), and Bertoldi et al. (1991).

Even when well stimulation occurs well below groundwater levels, leakage paths along existing wells or other permeable pathways in the rock— either naturally existing or generated by hydraulic fractures propagating beyond the target reservoir— may cause contamination. Some studies in other regions outside California have found a correlation between the location of hydraulically-fractured production wells and elevated concentrations of methane, arsenic, selenium, strontium, and, to a lesser extent, total dissolved solids (TDS). However, there is no consensus as to whether these are naturally occurring, due to hydraulic fracturing, production well defects, abandoned wells, or a combination of mechanisms. Pathways due to compromised or failed structural integrity of cement in oil and gas wells and well bores are generally considered the most likely potential pathway for groundwater contamination. While well integrity is a concern for all types of wells, including conventional oil and gas exploration wells, the risk of long-term damage or deterioration may be higher for hydraulic fracturing operations because of higher induced pressure and multi-stage fracturing. California-specific studies of the proportion of wells that exhibit indications of compromised wellbore integrity and corresponding groundwater contamination have not been conducted. California needs to determine the locations and conditions of preexisting wells near hydraulic fracturing operations in order to assess potential leakage hazards. Continued monitoring and data collection are warranted to avoid potential risks.

Conclusion 7: Current practice could allow flowback water to be mixed with produced water for use in irrigation. California needs to monitor the quality of flowback/produced water and review regulations on the appropriate use of flowback/produced water, based on its quality and the intended uses.

In California, there are documented cases of intentional and accidental surface releases of flowback fluids or chemicals associated with well stimulation. Detailed assessments are not available as to whether these releases contaminated surface water and/or groundwater, but this is a common pathway for surface and groundwater contamination. In other states, disposal of water in surface facilities causes more groundwater contamination than disposal by injection (Kell, 2011), and surface spills of various constituents have contaminated both groundwater and surface water.

Most flowback water is disposed of by Class II injection in California, but DOGGR does not distinguish between flowback and produced water. Current management practices in California also allow for the disposal of oil and gas wastewater, including the co-mingled well stimulation fluids, into unlined pits if the electrical conductivity (EC) is less than or equal to 1,000 micromhos per centimeter (μmhos/cm), chloride concentration is less than or equal to 200 milligrams per liter (mg/l), and boron concentration is less than or equal to 1 mg/l, with no testing required for, or limits on, other contaminants. Some produced water is permitted for irrigation, but data do not exist to determine if flowback fluid is included in that water. A more detailed assessment of wastewater disposal practices is needed to determine their levels of risk to surface water, groundwater, or agriculture. A lack of baseline data on groundwater quality is a major impediment to identifying or

clearly assessing the key water-related risks associated with hydraulic fracturing and other well stimulation techniques. *(Section 5.1.3, Potential Release Pathways, and 5.1.4, Case Studies of Surface and Groundwater Contamination)*

Air Quality and Climate Impacts

Conclusion 8: Estimated marginal emissions of NOx, $PM_{2.5}$, VOCs directly from activities directly related to WST appear small compared to oil and gas production emissions in total in the San Joaquin Valley, where the vast majority of hydraulic fracturing takes place. However, the San Joaquin Valley is often out of compliance with respect to air quality standards and as a result, possible emission reductions remain relevant.

Three major sources of air pollutants include the use of diesel engines, flaring of gas, and the volatilization of flowback water. The first, diesel engines (used for transport and pumping of estimated fluid volumes required for WST) emit a small portion of total-emissions nitrogen oxides (NOx), particulate matter ($PM_{2.5}$), and volatile organic compounds (VOC) associated with other oil and gas production operations as a whole.

Emissions from flaring in California are uncertain, because of variability in flare combustion conditions and a lack of information regarding the frequency of flare-use during WST operations. However, current California Air Resource Board inventories of pollutant emissions from all flaring suggest that flares as a whole emit less than 0.1% of the VOCs and are not a major regional air quality hazard.

Emissions from volatilization of flow-back water constituents have not been measured but might be bracketed. The California Air Resource Board has conducted a “bottom-up” VOC emission inventory by adding up all known sources of emissions. It is unknown whether these sources included emissions from WST-related produced or flowback water. However, the sum of the emissions in the inventory matches well with “top-down” measurements taken from the air in the San Joaquin Valley. This agreement between “bottom-up” and “top-down” estimates of VOC emissions from oil and gas production indicates California’s inventory probably included all major sources.

The inventory indicates that VOC emissions from oil and gas evaporative sources, such as from flowback water, might occur from stimulation fluids produced back after the application of WST, are small compared to other emission sources in the oil and gas development process. Data suggest that emissions from oil and upstream operations in general contribute to roughly 10% of anthropogenic VOC ozone precursor emissions in the San Joaquin Valley.

Some of the potential air-quality impacts can be addressed by regulation and largely avoided. *(Section 5.2.1, Air Quality)*

Conclusion 9: Fugitive methane emissions from the direct application of WST to oil wells are likely to be small compared to the total greenhouse gas emissions from oil and gas production in California. This is because current California oil and gas operations are energy intensive. However, all greenhouse gas emissions are relevant under California's climate laws, and many emissions sources can be addressed successfully with best-available control technology and good practice.

While WST will require additional energy use and could result in fugitive methane emissions, it is unlikely that these emissions will be large in comparison to other California oil and gas greenhouse gas emissions. California oil and gas production operations are generally energy intensive, due to steam-based thermal recovery operations and depleted oil fields with high water handling requirements. Therefore, greenhouse gas emissions from California oil and gas operations mostly result from energy consumption that releases CO_2. The California Air Resources Board (CARB) inventory indicates that methane emissions represent less than 10% of total greenhouse gas emissions, on a CO_{2e} basis, from all oil and gas production.

Greenhouse gas emissions due to WST activities would include the same three sources discussed above for air quality. For the same reasons listed above, these sources are likely to be small compared to other oil and gas production sources. Nevertheless, to help achieve California's climate goals, many significant sources of fugitive methane emissions associated with WST could be controlled through the requirement of green completions and by requiring vapor controls for flow-back water.

Emissions estimates from inventories are subject to uncertainty. Evidence across all scales (individual devices to continental atmospheric measurements) suggests that methane emissions from the natural gas and petroleum industries are likely larger than those expected from the US Environmental Protection Agency (EPA) inventories. More specifically to California, atmospheric measurement studies in Southern California indicate that state inventories of methane emissions from oil and gas production activities may be underestimated by a factor of about 5. Adjusting the CARB inventory by this factor would make the global warming potential of oil and gas production-related methane emissions larger, although still less than direct CO_2 emissions from fuel use.

New US EPA regulations requiring reduced emission completions (so called "green completions") for gas wells beginning in 2015 do not apply to the majority of wells in the San Joaquin Valley, as they are principally oil and associated gas wells. Similar control standards could be applied to oil wells in California.

While other regions are currently using WST for the production of oil (e.g., the Bakken formation of North Dakota) or gas (e.g., the Barnett shale of Texas), emissions from these regions may not be representative of emissions from California-specific application of WST. For example, the volume of fluid used for WST operations in California is typically lower than operations in other shale plays, potentially leading to lower evaporative emissions of methane from flowback fluid. *(Section 5.2.2, Climate Impacts)*

Seismic Risk

Conclusion 10: Hydraulic fracturing rarely involves large enough volumes of fluids injected at sufficient rate to cause induced seismicity of concern. Current hydraulic fracturing for oil and gas production in California is not considered to pose a significant seismic hazard. In contrast, disposal of produced water from oil and gas production in deep injection wells has caused felt seismic events in several states. Expanded oil and gas production due to extensive hydraulic fracturing activity in California would lead to increased injection volumes for disposal. If this produced water is disposed of by injection and not handled through an expansion of water treatment and re-use systems, it could increase seismic hazards.

Induced seismicity is a term used to describe seismic events caused by human activities. These include injection of fluids into the subsurface, when elevated fluid pore pressures can lower the frictional strengths of faults and fractures leading to seismic rupture. Induced seismicity can produce felt or even damaging ground motions when large volumes of water are injected over long time periods into zones in or near potentially active earthquake sources. The relatively small fluid volumes and short time durations involved in most hydraulic fracturing operations themselves are generally not sufficient to create pore pressure perturbations of large enough spatial extent to generate induced seismicity of concern. Current hydraulic fracturing activity is not considered to pose a significant seismic hazard in California. To date, only one felt earthquake attributed to hydraulic fracturing in California has been documented, and that was an isolated, low-energy event.

In contrast to hydraulic fracturing, earthquakes as large as magnitude 5.7 have been linked to injection of large volumes of wastewater into deep disposal wells in the eastern and central United States. To date, compared to some other states, water disposal wells in California have been relatively shallow and volumes disposed per well relatively small. There are no published reports of induced seismicity caused by wastewater disposal related to oil and gas operations in California, and at present the seismic hazard posed by wastewater injection is likely to be low. However, possible correlations between seismicity and wastewater injection in California have not yet been studied in detail. Injection of much larger volumes of produced water from increased WST activity and the subsequent increase in oil and gas production could increase the hazard, particularly in areas of high, naturally-occurring seismicity. Therefore, given the active tectonic setting of California, it will be important to carry out quantitative assessments of induced seismic hazard and risk. The chance of inducing larger, hazardous earthquakes most likely could be reduced by following protocols similar to those that have been developed for other types of injection operations. Even though hydraulic fracturing itself rarely induces felt earthquakes, application of similar protocols could protect against potential worst-case outcomes resulting from these operations as well. *(Section 5.3, Potential Seismic Impacts)*

Indirect environmental effects of WST-enabled production

Conclusion 11: Based on Conclusions 1 through 10 above, the direct impacts of WST appear to be relatively limited for industry practice of today and will likely be limited in the future if proper management practices are followed. If the future brings significantly increased production enabled by WST, the primary impacts of WST on California's environment will be indirect impacts, i.e. those due to increases and expansion in production, not the WST activity itself. Indirect impacts of WST through WST-enabled production will vary depending on whether this production occurs in existing rural or urban environments or in regions that have not previously been developed for oil and gas — as well as on the nature of the ecosystems, wildlife, geology and groundwater in the vicinity.

The indirect effects of WST were not a focus of this study. However, an understanding of the future of WST in California is incomplete without consideration of the idea that WST and other advanced technologies can enable more and new production. Consequently, we provide here a few comments relevant to future study.

If new plays in formations such as the Monterey Formation source rocks prove to be attractive economic targets, the industry is likely to want to explore them and find WST and production technologies that work in these environments. Existing or as yet unidentified technologies might be developed for these specific circumstances. Then, some years in the future — much like the unconventional gas plays that came into production because of high-volume hydraulic fracturing from horizontal wells — there could be novel technologies appropriate to novel plays in California. Such new technologies could have different environmental impacts over what is experienced today. To the extent that producers develop successful new methods, these technologies will deserve new scrutiny to ensure that they do not damage the environment of California.

Oil and gas production activities in general are known to present environmental, health, and safety risks via an array of industrial activities and technologies — including, but not limited to, drilling, truck traffic, land clearing, gas compressor stations, separator tanks, wastewater processing and disposal, and land subsidence. Our assessment of current WST practices in California suggests that the per-barrel impacts of producing oil with WST are comparable to the impacts of producing oil without WST. As a result, WST will mainly affect California's environment through indirect effects caused by an increase in production.

The intensity and extent of expanded production impacts will vary, depending on where operations occur: in new greenfield sites, existing rural fields, or in existing fields in dense, urban environments. Some locations for expanded production may present few new impacts and some may present unique challenges to public health and safety, because of high population densities, vulnerable demographics, and geographic proximity to oil and gas development activities and their corresponding environmental emissions.

Expanded WST-enable production in California oil and gas fields could have the indirect effect of increasing the risk of contamination to groundwater water systems, by exposing greater areas of groundwater to contaminants and increasing the number of adverse events. The overall risks, however, will depend on groundwater and geological characteristics and operating practices, including (especially) practices to dispose of produced/flowback water and ensure the integrity of well casings and wellbore cement. If the use of WST expands oil and gas production in California, strategies for better understanding and mitigating any increased groundwater risk should be considered during planning and implementation efforts. Similarly, expanded production could lead to an increase in VOC, methane, carbon dioxide and other associated air-pollutant emissions if other measures to reduce these emissions are not undertaken.

There is a large body of work showing that habitats are altered to the detriment of wildlife and vegetation in areas where oil and gas production occurs. While it is obvious that wildlife and vegetation will be impacted if well stimulation converts pristine areas to oil and gas fields, increasing the level of production in existing fields will also have negative impacts on organisms that inhabit the fields. *(Section 5, Potential Direct Environmental Effects of Well Stimulation)*

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