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Via Certified U.S. Mail and Electronic Mail

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Re: Comments on the Draft Environmental Impact Report for Revisions to the Kern County Zoning Ordinance – 2015(c), Including Implementation of All future Activities Undertaken Pursuant to the Amendment

To Mr. Mynk:

On behalf of the Natural Resources Defense Council (NRDC), which has 1.4 million members and activists, 250,000 of whom are Californians, we write to submit comments on the Draft Environmental Impact Report (DEIR) for an Amendment to Chapter 19.98 of the Kern County Zoning Ordinance and future oil and gas activities undertaken pursuant to that amendment.

I. Introduction

The Kern County Planning and Community Development Department (KCPCDD) has prepared an Environmental Impact Report (EIR) pursuant to the California Environmental Quality Act (CEQA) in order to identify and evaluate potential impacts associated with future oil and gas exploration, development, and production activities in the Project Area expected to be undertaken pursuant to the Amended Zoning Ordinance. The proposed Project includes (1) an amendment to Title 19 of the Kern County Zoning Ordinance, Chapter 19.98 (Oil and Gas Production) and related sections of the Kern County Zoning Ordinance for future oil and gas activities and (2) all future activities undertaken pursuant to that amendment.

The DEIR assumes 2,697 new producing wells per year or 67,425 wells in the next 25 years. DEIR Section 3.5 p. 3-30. Chapter 19.98, as amended, would require a permit from the Kern County Planning and Community Development Department prior to drilling any new exploratory or production wells. As part of that permit process there would be "Conformity Review," which the amendment seeks to make a non-discretionary or ministerial process. Applicants would be left to self-certify their project's compliance with the Zoning Ordinance during construction and upon completion.

In short, under this proposed permitting scheme no further CEQA review would be required until those, i.e. 25-year and/or 67,425 well, thresholds are crossed, at which point the County will consider if further review is mandated.

Our evaluation of the Project concludes it that fails to consider recent scientific recommendations for mitigating the impacts of well stimulation and it impermissibly attempts to avoid future CEQA review by grossly abusing the definition of a "project" under CEQA. The DEIR's alternatives analysis eliminates feasible, possibly environmentally superior options without basis. Finally, as detailed *below*, the Project will result in significant environmental impacts that have not been disclosed or mitigated in the DEIR.

KCPCDD can and must do more to describe and mandate various categories of mitigation that existing studies demonstrate are likely to be important and feasible methods of reducing impacts at many sites across Kern County. These mitigation measures should set a floor for future mitigation that KCPCDD in further, site-specific CEQA review, would require. (See arguments below for why this EIR cannot serve as the final CEQA review for any well.) For example, as we discuss below, KCPCDD can and must do more to describe and mandate mitigation for the air quality, groundwater, surface water, hazards and hazardous materials, and seismic impacts of well stimulation.

The DEIR includes numerous mitigation commitments that are not enforceable because they are not included in the proposed regulations or any supplemental permit conditions. Mitigation measures that are suggested in the DEIR itself that are unenforceable (i.e., not codified through regulatory or other mechanisms) should be acknowledged as such and reduced efficacy of mitigation due to the lack of enforcement should be analyzed and disclosed.

II. The DEIR lacks the insights of the state's scientific study on the impacts of well stimulation.

The state recently underwent an independent scientific assessment (CCST Study) of well stimulation in California,[1] as mandated by Senate Bill 4. The study makes several findings and recommendations that should be considered and incorporated in the Final Kern County EIR.

Those recommendations include, among several others, measures to identify opportunities for water conservation and reuse in the oil and gas industry; a recognition that oil resource assessments and future use in the Monterey Formation of California "remain uncertain"; acknowledgement that important investigation of impacts of fracking on hydrology have not been investigated; a recommendation that the use of hazardous and poorly understood chemicals should be limited; a determination that further work is needed to limit habitat fragmentation and wildlife impacts; a recognition that we should phase out disposal of produced water in percolation pits; a recommendation for better testing to evaluate the water chemistry of fracking and acid stimulation produced water chemistry; a call for further testing before reuse for irrigation is permitted; a recognition that underground injection as a disposal method brings with it risks of seismic activity; a stated need to control toxic air emissions from oil and gas

[1] Available here: https://ccst.us/projects/hydraulic_fracturing_public/SB4.php.

production wells and measure their concentrations; and a finding that we need to better assess the current level of and impact on public health and worker safety near and from oil and gas activity.

A few key findings and conclusions from the recent report include:

- "Operators currently dispose of wastewater from hydraulically fractured wells in percolation pits and also likely have occasionally injected wastewater contaminated with stimulation chemicals into protected groundwater. These practices should stop."
- "Operators have unrestricted use of many hazardous and uncharacterized chemicals in hydraulic fracturing. [T]he 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."
- "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..."
- "The majority of impacts associated with hydraulic fracturing are caused by the indirect impacts of oil and gas production enabled by the hydraulic fracturing."
- "Emissions concentrated near all oil and gas production could present health hazards to nearby communities in California."

Given what we already know about the dangers of well stimulation, it is irresponsible to proceed without incorporating the best science related to an assessment of the risks specific to California. Regulating in the scientific dark unnecessarily increases the risks to human health and the environment. All three volumes of the statewide study should inform the Kern County EIR process.

III. The DEIR is inappropriately framed as a project-level EIR.

At the behest of Western States Petroleum Association (WSPA), California Independent Petroleum Association (CIPA), and Independent Oil Producers Agency (IOPA) (collectively "Applicants"), the KCPCDD hereby seeks to create a "streamlined permitting" process whereby no further CEQA review would be required for an expansive spectrum of future oil and gas activities within unincorporated Kern County for the next 25 years, or 67,425 wells, and potentially beyond. DEIR at 2-23.

As an initial matter, the DEIR is inappropriately framed as a *project* EIR. Instead, the DEIR should be treated as a *program* EIR, which could be used to tier off of but would require additional cite-specific review on a case-by-case basis. The DEIR's scope is far too extensive for project-level EIR analysis.

A project EIR typically focuses "primarily on the changes in the environment that would result from [a single] development project." 14 Cal Code Regs §15161 ("CEQA Guidelines"). By way of contrast, and pursuant to CEQA Guidelines section 15168, a program EIR is "used for a series of related actions that can be characterized as one large project." *Ctr. for Sierra Nevada Conservation v. Cnty. of El Dorado*, 202 Cal. App. 4th 1156, 1171 (2012). Because it covers and considers a series of actions, a program EIR often requires further analysis, but can save time and effort by being the first "tiered EIR." *See Natural Resources Defense Council, Inc. v. City of Los Angeles*, 103 Cal.App.4th 268, 282 (2002).

As the California Supreme Court has explained, "a *program* EIR is distinct from a *project* EIR" in that the latter is "prepared for a specific project and must examine in detail site-specific considerations." *Ctr. for Sierra Nevada Conservation*, 202 Cal. App. 4th at 1184. The proposed Kern County DEIR contemplates not one but a "series of related actions," and the temporal, geographic, and substantive breadth and scope of those covered actions render the level of site-specific analysis and consideration that CEQA requires at the *project* level not just impracticable but impossible. *Id*. at 1171.

The DEIR purports to consider and reach conclusions as to the impact of an unprecedented amount of activity for a project-level EIR: a suite of oil and gas activities in a 3,700 square mile area for the next 25 years. This attempt to preemptively conduct CEQA review on a wide-ranging list of activities (from hydraulic fracturing to building evaporation ponds and constructing pipelines), across a diverse and complex County, and deep into future decades during a drought and time of both climate change and technological advancement, is an abuse of CEQA and—if permitted—would render CEQA and the public environmental review process it mandates a farce.

Under CEQA, a project EIR must include an accurate, stable, and consistent description of the proposed project. The project description must contain sufficient specific information about the project to allow a complete evaluation and review of its environmental impacts. CEQA Guidelines § 15124. Here, the DEIR lists twenty hypothetical categories of construction activities and seventeen hypothetical operational activities that are to be considered, and therefore covered, by this environmental impact review. DEIR at 3-35, 3-36.

The activities covered by this DEIR include:
Geophysical or "seismic" surveys; well pad preparation; well testing; road construction; electrical distribution line and substation construction; well drilling; well completion; construction of oil or gas treatment facilities; construction of water treatment facilities; steam generator construction; construction of tankage and containment structures; pipeline installation; construction of sumps, evaporation ponds, and percolation ponds; installation of produced water injection wells; construction of fencing; administrative facility construction; well re-working and workovers; well stimulation; decommissioning and abandonment of wells; reactivation of idle wells; geophysical monitoring; treatment of produced water, oil, and gas; water management; enhanced oil recovery activities; injection wells; sump pits; percolation and evaporation ponds; vegetation control; spill prevention procedures; non-hazardous solid waste management; well, pipeline, tank, and vessel testing and maintenance; centralized oil/water separation; operating steam generators; operating electrical substations; operating administrative buildings and personnel housing; and distribution of crude oil. DEIR at 3-35-59.

Any one of those activities might warrant project-level CEQA review, and yet, here the DEIR attempts to consider them all at once and for the next 25 years. Such a boundless project description entirely defeats the purpose and mandate of CEQA. A "finite project description is indispensable to an informative, legally adequate EIR." *County of Inyo v. City of Los Angeles*, 71

CA3d 185, 192 (1977). Without an accurate description on which to base the EIR's analysis, CEQA's objective of furthering public disclosure and informed environmental decision making are stymied.

In *Santiago County Water Dist. v. County of Orange*, the Court of Appeal considered the sufficiency of a project-level EIR that purported to examine the consequences of permitting a company to operate a sand and gravel mining operation. *Santiago Cnty. Water Dist. v. Cnty. of Orange*, 118 Cal. App. 3d 818 (Ct. App. 1981). Because that EIR failed to give sufficient information concerning the delivery of water to the proposed sand and gravel mine, the court held that it was as a whole inadequate. *Id.* at 829. As that court explained, a project description that omits integral components of the project results in an EIR that fails to disclose all of the impacts of the project. *See id.* Here, the integral components of the EIR, and the ones that are lacking, are impossible for the agency, public, or a court to identify because the huge scope and concomitant high level of generality of the DEIR. Without such specific identification of the components of the project, any environmental review is rendered meaningless.

As the court stated in *San Joaquin Raptor/Wildlife Rescue Ctr. v County of Stanislaus*, "[a]n accurate project description is necessary for an intelligent evaluation of the potential environmental effects of a proposed activity." *San Joaquin Raptor/Wildlife Rescue Ctr. v. Cnty. of Stanislaus*, 27 Cal. App. 4th 713, 730 (1994), *as modified* (Sept. 12, 1994). It is basic logic that an accurate and stable project description is necessary so that the lead agency and the public have enough information to "ascertain the project's environmentally significant effects, assess ways of mitigating them, and consider project alternatives." *Sierra Club v. City of Orange* 163 Cal. App. 4th 523, 533 (2008).

In this case, the "project" is so broadly defined—and the activities included are at such a high level of generality and hypothetical—that the site-specific review required for a project level EIR is not just lacking, it's not possible. To pretend otherwise is to deprive the public and decision-makers from the level of considered environmental review CEQA demands.

The sole potential benefit of a project-level EIR for such an expansive amount of activity is a reduction in the administrative burden on the County, which hopes to eliminate the need for any further CEQA review of the listed oil and gas activities. As attractive as that reduction in paperwork may be, a wholesale evaluation of 67,425 oil and gas wells, and all related activities, in the largest oil producing County in California, with no continuing process for re-evaluating the effects of specific projects, sets a dangerous precedent, is a disservice to the public and our environment, and makes a mockery of CEQA.

It makes no sense to rely on a static document to protect our health and environment for the next 25 years from a changing industry, environment, and climate. Oil and gas drilling is a heavy industrial activity with—as the DEIR as well as the California statewide EIR acknowledge—numerous significant unmitigable effects. There are constant technological advances in this field that must be considered both for their potential negative impact to the environment and for any possible new mitigation to ameliorate those impacts. Furthermore, we live in a time of climate change, drought, and uncertain oil futures. For all these reasons, environmental review far into the future is untenable and ill-conceived.

For these reasons, the DEIR should be reconceived of as a program EIR that will serve as a first-tier general document. The DEIR should make clear that future oil and gas activity in unincorporated Kern County will require site-specific CEQA review. *See In re Bay-Delta Programmatic Envtl. Impact Report Coordinated Proceedings*, 43 Cal.4th 1143, 1173 (2008) (when a program EIR is broad "later project-level EIR's may not simply tier from the [program EIR] analysis and will require an independent determination and disclosure of significant [site-specific] environmental impacts").

IV. The DEIR and proposed zoning ordinance's "ministerial" permit process fails to recognize that the County retains significant discretion in decision-making.

The proposed amendment to Chapter 19.98 of Kern County's zoning laws attempts to establish a ministerial permit procedure dubbed the "Oil and Gas Conformity Review" or "Minor Activity Review" for approval of future oil and gas activity. DEIR at 3-9. Under this proposed system, applicants would self-certify compliance and obtain permits for oil and gas wells, including fracking and acid matrix stimulation wells, without further public notice or environmental review. *See* Proposed Kern County Zoning Ordinance §§ 19.98.090(B); 19.98.100(C); 19.98.120(B).

Approval of the proposed permits, however, necessarily requires discretion, and any attempt to shield them from CEQA by misnaming them ministerial is a violation of CEQA.

Discretionary projects are defined by the CEQA Guidelines as actions requiring "the exercise of judgment, deliberation or decision," § 15357; *see also* CEQA Guidelines § 15002(i) ("CEQA applies in situations where a governmental agency can use its judgment in deciding whether and how to carry out or approve a project.") A ministerial decision, on the other hand, "cannot use personal, subjective judgment in deciding whether or how the project should be carried out." CEQA Guidelines §15369. Significant for purposes of this DEIR, a ministerial permit is "limited to those approvals which can be legally compelled without substantial modification or change." *Friends of Westwood, Inc. v. City of Los Angeles* (1987) 191 Cal.App.3d 259, 269. "Where a project involves an approval that contains elements of both a ministerial action and a discretionary action, the project will be deemed to be discretionary and will be subject to the requirements of CEQA." CEQA Guidelines § 15268(d).

Because the review required in this case is necessarily not ministerial, however, the zoning ordinance, and any County approval of future oil and gas activities without further environmental review is in direct violation of CEQA. The DEIR and zoning ordinance themselves require the County to make discretionary decisions to determine (1) whether "the proposed use meets the implementation standards and conditions specified" in the zoning code, Proposed Kern County Zoning Ordinance §§ 19.98.090(B); 19.98.100(C); 19.98.120(B), and (2) whether individual oil and gas permits comply with the specific mitigation measures—many of which themselves require specific consideration of site-specific conditions, practicability, availability, adequacy, and/or feasibility—outlined in the DEIR.

For example, Hazards and Hazardous Materials mitigation measure MM 4.8-6 requires that in order to minimize the risk of an oil spill, applicants adhere to best management practices, including, among others, using closed mud systems "when practical," sizing reserve pits "properly," selecting less toxic alternatives "when possible," minimizing waste generation, recycling oil-based muds and brines when "practical," and training personnel to use "sensible" waste management practices." DEIR at 4.8-86-87. Each of these considerations, and enforcement thereof, requires discretion.

Air quality mitigation measures MM 4.3-5(c), as a second example, allows the County to waive setback distances to sensitive receptors if setbacks are not met, as long as the County determines that the applicant can demonstrate it has achieved a certain level of risk. DEIR at 4.3-111. That determination also requires judgment and discretion.

In summary, the proposed ordinance and DEIR outline an approval system whereby the County retains significant discretion to deny the permit application if it finds that the mitigation measures are not met. Because such consideration requires subjective judgment by the County, and because the County may deny project approval based on its own analysis, the County's approval of oil and gas permits cannot be ministerial and is subject to full review under CEQA.

V. The DEIR's alternatives analysis eliminates feasible, possibly environmentally superior options without basis.

The alternatives analysis is central to an EIR. As the California Supreme Court has written, "The EIR is the heart of CEQA, and the mitigation and alternatives discussion forms the core of the EIR." *In re Bay-Delta Programmatic Envtl. Impact Report Coordinated Proceedings*, 43 Cal. 4th 1143, 1162 (2008). A major goal of any EIR is to "ensure that all reasonable alternatives to proposed projects are thoroughly assessed by the responsible official." *San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus* (1994) 27 Cal.App.4th 713, 735; *see also* Cal. Pub. Res. Code § 21002.1(a).

Given the central importance of the alternatives analysis to the integrity of its EIR, Kern County must do far more than merely go through the motions of analyzing and summarily dismissing alternatives before selecting its preferred alternative. Rather, the agency must identify and "consider a reasonable range of potentially feasible alternatives that will foster informed decisionmaking and public participation." CEQA Guidelines, § 15126.6(a). This range must include alternatives that "feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project." *Id.*

"[A]n agency may not approve a proposed project if feasible alternatives exist that would substantially lessen its significant environmental effects." *Save Panoche Valley v. San Benito Cnty.*, 217 Cal. App. 4th 503, 521 (2013) (citations omitted); *see also* Cal. Pub. Res. Code § 21081 (a); CEQA Guidelines, § 15091 (a)(3); *California Native Plant Soc. v. City of Santa Cruz*, 177 Cal. App. 4th 957, 1002 (2009). An agency's finding that an alternative is infeasible "must be supported by substantial evidence in the record." *Id.*; Pub. Resources Code § 21081.5; Pub. Resources Code § 21081(a)(3).

In this DEIR, Kern County eliminates several alternatives from further consideration for false or misleading reasons.

First, in considering a ban on agriculturally productive land, it determines that because the majority of the Project Area would be off limits to oil and gas activity under this alternative, it is not legally feasible. For the same reason, i.e. illegality, the second alternative—a ban on all new drilling within the County—was impermissibly eliminated as infeasible. Contrary to the representations made in the DEIR, the County has broad discretion to dictate where—the location—of oil and gas activity within its jurisdiction, and it is simply incorrect that the County lacks legal authority to exclude agricultural or other lands from oil exploration and production.

Under the California Constitution, "[a] county or city may make and enforce within its limits all local, police, sanitary, and other ordinances and regulations not in conflict with general laws." "This inherent local police power includes broad authority to determine, for purposes of the public health, safety, and welfare, the appropriate uses of land within a local jurisdiction's borders…" *City of Riverside v. Inland Empire Patients Health and Wellness Center, Inc*., 56 Cal.4th 729, 738 (2013) (emphasis added). A County's zoning power is "one of the most essential powers of the government, one that is the least limitable," and to hold otherwise would "preclude development and fix a city [or County] forever in its primitive conditions." *Beverly Oil Company v. City of Los Angeles*, 40 Cal. 2d 552, 557 (1953) (*quoting Hadacheck v. Sebastian*, 239 U.S. 394 (1915)). In *Marblehead Land Co. v. City of Los Angeles*, for example, the Ninth Circuit upheld the denial of an injunction against a Los Angeles zoning ordinance prohibiting oil well drilling operations on the basis of the "inherent right of the city to control or prohibit [oil and gas] production" even after the landowner had leased the land to drill on it and expended a considerable sum of money on preliminary work. 47 F.2d 528 (9th Cir. 1931).

The More Wells Within the Project Footprint alternative (DEIR at 6-13) would cap the total wells permitted per year within the Project Area at 3,500. That alternative was eliminated because it would cap the total wells and "may exacerbate the Project's significant environmental effects." DEIR at 6-13. The current proposed project has no cap on total annual wells, only an estimate and a total potential cap after 25 years. Accordingly, under the current project a total of *over* 3,500 wells per year could be drilled. Therefore, limiting wells logically would not have a greater impact on the environment than the proposed alternative, which does not limit total wells per year. DEIR at 6-13.

The Fewer Wells Within the Project Footprint alternative (DEIR at 6-13) was eliminated for two insufficient bases. First, it was determined that limiting the number of wells to 1,500 per year would not meet the objective to provide for growth of the oil and gas industry and streamline environmental review. An additional 1,500 wells per year is growth. Furthermore, this alternative has the potential to meet all the other stated objectives and have a lower environmental impact. "An EIR shall describe a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain *most* of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and evaluate the comparative merits of the alternatives." CEQA Guidelines § 1526.6(a) (emphasis added). That an alternative may be inconsistent with some project objectives, therefore, may not justify its elimination from review. *See also id*. §§(c), (f). Second, the alternative was rejected as legally infeasible. For the reasons explained above, this is incorrect. A County has broad authority to limit the number of total permits per year as an exercise of its land use and police powers. This alternative warrants further consideration in the Final EIR.

The Renewable Energy alternatives (DEIR at 6-14) would require that new oil and gas drilling operations be powered by renewable electric generation sources, such as wind and solar, rather than fossil-fuel powered electric generation sources. These alternatives were eliminated because of the variability inherent in these energy sources, but this ignores the ability to store wind and solar energy. Wind is further eliminated because it would generate noise, but that noise is never compared to the noise of on-site generators using fossil fuel. Solar is discounted for its ground disturbance, but the degree of ground disturbance and the ability to potentially consolidate that disturbance is not quantified or considered. The alternative offers significant advantages to the Project in the impact area of air quality by reducing each well site's reliance on polluting fossil fuel combustion, and this alternative is, as the County concedes, feasible and warrants further evaluation as well.

The Zero Net Gain alternative (DEIR at 6-16) assumes without explanation that if well permits were limited to the number abandoned there could not be growth in the County and other objectives would not be met. This is not correct. Wells are constantly retired, and new permits may be somewhat limited by the number of wells retired in any given year, but because some number of new wells would be permitted, growth would continue. Furthermore, this would have only a small impact on the ability to streamline environmental review and the other stated objectives. This alternative too warrants further consideration.

The No Project alternative (DEIR at 6-17) is eliminated for the stated reason that it would be environmentally inferior and not meet several of the Project's objectives. The rationale for finding that the No Project alternative would be environmentally inferior is that the proposed amendments to the zoning ordinance would not be made and the status quo would continue, which authorizes "unrestricted drilling" with no County permit in much of the project area. This representation misrepresents the status quo and ignores the statewide permit process and mitigation measures mandated by the statewide EIR.

The No Project alternative is concerned with the consequences of disapproving the project. CEQA Guidelines § 15126.6(e)(1). Here, the failure to amend Kern's zoning ordinance and implement a Kern County EIR would revert to a status quo that does not allow for oil and gas activity without any review, but rather, includes a state permit process, where the Division of Oil, Gas, and Geothermal Resources (DOGGR) acts as the Lead Agency. Under that DOGGR process, the mitigation measures set forth in the statewide programmatic EIR in addition to any further CEQA review would be required for each proposed well. Accordingly, an accurate representation of the environmental impact of the No Project alternative must consider the relative environmental impact of statewide CEQA review on a well-by-well basis with the Kern County proposed EIR process, which would conduct only a 1-time review for 25 years or 67,425 wells-worth of activity, with almost no site-specific information and without the mitigation mandated by the statewide EIR. Under these corrected comparison parameters, the No Project alternative would almost certainly be environmentally superior to the Project.

Furthermore, contrary to the finding in the DEIR, the No Project alternative would meet almost all of the County's and industry applicants' stated objectives, except for updating the zoning ordinance, and would more fully meet some objectives than the Project. Under the No Project alternative, oil and gas industry activity would be permissible and could grow. The process would necessarily consult and cooperate with state and federal law; the applicants would have a more "streamlined" process, because only one state permit would be required; and areas warranting protection—e.g. environmentally sensitive or agricultural lands—would be not suffer lower coverage under the statewide EIR process, and indeed, because that process would be flexible over time and more responsive to changes in climate and current conditions, it would be more likely to adapt and conserve resources than the proposed 1-time CEQA review followed by a "ministerial" permit process contemplated here. Applicants' objectives would also be fully met under this alternative. Applicants would enjoy greater statewide conformity and consistency, and it would be easier, not harder, to develop industry-wide best practices, performance standards, and mitigation measures because they would apply across the state and not just to one specific county, i.e. Kern. In sum, the No Project alternative is viable, environmentally superior, and can achieve most project objectives.

The DEIR's consideration of the CUP Alternative (DEIR 6-19-21) is equally flawed. Alternative Two would be the same as the Project in all respects except it would require a conditional use permit for each well, instead of the "unrestricted, and ministerial approval of, oil and gas exploration, development, and production activities." DEIR 6-20. The DEIR claims that because the Project would mitigate with a blind eye (i.e. without site-specific analysis) it would at times have the potential to "overmitigate with respect to some oil and gas wells." (DEIR 6-21). What this analysis ignores is that the Project would be just as likely to *under*mitigate because it would be wholly unresponsive to local and site specific conditions, as well as any changes to conditions in the County that might occur over the course of the next 25 years. The DEIR makes the claim that future applicants, under the Project, "will not have the opportunity to avoid compliance with many of the Project's new development standards or conditions," but that is unsupported by the mitigation measures detailed in the DEIR, which frequently provide for applicants to employ mitigation as "feasible," or "practicable," or "available." *See e.g.* Hazardous Materials Mitigation at DEIR at 4.8-86-87. The CUP alternative meets almost all of the stated objectives, and it would also build in long-term flexibility and incorporate site-specific analysis. Both of these additions would lead to an environmentally preferable alternative, and Alternative Two warrants further consideration.

The No Hydraulic Fracturing alternative (DEIR 6-23) was eliminated for the stated reason that any reduction in hydraulic fracturing would lead to an increased use of Enhanced Oil Recovery (or EOR) techniques. And, EOR would have a relatively higher level of emissions of greenhouse gases and criteria air pollutants. DEIR at 6-24. There is, however, no analysis included in the DEIR to help inform decision makers and to explain these conclusions. Indeed, it is questionable whether the same oil reserves that are made available using hydraulic fracturing could also be extracted using EOR. These are two distinct process that are typically used to surmount distinct extraction obstacles, and the elimination of one well stimulation process would not obviously result in a direct and corollary increase in EOR. Furthermore, there is no side-by-side comparison offered here of the GHG or emissions releases of hydraulic fracturing compared to EOR; there is compelling science that suggests quite the contrary, i.e. that the impact of hydraulic fracturing is typically greater than EOR. And, if a reduction in hydraulic fracturing led to a total reduction in oil and gas exploration in the County, it is likely that GHG and other emissions would be reduced. Finally, an elimination of hydraulic fracturing would have added environmental benefits of reducing the impacts associated with hazardous materials throughout the process. The No Hydraulic Fracturing alternative is likely environmentally superior to the Project and warrants full consideration.

No basis is provided for rejection of the Low-Emissions Enhanced Oil Recovery Technology alternative. This alternative would replace certain existing pre-1990 steam generators within five years with new low-emissions steam generators. This alternative should be adopted, or this requirement should be adopted as a mitigation measure that is part of the Project. There is no stated basis for rejecting this alternative in the DEIR, and it meets all of the objectives while being environmentally superior. *See* DEIR at 6-25-26.

The Recycled Water alternative also warrants further consideration. The only bases for eliminating this alternative are the initial up-front impacts of water treatment plant construction and the concern that requiring water treatment would impose economic hardship on industry and, therefore, slow the growth of oil and gas development in Kern County. First, the construction of water treatment facilities is an up-front impact with long-term benefits. The benefits of reused water must be accurately weighted against the harms of long-term shipping of fresh water across the state to supply the Kern oil operations and also the harms of injecting produced water in underground injection wells. The risks of underground injection include contamination of aquifers and must be considered in weighing the Project against this alternative. On the cost side of the equation, no analysis was conducted, or at least presented, to help inform decision makers and the public of the degree of any anticipated increased costs. And, those costs must be compared with the projected cost of fresh water during this historic drought and over the next 25 years. This alternative has numerous environmental advantages to the Project.

To implement the policy of reducing significant environmental impacts, CEQA requires that an EIR identify both feasible mitigation measures and feasible alternatives that could avoid or substantially lessen the project's significant environmental effects. The requirement that EIRs identify and discuss alternatives to the project stems from the fundamental statutory policy that public agencies should require the implementation of feasible alternatives or feasible mitigation measures to reduce the project's significant environmental impacts. Pub Res Code § 21002.

Here, the DEIR excludes from consideration alternatives that are apparently viable, environmentally superior, and can achieve most of the Project's stated objectives.

VI. The DEIR understates the Project's significant air quality impacts and fails to properly mitigate these impacts.

The San Joaquin Valley Air District is in extreme nonattainment for ozone and nonattainment for PM 2.5. The job of the Air District to bring itself into attainment for ozone will get tougher when EPA announces its new ozone rule, expected in a month or two. The DEIR has a table of ozone and PM 2.5 exceedances on pp. 4.3-8 – 4.3-9, showing 85 days of ozone nonattainment in 2012 in Arvin and 55 days of nonattainment in 2012 in Bakersfield. Diesel particulate matter emissions in 2009 were over 6,000 tons/year, with on-road diesel-fueled vehicles contribute approximately 61% of the total and an additional 38% attributed to other diesel-fueled mobile sources such as construction and agricultural equipment. DEIR 4.3-25. In Kern County in 2012, NOx emissions (an ozone precursor) were 72.3 tons/day. DEIR 4.3-31. These numbers are a public health disaster.

Kern County will be subject to increased emissions of particulate matter and ozone (and its precursors) from the project. Emission increases associated with activities under the Project's permitted sources would come from boilers, cogeneration plants, process heaters, reciprocating internal combustion engines, steam generators, production tanks, thermally enhanced oil recovery wells, and VOCDD (flares). There will be additional emissions from unpermitted sources. DEIR 4.3-67. Off-road construction equipment will also contribute to emissions of NOx (an ozone precursor) and PM.

The DEIR presents figures for the project's increased emissions but it is impossible to tell how those numbers were derived. There are references in terms of emissions to reports from a consultant called “Vector” but those reports are not part of, or linked to in, the DEIR; nor are they available on the County's website. This omission violates the CEQA requirement to provide understandable and comprehensive data to the public and to decision makers and so, by itself, invalidates the entire air quality analysis in the DEIR.

The approach of the DEIR to the permitted emissions from the project is that they will be reduced below significance by existing regulations. If that were true, the SJVAQMD would not be in nonattainment in the first place. Moreover, to the extent that permitted emissions rely on offsets or credits for their legality, there is no assurance or proof that those offsets or credits will exist or will be real, excess, permanent and enforceable if they do.

With respect to the unpermitted emissions from the project, the DEIR takes the view that voluntary agreements will reduce these emissions below significance. This is faith-based planning and not the concrete, verifiable, enforceable mitigation measures that CEQA requires.

The mitigation measures presented in the DEIR are weak and ineffective. The DEIR should evaluate a mitigation measure, discussed below, that would require the multi-year oil and gas drilling project to reduce emissions in the San Joaquin Valley Air District, not merely hold them even.

A. The DEIR shows huge, negative air quality effects from the Project.

If the Vector data and analyses are correct – which is impossible to determine from the DEIR – the DEIR shows huge, negative air quality impacts from construction and operational emissions associated with the project.

Tables 4.3-12 and 4.3-13 (at pp. 4.3-77 to 78) show that emissions associated with well construction activities would exceed SJVAPCD Construction Emissions Threshold. Since the San Joaquin Valley Project region is nonattainment for PM10, PM2.5, and ozone, well construction-related criteria pollutant emissions would result in considerable net increase of the criteria pollutants NOX, VOC, CO, PM10 and PM2.5 and would be significant impacts.

With respect to operational emissions, the DEIR admits that such emissions would exceed the SJVAPCD Operational Emissions and therefore would represent a potentially significant impact. The annual contribution of PM10 and PM2.5 would be almost 30 times the threshold. The emissions of ozone precursors (NOx, ROG, and CO) would exceed their respective thresholds: NOX would be almost 50 times the threshold, VOC more than 170 times the threshold, and CO more than eight times the threshold.

The EIR claims that all emissions increases from permitted equipment plus the 10% allowance from non-permitted equipment would be required to be fully offset pursuant to District Rule 2201. But, as noted above, there is no showing that such offsets would exist or would be consistent with CAA requirements.

The DEIR summarizes air quality impacts from permitted stationary sources, permit-exempt equipment, and mobile sources at a Project level as resulting in emissions levels that would exceed SJVAPCD Operational Emissions Threshold. Only the permitted stationary sources would be required to be offset because it is a condition of SJVAPCD air permits. Since the remaining emissions would exceed the SJVAPCD Construction Emissions Threshold and would not be offset, operational emission would result in considerable net increase of the criteria pollutants NOX, VOC, CO, PM10 and PM2.5 and would be significant.

The DEIR also asserts that mandated emission reductions will be achieved by a menu of options that range from paying a calculated mitigation fee for use in doing emission reduction projects through a grant-type program, to applicants' changing equipment on existing operations or proposing projects for implementation instead of paying the fee. As we will discuss below, the mitigation measures required in the DEIR come nowhere close to this.

Based on this imaginary mitigation, the DEIR claims that impacts from the project will not be significant after mitigation. This conclusion is unsupported in the record.

The disclosed air quality impacts due to the Project are significant, adverse, and large. The Project's impacts, however, are understated. The Project is expansive and includes a wide spectrum of activity (see discussion of activity *above*), and accordingly the sources of emissions are also myriad. In its current form, however, the DEIR's source list of volatile organic compounds (VOCs) and other air toxic emissions is incomplete. Well stimulation emissions in the DEIR are restricted to diesel particulate emissions from pumps/engines. This anemic universe of potential emissions sources is not consistent with Federal rulemaking. The sources of air emissions covered by the 2012 New Source Performance Standards, for example, include emissions from completion of hydraulically fractured wells, equipment leaks, pneumatic controllers, pneumatic pumps, storage tanks, and compressors (in some cases).[2] Here, the DEIR's analysis is missing fugitive VOCs from completions of hydraulically fractured wells. There is also no consideration of air quality threats from equipment leaks, compressors, infiltration ponds, sumps, or separators none of which are currently subject to permits or emission limits. As noted above, the potential for health threats from the volatilization of stimulation chemicals present in produced water or wastewater was not included in the DEIR.

In addition, the Project would have significant, unavoidable odor impacts. The analysis of odors, however, is incomplete. The odor analysis includes no discussion of the chemical constituents responsible for odors and whether air quality issues may be the source. Nor does the DEIR discuss the public health impacts from the chemicals causing the odors.

B. The proposed mitigation measures will not be effective.

The proposed mitigation measures appear at DEIR pages 4.3-68 et seq. The DEIR identifies Impact 4.3-1 as: Conflict with or Obstruct Implementation of the Applicable Air Quality Plan. The proposed mitigation measures, which allegedly will reduce the impacts below significance, are:

- *MM 4.3-: Get a permit and comply with AQMD rules*. As noted above, if this were effective, the SJVAQMD would not be in non-attainment for PM and ozone. Also, the permit system depends heavily on offsets which may or may not exist or comply with the Clean Air Act at the time they are needed.
- *MM 4.3-2: Develop a fugitive dust control plan*. This does nothing for particles smaller than PM 10 or for NOx emissions. The mitigation measure claims to reach particles as

[2] *See* http://www.epa.gov/airquality/oilandgas/pdfs/og_table_081815.pdf.

small as PM 2.5 but, in general, particles that small are not generated from fugitive dust but rather from combustion emissions, which this mitigation measure does not address.

- *MM 4.3-3: Off-road construction equipment requirements*. This requires most construction equipment to meet California Tier 3 standards and limits idling to 5 minutes. However, there is cleaner, Tier 4 equipment available and, given the SJVAQMD's state of non-attainment, it should be required. See EPA Tier 4 rules; California Tier 4 rules.
- *MM 4.3-4: On-road heavy duty diesel haul equipment*. For NOx control, California 2007 or Tier 3 engines are required. However, cleaner California and EPA 2010 engines are available and should be required; these are notable for much lower NOx emissions that 2007 engines.

Impact 4.3-2 is: Violate Any Air Quality Standard as Adopted in (c)i or (c)ii, or Established by EPA or Air District or Contribute Substantially to an Existing or Projected Air Quality Violation. The proposed mitigation measures are MM 4.3-1 through MM 4.3-4 as discussed above. The DEIR asserts that the Level of Significance After Mitigation will be less than significant. This is pure fantasy – there is no showing that the four mitigation measures listed above will keep the SJVAQMD in attainment or are the best or most feasible mitigation measures available.

Impact 4.3-3 is: Expose Sensitive Receptors to Substantial Pollutant Concentrations. The health risk assessment shows that the potential cancer risk exceeds the current CEQA significance thresholds (as of May 2015), for drilling a 10,000-foot well in any Project year, and for drilling a 5,000-foot well in year 2015, and for operations of the oil processing equipment. 4.3-110. The DEIR claims that the health risk assessment was prepared using the OEHHA 2015 guidelines; if that is not so, the numbers would likely be higher by as much as a factor of three. The emission factors used in the modeling are said to be from the totally opaque Vector study. Nonetheless, the DEIR asserts that the Level of Significance After Mitigation will be Less than significant.

The setback distances provided for by the DEIR are based only on risks related to diesel particulate matter during well construction. The setback distance fails to consider VOC/air toxics emissions from completions, air toxics emissions from processing equipment, or emissions during well production. Although cancer risk was considered significant (10 in a million) at distances under 800 feet from oil processing equipment, no setback distance was included to protect public health or schools at these distances. The setback distances for wells in the DEIR are also inconsistent with CARB Recommended Minimum Setback Distances between sources of diesel PM and sensitive populations (500 ft. minimum).

Finally, the CCST Study noted that "most of the hydraulic fracturing in the San Joaquin Basin occurs shallower than 300m (1,000 ft.)"[3]. Therefore many wells in Kern County will be below the threshold of depth requiring a setback in the DEIR (<2,000 ft.). The DEIR fails to explain that as described many of the wells in Kern County will not have setback requirements. This directly contradicts the findings from the CCST Study noting the concentration of emissions at production sites which could threaten human health and the recommendation that health-protective setbacks be required to protect the health of vulnerable populations.

[3] CCST 2015. An Independent Scientific Assessment of Well Stimulation in California Volume III p.268

The identified mitigation measures are:

- MM 4.3-5: The Site Plan Application shall include a Site Vicinity Figure showing the location of any sensitive receptor(s) within 3,000 feet of the construction site (potential impact area) for the proposed new well or other ancillary facility or equipment (excluding pipelines).
    a. If there are no sensitive receptors within this potential impact area, then no construction mitigation measures shall be required.
    b. If there are sensitive receptors within the potential impact area, then additional information must be provided showing the setback from the closest edge of the well pad to the property line of the nearest sensitive receptor. The minimum distances shall be as follows: ….4.3-111
    c. If the above setbacks cannot be met, the Applicant shall implement the following risk minimization measures, or other such measures that are demonstrated by the Applicant to achieve a level of risk less than the threshold risk level:
        1. Placement of engines in the potential impact area away from the sensitive receptors.
        2. Utilize directional drilling to locate rig away further from the sensitive receptor(s).
        3. Use of late-model engines, low-emission diesel products, alternative cleaner fuels (e.g., natural gas or liquefied petroleum gas), engine retrofit technology, add-on devices such as diesel particulate filters or oxidation catalyst, and/or other options as such become available to reduce emissions from off-road and other equipment.
        4. Utilize electricity line power if available.
        5. Shutdown all equipment when not in use, and otherwise minimize engine idling by limiting idling to 15 minutes.
        6. Use of automatic rigs.
        7. Assist and pay to relocate residents to an area hotel during well construction, drilling, and completion activities.
- MM 4.3-6: Applicants shall include in their Worker Environmental Awareness Program information on how to recognize the symptoms of Valley Fever and to promptly report suspected symptoms of work-related Valley Fever to a supervisor. Workers exposed to fugitive dust shall be provided with the option of using a filter fitted over their nose and mouth, secured by a strap, including training for appropriate mask practices as part of the Worker Environmental Awareness Training Program.

It is impossible to assess the strength of these mitigation measures because the underlying emissions factors cannot be tested given the information in or linked to the DEIR.

- Impact 4.3-5: Results in a Cumulatively Considerable Net Increase of Any Criteria Pollutant for which the Project Region is Nonattainment Under an Applicable Federal or State Ambient Air Quality Standard including Releasing emissions which exceed quantitative threshold for ozone precursor.
- Implement MM 4.3-1 through MM 4.3-4, as described above. As we have discussed, there is no showing that these mitigation measures will be available or effective in the future.

- MM 4.3-8: For Project facilities or equipment that are not required to offset emissions under a District rule as described in MM 4.3-1, and for Project vehicle and other mobile source emissions, the County will enter into emission reduction agreement with the San Joaquin Valley Air Pollution Control District, pursuant to which the Applicant shall pay fees to fully offset Project emissions of oxides of nitrogen, reactive organic gases, and particulate matter of 10 microns or less in diameter (including as applicable mitigating for reactive organic gases by additive reductions of particulate matter of 10 microns or less in diameter) (collectively, "designated criteria emissions") to avoid any net increase in these pollutants. The air quality mitigation fee shall be paid to the County as part of the Site Plan review and approval process, and shall be used to reduce designated criteria emissions to fully offset Project emissions that are not otherwise required to be fully offset by District permit rules and regulations.

As an alternative to paying the fee, an Applicant may reduce emissions for one or more designated criteria emissions through actual reductions in air emissions from other Applicant sources, as submitted to the County and validated by the District. This Project offset requirement shall be enforced by the County and verified by San Joaquin Valley Air Pollution Control District. If a voluntary emission reduction agreement is not executed by the County and San Joaquin Valley Air Pollution Control District, then each Applicant must mitigate for the full amount of designated criteria pollutants as verified by the San Joaquin Valley Air Pollution Control District, with evidence of such District-verified offsets presented as part of the Site Plan Conformity Review application documentation.

Examples of feasible air emission reduction activities that may be funded by air quality fees paid by Applicant or proposed and implemented by the Applicant under the emission reduction agreement include, but are not limited to, the following:

a. Replacing or retrofitting diesel-powered stationary equipment such as motors on generators, pumps and wells with electric or other lower-emission engines that are not subject to Title V reductions.
b. Replacing or retrofitting diesel-powered school, transit, municipal and other community mobile sources such as buses, car fleets, and maintenance equipment, with electric or other lower-emission engines.
c. Reducing emissions from public infrastructure sources such as water and wastewater treatment and conveyance facilities, and reducing water-related emissions through water conservation and reclamation. Funding lower-emission equipment and processes for local businesses, schools, non-profit and religious institutions, hospitals, city and county facilities.

Mitigation fees in this sense are a license to pollute, without any showing that the projects funded by the fees will reduce emissions of NOx, ozone and other pollutants enough to make a difference. Not surprisingly, the DEIR lists the Level of Significance After Mitigation for this cumulative impact as significant and unavoidable.

C. The DEIR fails to analyze additional mitigation measures that may be effective.

Only two additional mitigation measures are discussed, both of which are quickly rejected at page 4-3.122:

> Require oil and gas projects to generate their own clean electricity during production using photovoltaic (PV) solar, direct line power, or both, to eliminate all needs for operational power diesel generator onsite.
>
> There should be a percent limit on the amount of time they can flare gas.

What is not discussed is the obvious measure that no well should be drilled and/or operated until the well proponent can show real, surplus, effective mitigation measures such that there will be a *reduction* in emissions of ozone, ozone precursor or PM 2.5 emissions in the SJV Air Basin. Holding emissions to no net increase will harm, not help, the Air District's long and so far ineffective efforts to come into attainment for these criteria pollutants. At minimum, the Air District should obtain U.S. EPA approval for forward-looking attainment demonstrations for these substances before a single new well is begun.

The air quality analysis in the DEIR is so flawed that it needs to be re-done. All the emissions modeling inputs, methodology and outputs should be available to the public and to the decision makers. The proposed mitigation measures are laughably weak and need to be enhanced. Otherwise, the Air District is looking at additional decades of unhealthy air.

VII. The DEIR fails to fully disclose, analyze, and mitigate the Project's potential impacts to hydrology and water quality.

A. The DEIR's water supply and demand scenarios fail to consider potential demand increases that could result from development of the Monterey Formation.

The three future water supply and demand scenarios considered in the DEIR do not adequately assess the range of possible activity, in particular the possibility of development of unconventional resources in the Project Area and resultant impacts on water demand and waste water handling needs and methods. As stated in the DEIR, "The three scenarios focus on potential variation in the amount of surface pond disposal, injection well disposal, and reuse of produced water that could occur under future conditions." In other words, the scenarios focus primarily on potential changes in water disposal practices, and none of the three scenarios considers the potentially significant increase in water demand and wastewater management needs that could result from development of the Monterey Formation source rock play.

Development of the Monterey Formation source rock play would likely require the use of high volume hydraulic fracturing, as has been used to develop other tight oil plays such as the Bakken in North Dakota and Eagle Ford in Texas. As stated in the DEIR, the average fracturing operation in California uses about 0.38 AF of water. A limited number of wells that target Monterey Formation unconventional resources exist in California, and these wells use water volumes for hydraulic fracturing greatly in excess of this average. Horizontal wells in the Rose Field targeting the McClure Shale member of the Monterey Formation used an average of 1.3 acre feet of water per well for hydraulic fracturing, or more than three times the CA average.[4] Horizontal wells in the Lost Hills Field targeting the McDonald Shale member of the Monterey Formation used an average of 8 acre feet of water per well for hydraulic fracturing, or more than 21 times the CA average.[5]

While the prospect for large-scale development of this play is highly uncertain, production of these resources is likely to require much larger volumes of fresh water than current production methods in the project area and could significantly increase the volumes of wastewater that subsequently need to be managed. The analysis of hydrology and water quality is incomplete due to the failure to analyze a scenario that considers development of unconventional resources.

B. The DEIR's claims regarding spill incidence and volume are unsupported and its mitigation measures for spills are inadequate.

The DEIR states that the frequency of occurrence of spills and spill volumes are expected to be low in all phases of oil and gas operations. The supposed support for this claim is the statewide DEIR for well stimulation, which includes the number of spills in the Project Area from 2009-2014 and the range of spill sizes. This analysis however does not include a statistical analysis of the frequency of occurrence or size of spills. A 2015 report prepared for the Natural Resources Defense Council (NRDC) by the UCLA Institute of the Environment and Sustainability (UCLA-IES) found that while the number of spills in Kern County was found to have decreased, this was attributed to the decrease in oil and gas production rather than a change in operational practices.[6]

Moreover, the spill analysis in the statewide DEIR is far from complete. The spills represented only include spills of hazardous materials reported to the California Office of Emergency Services (OES). As detailed in the UCLA-IES report for NRDC, spills reported to OES are subject to reporting thresholds and only include listed hazardous substances and therefore do not represent a full accounting of all spilled materials that may have adverse environmental or health impacts.[7] The statewide DEIR clearly states, "It is additionally noted that this data is considered incomplete due to differences in how reporting is logged and variations in local regulations for when reporting is required." The UCLA-IES report concurs with this, stating, "…the CA OES data format is incomplete, disorganized, and difficult to analyze effectively."[8] As such, the claims made in the DEIR that the incidence of spills and volumes are expected to be low are completely unsupported.

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[4] California Division of Oil, Gas, and Geothermal Resources. 2015. Interim Well Stimulation Disclosures Index. Available at: ftp://ftp.conservation.ca.gov/pub/oil/Well_Stimulation_Treatment_Disclosures/20140507_CAWellStimulationPublicDisclosureReport.xls

[5] *Ibid.*

[6] Caryotakis, A., Davies, I., Hafiz, S., Niketen, J., Noakes, D., Wang, R., and Wu, A. 2015. An Analysis of Hazardous Materials Spills with a Focus on Oil and Gas Production: A 2015 Undergraduate Practicum Project for the UCLA Institute of the Environment and Sustainability. Report prepared for the Natural Resources Defense Council. *See* Attachment 1.

[7] *Ibid.*

[8] *Ibid.*

Among the most commonly cited environmental impacts of oil and gas production are degradation of soils and water caused by releases of hydrocarbons and produced water.[9] The critical importance of properly mitigating the risk of spills and leaks is demonstrated by the many tens of studies describing the environmental impacts of hydrocarbon and produced water releases.[10] A multi-year, interdisciplinary study of hydrocarbon and produced water releases at an oil production site in Oklahoma undertaken by the United States Geological Survey ("USGS") found that soil and groundwater at the site were still polluted after more than 60 years of natural attenuation.[11] Contamination caused by releases of hydrocarbons and produced water can be extremely technologically and financially difficult to remediate, if not impossible. The DEIR does not include any mitigation to address impacts to hydrology and water quality from spills beyond stating that operators must comply with existing law. This is completely inadequate and unacceptable.

C. The DEIR fails to adequately disclose and mitigate the potential impact of drilling fluids.

Regarding the potential impacts of drilling fluids, the DEIR states, "…drilling activities do not typically utilize high concentrations of potential constituents of concern," and, "…the generally low concentrations of drilling or rework-related constituents added to drilling fluids reduces the likelihood that temporary drilling fluid and mud contact with water-bearing formations would cause a significant impact to groundwater quality." These statements are completely unsupported. California does not require operators to disclose the chemical contents of drilling fluids, which can include chemical products such as weighting agents, clay, organic colloids, polymers, thinners, surfactants, inorganic chemicals, lost circulation material, and other specialty chemicals. The DEIR contains only a generic list of possible drilling fluid additives, listed by trade name, as reported by one operator. The well-by-well identity of the chemical components of drilling fluids, and therefore the potential environmental or human health impacts, are unknown. This is a significant undisclosed and unmitigated impact to hydrology and water quality.

D. The DEIR fails to adequately disclose, analyze, and mitigate the potential impacts of improperly designed, constructed, or maintained wells.

Proper well design and construction are crucial first step to ensuring long-term mechanical integrity. Oil and gas wells represent one of the most likely pathways for contaminants to reach protected water because the wellbore directly connects protected water and introduced or naturally occurring contaminants.[12] Casing, cement, and other well construction materials must

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[9] Kharaka, Y. K., & Dorsey, N. S. (2005, June). Environmental issues of petroleum exploration and production: Introduction. *Environmental Geosciences, 12*(2), 61-63.

[10] Otton, J. K. (2006). *Environmental aspects of produced-water salt releases in onshore and estuarine petroleum-producing areas of the United States - a bibliography.* Retrieved from U.S. Geological Survey Open-file report 2006-1154: http://pubs.usgs.gov/of/2006/1154/pdf/of06-1154_508.pdf

[11] Kharaka, Y. K., Otton, J. K., & eds. (2003). *Environmental impacts of petroleum production - Initial results from the Osage-Skiatook Petroleum Environmental Research Sites, Osage County, Oklahoma.* U.S. Geological Survey Water-Resources Investigations Report 03-4260.

[12] See, e.g. U.S. Environmental Protection Agency, Office of Drinking Water. (1980, May). *Statement of Basis and Purpose, Underground Injection Control Regulations.* Retrieved from

therefore isolate these sources of contaminants from protected water. Failure to do so, as a result of poor well design and/or construction, is a frequently cited cause of environmental impacts to groundwater.[13] Proper well design, construction, maintenance, and plugging are therefore paramount to protecting groundwater. California's current well construction rules are outdated and inadequate and must be updated to reflect technological advancements in oil and gas extraction techniques. Operators must demonstrate that wells will be designed and constructed to ensure both internal and external mechanical integrity. The DEIR must include mitigation measures to ensure proper well design, construction, and maintenance.

E. The DEIR fails to adequately disclose, analyze, and mitigate the potential impacts of the use of produced water for irrigation.

The recent statewide scientific study of well stimulation by the California Council on Science and Technology (CCST) found that required testing and treatment of produced water destined for reuse may not detect or remove contaminants of concern.[14] The DEIR must include mitigation measures requiring disclosure, testing, and treatment of produced water destined for reuse to detect and remove chemicals of concern including but not limited those that are naturally present and also chemicals used in drilling, stimulation, maintenance, workover, and enhanced recovery operations.

F. The DEIR fails to adequately disclose, analyze, and mitigate the potential impacts of percolation pits.

California is one of the few states that allow the outdated practice of disposing of potentially toxic oil and gas waste water into percolation pits/ponds, which are designed to allow this waste to infiltrate groundwater. The DEIR that, "…the disposal of produced water to earthen, unlined ponds in Project Area has impacted groundwater quality." The recent statewide scientific study completed by the California Council on Science and Technology highlighted the significant risk that these pits pose to groundwater and recommended that the practice should be stopped.[15] The DEIR does not include any mitigation to address the significant threat to hydrology and water

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http://www.epa.gov/ogwdw/uic/pdfs/rept_uic_statemt_basis_purpose_uic_1980.pdf ; Kharaka, Y. K., & Dorsey, N. S. (2005, June). Environmental issues of petroleum exploration and production: Introduction. *Environmental Geosciences*, *12*(2), 61-63.; Jackson, R. B., Vengosh, A., Carey, J. W., Davies, R. J., Darrah, T. H., O'Sullivan, F., et al. (2014). The Environmental Costs and Benefits of Fracking. *Annual Review of Environment and Resources, 39*, 327-362.

[13] See, e.g. URS Corporation. (2006). Phase I hydrogeologic characterization of the Mamm Creek Field area in Garfield County: Prepared for the Board of County Commissioners, Garfield County, Colorado.; Papadopulos & Associates, Inc. (2008). Phase II hydrogeologic characterization of the Mamm Creek Field area, Garfield County, Colorado: Prepared for the Board of County Commissioners, Garfield County, Colorado.; Pennsylvania Department of Environmental Protection. (2009, November 4). Consent Order and Agreement between Cabot Oil and Gas Corporation and the Pennsylvania Department of Environmental Protection. Retrieved August 30, 2012, from http://loggerhead.epa.gov/arweb/public/pdf/2141700.pdf; Darrah, T. H., Vengosh, A., Jackson, R. B., Warner, N. R., & Poreda, R. J. (2014). Noble gases identify the mechanisms of fugitive gas contamination in drinking-water wells overlying the Marcellus and Barnett Shales. Proceedings of the National Academy of Sciences, 111(39), 14076-14081.; Dusseault, M. B., Jackson, R. E., & Macdonald, D. (2014). Towards a Road Map for Mitigating the Rates and Occurrences of Long-Term Wellbore Leakage. University of Waterloo and Geofirma Engineering LTD.

[14] California Council on Science and Technology. 2015. *An Independent Scientific Assessment of Well Stimulation in California, Volume II, Potential Environmental Impacts of Hydraulic Fracturing and Acid Stimulations.*

[15] California Council on Science and Technology. 2015. *An Independent Scientific Assessment of Well Stimulation in California, Volume II, Potential Environmental Impacts of Hydraulic Fracturing and Acid Stimulations.*

quality from percolation pits beyond stating that operators should comply with current law. This is completely inadequate.

G. The DEIR fails to adequately disclose, analyze, and mitigate the potential impacts of underground injection operations, including disposal and enhanced oil recovery (EOR).

California's rules for underground injection are outdated and inadequate and oversight and enforcement of the program is lax, endangering the drinking water of millions of people. A 2010 review of California's Underground Injection Control (UIC) program found a number of significant deficiencies, which may be endangering groundwater and have yet to be corrected.[16] More recently, it was revealed that the State of California has improperly permitted more than 2,500 Class II Underground Injection Control (UIC) wells to inject oil and gas wastewater and other fluids into federally protected Underground Sources of Drinking Water (USDWs).[17] There are also potentially hundreds or thousands more wells located geographically within the boundary of an exempt aquifer, but where the fluids being injected in to that well are migrating into non-exempt USDWs. These actions seriously endanger California's dwindling and drought-threatened groundwater as well as the public health and safety of Californians who rely on this groundwater for drinking, irrigation, or other uses. The DEIR does not include any mitigation to address the significant threat to hydrology and water quality from underground injection operations beyond stating that operators should comply with current law. This is completely inadequate.

H. The DEIR fails to adequately disclose, analyze, and mitigate the potential impacts of well stimulation operations, including hydraulic fracturing and acidizing.

As discussed above, the CCST recently published the first ever statewide, comprehensive scientific assessment of the potential environmental impacts of well stimulation in California. The researchers found that well stimulation activities and oil and gas development in general can result in a range of impacts to the environment and human health, including to hydrology and water quality, but much more data is needed to completely analyze the risks. The reports also include a long list of recommendations to begin addressing these impacts. The DEIR fails to disclose or analyze the significant impacts detailed in the CCST Study or to implement the recommended mitigation measures.

VIII. The DEIR fails to fully disclose, analyze, and mitigate the Project's potential hazards and hazardous materials impacts to public health, air, and water quality.

The DEIR's evaluation of stimulation chemicals is incomplete and its findings are not incorporated into health risk analysis. Chemical information was obtained from FracFocus.org, a voluntary chemical disclosure registry, from reports dated between 2012 and 2014 in Kern County. Reporting to FracFocus is voluntary; as such, only three of the six major operators in

[16] Horsley Witten Group, Inc. 2011. *California Class II Underground Injection Control Program Review.*
[17] California Department of Conservation Division of Oil, Gas and Geothermal Resources, 2015. "General Information Underground Injection Control (UIC)." Web. 10 Sept. 2015.

Kern County (Aera Energy LLC, Chevron USA, Inc; and California Resources Corporation, formerly Occidental Oil and Gas) have submitted a substantial number of chemical disclosure reports. In addition, voluntary reporting yields little accountability for operators to report well stimulation activities and quality of reporting can vary greatly. Additionally, chemical information is disorganized and strewn throughout the document; this lack of organization directly obstructs the ability of readers to understand and analyze this information further.

Toxicity data used to evaluate impacts to public health from stimulation chemicals were sparse and incomplete. The DEIR analysis did not include other exposure pathways (e.g. inhalation, skin contact, etc.) that were included in the CCST Study. This report also failed to evaluate endocrine disruption and bioaccumulation potential, both relevant health endpoints for stimulation chemicals. Additionally, no regulatory thresholds were applied to chemicals to evaluate potential health hazards.

The DEIR failed to conduct a robust health hazard assessment regarding chemicals used in well stimulation fluids. The minimal, and inadequate, analysis that was conducted was not included in the health risk analysis and therefore ignored when discussing the potential for hazards and threats to public health. The DEIR concludes that risks would not be significant after implementation of mitigation measures; however, that conclusion lacks analysis and is not consistent with the CCST Study. That recent independent report concluded that data gaps in the identity and toxicity of chemicals used for well stimulation result in significant uncertainties regarding the potential impacts of those chemicals.

As noted above, the DEIR does not consider the CCST Study's recommendation that applicants be required to restrict stimulation chemicals to those with known and non-toxic risk profiles. The Final EIR should consider this feasible mitigation measure that would have potential positive impacts to human health, air, and water quality.

IX. Conclusion

KCPCDD's proposed Project attempts to shield all oil and gas activity, including well stimulation, in unincorporated Kern County from any further CEQA review. By purporting to analyze hypothetical, future conditions that are largely unknown and unknowable at this time, the profound risks to public health and safety from the Project have been completely obscured, robbing the public of its right to engage in the CEQA process and impeding decision-makers in contravention of the very purpose of CEQA review.

The DEIR fails to adequately disclose, analyze, and mitigate the Project's significant environmental impacts. KCPCDD must give full consideration to the alternatives that would provide environmental benefits not provided by the Project and were eliminated without adequate basis or rationale, including a drilling ban on agriculturally productive lands, a drilling ban on all lands, the fewer wells alternative, the renewable energy alternative, the no project alternative, the CUP alternative, the no hydraulic fracturing alternative, the low-emissions EOR technology alternative, and the recycled water alternative.

KCPCDD should impose a moratorium on well stimulation in Kern County until it can address the flaws in, and recirculate for public comment, a revised DEIR.

Respectfully submitted,

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Attachment

Attachment 1

An Analysis of Hazardous Materials Spills with a Focus on Oil and Gas Production

A 2015 Undergraduate Practicum Project for the
UCLA Institute of the Environment and Sustainability

Client: Natural Resources Defense Council

Advisor: Dr. Felicia Federico

Team: Alex Caryotakis, Ian Davies, Sarah Hafiz, Justine Niketen, Daniel Noakes, Ruoyu Wang, Alison Wu

UCLA
Institute of the Environment and Sustainability

NRDC

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I. Executive Summary

Our team analyzed reported hazardous material releases in California to assess the number, volume, characteristics and trends over time, with particular attention paid to oil and gas related releases. Within a nine-year period from 2006 to 2014, we analyzed characteristics that included substance, location, site characteristics, containment, water body impacts, injuries or fatalities, and cleanup services. Our analysis found that spill frequency remained constant in California from 2006 to 2014, but total spill volume increased 69% from 2013 to 2014. Oil and gas spills in Kern County decreased, mirroring the decrease in California oil production. We also sought to determine if there were differences in the number of spills associated with unconventional oil and gas production (hydraulic fracturing) compared to conventional production; however, we were unable to conduct a meaningful statistical analysis due to data limitations relating to both spills and oil wells. We include recommendations for the Division of Oil, Gas, and Geothermal Resources (DOGGR) and the California Office of Emergency Services (Cal OES) around improving the quality and accessibility of their data.

II. Introduction

The United States' oil production is at a 15 year high (Heinberg, 2013). New methods of oil extraction, namely hydraulic fracturing, have allowed oil and gas producers across the nation and in California to extract more oil than was possible in decades before. However, with these new methods of extraction come a host of new concerns, including the potential for groundwater contamination and hazardous chemical spills.

The goal of this project was to analyze hazardous materials spills in California, to understand their frequency, location, and characteristics, and to determine if there are relationships between oil and gas production methods and hazardous materials spills.

This report provides: a background on the processes and regulations relating to oil and gas production and hazardous material releases (Section C), our analysis methodology (Section D), and the results, conclusions and recommendations resulting from our research (Sections E-H).

III. Background

A. Non-Traditional Oil and Gas Production: Well Stimulation Treatments

1. Production Process

Hydraulic fracturing, often called "fracking", is a well stimulation process used to extract oil and natural gas from reservoir rocks of low permeability, usually fine-grained sandstones and shales (FracFocus, 2015a). In hydraulic fracturing, large amounts of water and chemical additives are injected into a well at high pressures to fracture the rock formation and allow for extraction of the trapped hydrocarbons.

After hydraulic fracturing has occurred but before production begins (i.e. before oil or gas begins flowing through the well), fracturing fluid may return through the wellbore to the surface as flowback water which is then stored and reused in other drilling operations. However, up to 90% of fracking fluid may remain underground (Lutz et al., 2013). After production has begun, "produced water", which has had contact with oil and gas, returns to the surface (Geological Society of America, 2015; EPA, 2012b).

Based on available well data, an estimated 100 to 150 wells per month are hydraulically fractured in California, mostly for heavy crude oil (Jordan et al., 2014).

2. Chemicals Used

Although water comprises over 99% of fracking fluid by weight, a variety of chemicals are also used. The composition of fracking fluid is adapted to the requirements of each well. Common components include acids to dissolve material and reduce clogging, friction reducers, and surfactants to improve flow through pipes (Colborn et al, 2011).

A study conducted by Congressional Committee on Energy and Commerce shows that a about 2500 products and 750 chemicals are used by 14 companies (Waxman, 2011). The most widely used chemical was methanol (found in 342 products), followed by isopropyl alcohol (274 products), 2-butoxyethanol (126 products) and ethylene glycol (119 products). (Waxman, 2011). Twenty-nine of the reported products were known or possible carcinogens, regulated contaminants under the Safe Drinking Water Act, or hazardous air pollutants under the Clean Air Act. Additionally, many unconventional oil and gas operators use proprietary chemicals in their fracking fluids. These “trade secret” chemicals are protected from disclosure (Waxman, 2011).

When flowback water returns to the surface, it is made up mostly of the original fluid and chemical mix with a salinity content that increases as a function of time since initial injection. Produced water, on the other hand, contains hydrocarbons as well as naturally occurring chemicals from within the rock formations. These chemicals typically include hyper saline reservoir water, oil and other hydrocarbons, and toxic elements like radium, barium and strontium. All of these chemical characteristics vary with the geology of the exploited formation (Vengosh et al., 2014).

Due to the overlap of many chemicals used in both processes, it is difficult to differentiate between spills and contamination from traditional oil and gas operations and those from WSTs. However, efforts have been made to more effectively and appropriately attribute spills to WSTs, such as using boron and lithium as tracers from shale formations (Warner et al., 2014). These techniques, coupled with greater transparency for proprietary chemical disclosures, are promising advances in tracing spills and contaminant migration to unconventional oil and gas sources.

3. Pollution Pathways

In hydraulic fracturing, waste materials are generated during both the fracturing and production phases. The main areas of concern lie in pollution from above ground spills during the handling, transport, and storage of waste and in the potential for unrecovered subsurface fracturing fluid to migrate to aquifers, and groundwater contamination from natural gas leaks around fractured wells (Vengosh et al., 2014). Pollution pathways are divided into direct and indirect processes.

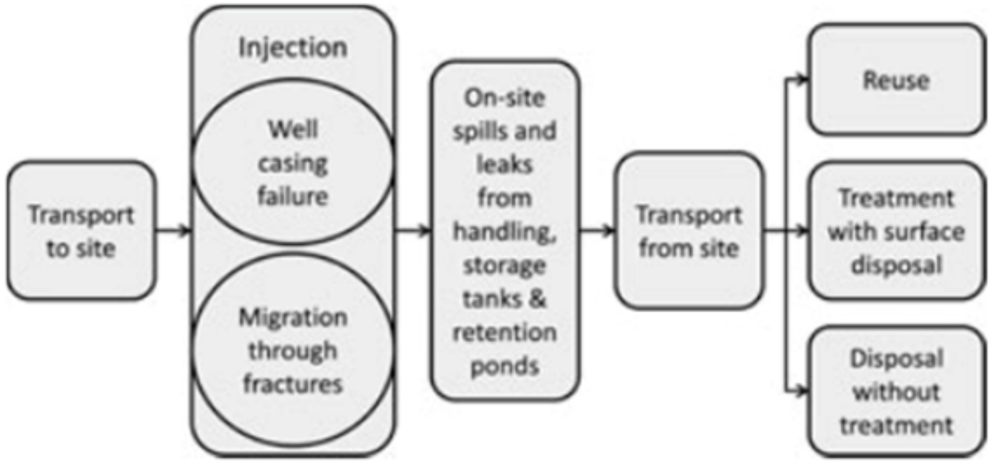

Figure 1: Potential pollution pathways from hydraulic fracturing. (Source: Rozell & Reavan, 2012)

a) Direct Pollution

Direct pollution is the (mostly subsurface) contamination of soil or groundwater resulting from high-pressure fracturing and the withdrawal of fluids and hydrocarbons. There is concern that the high-pressure fracturing process can create pathways for fracking fluid and hydrocarbons, especially methane, to migrate into aquifers used for drinking water and irrigation. Other pathways are well-casing failures and seal failure near the mouth of the wellbore. Statistical analysis of hydraulic fracturing contamination events suggests that well failure, not high-pressure fracturing, causes most groundwater pollution (Darrah et al., 2014).

Another study suggested that fluid migration through fractures is a high potential risk, but waste disposal contamination risk is several orders of magnitude larger (Rozell et al., 2012). In nearly all studies of this kind, uncertainty over pollution pathways made it difficult to determine the degree of threat posed by fluid migration. Nearly all studies emphasize the much greater risk that mishandling, illicit dumping, and unregulated disposal of produced water waste poses to natural resources in the U.S.

b) Indirect Pollution

Indirect pollution is soil or water contamination resulting from processes related to hydraulic fracturing that occur beyond the fracturing and withdrawal process. This includes the transport, storage, and disposal of flowback and produced water.

Although hydraulic fracturing generates less wastewater than conventional methods per unit of resource produced, especially in California, proper disposal of produced water from unconventional oil and gas operations is a serious environmental concern (Lutz et al., 2013). According to an EPA study, the most common disposal process for hydraulic fracturing waste involves separating fracturing fluids from the recovered oil and gas, pumping it into trucks, treating it to proper disposal standards at a plant, and injecting it into wells (California Research Bureau, 2014). Every step of this process presents a possible pollution pathway for produced water. Wastewater treatment facilities are sometimes used for disposal, but are often unable to completely remove the radioactive elements and total dissolved solids (TDS) that produced water carries (Lutz et al., 2013). Because of this, between 95-98% of wastewater from fracking in the US is injected into Safe Drinking water Act (SDWA) Class II underground injection control (UIC) wells (see section Oil and Gas Regulations) (Lutz et al., 2013).

Offsite commercial disposal is used mostly by small operators for whom building, running, and closing an onsite disposal facility is not economically feasible (Argonne, 2009). In California, the water that is not injected underground is mostly disposed of through settling ponds or is treated for beneficial reuse, such as agriculture (Argonne, 2009). In Kern County, increased scrutiny has fallen on the use of unlined ponds for produced water disposal. Several studies, including one in 2014 by Clean Water Action, demonstrated that waste in unlined pits near McKittrick, CA migrated into wells used for irrigation and drinking water (Clean Water Action, 2014).

B. Public Health and Environmental Effects of Well Stimulation Treatments

1. Water Pollution:

This review looked for instances of the release of chemicals from fracturing operations into water resources via the pathways previously discussed. Excluded were studies on the disposal of treated hydraulic fracturing wastewater directly into surface waters, as the majority of fracturing fluid in California is disposed of via underground injection or in wastewater pits (DOGGR, 2014). The discussion below includes two studies on contamination of water resources via underground pathways, one on surface spills, and one on instances of improper underground injection disposal of hydraulic fracturing waste.

a) Indirect:

A study by Gross et al., in the *Journal of the Air and Waste Management Association* analyzed whether surface spills at hydraulic fracturing operations led to groundwater contamination, specifically of benzene, toluene, ethylbenzene, and xylene (BTEX) chemicals. The Colorado Oil and Gas Conservation Commission (COGCC) database provided data on surface spills at sites in Weld County, Colorado between July 2010 and July 2011 (Gross et al, 2013). Researchers analyzed 77 spills. Groundwater samples collected at the spill sites showed that benzene levels were 2.2 times higher, toluene levels 3.3 times higher, ethylbenzene levels 1.8 times higher, and xylene levels 3.5 times higher than groundwater samples collected outside the spill area. BTEX levels tended to decrease rapidly with time and distance from the spill site (Gross et al, 2013). However, the study serves as a demonstration of the potential of surface spills to directly affect groundwater quality.

The second study provides a recent example of mismanagement of underground fracking wastewater disposal occurred within Californian Class II injection wells. In September 2014, the State Water Board conceded to the EPA that 9 underground injection control wells injected wastewater from natural gas operations into drinking water aquifers protected under the Safe Drinking Water Act. The board tested 8 public wells within a 1 mile radius of the UIC wells in question and found that four exceeded the Maximum Contaminant Level (MCL) for nitrate, arsenic, and thallium (Bishop, 2014; Schon, 2014).

b) Direct:

A study by Fontenot et al., in *Environmental Science and Technology* looked at water quality in 100 private wells surrounding the Barnett Shale formation in North Texas. Historic levels of arsenic, nitrates and volatile organic compounds (VOCs) from the United States Geological Survey were compared to current groundwater quality in 91 wells within a 5 kilometer radius of active natural gas extraction operations, 4 wells with no active operations within a 14 kilometer radius, and 5 inactive, control wells (Fontenot et al, 2013). The results showed that mean total dissolved solids (TDS) in active extraction areas exceeded the maximum contaminant level (MCL) set by the EPA, but historical data indicated similar levels for the region. Similarly, researchers observed methanol and ethanol in samples from both the active and inactive study areas. The chemicals were not correlated with distance to the nearest gas well (Fontenot et al, 2013). The constituents found to be higher in active areas than inactive areas were arsenic, selenium, and strontium. The researchers suggest a variety of contributing factors to this contamination, including mechanical disturbances from drilling activity, reduction of the water table from groundwater withdrawals, and faulty drilling equipment and well casings (Fontenot et al, 2013).

A study by Osborn et al., in the *Proceedings of the National Academy of Science* looked at methane contamination in drinking-water wells in the Marcellus and Utica shale formations in northeastern Pennsylvania and upstate New York, comparing wells within areas of active natural gas exploration and wells in inactive areas. Of 60 wells studied, 51 showed methane contamination. Concentrations of methane were 17-times higher nearby natural gas drilling operations (Osborn et al, 2011). Even more, the authors used stable isotope analysis to differentiate between shallow, naturally occurring methane and deep, thermogenic methane associated with fracking. Thermogenic methane was found to be the source of contamination at active sites, while biogenic methane was common at inactive sites (Osborn et al, 2011). The study also looked at general groundwater contamination associated with fracturing fluids. Using a contemporary sample of 68 wells and the historical data of 124 wells in the Catskill and Lockhaven aquifers, the researchers used three indicators of contamination: major inorganic chemicals, stable isotope signatures of water, and isotopes of dissolved constituents. The study found no connection between active drilling areas and general contamination in nearby wells (Osborn et al, 2011).

It is important to keep in mind that much of the literature on public health effects of WST fluid or spill contamination is limited by knowledge of the specific chemical composition of fracturing fluid. Incomplete MSDS information, a lack of Chemical Abstract Service (CAS) numbers to uniquely identify chemicals and chemical mixes, and trade secret claims by operators limited the all of the above studies and others of their kind. In addition, without baseline information on water quality or isotope tracking, it is difficult to impossible to causally link hydraulic fracturing operations to groundwater contamination. The study by Gross et al provided no measure of historical background levels of BTEX, therefore causality is not certain. In fact, a review by Samuel Schon faults the study by

Osborn et al., for not providing geochemical measurements of dissolved methane (Schon, 2014).

Next, it is worthy to note that many of the studies on hydraulic fracturing chemicals and accidental release come from outside California. The study from the *Journal of Human and Ecological Risk Assessment* obtained product and chemical information from Colorado, Wyoming, New Mexico, Texas, Washington, Montana, Pennsylvania, and New York. The three other cited studies come from the Barnett, Marcellus, and Utica shale formations. In all, much of the published literature on hydraulic fracturing and its effects on groundwater are from study areas outside of California, likely due to the fact that the state does not have as extensive of a hydraulic fracturing industry as other parts of the US (US Department of Energy, 2011). Thus, one should keep in mind the difference between California fracking and general American fracking amount when weighing the probability of groundwater quality damage from fracking.

In all, the above studies give context for the public health concerns of hydraulic fracturing fluid and the ways in which it may enter groundwater. More research is needed to steadfastly claim a causal connection between fracking and groundwater contamination; however, data point to probable risk.

2. Air Pollution:

A recent independent study by P. Macey et al, "Air Concentrations of Volatile Compounds near Oil and Gas Production" examined the air concentrations of volatile compounds in hydraulic fracturing sites through a community-based exploratory study in five American states: Ohio, Pennsylvania, Arkansas, Colorado, and Wyoming. A total of 75 volatile organics were measured through passive air samples near industrial operations. Levels of eight of these volatile chemicals were found to exceed federal guidelines (Macey, 2014). Benzene, formaldehyde, and hydrogen sulfide were the most common compounds to exceed acute and other health-based risk levels (Macey, 2014). For instance, the exposure to benzene experienced in five minutes at one Wyoming site was equal to the exposure experienced living in LA for two years. Benzene is known to cause irritation of the skin, eyes, and upper respiratory tract (U.S. EPA 2011). Long-term exposure may cause blood disorders, reproductive and developmental disorders, and cancer (Outdoor Air, 2011). Hydrogen sulfide levels in the Wyoming site were also 90 to 60,000 times greater than the recommended levels at one given time during the study period (Francis, 2014). Hydrogen sulfide can cause respiratory tract and eye irritation, headaches, poor memory, and loss of appetite among other symptoms (Francis, 2014).

C. Environmental Justice

According to the EPA, environmental justice is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies (U.S. EPA, 2014a).

A study by Srebotnjak et al. examined which communities were the most disproportionately at risk due to oil and gas drilling in California. According to their research, approximately 5.4 million Californians (14 % of the state's population) live within one mile of an existing oil and gas well (Srebotnjak, 2014). In addition, 1.8 million of these individuals live in already environmentally polluted areas (Rotkin-Ellman, 2014). Approximately 92% of the individuals within those 1.8 million are people of color. The demographics of the population living near wells in California consist primarily of Hispanics/ Latinos (Srebotnjak, 2014).

A separate study analyzed one particular oil and gas community in Kern County, California. Kern County has more than 63,000 of the state's 84,434 active and new oil and gas wells (Rotkin-Ellman, 2014). The researchers found that one in three residents live within one mile of an oil or gas well (35% of the county's population) (Rotkin-Ellman, 2014). These individuals are at a greater risk of potential health impacts. According to the Desert Renewable Energy Conservation Plan, Kern County's total population size is about 839,153 with 61.4% belonging to a minority group (Desert Renewable Energy Conservation Plan, 2014). The percent of low-income individuals in Kern County is 22.5%. California as a whole has a minority population of 59.9%, with 15.3% falling within the low-income population. (Desert Renewable Energy Conservation Plan, 2014)

D. Regulatory Background

1. Hazardous Materials and Oil and Gas Regulation

a) Hazardous Material Release Regulations

Reporting is to be made to the Office of Emergency Services. The California Code hat the immediate reporting of a hazardous material spill to land is only required if there is "reasonable belief" that the spill may pose a threat to public health, property, or the environment. A written report of the spill initially called into OES is required 30 days after the release and sent to the Chemical Emergency Planning and Response Commission. The reportable quantities of chemicals can be found on two lists. The first is the Extremely Hazardous Substances list. The second is the more detailed Consolidated List of Chemicals (California Office of Emergency Services, 2014a).

b) Oil and Gas Regulations

i. Federal Level Regulations

Some hazardous material from conventional oil and gas production has been exempted from CERCLA, CWA, and RCRA. CERCLA requires the clean up of hazardous substances, however, substances derived from oil and gas production are not required to be reported under CERCLA unless reaching waters of the United States and creating a "sheen" or "film". The Clean Water Act regulates the discharges of pollutants into the waters of the United States. It excludes sediment as a pollutant when it is generated from oil and gas production. Last, RCRA governs the disposal of hazardous wastes. It exempt oil and gas produced water and drilling fluids from monitoring and disposal requirements (U.S. EPA, 2002, 2012, 2014b).

ii. State Level regulations :

In California, DOGGR monitors oil and gas production in California. DOGGR oversees the drilling, operation, maintenance, and plugging and abandonment of oil, natural gas, and geothermal wells (California Department of Conservation, 2014).In recent years, DOGGR acknowledged the gaps in regulations placed on oil and gas production and the information provided to the division about hydraulic fracturing (California Department of Conservation, Division of Oil Gas and Geothermal Resources (DOGGR), 2014). In 2011, Senator Pavley drafted Senate Bill 4 in 2013, passed in September 2013, which directly deals with WST reporting. Senate Bill 4 was enacted by the California legislature due to five concerns: (1) Hydraulic fracturing and well stimulation treatments are increasing in California. (2) The state considers current scientific information on the risks of well stimulation treatments incomplete. (3) The legislature believes that government and industry transparency is vital. (4) Public disclosure is important so as to allow the public to determine if they are being exposed to WST chemicals, (5) the legislature would like to understand the components of produced water used in WST so that it may be reused or treated (California Environmental Law and Policy Center, 2015)

SB4 requires: (1) an independent scientific study on well stimulation treatments to be conducted by the Secretary of California's Natural Resources Agency, (2) development of WST regulations by DOGGR including threshold values for acid volume used, disclosure requirements of chemical composition of well stimulation fluids, and source and volume information of all water used, (3) public disclosure of WST fluid composition (4) an end to the ability of operators and suppliers to claim trade secret protections on many of their products, (5) the creation of a permitting process for WST operation, (6) that landowners within 500 feet of a horizontal project of a WST or within a 1500 foot radius of the wellhead be notified of treatment, (6) that SWRCB to develop regional or well specific groundwater monitoring criteria by July 15, 2015 (California Environmental Law and Policy Center, 2015).

Currently, the California Office of Emergency Services (Cal OES) is responsible for receiving spill reports. The Comprehensive Environmental Response and Liability Act, the Emergency Planning and Community Right-to-Know Act, and various California laws require that hazardous substance releases in excess of reportable quantities must be reported by the responsible party to the National Response Center. Furthermore, if there is an accidental release that exceeds minimum reportable quantities, it must be reported to the State Emergency Response Commission and to the Local Emergency Planning Committees. This includes any spills relating to oil and gas. Regarding oil and gas spills, any release that has caused harm or the potential to cause harm must be reported to Cal OES. Any discharge of oil into state waters must be immediately reported. The federal and state regulations on spill reporting, along with regulations specific to oil and gas spills, are summarized in the below tables.

Table 1: Summary of US Federal and State regulations governing spill reporting (Farella, Braun, and Martel, 2013).

Type of Release	Law	When to Report & to Whom	Who Reports
Oil discharge	Clean Water Act	Immediately report to	Any person in

(film/sheen/discoloration) to water surface or shoreline, or violation of water quality standards and discharge of hazardous substance [equal to or above Reportable Quantity (RQ)]	311 Code of Federal Regulations Title 33: 153.203, Title 40: 110.6	National Response Center: (800) 424-8802 or (202) 267-2675	charge of a vessel or facility (offshore or onshore)
Discharge of oil or petroleum product to surface or groundwater of the state	Water Quality Control Act California Water Code: 13272	Immediately report to the Cal OES (800)852-7550 or the appropriate Regional Water Quality Control Board	The person who causes or permits the discharge
Discharge of oil or petroleum product to marine water of the state	Oil Spill Prevention And Response Act California Government Code: 8670.25.5, 8670.26, 8670.64-8670.67, California Health And Safety Code: 25501, 25507, California Code Of Regulations: 2703, 2705	Immediately provide verbal report to Cal OES, but not later than 30 minutes after discovery of the spill or threatened release; Submit written emergency release follow-up notice within 30 days of the release and sent to Chemical Emergency Planning and Response Commission Local Emergency Planning Committee (LEPC) Notify Coast Guard in certain circumstances (800) 424-8802	Any party responsible for the discharge or threatened discharge; Responding local or state agency
Discharge of one barrel or more oil (cannot pass into or threaten the waters) in the gas and oil lease fields.	California Public Resources Code 3233	Immediately report to the Cal OES	Facility owner or operator
5 barrels or more uncontained in certain San Joaquin Valley oil fields - if no threat to state waters; 10 barrels or more contained in certain San Joaquin Valley oil fields if identified in spill contingency plan - if no threat to state waters.	San Joaquin Valley Field Rule (August 1998)		
Every rupture, explosion, or fire involving a pipeline	Elder California Pipeline Safety Act of 1981 California Government Code 51018	Immediately report to the fire department having fire suppression responsibilities and to the Cal OES.	Pipeline operator

Unauthorized release of a flammable or combustible liquid, including petroleum products and oil that escapes from secondary containment of a underground storage tank, or from primary containment if no secondary containment exists; increases the hazard of fire or explosion; or causes deterioration of the secondary containment	Underground Storage Tank Law California Health and Safety Code, 25295, 25299 California Code Of Regulations, Title 23: 2650-2652	Verbal report within 24 hours after the release was detected or should have been detected; written report within 5 working days of the release	Owners and operators of USTs
Spill or other release of one barrel (42 gallons) or more of petroleum from an aboveground storage tank, that is required to be reported	Aboveground Petroleum Storage Tank Act California Health and Safety Code 25270., 25270.12	Immediately report to the Cal OES and the CUPA/AA using the appropriate 24-hour emergency number or the 911 number, as established by the CUPA, or by the governing body of the CUPA	Owner or operator of aboveground tank facility
Any facility that accidentally releases into the environment one of the following types of chemicals in an amount greater than or equal to the minimum reportable quantity as required by the Emergency Planning and Notification regulation http://www.gpo.gov/fdsys/pkg/CFR-1996-title40-vol14/pdf/CFR-1996-title40-vol14-part355.pdf	Emergency Planning and Community Right-to-Know Act Section 304	Immediately report to the State Emergency Response Commissions and the National Response Center for any area that is likely to be affected by the release. A written follow-up is required.	Facility
PCB spill (equal to or greater than 50 parts per million) with release to surface water, drinking water supplies, sewers, grazing lands, etc.	Toxic Substances Control Act (TSCA) 40 CFR 761.120 & 761.125	Report within 24 hours to National Response Center (NRC) at 1-800-424-8802, EPA Region 7 Spill Line at 913-281-0991, and LEPC, SERC,TERC. Follow up as required by agency.	Person in charge
Hazardous substance release (equal to or greater than RQ)	Comprehensive Environmental, Response, Compensation, and Liability Act (CERCLA or Superfund) 40 CFR 302.6(a)	Report within 15 minutes to LEPC, SERC, TERC or local emergency response personnel (911 in case of transportation-related release)	Person in charge of vessel or facility

Release, fire, or facility explosion that threatens health outside the facility	Resource Conservation and Recovery Act (RCRA) 40 CFR 262.34; 263.30; 264.56 & .196; 265.56 & .196; 270.14 & .30; 273.17, .37 & .54; 279.43 & .53; 280.50, .52, .53, .60 & .61	Report within 24 hours to National Response Center (NRC) at 1-800-424-8802, EPA Region 7 Spill Line at 913-281-0991, and LEPC, SERC,TERC	Emergency coordinator or owner/operator

At the state level, hazardous material releases are regulated by three California codes: the California Government Code, the California Health and Safety Code, and the California Code of Regulations. These regulations establish the Office of Emergency Services as responsible for coordinating the reporting of spills in the state. The follow-up reporting on these spills is the responsibility of the Chemical Emergency Planning and Response Commission. The table below summarizes the most important regulations that govern spill reporting in California (Cal OES, 2014).

Table 2: California regulations governing spill reporting (Cal OES, 2014).

Law	Content
California Government Code (GC) 8589.7	The Office of Emergency Services (OES) shall serve as the central point in state government for the emergency reporting of spills, unauthorized releases, or other accidental releases of hazardous materials and OES shall coordinate the notification of the appropriate state and local administering agencies that may be required to respond (the State Lands Commission, Coastal Commission, or regional water boards for oil spills; the State Fire Marshal for a rupture or explosion involving a pipeline, DOGGR for a crude oil spill, etc) Any person subject to Section 25510 of the Health and Safety Code shall immediately report all releases to the local administering agency and each local administering agency shall notify OES.
California Health and Safety Code (HSC) Sections 25500-25519: Legislative Intent	Establishes business and area plans relating to the handling and release or threatened release of hazardous materials. Basic information on the location, type, quantity, and health risks of hazardous materials in the state is required to be submitted to firefighters, health officials, planners, and other interested persons.
HSC 255510: Release Reporting Requirements	The handler or an employee, representative, agent, etc, shall immediately report any release or threatened release of a hazardous material to the unified program agency.
HSC 25515.2: Administrative Enforcement	A business that violates the HSC article is liable to a penalty not greater than $2,000 for each day in which the violation occurs. If the violation results in or contributes to an emergency, including a fire or health problem, the business shall also be assessed the full cost of the county,

	city, fire district, or local EMS agency emergency response as well as the cost of cleaning up the hazardous materials.
California Code of Regulations, Title 19, Division 2, Chapter 4, Section 2701: Reporting Requirements	A person shall provide an immediate verbal report of any release to the administering agency and the California Emergency Management Agency as soon as (1) a persons had knowledge of the release, (2) notification can be provided without impeding control of the release (3) notification can be provided without impeding medical measures. The reporting shall include at a minimum (1) the exact location (2) the name of the person reporting, (3) the hazardous materials involved, (4) an estimate of the quantity, (5) the potential hazards involved in the release or threatened release Immediate reporting is not required if there is reasonable belief that the release poses no significant present or potential hazards to human health and safety, property, or the environment.
California Code of Regulations, Title 19, Division 2, Chapter 4, Section 2705	A written emergency release follow-up notice pursuant to 42 U.S.C section 11004(c) shall be prepared using the form specified in subsection (c) of this section and shall be sent to the Chemical Emergency Planning and Response Commission (CEPRC) no more than one month after the release.

A copy of the Emergency Release Follow-Up Notice Reporting Form can be found in Appendix A.

Continuous releases, or those releases that are continuous and stable in quantity and rate, occur without interruption or abatement, or are routine, anticipated, or intermittent, are subject to different reporting requirements than discrete hazardous material releases (EPA, 2015). Regulated federally under CERCLA and EPCRA, these releases may be subject to reduced reporting requirements. The responsible party must notify the National Response Center, or the respective State Emergency Response Commission, when the release is first identified. Afterwards, a first-year anniversary report is required to be submitted to quantify the total effect of the continuous release over the year. A complete guide to the reporting requirements for continuous releases can be found in the Appendix E.

IV. Methodology

A. Data Sources

1. Spill Data

We used data from the California Office of Emergency Services, now called California Office of Emergency Services, for hazardous material release information. The data was downloaded in January 2015 from the Cal OES website for the years 2006-2014. Recently, the data was moved to the CA OES website, however the formatting is the same. Each Microsoft Excel spreadsheet file for a specific year contains a list of all spills called into the CA OES Warning Center for the given year. . Appendix A has a link to the new data location on the CA OES website.

The following table explains the different columns within the Historical Hazmat Spill Notification spreadsheet. "Column Name" provides the spreadsheet letter and heading of each column. "Column Description" provides a definition for each column's content (written by the team and not provided by Cal EMA). "Example Entries" gives real examples of entries within each column and clarifies the idiosyncrasies and challenges of the dataset.

Not every column in the dataset is listed below, only those that were used in this project and referred to throughout this paper.

Table 2: Denoted below is the column name, a description of the data found in that column, a few examples for each column, and the analyses in which we used data from that column.

Column Name	Column Description	Example Entries	Analyses Used
A: Control #	A unique number identifier for each spill; the first two digits of the control number indicate the spill year.	’13-2536, ’06-2805, ‘11-6123	None
D: 1. Substance	The primary substance released. Self-reported, one substance may be reported in several different ways.	Crude Oil, Oil-Crude, Diesel, Paint Flakes, Antifreeze	Types of substances spilled
E: 1. Quantity	The amount of material spilled, if known. May be a finite number, a range, or other format (such as date or time-dependent).	0.4, 500, 120-140, Apr-4, 4 GPM, a drop, N/A	Annual spill volume and box and whisker
F: 1. Measure	The unit a spill is measured in. May be volumetric or mass-based.	Bbl. (s), gallons, cups, pints, grams, pounds, tons, sheen, N/A, unknown	Annual spill volume and box and whisker

G: 1. Type	A broader category than Substance that specifies the kind of substance spilled.	Petroleum, Radiological, Railroad, Vapor, Chemical, Other, Unspecified	Types of substances spilled, number of spills, spill volume
Y: Description	Detailed description of the situation surrounding the spill.	"Caller states substance is seeping from the ground at two locations approximately 150 ft apart in an area that is known for this to occur…"	Kern oil and gas spill filtering process
Z: Contained	Indicates whether the spill was contained or not.	Yes, No, Unknown, 80%, 50%	Containment analysis
AA: Water?	Indicates whether the spill affected waterbodies or not.	Yes, No, Unknown	Spills affecting waterbodies
AC: Location	Street address, PLSS section, or rough location of the spill.	Section 3 Township 31S Range 22E, ½ Mile off Highway 65	Kern oil and gas spills spatial analysis
AD: City	City in which the spill occurred	Fellows, Orcutt, Unincorporated Kern County	None
AE: County	County in which the spill occurred.	Kern County, Los Angeles County, Santa Barbara County	Annual spill volume, box and whiskers, spill characteristic analyses
AI: Spill Site	General category that specifies the type of location the spill occurred in.	Oil Field, Refinery, Pipe Line, Merchant/Business, Residence	Spill frequency in Los Angeles and Kern counties
AS: Cleanup	Indicates who cleaned up the spill.	Contractor, Responsible Party, Site Personnel	Clean up analysis

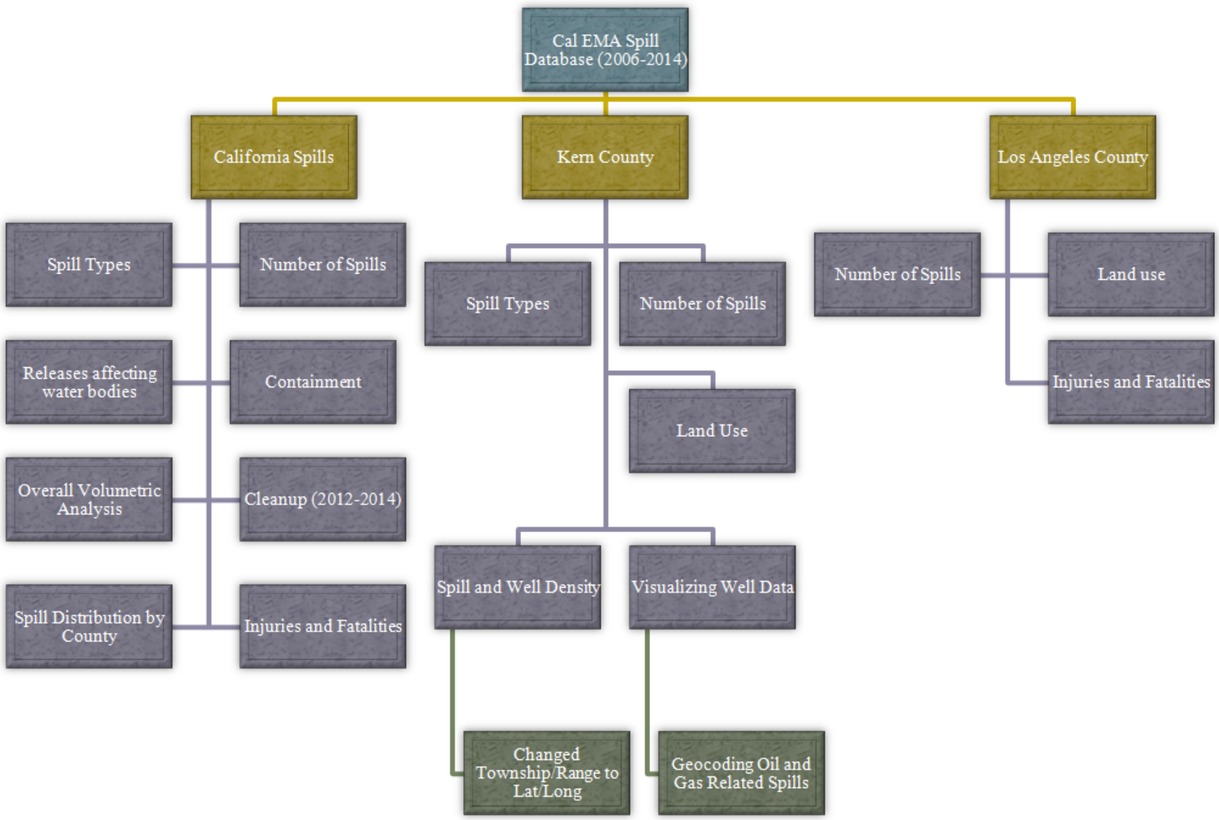

Figure 2: Methodology tree of the different analyses and procedures performed on the datasets.

B. Spill Volume vs. Spill Count

Analyses of the spill database were done both by aggregating the volume of each spill in a particular subset and in by counting each individual spill in a particular subset. The table below outlines which procedures dealt with spill volume and which dealt with spill count. The type analysis using the database column "Type" involved both volume and spill count. Petroleum type was summarized by total volume, while the remaining type categories (such as radiological or sewage) were summarized by number. The spill distribution by county analysis also involved both volume and number summaries, as a volumetric analysis was done for Kern and LA counties while remaining counties were analyzed by number of spills.

Table 3: Below is a breakdown of the procedures which analyzed spill volume and spill count.

Procedure	Spill Volume	Spill Count
Box and Whisker Plot	X	

Type Analysis	X	X
Containment Analysis		X
Waterbody Analysis		X
Injuries and Fatalities Analysis		X
Cleanup Analysis		X
Spill Frequency Analysis	X	
Spill Distribution by County Analysis	X	X

C. Number and Volume of Spills

1. Spill Count

The first step in analyzing spills in California was to understand the total number of spills reported each year. This analysis was done for all of California as well as for Kern County, Los Angeles County, Kern County oil and gas production spills, and petroleum spills (denoted as Type-Petroleum in Column G). Kern and Los Angeles counties were chosen for additional analysis since these are the two top oil producing counties in the state, accounting for 75 and 12 percent of the state's oil production, respectively, in 2009 (California Department of Conservation, 2009). Kern County oil and gas production was chosen as it provides more specific insight into oil and gas spills in Kern County. Petroleum type was chosen for additional analysis for an overall picture of oil and gas spills across the state, since oil and gas spills could not be individually filtered out for the entire state due to time limitations. We also calculated the annual number of spill incidents for each county in California from 2006 to 2014.

The analysis of spill count and all subsequent analyses excluded vapor and railroad incidents. We had insufficient data to convert vapor releases to a liquid equivalent; furthermore, such releases are likely to have impacted air quality only rather than soils or surface/ground water and therefore did not fit the traditional definition of "spills". Railroad incidents rarely involved spills, but rather were primarily train collisions involving automobiles or humans.

2. Volumetric Analysis

The total volume of spills was calculated for each year from 2006 to 2014 for all of California in addition to subtotals for Kern County, Los Angeles County, TYPE = Petroleum (Column G), and Kern County oil and gas production spills. Excluded from the calculation of petroleum spills in California is a spill of nearly 3 million gallons of kerosene in 2011. The description of this spill, number '11-5972, repeatedly refers to the spill as a "drill".

Spill quantity was reported in 12 different units (excluding "Unknown" or "N/A" values) some of which were volumetric and some of which were mass measures. To solve this problem, all volumetric measures were converted to gallons as it was the most frequently used unit for volume. All volumetric measures had direct conversion factors to gallons except barrels; the team used the standard 42:1 gallon to barrel conversion factor used in the oil and gas industry. Spill reported in units of mass (e.g. tons, pounds, ounces, and grams) were left out of the analysis, along with "N/A" and "Unknown" measures, due to time constraints and uncertainties related to converting from mass to volume. We believe that, despite this omission, the volumetric analysis provides a good representation of the data. On average, spills reported in mass units comprised only 5.2% of all reported spills with a maximum of 9.2% in 2006 and a minimum of 3.9% in 2012. In the volumetric calculation process, several formatting changes had to be made to values in "1. Quantity" (Column E), in order for the addition function to work properly. A summary of these formatting changes can be found in the Appendix B.

We generated box and whisker plots in R to examine the statistical distribution of spill volumes across years. Each individual datum from the "Quantity" column was converted into gallons and then analyzed in R. Data that could not be analyzed in volumetric form, such as unclear quantities and mass measures, were omitted for this analysis.

D. Spill Characteristics

1. What types of hazardous materials were released?

We generated pivot tables in Microsoft Excel to analyze spill count per type category. On average, there were 18 type categories per year in California overall, which we consolidated into 7 categories: petroleum, chemical, radiological, railroad, sewage, vapor, and unspecified/other. Identical type categories were generated for Kern County and Los Angeles County spills.

We created tables to show the top 20 substances spilled each year. The tables summarized the column "1.Substance" (Column D) by spill frequency. However, inconsistent data entry into the Cal OES database required significant reformatting before the data could be analyzed.

First, many substances were reported as "unknown", "N/A", "unknown material", etc. These substances were discarded.

Second, one substance might be reported in multiple ways. It was therefore necessary to merge repeated instances of a given substance type into the summarized row by adding all the counts (e.g. "Diesel", "Diesel Fuel", "Diesel Oil", "Fuel – Diesel", "#2 Diesel", into "Diesel"). Merging all instances of repeat substance for all eight years was prohibitively time-consuming, so only rows with more than 5 counts were merged. Finally, we calculated what portion of the total yearly volume of spills these substances represented.

Through this analysis, we also want to see how well all the spills are categorized. Among those most frequently reported substances, substances such as motor oil or mineral oil are also classified into the petroleum type in Cal OES database. Although these substances are petroleum products, they are not necessary related to oil and gas production. Therefore, spills of the petroleum type cannot be used to analyze the spills of oil and gas production, since this would be an overestimation.

2. What percentage of releases were contained?

Possible responses in the "Contained" column (Column Z) within the Cal OES spills database included: "Yes", "No", "Unknown", or "X%" (see Fig. 1). Partially contained spills were difficult to categorize based on their percentage and only accounted for <1 % of total data, so we excluded them from our analysis. We use pivot tables to generate summary statistics on spill containment.

3. What percentage of releases affected waterbodies?

The "Water?" column (Column AA) within the Cal OES spills database contained a "Yes", "No", or "Unknown" with regards to whether a spill involved water when it was released (see Fig. 1). We used pivot tables to count the annual total of each response and summarize their results.

4. Were there reported injuries or fatalities?

An analysis of injuries, fatalities, and evacuations was performed on three levels: all California spills, all Kern County Spills, and all Kern County oil and gas spills. This was done using columns "Injuries #" (Column AN), "Fatals #" (Column AP), and "Evacs" (Column AR) from the Cal OES spills database.

5. Who provided clean-up services?

The "Cleanup" column (Column AS) within the Cal OES spills database was analyzed in a grouped pivot table. This time-intensive analysis was only done on a subset of years from 2012 to 2014. Before grouping in the pivot table, an average of 7,453 unique clean-up descriptions existed for each year from 2012 to 2014. The entries frequently described the same yet reworded cleanup method and thus were ultimately grouped into 9 categories. In order from highest to lowest occurrence, the following categories were chosen: N/A, onsite, contractor, public agency, fire department, county, city, private company, and other. Explanations for each category and sample entries found within each can be found in the Appendix C. These 9 categories were chosen to organize the cleanup responses in a more understandable manner and to better understand spill severity.

E. Spatial Analysis

1. Distribution of Oil and Gas Related Spills in Kern County

Understanding the more detailed spatial characteristics of spills in California was limited by our available time, so we focused on spills related to oil and gas production in Kern County, by far the most productive county in the state.

We began with the complete Cal OES spills database and conducted a number of steps to remove all spills that were not associated with oil and gas production in Kern County. These steps were done successively from general to more specific details and only spills that were clearly not associated with oil and gas production were removed. The steps are as follows:

Filter 1: Remove all spills where the "County" column ≠ Kern

Filter 2: Sort the "1.Substance" column to remove spills where the involved substances were not oil or gas products.

Filter 3: Sort the "Agency" column to remove spills where the responsible reporting agency is not an oil or gas well operator.

Filter 4: Sort through the "Description" columns to further remove spills unrelated to oil and gas production. We used our best judgment to remove spills that did not occur on a production site.

Filter 5: Lastly, the "Spill Site" column was sorted through to remove spills containing the following keywords which indicated they did not occur on a production site: Service Station, Utility Substation, Railroad, Road Collision, Pipeline, Merchant Business, Refinery.

To verify that no spills were improperly removed from our final set of Kern County Oil and Gas Production Related Spills, we sorted the set of removed spills by "Spill Site" and added any spills with keywords "well" or "oil field" back into the dataset.

The table below shows the total spills remaining in the dataset after each successive filter was applied.

Table 4: Spills that were not directly involved with the production of oil or gas were removed from the database with each successive filter.

Year	No Filter	Filter #1	Filter #2	Filter # 3	Filter # 4
	Original Data	Filtered by "Type" column	Filtered by "County" = Kern	Filtered by spills related to oil and gas production	Excluding refinery and pipeline spills**
2006	7424	5599	291	186	158
2007	7769	5764	322	207	207
2008	8812	6146	321	181	172
2009	8391	5967	261	133	117
2010	7713	5370	223	141	121
2011	7358	5146	288	131	125
2012	7687	5396	273	97	90
2013	7630	5554	248	94	80
2014	7013	5209	218	89	77

2. Geocoding Oil and Gas Related Spills in Kern County

Responses for the "Location" column of the Cal EMA spills database were predominantly reported using the Public Land Survey System (PLSS) and were thus formatted as Township-Range-Section (TRS). For the data to be spatially represented using ArcGIS, these TRS entries needed to be converted to latitude and longitude. Because of irregular formatting of TRS entries in the database, locations were manually converted to Latitude and Longitude using the EarthPoint online conversion service (see Appendix D). Any data that was either incomplete or unreadable by EarthPoint was discarded. Due to accuracy limitations in the PLSS (where the smallest geographical units – sections – are roughly 1 square mile) the converted spills were given the latitude and longitude for the centroid of their respective PLSS section.

Additionally, locations reported as addresses or in Degrees-Minutes-Seconds were formatted so that they could be properly geocoded in ArcMap. All addresses that were incomplete or improperly entered into the database were discarded. After conversion and formatting, all remaining data was geocoded in ArcMap 10.2/10.3 using the US-Composite Address Locator available from UCLA MapShare.

Table 5: Geocoding success.

Year	Spills Visualized	Success Rate
2014	77/89	86.9%
2013	88/94	93.6%
2012	91/96	94.8%
2011	111/125	88.8%
2010	129/141	91.5%
2009	127/160	79.4%
2008	171/215	79.5%
2007	179/206	86.9%
2006	133/148	89.9%
Total	**1106/1274**	**86.8%**

3. Visualizing Well Data

We acquired the data for conventional wells from the DOGGR AllWells database. Unconventional well data was acquired from Appendix M of the SB 4-mandated interim report conducted by the California Council on Science and Technology (CCST). Appendix M combined data from FracFocus, South Coast Air Quality Management District, Central Valley Regional Water Quality Control Board, and DOGGR and was composed entirely of hydraulically fractured wells mostly spanning 2002 to 2014. These sources contained data of varying accuracy and breadth, as different agencies have varying reporting requirements. Using their best judgment, CCST integrated the most accurate of these data based on how comprehensive reporting requirements were for a source.

For this analysis, we focused on wells that were active as of May 2015. We assumed that wells that are active have been active for at least 9 years (since 2006) and that wells which have been plugged, cancelled, buried, or idle have been so for 9 years. This assumption introduces error but is necessary because there is no date of abandonment on the majority of wells, and the list spans over 100 years. This reduces the list of traditional wells we are interested in from 138,959 to 68,129. The AllWells data included 144 wells where longitude = 0, so they were removed, bringing the total number of active conventional wells in Kern County to 67,985. Hydraulically fractured wells from Appendix M lack a similar status column, so we assume that all listed wells have been active throughout our study period.

The AllWells database contained both conventional and hydraulically fractured wells, so we eliminated the latter by deleting features from AllWells which spatially overlapped with the hydraulically fractured wells from Appendix M. We assume the accuracy of well coordinates from both AllWells and Appendix M is high enough that overlapping wells are indeed hydraulically fractured. A total of 2,965 wells were designated as hydraulically fractured and erased from AllWells. The total number of hydraulically fractured wells from AppendixM was 3,922.

4. Spill and Well Density

The accuracy of our spills was limited to anywhere within the roughly 1 square mile area of their PLSS section. To avoid overstating the accuracy of our data, we represented spill density as the number of spills within a PLSS section square. The densities of both conventional and hydraulically fractured wells were represented in the same way for the PLSS sections on which they were sited.

5. Land Use Analysis

Land use designation data was acquired from Kern County Engineering, Surveying, and Permit Services and from Bakersfield IT Division. The land use data for Kern County and the City of Bakersfield did not overlap, so they were joined and similar land-use designations were merged into large, generic classes for more coherent analysis. Wells and spills sited on lands designated for human habitation pose a greater public health risk than those on vacant land. With this in mind, we grouped land designated specifically for human habitation – like "Mobile Home", "High-density Residential", or "Suburban" – into a group to identify the frequency of high-risk spills and wells. The land use designation for every parcel on which wells and spills occurred was summed, generating a list that indicates where, according to official zoning, all spills and wells are sited.

F. Spills from Conventional and Unconventional Oil and Gas Production

1. Spill volume per unit production in Los Angeles and Kern Counties

The largest oil producing counties in the state, Los Angeles and Kern, differ in the fraction of wells which are hydraulically fractured. If hydraulic fracturing has an effect on spills, it might manifest in a comparison between these two counties. The team compared the ratio of oil spill volume to annual oil production in Los Angeles and Kern counties.

For purposes of this analysis, we looked oil spills in which the reported "Spill Site" (Column AI) was "Oil Field". To ensure that no natural gas spills were included in this sample of the data, the Type column (Column D) was filtered to exclude "vapor" spills. Spills at oil fields were used as a proxy for spills known to be associated with oil production. It was beyond the scope of this project to use the filtering process described in section 4B to identify oil production spills in areas aside from Kern County.

Oil production statistics (annual barrels produced) were obtained from the California Department of Conservation website. California oil production was reported by county for the years 2006-2009 in the Annual Reports of the State Oil & Gas Supervisor. For the years 2010-2013, an annual report was not provided on the Department of Conservation website. To account for this gap, we took the average portion of California oil production that Los Angeles and Kern Counties accounted for over the years 2006-2009. This portion, calculated as a percentage, was then used to estimate the oil production for LA and Kern counties for the years 2010-2013. We found that, on average, LA County represents 12% percent of California oil production while Kern County represents 77% of California oil production.

The last step in this analysis was to divide annual oil field spill volume for California, Kern County, and Los Angeles county by each area's respective annual oil production. In the process of this analysis, we chose to also look at these ratios for Ventura and Santa Barbara counties, the 3rd and 4th largest oil producing counties in the state after Kern and LA counties.

2. Effect of Hydraulic Fracturing on Spill Frequency

To ascertain any effect which hydraulic fracturing may have on the frequency of spills, we calculated the number of spills per well in every PLSS section for each year from 2006 to 2014. We first looked at spills that occurred in PLSS sections with hydraulically fractured wells, then we looked at spills in sections with conventional wells but no hydraulically fractured wells. If hydraulic fracturing leads to a greater frequency of spills, we would expect the first set of spills per well to be greater than the second set occurring only due to conventional oil production.

V. Results

A. Number and Volume of Spills

1. Number of Reported Spills

Table 6 breaks down the number of spills by the subsets of primary interest – all spills, LA County, Kern County, Kern County oil and gas production spills, and petroleum spills.

Table 6: Number of spills for LA County, Kern County, California overall, and petroleum type.

Year	California – All Spills	LA County – All Spills	Kern County – All Spills	Kern County Oil and Gas Production	Petroleum Spills
2006	6,301	952	277	131	3,607
2007	6,927	1,296	310	157	3,813
2008	7,941	1,253	317	147	4,127
2009	7,126	1,083	225	112	3,654
2010	6,863	1,094	223	136	3,646
2011	6,472	983	247	110	3,449
2012	6,794	1,039	225	93	3,584
2013	6,639	1,140	240	93	3,654
2014	6,024	977	204	71	3,387

In general, Los Angeles County has the highest number of spills each year, ranging from 1,139 to 1,538 spills per year (Table 8). The second highest spills location is San Diego County, about 545 to 909 spills per year. The number of spills occurred in Kern County ranges from 254 to 358 spills per year.

The number of spills in California each year ranges between about 6,500 and 8,000 (Table 6). On average, petroleum spills account for about half of all spills in the state each year.

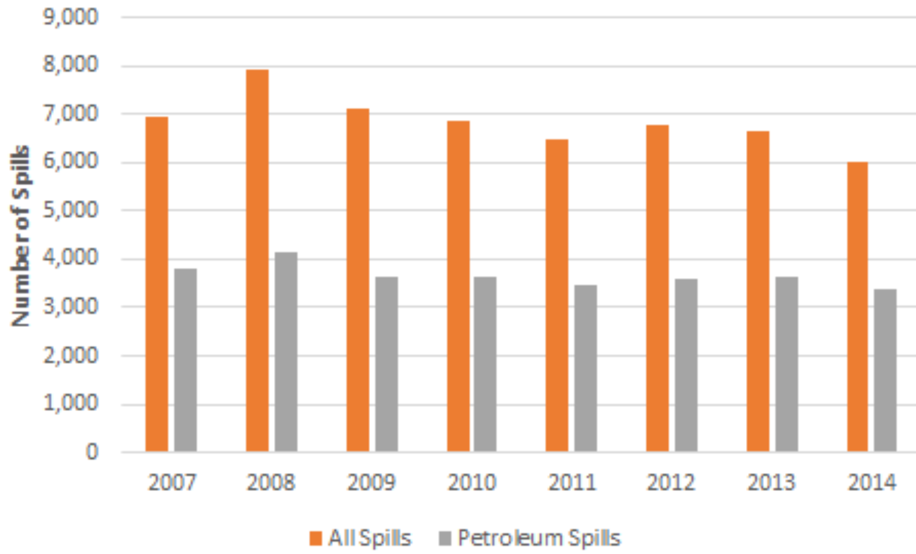

Figure 3: Number of Spills: All and Petroleum.

The number of spills in Los Angeles fluctuates over the years but shows no increasing or decreasing trend. Kern County spills have generally decreased compared to before 2008, while Kern County oil and gas spills show a fairly consistent decrease since 2008.

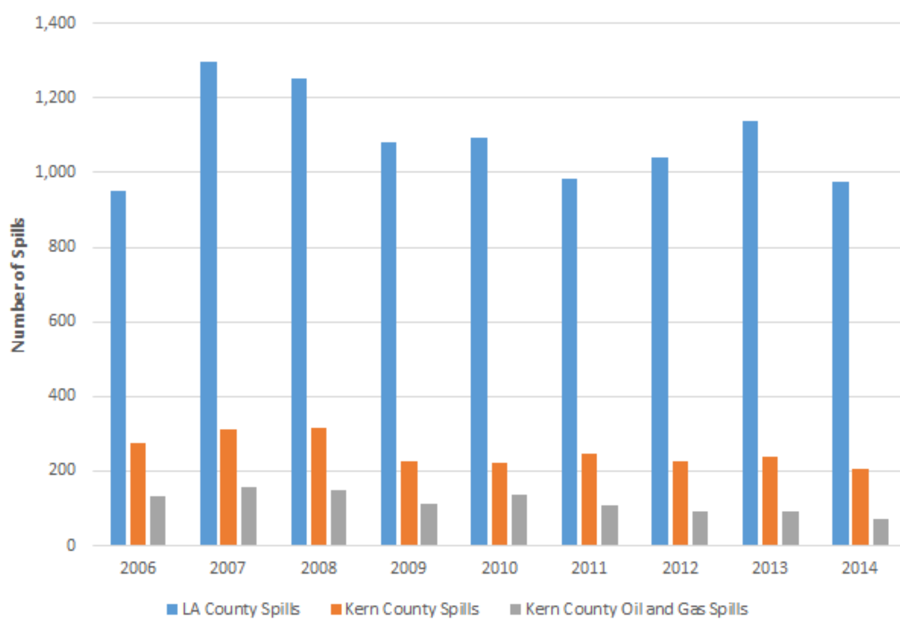

Figure 4: Number of Spills for LA County, Kern County, and Kern County Oil and Gas.

2. Annual Volumetric Analysis of Spills

The results below describe spill volume in California, Kern County, Los Angeles County, Petroleum, and Kern Oil and Gas calculations. As was mentioned in Methods, the spill volume calculations exclude vapor releases and railroad incidents.

Annual hazardous spill volume in California peaks in 2007, is fairly stable from 2008 to 2012, and rises from 2013 to 2014. The peak in 2007 is due to a spill of 160 million gallons of treated sewage at the Terminal Island wastewater treatment plant. Since this spill skewed the shape of the graph of California spill volume, it is removed in Figure 5 below.

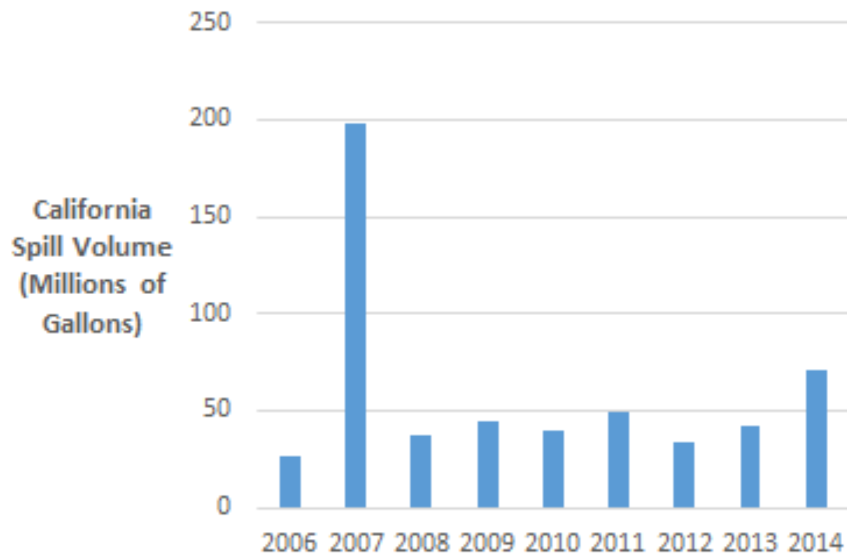

Figure 5: California Spill Volume

Kern County spill volume is fairly stable from 2007 to 2014 except for a spike in 2009 (Figure 6). This spike is primarily due to a spill of 3 million gallons of sewage.

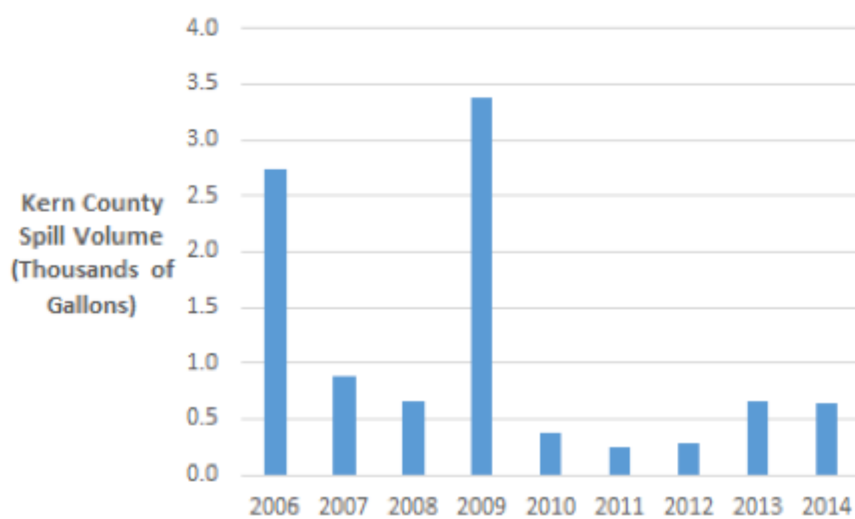

Figure 6: Kern County Spill Volume

LA County spill volume is similar to Kern County's, fairly stable with a spike in one year (Figure 7). LA spill volume also spiked in 2007 due to the large Terminal Island sewage spill seen in the California analysis, but the release is left out of this analysis so trends in LA spills can be seen more clearly. The smaller spike in LA County spill volume in 2014 is due to spill ‘14-4269 of 20 million gallons of “drinking water” into Ballona Creek, reported by the LA City Watershed Protection Division.

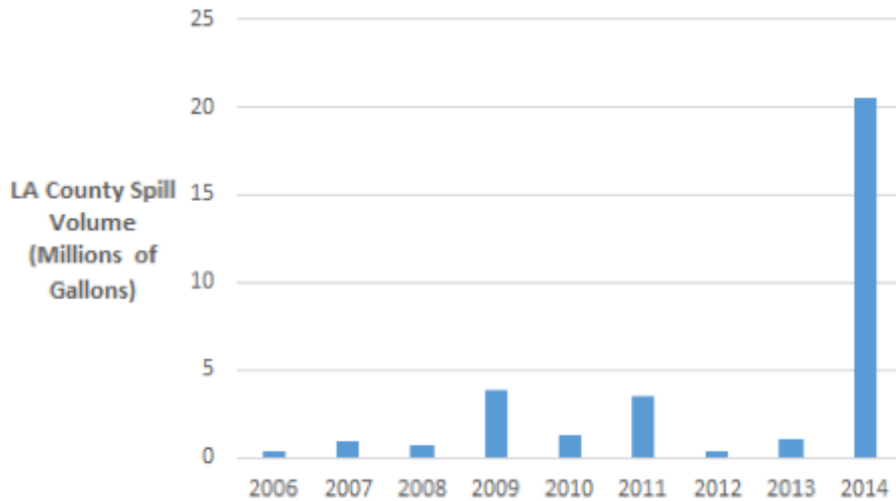

Figure 7: LA County Spill Volume

The annual volume of petroleum spilled in California exhibits a decreasing trend, falling from about 800 millions gallons in 2006 to about 500 million gallon in 2014 (Figure 8). Excluded from the calculation of petroleum spills in California is a spill of nearly 3 million gallons of kerosene in 2011. The description of this spill, number ‘11-5972, repeatedly refers to the spill as a “drill”. During the same time period, California oil production also exhibited a downward trend.

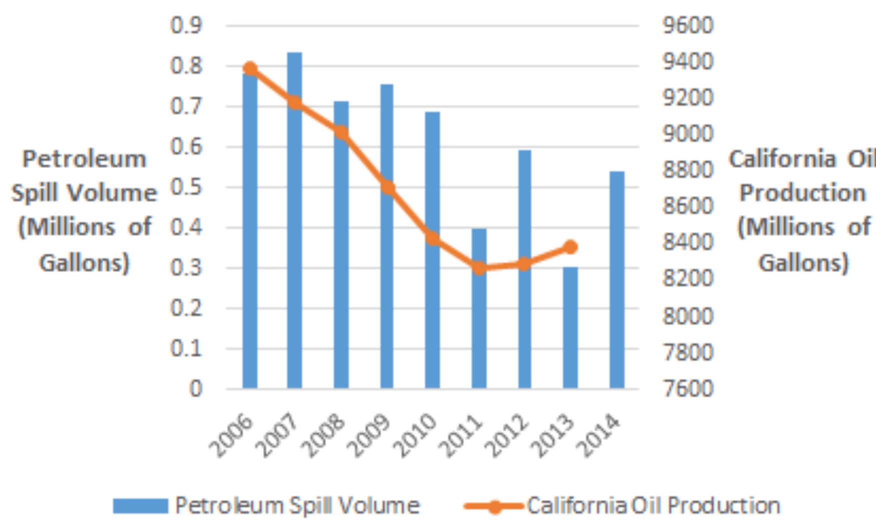

Figure 8: California Petroleum Spill Volume and California Oil Production

Oil and gas spills in Kern County for the years 2006-2014 show a general downward trend as well (Figure 9). Kern County spills predictably track the petroleum spills trend, since Kern County accounts for about 77% of the state’s oil production from 2006-2013 (see section 3A).

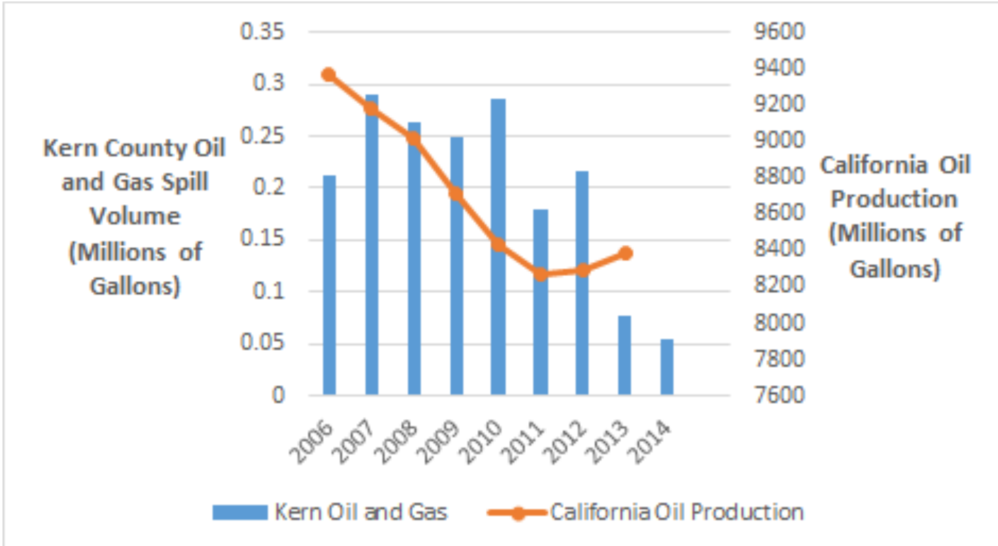

Figure 9: Kern County Oil and Gas Spills and California Oil Production

3. Statistical Distribution of Spill Volumes

Box and whisker plots of spill volume were created for all of California, Kern County, and Los Angeles County (Figures 10-12) exhibit distinct characteristics, with Kern County showing the highest median spill volume on average, followed by Los Angeles and all of California, which are very similar. Each year was also fairly consistent for all of California and Los Angeles County, with the most variation from Kern County.

The box and whiskers revealed that for all of California the median for spills from 2006-2014 stays consistent year after year. Furthermore, the plots show that there is little variation in the interquartile range. When looking at the outliers, there is one in 2007 that is higher than the rest. This is due to a large sewage spill in Los Angeles.

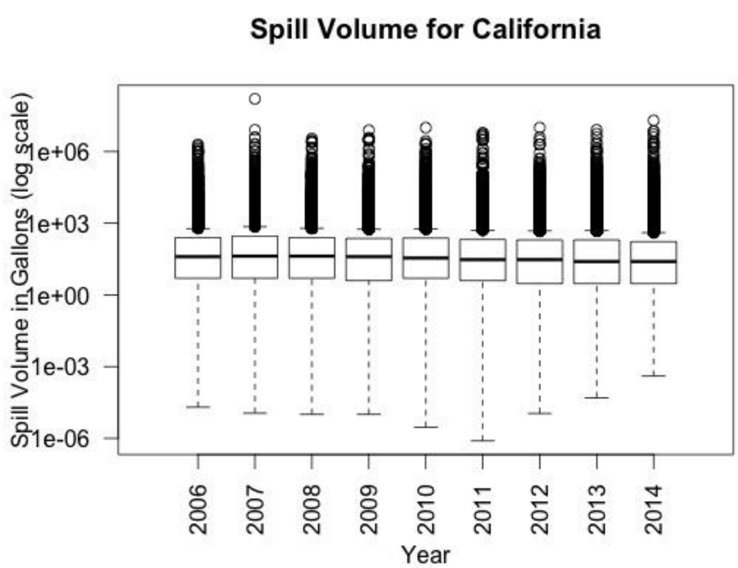

Figure 10: Box and Whisker Plot of All Spills in California

Kern County's median spill volume was higher than both LA county and California. Nevertheless, the median was still consistent for all years. However, the interquartile ranges are much higher than for all of California and for Los Angeles County. The interquartile ranges were roughly the same for all years, but did show some variation.

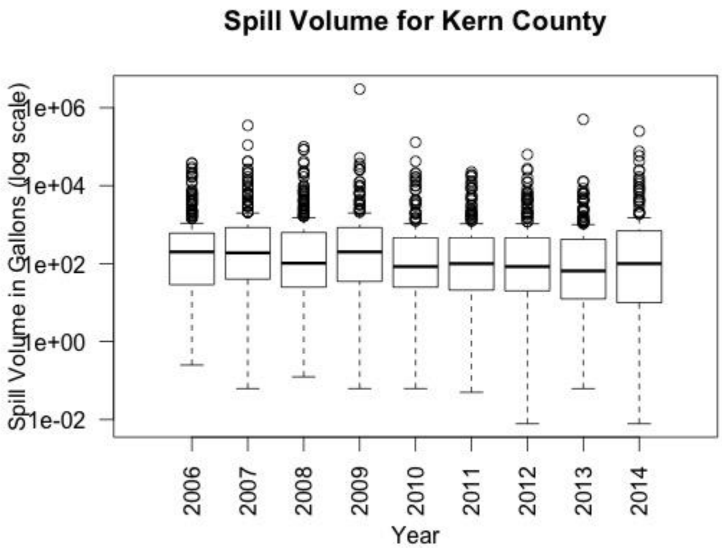

Figure 11: Box and Whisker Chart of Kern County Spill Volume

Los Angeles County's median is on a slight decreasing trend after 2007, indicating the spill volume is decreasing through time. 2007 has the highest median value and the maximum whisker length. Additionally, there is more variation in the interquartile range and the whisker lengths. The spill volume stays relatively constant throughout time.

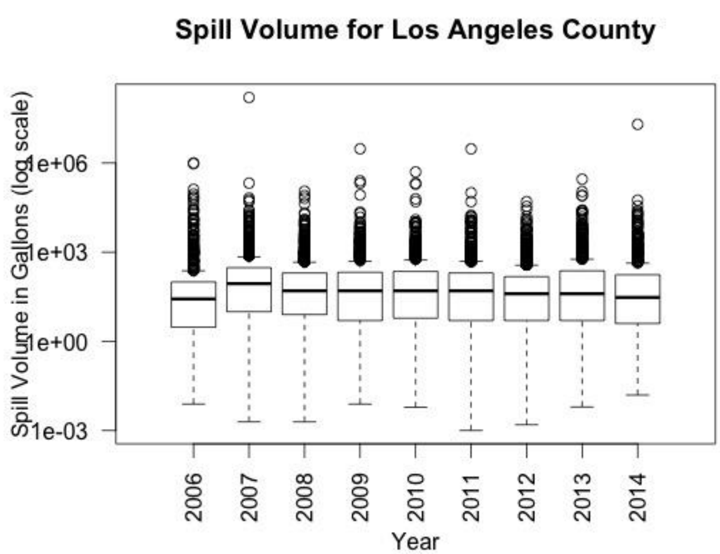

Figure 12: Box and Whisker Chart for LA County Spill Volume

B. Spill Characteristics

1. What types of hazardous materials were released?

The number of petroleum spills was greatest amongst the six categories (petroleum, sewage, chemical, other, unspecified, and radiological). Petroleum spills occurred at an average of 54% for California overall (**Figure 13**), 81% for Kern County (**Figure 14**), and 52% for Los Angeles County (**Figure 15**). The second highest category of spill by count reported for California overall and for Los Angeles County was sewage spills, followed by chemical. For Kern County the second highest category was chemical, followed by sewage.

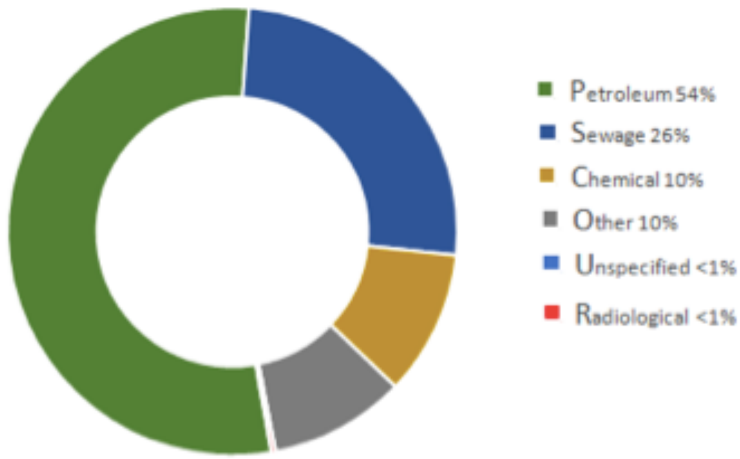

Figure 13: Average spill count by type in California (2006 - 2014)

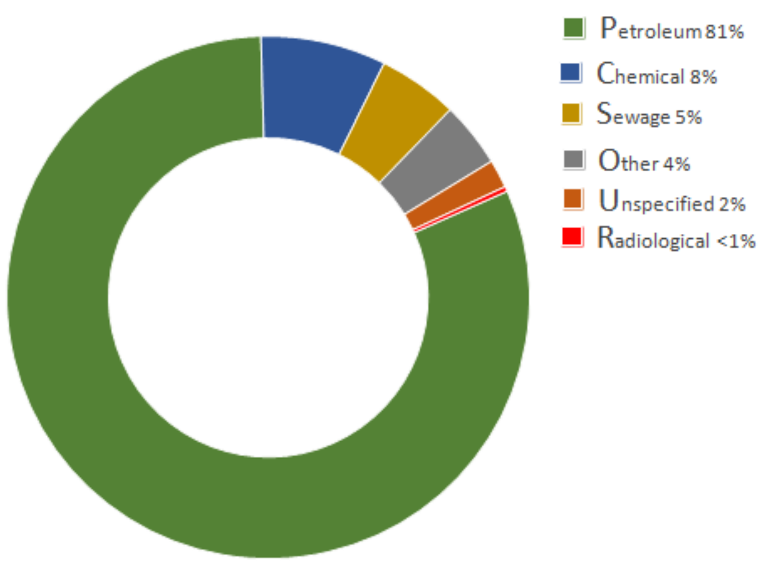

Figure 14: Average spill count by type in Kern County (2006 - 2014)

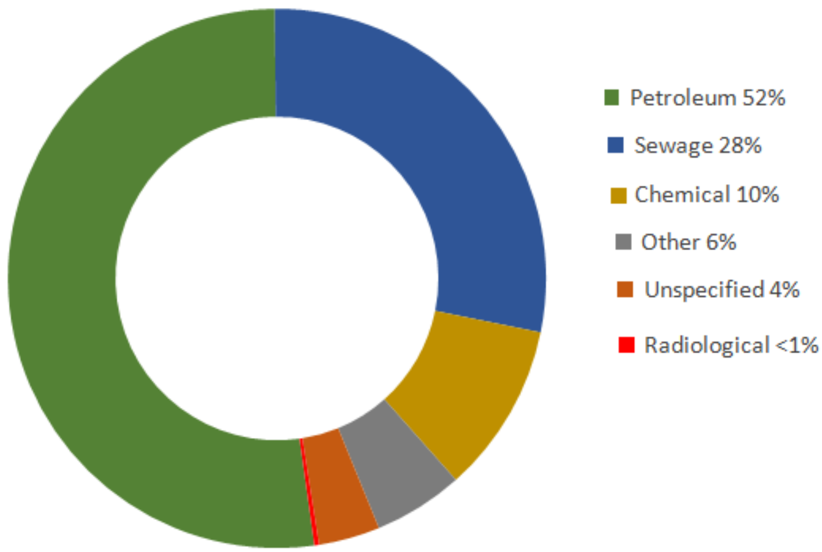

Figure 15: Average spill count by type in Los Angeles County (2006 - 2014)

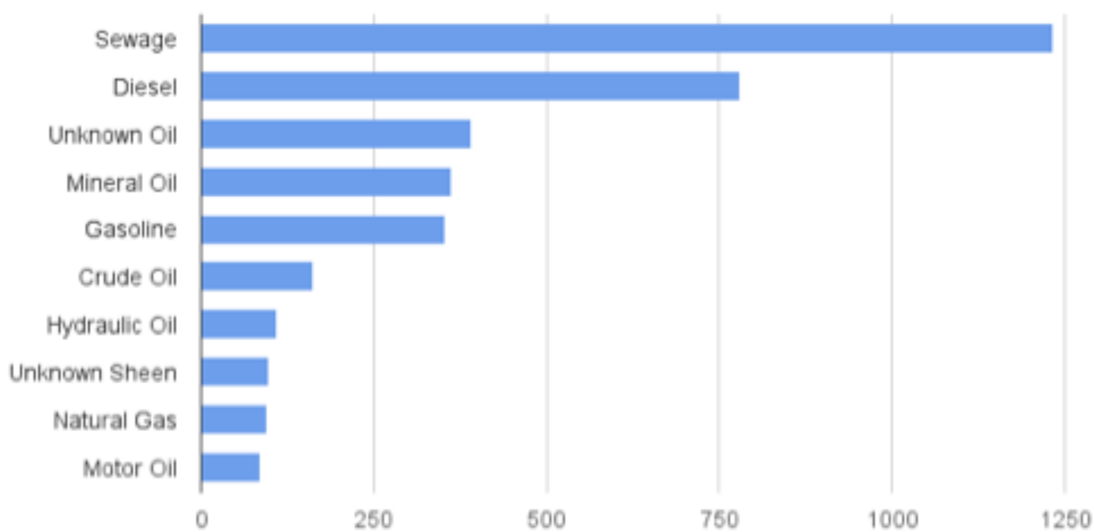

Figure 16: Most frequently reported substances by average number of spills (2006 - 2014)

The specific substance most reported in each year is sewage, followed by diesel (Figure 16). Overall, substances related to oil production have the second highest occurrence. In fact, those most frequently reported substances represent a large portion of all the hazardous materials reported. By count, on average, about 60% of reports are for a petroleum-type substance. The remaining 40% include substances with lower reported occurrences or those frequent petroleum-type substances reported using different descriptors, or both.

2. What percentage of releases were contained?

The percentage of spills that were contained after release is relatively constant from 2006 to 2014. On average, about 10% of total spills that occurred in California were reported as not contained, about 73% of total spills were contained, and about 17% were unknown.

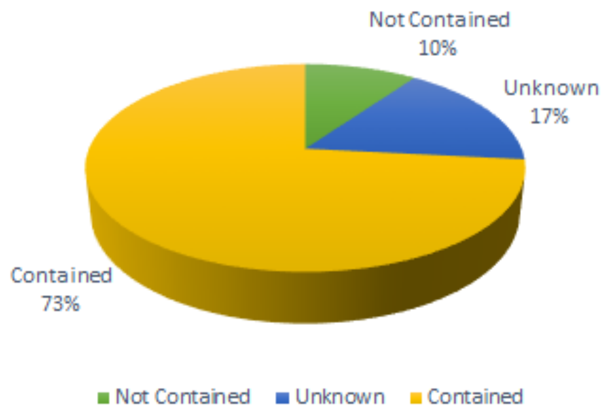

Figure 17: Percentage of spills in California by containment status as reported (2006 - 2014)

3. What percentage of releases affected waterbodies?

The percentage of releases that affected waterbodies is also relatively constant from 2006 to 2014. On average, about 37% of total spills affected water bodies (Figure 17).

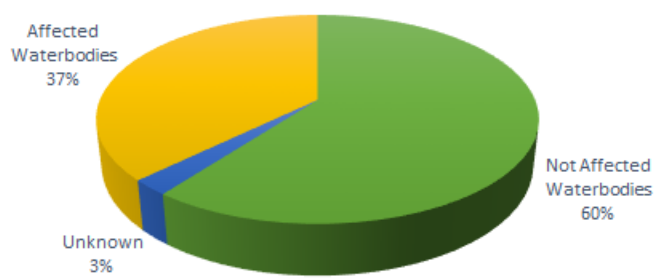

Figure 18: Average number of spills and their relation to waterbodies in California (2006 - 2014)

Of those spill that affected waterbodies, about 16% on average were not contained when reported, and about 29% have no information about containment.

4. Were there reported injuries or fatalities?

The number of injuries, fatalities, and evacuations that occurred due to hazardous spills in California was relatively consistent from 2006-2014. Some minor spikes in the data are observed, especially with the Total Evacuations line, but no discernable trend can be ascertained.

Table 7: Total counts of injuries, fatalities, and evacuations associated with spills in California and Kern County from 2006 to 2014

Location	Total Spills	Total Injuries	Total Fatalities	Total Evacuations
California	58,035	2,935	506	15,714
Kern County	2,189	137	17	611
Kern County Oil and Gas	1,213	43	3	150

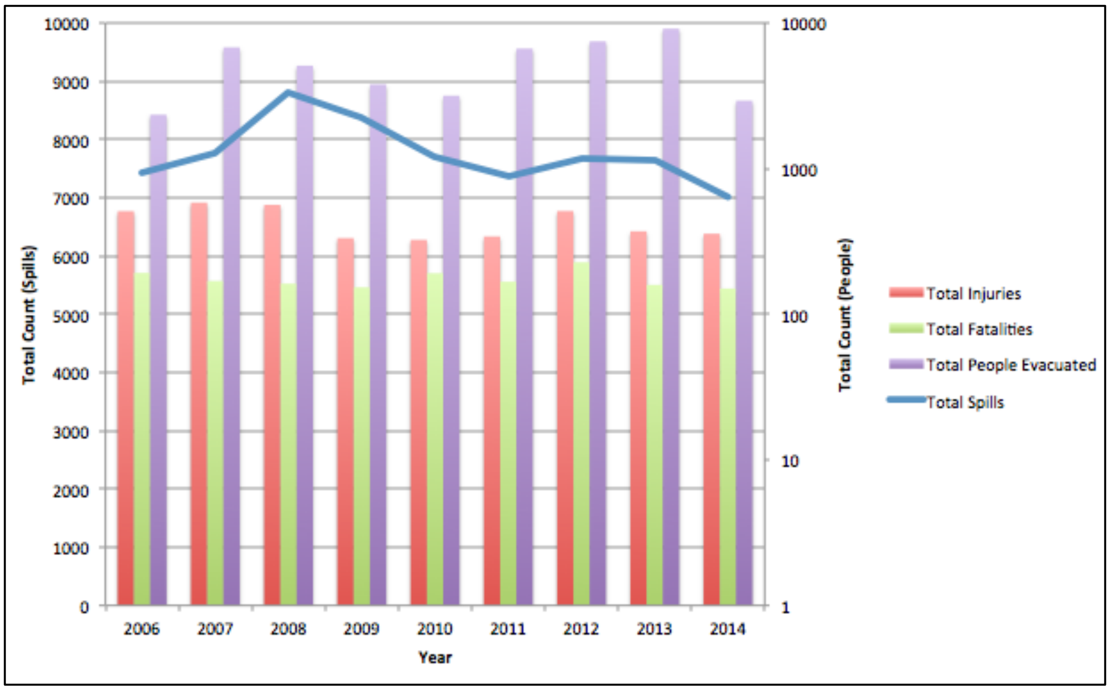

Figure 19: Injuries, fatalities, and evacuations in California from hazardous materials spills (2006 - 2014)

The number of injuries, fatalities, and evacuations that occurred due to hazardous spills in Kern County was highly variable from 2006-2014. There are major spikes in the data that do not follow any meaningful trend. This dataset has a much smaller sample size than the complete California data, so there is more volatility in the data over the years. The extreme volatility of the number of evacuations per year is generally a byproduct of one or two spills in a certain year resulting in the evacuation of 50-100 people.

Table 8: Injuries, fatalities, and evacuations in Kern County from Oil and Gas Production from 2006 – 2014.

Year	Total Spills	Total Injuries	Total Fatalities	Total People Evacuated
2006	182	2	0	0
2007	203	40	3	0
2008	171	0	0	0
2009	128	0	0	0
2010	133	0	0	0
2011	121	0	0	50
2012	95	0	0	0
2013	92	0	0	100
2014	88	1	0	0

5. Who provided clean-up services?

In California overall, 42% of spills were cleaned-up on site, usually by onsite personnel or attendants. 28% of spills were grouped as N/A, meaning these spills were either not cleaned up at the time of the call, dissipated, or a clean up was not necessary according to the reporting party. 23% of spills were cleaned by an outside contractor that could be identified as a separate entity from the responsible party. 4% of spills were cleaned by a public agency such as public works, sewer districts, or environmental health departments. The remainder of spills, less than 4%, were cleaned by the fire department, city, or county.

Table 9: Parties responsible for cleaning up hazardous releases in California (2006 – 2014)

	Onsite	N/A	Contractor	Agency	Fire Dept	City	County	Blank	Total
2012	2,894	2,053	1,420	254	100	53	23	7	6,804
2013	2,703	1,836	1,642	290	94	54	24	22	6,665
2014	2,580	1,539	1,454	274	80	67	17	13	6,024
All	8,177	5,428	4,516	818	274	174	64	42	19,493
Percent of Total	42%	28%	23%	4%	1%	1%	0.3%	0.2%	100%

C. Spatial Analysis

1. Spatial Distribution of Oil and Gas Related Spills in Kern County

Due to spill locations that were converted from PLSS to latitude and longitude, the highest spatial resolution shared by all spill and well data is approximately 1 square mile. We represented these data as PLSS sections with values for the number of overlying events. The distribution of these PLSS sections can be seen in Figures 20-22.

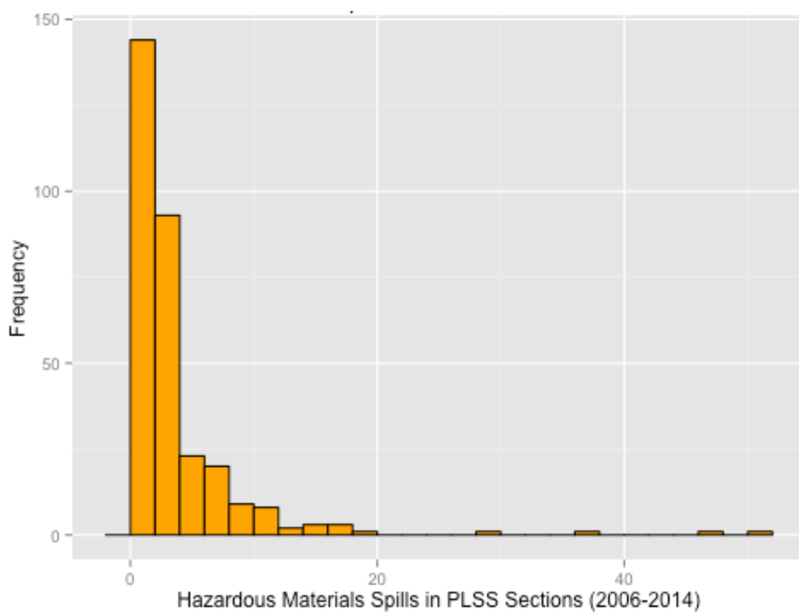

Figure 20: Distribution of hazardous material releases across Kern County PLSS sections (2006 – 2014)

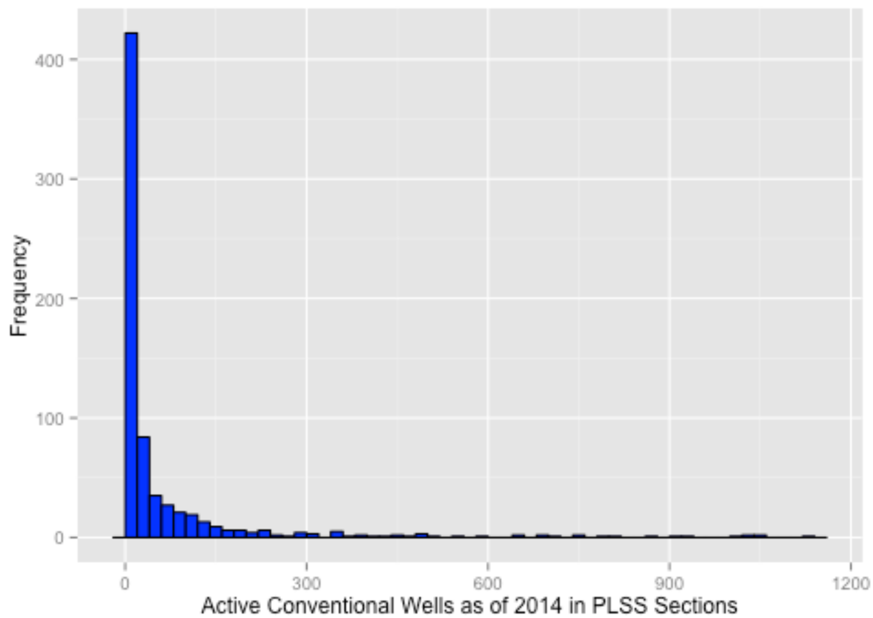

Figure 21: Distribution of convention wells across Kern County PLSS sections (2006 – 2014)

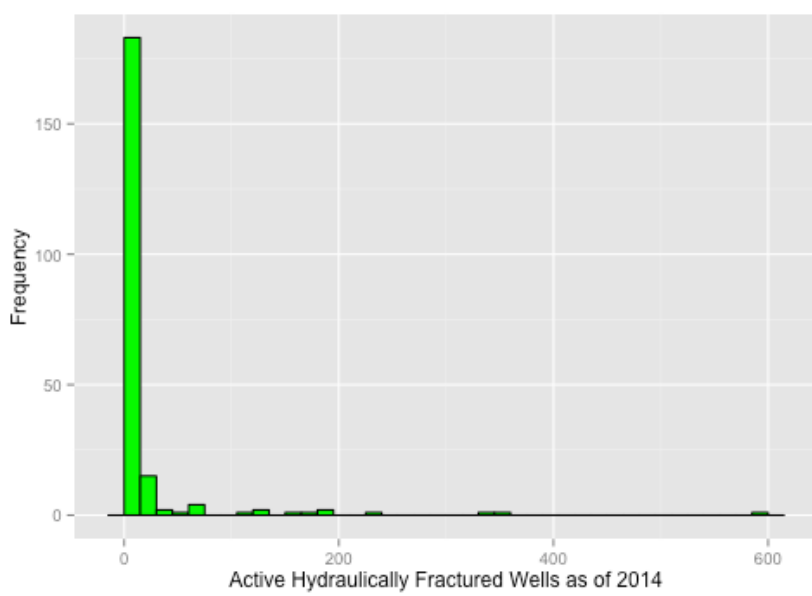

Figure 22: Distribution of hydraulically fractured wells across Kern County PLSS sections (2006 – 2014)

To maintain a scale for these histograms at which all values were visible, PLSS sections with no spills were omitted. The distribution of conventional wells, hydraulically fractured wells, and spills across PLSS sections are strongly positively skewed. This is a consequence of the spatial clustering of wells and spills – there are many PLSS sections with few or no events, and a small number of sections with a great number of clustered events.

2. Spill and Well Density

Figures 23-25 display the densities of wells and oil and gas production spills in Kern County from 2006 to 2014. The majority of wells, both conventional and hydraulically fractured, are located in the oilfields that lie in the western hills of Kern County. The rest are clustered to the north and east of Bakersfield, where several large oilfields reside. Consequently, spills related to oil and gas production are also clustered around those areas but with more sporadic, non-clustered events. This makes sense given that wells are intentionally placed on oilfields and tend to cluster on productive geology, whereas spills are unplanned. Visualizing spill and well density uncovered a number of sites with intensely frequent spills and well activity.

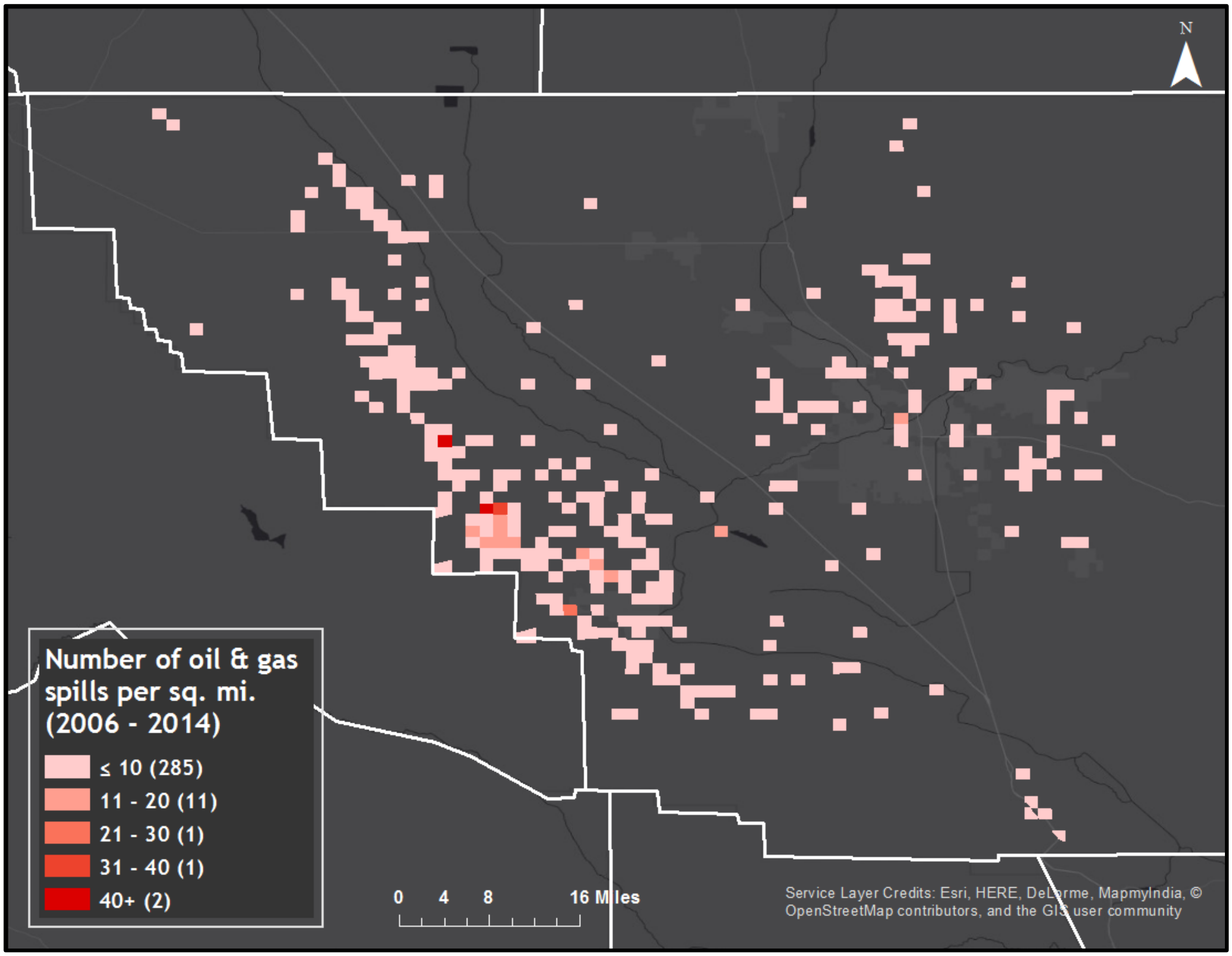

Figure 23: Density map of all hazardous material spills from oil and gas production in Kern County per PLSS section, roughly one square mile. The value assigned to the sections corresponds to the number of all overlying spills that occurred during the study period from 2006 to 2014.

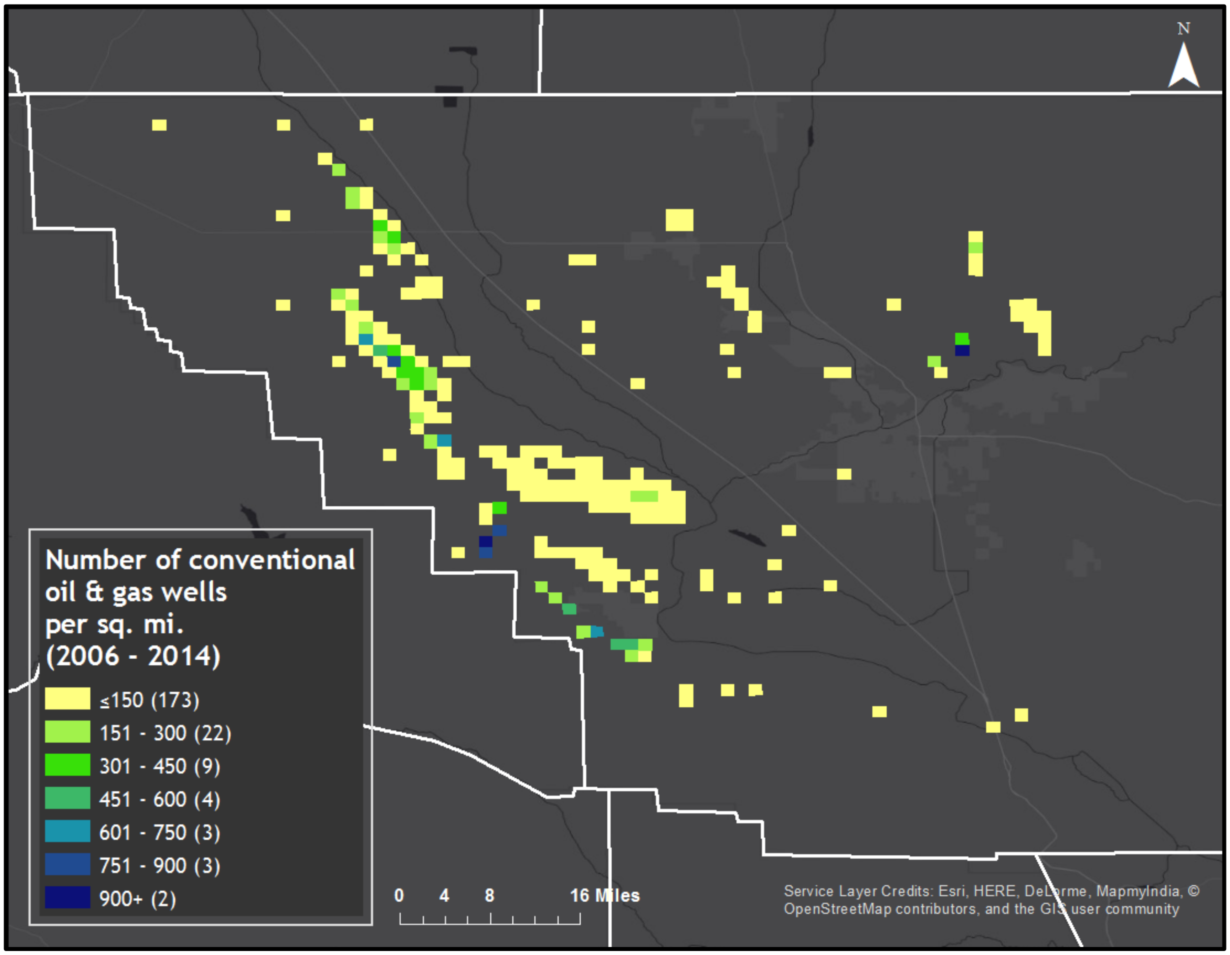

Figure 24: Density map of all conventional oil and gas wells in Kern County per PLSS section, roughly one square mile. The value assigned to the sections corresponds to the number of all overlying active conventional wells as of 2014.

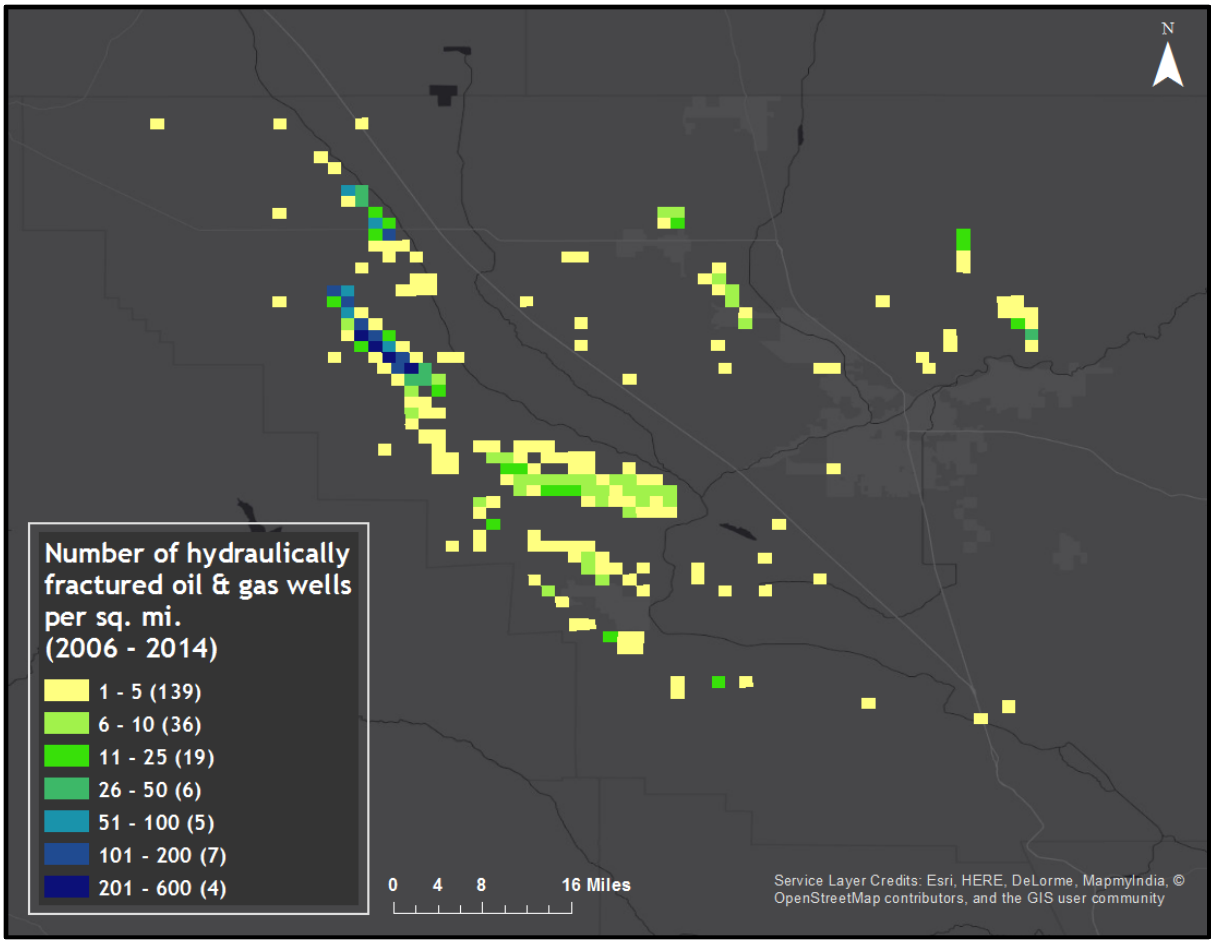

Figure 25: Density map of all hydraulically fractured oil and gas wells in Kern County per PLSS section, roughly one square mile. The value assigned to the sections corresponds to the number of all overlying active hydraulically fractured wells as of 2014.

3. Land Use Analysis

Land designated for human habitation contained 226 conventional wells, 1 hydraulically fractured well, and witnessed 52 spills related to oil and gas production from 2006 to 2014. The overwhelming number of wells and spills were sited on land that was designated by the City of Bakersfield and the County of Kern as agricultural.

Table 10: Land use designations for spills and wells in Kern County (2006 - 2014)

Land Use Type	Number of conventional wells (2006 – 2014)	Number of hydraulically fractured wells (2006 – 2014)	Number of spills (2006 – 2014)
Agriculture	56480	3894	972
Mineral Petroleum	0	0	19
Resource Management Area	3402	22	57
Heavy Industrial	632	0	38
Light Industrial	314	1	9
Service Industrial	242	1	16
Parks and Rec	298	0	1
Low Density	105	2	21

Residential			
Rural Residential	49	0	0
Mobile Home	2	0	0
Suburban	90	0	21
Estate	50	0	6
General Commercial	48	0	27
Medium Density Residential	30	0	0
Special Use	23	0	0
Other Jurisdiction	13	0	0
Publicly Owned	11	0	2
Open Space	1	0	0
School	1	0	0
Public Transit Corridor	0	0	3
Recreation Forestry	0	0	3
Urban	0	0	3
Slopes >30%	0	0	2

D. Spills from Conventional and Unconventional Oil and Gas Production

1. Spill volume per unit production in Los Angeles and Kern Counties

Kern County has a higher volume of oil production-related spills per unit of oil produced than Los Angeles County, with 3 gallons of oil spilled per 100,000 gallons of oil produced compared to 2 gallons , respectively. However, other counties such as Santa Barbara and Ventura County exhibit much higher ratios although they contribute less oil production to the state overall. Santa Barbara County has a ratio almost 4 times greater than Kern's, at 11 gallons spilled per 100,000 gallons of oil produced in the county (Table 11).

Table 11: Oil production-related spills per unit of oil produced in the four most productive counties in California

	California	Kern County	LA County	Ventura County	Santa Barbara County
Average Annual Oil Field Spill Volume (gallons)	308,700	217,000	23,600	25,000	13,700
Average Annual Oil Production (Hundreds of thousands of gallons)	87,060	65,830	10,480	3,000	1,290
Oil Spill Density (per every 100,000 gallons of production)	3.5	3.3	2.3	8.3	10.6

2. Effect of Hydraulic Fracturing on Spill Frequency

Table 12 displays the median and average number of spills per well for two sets of PLSS sections – those with hydraulically fractured wells, and those with only conventional wells. The median number of spills per well for each PLSS section is the same for sections with hydraulically fractured wells as it is for those with only conventional wells. The average number of spills per well also does not show an appreciable difference between the two sets of PLSS sections.

Table 12: Average ratio of spills per well for two sets of 1 sq. mi. PLSS sections – those with hydraulically fractured wells, and those with conventional wells but no hydraulically fractured wells.

	Spills per well in PLSS sections with hydraulically fractured wells	Spills per well in PLSS sections with conventional wells but no hydraulically fractured wells
2006	1.69	1.69
2007	6.76	2.14
2008	3.76	3.99
2009	0.78	1.60
2010	7.81	11.26
2011	0.29	1.34
2012	5.33	7.63
2013	0.22	0.25
2014	0.86	0.36
Median	1.69	1.69
Average	3.05	3.36

Our analysis of spill volume per spill for each set of PLSS sections yielded similar results, with slightly lower average spill volume for PLSS sections with hydraulically fractured wells (Table 13).

Table 13: Average ratio of spill volume per spill for two sets of 1 sq. mi. PLSS sections – those with hydraulically fractured wells, and those with conventional wells but no hydraulically fractured wells.

	Average volume per spill in PLSS sections with hydraulically fractured wells (gallons)	Average volume per spill in PLSS sections with conventional wells but no hydraulically fractured wells (gallons)

2006	1361.7	770.3
2007	1777.8	2027.6
2008	2302.5	1556.5
2009	4599.6	1457.4
2010	3664.4	8826.1
2011	2008.2	1233.2
2012	2048.7	4741.0
2013	1476.3	578.9
2014	1542.7	549.5
Average	2309.1	2415.7

VI. Discussion and Conclusions

NRDC proposed eleven research questions for our project, including: the total number and volume of releases reported annually in California, differences in characteristics between unconventional and conventional oil and gas production operations, and seven different general characteristics of hazardous spills including substance, health and environmental effects, location, site characteristics, containment, water body impacts, injuries or fatalities, and clean-up services. The last research objective was to provide conclusions and recommendations to reduce the frequency and severity of spills in California's oil and gas industry.

In general, we were able to definitively answer several questions about spill number, volume, and characteristics. The annual number of spills for all spills, petroleum spills, and LA County spills stays fairly constant throughout the study period. The number of spills for Kern County and Kern County oil and gas, however, decreases over the study period. Likewise, annual spill volume in Kern County and for Kern oil and gas spills is decreasing, mirroring the decrease in California oil production from 207 million barrels in 2009 to 199 million barrels in 2013 (California 2013 Annual Report). The volume of petroleum spills is also decreasing with time, although the number of petroleum spills stays roughly constant.

It is interesting that the number of petroleum spills does not decrease with time but the number of Kern County spills does. This could be due to the fact that petroleum spills also result from highway crashes, spills at gas stations, pipeline leaks, etc. Thus, the petroleum spill and volume analyses do not necessarily imply similar results for oil and gas production.

Our team was also asked to discern any difference in characteristics between conventional and unconventional oil and gas production. Because we were unable to associate specific spills with either mode of production-- no distinction was made in the database-- and the spatial resolution of geocoded spills was limited to one square mile, we were unable to answer this question. A lack of comprehensive data on the year in which wells were drilled also made it difficult for the team to attribute spills in certain years to certain wells.

The database did allow us to answer many questions on spill characteristics. Broadly, about half of all spills are of a petroleum substance, followed by about a quarter of sewage. Looking more closely at spill substance, we found that petroleum spills are heavily split between substances such as diesel, motor oil, or "unknown" oil.

The county with the highest annual number of releases is Los Angeles, followed by San Diego and San Bernardino. Kern County is the seventh highest county in terms of annual spill count.

73% of spills were contained, although it is unclear what exactly that may mean. It is unknown whether the 10% of spills not contained and the 17% unknown were contained after the call or simply were released into the environment without clean-up efforts. When spills were cleaned, efforts were mostly undertaken on-site by the responsible party or not at all, indicating that most spills are smaller in nature and do not require the assistance of the city, county, local government agency, or the fire department.

Our analysis of injuries and fatalities indicates that these spill events are significant and likely disruptive to businesses and local economies, since from 2006-2014 there were a total 15,714 evacuations.

We were not able to answer the questions of spill characteristics that related to health and environmental effects and site characteristics. The spills reported to the database are highly variable, thus it is difficult to predict what kinds of sites are prone to spills or to sum up the wide variety of health and environmental risks that may result from California's hazardous material releases.

An overall conclusion resulting from our study process is that the CA OES data format is incomplete, disorganized, and difficult to analyze effectively. The numerous entries of "unknown" or "N/A" indicate a lack of follow-up data entry. Although follow-up reports are required to be sent to CEPRC, these reports are apparently not coordinated with OES data collection and are not publicly available in an aggregate form. Further, a more user-friendly reporting process, such as online submittal or a mobile application, may fix some of these issues by allowing for more accurate location and substance data.

Similarly, we conclude that more user-friendly DOGGR well data could allow for a more conclusive study on the connection between unconventional oil and gas production and hazardous spills. The team acknowledges the budgetary barriers to modifying the DOGGR website to allow users to download data on specific wells across the state. However, we hope that at least new regulations under SB4 on fracking disclosure will allow for more transparent well locations in the future.

Last, our understanding of spill reporting requirements indicates that the higher spill frequency in Santa Barbara and Ventura Counties may be due to releases entering water and thus forcing the responsible parties to report, even if a spill is under the required reporting threshold. 59% of spills in Santa Barbara affected water, and if these spills had large enough volumes, spill volume per oil production could be affected. Another potential explanation for this pattern is that Kern and LA counties, being the top two oil-producing locations in the state, are more experienced in oil production so as to lower incidents and releases as barrels of production increase.

VII. Recommendations

A. The California Office of Emergency Services (Cal OES)

Compared to the call center currently used to report spills, an online reporting system might be more efficient for both Cal OES and response parties. Instead of doing the calling, people can simply report a spill by filling an online form. In order to make the reporting process more convenient, we suggest designing a mobile application as well.

When reporting the spilled substance, there should be a drop down list for the reporter to choose from in order to avoid the problem of one substance reported in multiple ways. One major reason for one substance reported in multiple ways is the lack of standardization of substance names. For example, hydraulic oil can be reported as "hydraulic fuel" or "oil - hydraulic type". This can be solved if the drop down list is better constructed and adding searching functions when choosing the substance. Another reason for one substance reported in multiple ways is that people try to add the details of the substances when they report it. For example, diesel can be reported as "diesel, unleaded" or "#2 diesel". Instead of putting these details into the substance name, the new reporting system should allow people to add details of a substance in another field after they choose it from the drop down list.

One major obstacle we encountered when doing the spatial analysis was the inaccuracy of the spill location, especially those spills reported with township and range, because this has extremely low spatial resolution (one square mile). Therefore, it is recommended to require reporting of the well number (where applicable) as well as latitude and longitude. That is another important reason for using an mobile application since it is much easier to report one's latitude and longitude using a smartphone.

Moreover, too many of the database's fields are listed as "unknown" when describing the material, the amount released or clean-up methods. It is possible that sometimes the caller is unsure about the spill volume and doesn't know who is responsible for the cleanup, but this information needs to eventually be provided. There should be a follow-up requirement, especially for spills over threshold volume (e.g. oil spills over 42 gallons). to provide the data initially missing, thereby improving the completeness and utility of the database.

Finally, CA OES should produce an annual report of hazardous material spills and make it publically available. Currently, this information is not being disseminated or discussed.

B. The California Division of Oil, Gas, and Geothermal Resources (DOGGR)

Any robust analysis of well activity in California is severely limited by the data made available through DOGGR. Although the AllWells database included comprehensive identifying information for each well, like API number, operator, and spud date (when drilling begins on a well), there is no production information, drilling completion date, and the vast majority of abandonment dates are left blank. This information exists on DOGGR Well Finder, but the configuration of that database is such that users must click on wells individually in the interactive map to access information. Both our research and the SB 4 interim report conducted by CCST found that accessing this information in any large quantity was impossible. So that their data is useful to interested parties, we recommend that DOGGR allow users to download this information in bulk. To reduce downloads to a reasonable size while still encouraging bulk download for holistic research, DOGGR could restrict bulk download to individual oil fields or survey townships.

VII. Appendices

Appendix A:

Cal OES updated spills notification database:

http://www.caloes.ca.gov/cal-oes-divisions/fire-rescue/hazardous-materials/spill-release-reporting

Appendix B:

Formatting changes to spill quantity.

- Taking the midpoint of any quantities given in range format, such as 10-20 (changed to 15) or Apr-5 (actually Excel mis-formatting for 4-5, changed to 4.5)
- Taking the midpoint of any "less than" quantities (Less than 100 changed to 50)
- Making conversions where possible, such as changing 100 cubic yards to cubic feet
- Making positive any negative quantities
- Some quantities had to be thrown out, such as "more than" quantities, unknown quantities, sheen, time dependent values such as gallons per minute, concentrations, such as parts per million, or estimations such as "a drop" or "several thousand".

Appendix C:

Determining the party responsible for spill cleanups.

- N/A: entries including "n/a", "no", "not necessary", "substance dissipated", etc
- Onsite: entries including "onsite", "personnel", "attendant onsite", etc
- Contractor: entries including the keyword "contractor" or the name of a confirmed environmental contractor
- Public Agency: entries including public works, sewer districts, environmental health departments
- Fire Department: City or County fire department
- Private Company: A private entity cleaned the spill, aside from a private contractor, such as "Chevron" or "SoCal Gas"
- Other: entries that did not fall into any of the above category, less than 10 per year

Appendix D:

EarthPoint PLSS Conversion service used to get the latitude and longitude for Kern County oil and gas production releases that were reported as township and range.

http://www.earthpoint.us/TownshipsSearchByDescription.aspx

Appendix E:

Extended background research.

I. Introduction

In recent years there has been a rapid development of well stimulation treatment (WST) technologies such as hydraulic fracturing, acid fracturing, and matrix acidizing within the United States (Long et al, 2015). In California, for more than 30 years, oil and gas companies have utilized WSTs as production stimulation methods to increase recovery of conventional oil and natural gas reservoirs (Long et al., 2015). An independent assessment by the Lawrence Berkeley National Laboratory on the subject of WSTs found that, in the last decade, this unconventional oil production method has grown to about one fifth of total production in the state (Long et al, 2015).This assessment found that operators have used hydraulic fracturing on 125 to 175 wells out of the approximately 300 wells drilled each month in California. The independent assessment also concludes that almost all hydraulic fracturing in California occurs primarily in the fields of the San Joaquin Basin, particularly in Kern County, where oil is the primary resource obtained.

Of particular importance to this literature review is a 2014 study conducted by *EnergyWire* (Soraghan, 2014) that found that, although drilling activity decreased in 2013 across the country, the number of spills at oil and gas production sites increased by about 17%. This study determined that the combined volume of spills in 2013 included more than 26 million gallons of oil, hydraulic fracturing fluid, wastewater, and other miscellaneous fluids, all of which are dangerous to humans, animals, and the environment. Although the study states that the increase in spills may be caused by changes in reporting practices, such as lower spill reporting thresholds, there has been no quantitative examination of the cause for the increase in spills. Therefore, an analysis of the relationship between unconventional oil and gas production technologies and the increased frequency of hazardous material gas spills is urgently required.

Our research will attempt to address this need. [for your final paper, this is where you would expand to include an overview of the entire report, but this is fine for now] After reading this literature review, the reader should better understand (1) how conventional and unconventional oil and gas production processes differ, (2) the potential environmental and public health risks are of both types of production, and (3) the regulatory landscape of oil and gas production and hazardous material spills in California.

II. Traditional Oil and Gas Production

A. Production Process

Once an oil or natural gas reserve is identified, the process of preparing the land for production begins. First, the land must be researched to compile an environmental impact assessment. To prepare the location for drilling to commence, the area must be cleared and leveled to accommodate the drilling platform. In remote regions, access roads will be constructed (Freudenrich, 2010).

Once the land is ready, drilling can begin. To start the drilling, first a large shallow hole is constructed and lined with a conductor pipe (Freudenrich, 2010). There are seven primary components to an oilrig. The power system includes a powerful engine to provide the power for drilling. The mechanical aspect of the rig is made up of a hoisting apparatus and a turntable. The mechanism that enables rotary drilling is composed of a swivel, Kelly (polygonal tubing), turntable, drill pipe, drill collars, and drill bits. Casings provide structural support for the well. The circulation system of the rig pumps the drilling slurry into the earth at strong pressures. The derrick is the most visually recognizable aspect of the oilrig apparatus. This structure is the tall support structure that can be seen for a distance. To prevent hazards, blowout preventers mitigate pressure buildups that can lead to spills (Freudenrich, 2010)

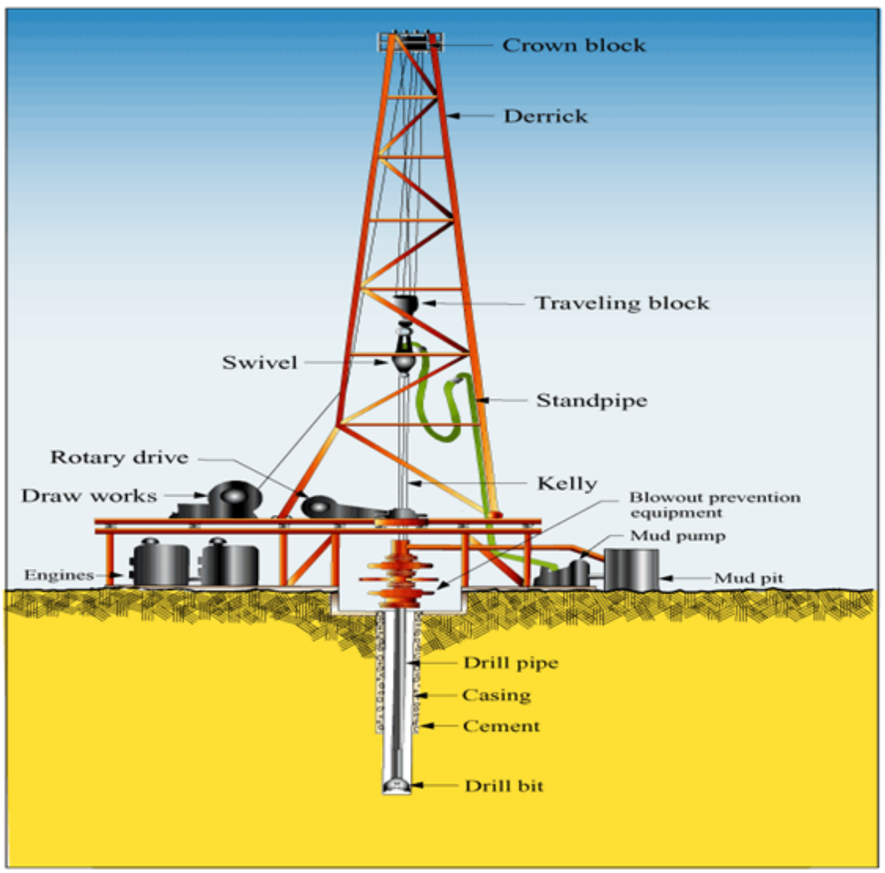

Figure 1: Oil Right Anatomy. (Source: California Department of Conservation, 2013).

Once this rig is constructed, drilling begins. Operators drill to a depth known to be above the depth that oil is expected. Once this depth is reached, cement casings are installed in the well hole to provide structural support for the system. From here on, drilling is done incrementally. Operators drill, then reinforce, then drill, and so on until they reach the oil reserves (Borchart, 1989). Once the well casing is in place, oil flow can be established through the rig. This is achieved by using a device called a perforating gun to create holes, which allow oil to flow into the well casing (Borchart, 1989). Tubing is lowered into the well to bring oil and gas to the earth's surface. To initiate the flow of oil or gas through the well, a perforating gun is lowered into the depths of the well and used to puncture holes in the well walls. This gun often uses high-pressure gas or fires some sort of projectile to perform this function (Borchart, 1989). With the oil flowing, the oilrig is removed and the extraction process beings.

With the removal of the oilrig, a pump is installed on the well. This pump has a lever that is driven by an electric motor. The pump brings oil up the well by creating suction. In cases where the oil is too thick to pump up the well by these means, a process called enhanced oil recovery is applied. Enhanced oil recovery may be able to assist in the capture of 20-40% of the reservoir's original capacity (U.S. Department of Energy, 2015). In this process, a second hole is drilled into the same oil reserve. Steam is injected into this hole, which loosens the thick oil making it less viscous and freer flowing up the well (Freudenrich, 2010). Gas injections are sometimes used to assist in pushing the oil to the Earth's surface.

B. Chemicals Used

There are a multitude of chemicals used in the process of traditional oil and gas production. Over the lifetime of an average oil or gas production well, hundreds of different chemicals will have been injected. There are four primary chemical classes used in the oil and gas production industry, seen below in Table 1.

Drilling Completion Fluid Additives, commonly referred to as drilling muds, serve the purpose in assisting the drill bit in performing its duty. These chemicals lubricate and cool the drill bit. By doing so, drilling can be faster, safer, and reach greater depths. (Borchart, 1989)

Cementing additives are used in the cement slurry used to make the well walls. These chemicals serve the primary purpose of controlling the amount of time the cement takes to set and the strength of the cement once it is set. The cement casing must be capable of sustaining immense pressure along with a great amount of wear and tear over the lifetime of the well (Borchart, 1989). These cement additives are intended to make the well more durable, enabling the cement to survive against corrosion and other natural occurring phenomenon that can damage the well structure over time.

Completion Fluids are used in the final stages of preparing the well for production and continue to be used throughout the well's lifespan. Their first function is assisting the perforating tool in penetrating the well wall in a controlled and effective way. Once this is complete, different chemicals are used during the extraction of oil and gas. These chemicals serve a wide variety of purposes, including reducing loss of fluids, altering viscosity of the product, and maintaining the well in working condition. (Borchart, 1989)

Table 1: Chemicals used at oilfield well sites (Source: Ailey, Clouse, Hill, 1997)

Drilling Completion Fluid Additives	Cementing Additives	Stimulation Fluid Additives	Production Chemicals
Deflocculants	Accelerators	Bactericides	Bactericides
Defoamers/Foamers	Dispersants	Breakers	Demulsifiers

Fluid-loss reducers	Extenders	Clay stabilizers	Gels
Lubricants	Fluid-loss reducers	Corrosion inhibitors	Inhibitors
pH controllers	Gas migration controllers	Crosslinkers	Oxygen Scavengers
Pipe-freeing agents	Retarders	Diverting agents	Surfactants
Polymeric viscosifiers	Spacers and chemical washes	Fluid-loss reducers	
Shale inhibitors		Mutual solvents	
Specialty Salts		pH controllers	
Surfactants		Polymeric viscosifiers	

C. Potential Pollution Pathways

There are a variety of negative environmental effects that come as a byproduct of the normal process of drilling, extracting, transporting refining, and using these resources (Soraghan, 2014). However, for the sake of this study, it is relevant for us to focus only on the pollution that can occur on oil fields as a result of oil and gas production. These oil and gas reserves are under severely pressurized conditions, so once drilling reaches the reserve these substances can escape their previous confinement with great force.

In the event of an abnormal event at an oil or natural gas extraction site, catastrophic effects to the environment may be incurred. Despite improved technology in drilling and extraction techniques, spills do still occur. Regions exposed to major oil spills have historically taken a great period of time to recover (Office of Indian Energy and Economic Development, 2015). In the case of oil spills, there are a few natural processes that work to rid the area of the spilled material. Firstly, some evaporation of hydrocarbons with low boiling points occurs over the course of a few months. Similarly, dissolution of hydrocarbons also targets the molecules with low boiling points. Dissolution is an extremely slow process, though. Biochemical degradation of the spill is dependent upon the presence of proper nutrients to support the necessary plant or bacterial organisms. If these nutrients are present, this process can occur very quickly (Blumer, Ehrhardt, and Jones, 1973). The Office of Response and Restoration is responsible for responding to hazardous materials spills. Under the National Contingency Plan, the National Oceanic and Atmospheric Administration is charged with providing scientific support for spills. Implications of oil spills linger for many years and have irreversible effects on the environment. (U.S. Environmental Protection Agency, 2014b)

III. Non-Traditional Oil and Gas Production: Well Stimulation Treatments

A. Production Process

Hydraulic fracturing, often called "fracking", is a well stimulation process used to extract oil and natural gas from reservoir rocks of low permeability, usually fine-grained sandstones and shales (FracFocus, 2015a). In hydraulic fracturing, large amounts of water and chemical additives are injected into a well at high pressures to fracture the rock formation and allow for extraction of the trapped hydrocarbons. These rock formations lay thousands of feet below the water table (Halliburton, 2015). The amount of water used can vary from 50,000 - 350,000 gallons for tight formations and up to 5 million gallons for shale formations (EPA, 2012b). Once the rock is fractured, the pressure between the petroleum-bearing rock pores and the wellbore must be equalized, so proppants such as sand or ceramic beads are pumped in to prop fractures open and allow for oil or gas to flow up the well (Daneshy, 2010).

After hydraulic fracturing has occurred but before production begins (i.e. before oil or gas begins flowing through the well), fracturing fluid may return through the wellbore to the surface as flowback water which is then stored and reused in other drilling operations. However, up to 90% of fracking fluid may remain underground (Lutz et al., 2013). After production has begun, "produced water", which has had contact with oil and gas, returns to the surface (Geological Society of America, 2015; EPA, 2012b).

California's largest shale plays are the Monterey and Monterey-Temblor formations. These make up an active drilling area of 1,752 square miles across the San Joaquin and Los Angeles basins. Based on available well data, an estimated 100 to 150 wells per month are hydraulically fractured in California, mostly for heavy crude oil (Jordan et al., 2014). Some wells are stimulated using acidization in which acids, generally hydrochloric (HCl) or hydrofluoric (HF), are injected into wells to dissolve rocks and permit access to oil and gas reserves (Jordan et al, 2014). Currently, acidizing occurs about 10% as often as fracking in California, and like fracking, is concentrated almost entirely in the San Joaquin Basin. Most experts do not foresee acidizing becoming a significant WST in California on par with fracking, mainly due to the lack of carbonate reservoirs in which acidizing is most effective (Jordan et al., 2014). For this reason, the literature review will focus mostly on the environmental hazards of hydraulic fracturing which accounts for about 20% of oil production in California (California Council on Science and Technology, 2015).

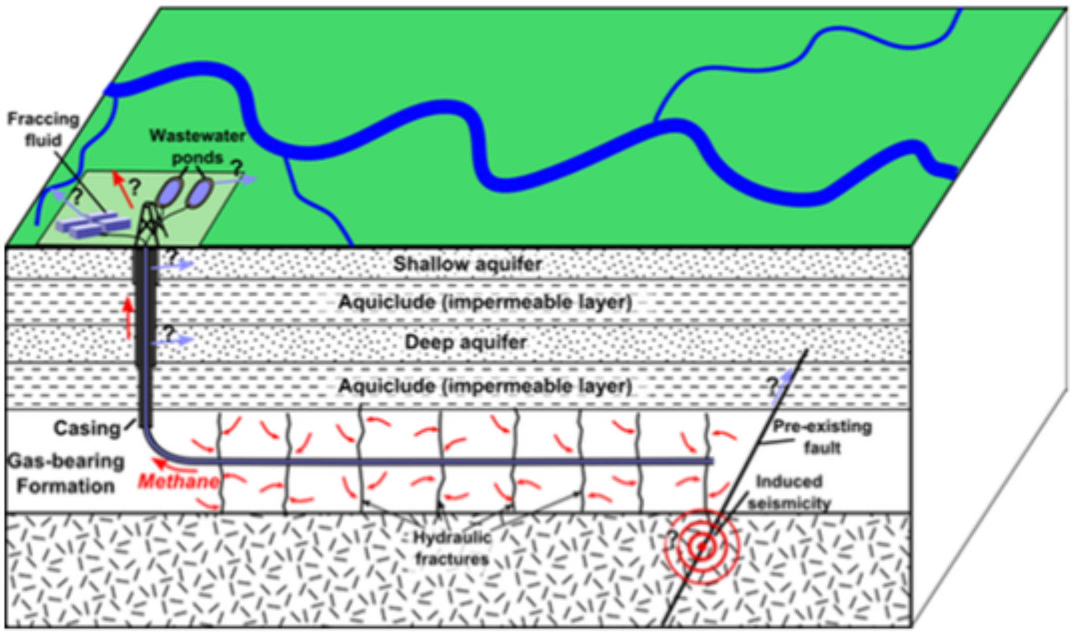

Figure 2: Potential pathways for fluid migration in horizontal hydraulic fracturing well (Source: Geological Society of America, 2015).

B. Chemicals Used

Although water comprises over 99% of fracking fluid by weight, a variety of chemicals are also used. The composition of fracking fluid is adapted to the requirements of each well. Common components include acids to dissolve material and reduce clogging, friction reducers, and surfactants to improve flow through pipes (Colborn et al, 2011).

In 2011 the Congressional Committee on Energy and Commerce conducted a study on chemicals in hydraulic fracturing products. The committee sent letters to 14 oil and gas companies asking for the chemical content of their fluid between 2005 and 2009. They received a list of 2500 products and 750 chemicals used by 14 companies (Waxman, 2011). Ingredients ranged from salt and citric acid, to instant coffee and walnut hulls, to the very toxic chemicals benzene and lead. The most widely used chemical was methanol (found in 342 products), followed by isopropyl alcohol (274 products), 2-butoxyethanol (126 products) and ethylene glycol (119 products). BTEX chemicals (benzene, toluene, ethylbenzene, and xylene) were found in 60 products (Waxman, 2011). Twenty-nine of the reported products were known or possible carcinogens, regulated contaminants under the Safe Drinking Water Act, or hazardous air pollutants under the Clean Air Act. Additionally, many unconventional oil and gas operators use proprietary chemicals in their fracking fluids. These "trade secret" chemicals are protected from disclosure (Waxman, 2011).

When flowback water returns to the surface, it is made up mostly of the original fluid and chemical mix with a salinity content that increases as a function of time since initial injection. Produced water, on the other hand, contains hydrocarbons as well as naturally occurring chemicals from within the rock formations. These chemicals typically include hyper saline reservoir water, oil and other hydrocarbons, and toxic elements like radium, barium and strontium. All of these chemical characteristics vary with the geology of the exploited formation (Vengosh et al., 2014).

Due to the overlap of many chemicals used in both processes, it is difficult to differentiate between spills and contamination from traditional oil and gas operations and those from WSTs. However, efforts have been made to more effectively and appropriately attribute spills to WSTs, such as using boron and lithium as tracers from shale formations (Warner et al., 2014). These techniques, coupled with greater transparency for proprietary chemical disclosures, are promising advances in tracing spills and contaminant migration to unconventional oil and gas sources.

C. Pollution Pathways

In hydraulic fracturing, waste materials are generated during both the fracturing and production phases. The main areas of concern lie in pollution from aboveground spills during the handling, transport, and storage of waste and in the potential for unrecovered subsurface fracturing fluid to migrate to aquifers. Similar concerns surround the potential for groundwater contamination from natural gas leaks around fractured wells (Vengosh et al., 2014). Pollution pathways are divided into direct and indirect processes.

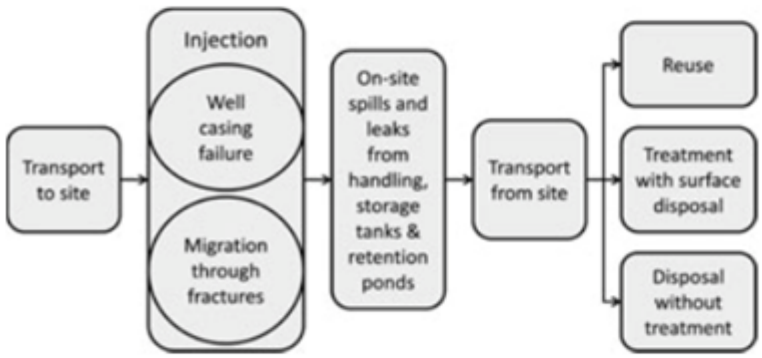

Figure 3: Potential pollution pathways for hydraulic fracturing. (Source: Rozell & Reavan, 2012)

1. Direct Pollution

Direct pollution is the (mostly subsurface) contamination of soil or groundwater resulting from high-pressure fracturing and the withdrawal of fluids and hydrocarbons. There is concern that the high-pressure fracturing process can create pathways for fracking fluid and hydrocarbons, especially methane, to migrate into aquifers used for drinking water and irrigation.

Well-casing failures represent another subsurface pollution pathway. The wellbore for hydraulic fracturing consists of multiple concentric steel tubes surrounded by cement for multiple layers of protection against leakage (FracFocus, 2015b). The outer cement layer is often the weakest link in a fracking wellbore, with as much as 10 - 50% of shale wells in parts of Pennsylvania suffering cement damage (Vengosh et al., 2014). Even without casing leaks, seal failure near the mouth of the wellbore are common in the petroleum industry and can allow stray gases to flow up through the gaps between concentric pipes (Darrah et al., 2014). According to one estimate, the rate of seal failure is 1-3% in the Marcellus Shale (Vidic et al., 2013). Consistent with the studies above, statistical analysis of hydraulic fracturing contamination events suggests that well failure, not high-pressure fracturing, causes most groundwater pollution (Darrah et al., 2014).

Another study, which analyzed pollution risk using models based on best and worst case probability bounds, suggested that fluid migration through fractures is a high potential risk, but waste disposal contamination risk is several orders of magnitude larger (Rozell et al., 2012). In nearly all studies of this kind, uncertainty over pollution pathways made it difficult to determine the degree of threat posed by fluid migration. Nearly all studies emphasize the much greater risk that mishandling, illicit dumping, and unregulated disposal of produced water waste poses to natural resources in the U.S.

2. Indirect Pollution

Indirect pollution is soil or water contamination resulting from processes related to hydraulic fracturing that occur beyond the fracturing and withdrawal process. This includes the transport, storage, and disposal of flowback and produced water.

Although hydraulic fracturing generates less wastewater than conventional methods per unit of resource produced, especially in California, proper disposal of produced water from unconventional oil and gas operations is a serious environmental concern (Lutz et al., 2013). According to an EPA study, the most common disposal process for hydraulic fracturing waste involves separating fracturing fluids from the recovered oil and gas, pumping it into trucks, treating it to proper disposal standards at a plant, and injecting it into wells (California Research Bureau, 2014). Every step of this process presents a possible pollution pathway for produced water. Wastewater treatment facilities are sometimes used for disposal, but are often unable to completely remove the radioactive elements and total dissolved solids (TDS) that produced water carries (Lutz et al., 2013). Because of this, between 95-98% of wastewater from fracking in the US is injected into Safe Drinking water Act (SDWA) Class II underground injection control (UIC) wells (see section Oil and Gas Regulations) (Lutz et al., 2013).

Offsite commercial disposal is used mostly by small operators for whom building, running, and closing an onsite disposal facility is not economically feasible (Argonne, 2009). In California, the water that is not injected underground is mostly disposed of through settling ponds or is treated for beneficial reuse, such as agriculture (Argonne, 2009). In Kern County, increased scrutiny has fallen on the use of unlined ponds for produced water disposal. Several studies, including one in 2014 by Clean Water Action, demonstrated that waste in unlined pits near McKittrick, CA migrated into wells used for irrigation and drinking water (Clean Water Action, 2014).

IV. Public Health and Environmental Effects of Well Stimulation Treatments

A. Water Pollution:

This review looked for instances of the release of chemicals from fracturing operations into water resources via the pathways previously discussed. Excluded were studies on the disposal of treated hydraulic fracturing wastewater directly into surface waters, as the majority of fracturing fluid in California is disposed of via underground injection or in wastewater pits (DOGGR, 2014). The discussion below includes two studies on contamination of water resources via underground pathways, one on surface spills, and one on instances of improper underground injection disposal of hydraulic fracturing waste.

1. Indirect:

A study by Gross et al., in the *Journal of the Air and Waste Management Association* analyzed whether surface spills at hydraulic fracturing operations led to groundwater contamination, specifically of benzene, toluene, ethylbenzene, and xylene (BTEX) chemicals. The Colorado Oil and Gas Conservation Commission (COGCC) database provided data on surface spills at sites in Weld County, Colorado between July 2010 and July 2011 (Gross et al, 2013). Researchers analyzed 77 spills. Groundwater samples collected at the spill sites showed that benzene levels were 2.2 times higher, toluene levels 3.3 times higher, ethylbenzene levels 1.8 times higher, and xylene levels 3.5 times higher than groundwater samples collected outside the spill area. BTEX levels tended to decrease rapidly with time and distance from the spill site (Gross et al, 2013). However, the study serves as a demonstration of the potential of surface spills to directly affect groundwater quality.

The second study provides a recent example of mismanagement of underground fracking wastewater disposal occurred within Californian Class II injection wells. In September 2014, the State Water Board conceded to the EPA that 9 underground injection control wells injected wastewater from natural gas operations into drinking water aquifers protected under the Safe Drinking Water Act. The board tested 8 public wells within a 1 mile radius of the UIC wells in question and found that four exceeded the Maximum Contaminant Level (MCL) for nitrate, arsenic, and thallium (Bishop, 2014; Schon, 2014).

2. Direct:

A study by Fontenot et al., in *Environmental Science and Technology* looked at water quality in 100 private wells surrounding the Barnett Shale formation in North Texas. Historic levels of arsenic, nitrates and volatile organic compounds (VOCs) from the United States Geological Survey were compared to current groundwater quality in 91 wells within a 5 kilometer radius of active natural gas extraction operations, 4 wells with no active operations within a 14 kilometer radius, and 5 inactive, control wells (Fontenot et al, 2013). The results showed that mean total dissolved solids (TDS) in active extraction areas exceeded the maximum contaminant level (MCL) set by the EPA, but historical data indicated similar levels for the region. Similarly, researchers observed methanol and ethanol in samples from both the active and inactive study areas. The chemicals were not correlated with distance to the nearest gas well (Fontenot et al, 2013). The constituents found to be higher in active areas than inactive areas were arsenic, selenium, and strontium. The researchers suggest a variety of contributing factors to this contamination, including mechanical disturbances from drilling activity, reduction of the water table from groundwater withdrawals, and faulty drilling equipment and well casings (Fontenot et al, 2013).

A study by Osborn et al., in the *Proceedings of the National Academy of Science* looked at methane contamination in drinking-water wells in the Marcellus and Utica shale formations in northeastern Pennsylvania and upstate New York, comparing wells within areas of active natural gas exploration and wells in inactive areas. Of 60 wells studied, 51 showed methane contamination. Concentrations of methane were 17-times higher nearby natural gas drilling operations (Osborn et al, 2011). Even more, the authors used stable isotope analysis to differentiate between shallow, naturally occurring methane and deep, thermogenic methane associated with fracking. Thermogenic methane was found to be the source of contamination at active sites, while biogenic methane was common at inactive sites (Osborn et al, 2011). The study also looked at general groundwater contamination associated with fracturing fluids. Using a contemporary sample of 68 wells and the historical data of 124 wells in the Catskill and Lockhaven aquifers, the researchers used three indicators of contamination: major inorganic chemicals, stable isotope signatures of water, and isotopes of dissolved constituents. The study found no connection between active drilling areas and general contamination in nearby wells (Osborn et al, 2011).

It is important to keep in mind that much of the literature on public health effects of WST fluid or spill contamination is limited by knowledge of the specific chemical composition of fracturing fluid. Incomplete MSDS information, a lack of Chemical Abstract Service (CAS) numbers to uniquely identify chemicals and chemical mixes, and trade secret claims by operators limited the all of the above studies and others of their kind. In addition, without baseline information on water quality or isotope tracking, it is difficult to impossible to causally link hydraulic fracturing operations to groundwater contamination. The study by Gross et al provided no measure of historical background levels of BTEX, therefore causality is not certain. In fact, a review by Samuel Schon faults the study by Osborn et al., for not providing geochemical measurements of dissolved methane (Schon, 2014).

Next, it is worthy to note that many of the studies on hydraulic fracturing chemicals and accidental release come from outside California. The study from the *Journal of Human and Ecological Risk Assessment* obtained product and chemical information from Colorado, Wyoming, New Mexico, Texas, Washington, Montana, Pennsylvania, and New York. The three other cited studies come from the Barnett, Marcellus, and Utica shale formations. In all, much of the published literature on hydraulic fracturing and its effects on groundwater are from study areas outside of California, likely due to the fact that the state does not have as extensive of a hydraulic fracturing industry as other parts of the US (US Department of Energy, 2011). Thus, one should keep in mind the difference between California fracking and general American fracking amount when weighing the probability of groundwater quality damage from fracking.

In all, the above studies give context for the public health concerns of hydraulic fracturing fluid and the ways in which it may enter groundwater. More research is needed to steadfastly claim a causal connection between fracking and groundwater contamination; however, data point to probable risk.

B. Air Pollution:

A recent independent study by P. Macey et al, "Air Concentrations of Volatile Compounds near Oil and Gas Production" examined the air concentrations of volatile compounds in hydraulic fracturing sites through a community-based exploratory study in five American states: Ohio, Pennsylvania, Arkansas, Colorado, and Wyoming. A total of 75 volatile organics were measured through passive air samples near industrial operations. Levels of eight of these volatile chemicals were found to exceed federal guidelines (Macey, 2014). Benzene, formaldehyde, and hydrogen sulfide were the most common compounds to exceed acute and other health-based risk levels (Macey, 2014). For instance, the exposure to benzene experienced in five minutes at one Wyoming site was equal to the exposure experienced living in LA for two years. Benzene is known to cause irritation of the skin, eyes, and upper respiratory tract (U.S. EPA 2011). Long-term exposure may cause blood disorders, reproductive and developmental disorders, and cancer (Outdoor Air, 2011). Hydrogen sulfide levels in the Wyoming site were also 90 to 60,000 times greater than the recommended levels at one given time during the study period (Francis, 2014). Hydrogen sulfide can cause respiratory tract and eye irritation, headaches, poor memory, and loss of appetite among other symptoms (Francis, 2014).

C. Environmental Justice

According to the EPA, environmental justice is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies (U.S. EPA, 2014a).

A study by Srebotnjak et al. examined which communities were the most disproportionately at risk due to oil and gas drilling in California. According to their research, approximately 5.4 million Californians (14 % of the state's population) live within one mile of an existing oil and gas well (Srebotnjak, 2014). In addition, 1.8 million of these individuals live in already environmentally polluted areas (Rotkin-Ellman, 2014). Approximately 92% of the individuals within those 1.8 million are people of color. The demographics of the population living near wells in California consist primarily of Hispanics/ Latinos (Srebotnjak, 2014).

A separate study analyzed one particular oil and gas community in Kern County, California. Kern County has more than 63,000 of the state's 84,434 active and new oil and gas wells (Rotkin-Ellman, 2014). The researchers found that one in three residents live within one mile of an oil or gas well (35% of the county's population) (Rotkin-Ellman, 2014). These individuals are at a greater risk of potential health impacts. According to the Desert Renewable Energy Conservation Plan, Kern County's total population size is about 839,153 with 61.4% belonging to a minority group (Desert Renewable Energy Conservation Plan, 2014). The percent of low-income individuals in Kern County is 22.5%. California as a whole has a minority population of 59.9%, with 15.3% falling within the low-income population. (Desert Renewable Energy Conservation Plan, 2014)

V. Oil and Gas and Hazardous Material Regulation

A. Oil and Gas Regulation

Oil and gas production is subject to regulation at the state and federal level, although with many exemptions as described further below. Those regulations include the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), the Clean Water Act (CWA), the Safe Water Drinking Act (SDWA), and the Resource Conservation and Recovery Act (RCRA) (U.S. EPA 2014b; U.S. EPA, 2006). A specific point of concern is the regulation of hydraulic fracturing, which is also occasionally exempted from regulations placed on conventional production. There are many agencies that intersect with oil and gas production regulation, including the US Environmental Protection Agency (EPA), the Department of Oil, Gas, and Geothermal Resources (DOGGR), the Department of Energy, and the Department of Conservation. At the federal level, the US EPA has constructed some legislation that applies to oil and gas production. At the California state level, regulation was nearly nonexistent until the passage of Senate Bill 4 (signed into law on Sept 20, 2013).

The US EPA monitors conventional oil and gas production. The oil and gas industry is subject to regulation under the CWA and the SDWA. Under Section 311 of the CWA, regulations mandate prevention and preparedness for oil discharges into navigable waters of the US. A 1994 amendment also requires that storage facilities prepare Facility Response Plans for such an event (U.S. EPA, 2014b). In addition, oil companies may apply for National Pollutant Discharge Elimination System (NPDES) permits for the discharge of wastewater, under section 402 of the CWA (U.S. EPA, 2012). Furthermore, conventional oil and gas production is subject to air pollution standards under the CAA that reduce emissions of smog-forming volatile organic compounds. (U.S. EPA, 2015).

Hydraulic fracturing and other WSTs have been exempted from major components of environmental legislation. This includes exemption from the Safe Water Drinking Act and the Clean Water Act (Brady, 2012). This exemption was placed into effect after 2005 amendments to the Energy and Policy Act freed water contamination from WSTs from regulation (Rabe, 2013). The exemption states that underground injection control requirements do not have to be adhered to unless diesel fuels are part of the mixture being injected to frack the well (Clean Water Action, 2014). However, the EPA mandates that storm water regulation and spill prevention, control, and countermeasure plans be created to prevent the release of toxic chemical discharge into water supplies.

In California, the Division of Oil, Gas and Geothermal Resources (DOGGR), which is a subdivision of the Department of Conservation, monitors oil and gas production in California. DOGGR oversees the drilling, operation, maintenance, and plugging and abandonment of oil, natural gas, and geothermal wells (California Department of Conservation, 2014). DOGGR is also responsible for the administration of the California Environmental Quality Act (CEQA) over oil and gas development in the state. CEQA is designed to identify potential environmental impacts and to avoid or mitigate environmental damage (California Natural Resources Agency, 2014). Similar to CEQA notification is the Emergency Planning and Community Right-to-Know Act. This requires that companies and manufacturers release a detailed Toxic Release Inventory for chemicals utilized and released into the environment. However, the oil and gas industry is completely exempted from this TRI reporting.

In recent years, DOGGR acknowledged the gaps in regulations placed on oil and gas production and the information provided to the division about hydraulic fracturing (California Department of Conservation, Division of Oil Gas and Geothermal Resources (DOGGR), 2014). In 2011, Fran Pavley, a California state senator, requested information on hydraulic fracturing in California from DOGGR. The agency had "no information" on water use, "no data on the safety, efficacy and necessity" of WSTs and "no permitting process" relating to hydraulic fracturing (Sharp, 2012). In response, Pavley drafted Senate Bill 4 in 2013, passed in September 2013, which directly deals with WST reporting. SB4 will be discussed in detail in the next subsection.

Table 2: Regulations on Oil and Gas in California and the United States. (Source: U.S. EPA, 2002, 2012, 2014b; Brady, 2012; Clean Water Action, 2014; California Natural Resources Agency, 2014)

Regulation	Content	Traditional Production	Non-Traditional Production

CERCLA	Cleans up controlled releases of specified hazardous substances.	Regulated when oil discharge reaches waters of the United States. Must be reported if discharge creates a "sheen" or "film." However, some toxic chemicals included on the hazardous substances list are exempted if they are included in oil and gas production.	Same as traditional production.
Clean Water Drinking Act	Regulates discharges of pollutants into waters of the United States.	Excludes sediment as a pollutant when it is generated from oil and gas production.	Same as traditional production.
Safe Water Drinking Act	Protects America's drinking water from pollutants, whether it is from groundwater or above ground resources.	Not exempted from regulation.	Exempted from SWDA. However, if diesel is used to frack a well, a SWDA permit must be issued.
RCRA	Governs disposal of solid and hazardous wastes.	Exempts oil and gas produced water, and drilling fluids from requirements for monitoring and disposal.	Hydraulic fracturing fluids and produced waters are exempted.
Emergency Planning and Community Right-to-Know Act	Requires companies and manufacturers meeting specified criteria to report detailed Toxic Chemical Reports.	Exempted, even if criteria is met.	Exempted, even if criteria is met.
Senate Bill 4	Specific to WSTs. Requires filing of satisfactory certifications under penalty of law. This includes monitoring of groundwater before and after drilling, neighbor notification, and public disclosure of chemicals.	Not included.	Subject to regulation.
CEQA	Requires that environmental impact reports be generated.	Subject to regulation	Subject to regulation

1. Senate Bill 4

Senate Bill 4 was enacted by the California legislature due to five concerns enumerated within the legislation. First, hydraulic fracturing and well stimulation treatments are increasing in California. Second, the state considers current scientific information on the risks of well stimulation treatments incomplete. Third, the legislature believes that government and industry transparency are vital. Fourth, public disclosure is important so as to allow the public to determine if they are being exposed to WST chemicals. Fifth, the legislature would like to understand the components of produced water used in WST so that it may be reused or treated (California Environmental Law and Policy Center, 2015)

First, SB4 requires an independent scientific study on well stimulation treatments to be conducted by the Secretary of California's Natural Resources Agency. The study will provide information on existing and potential oil and gas reserves and analyze risks of WSTs (California Environmental Law and Policy Center, 2015). Study completion was set for January 1st, 2015. On January 14th, 2015, the department of Conservation released Volume I of the study, titled "An Independent Scientific Assessment of Well Stimulation Technologies in California: Well Stimulation Technologies and their Past, Present, and Potential Future Use in California." (California Council on Science and Technology, 2015). It describes what WSTs are, the operations involved, and where they are practiced. The California Council on Science and Technology and the Lawrence Berkeley National Laboratory prepared the study. Volumes II and III of the study are set to be released in July 2015. Volume II is of most interest to our project; it will detail the effects of WSTs on water bodies, among other natural resources. Volume III will focus on how WSTs will affect the environment in specific geographic regions (California Council on Science and Technology, 2015)

Next, SB4 requires the development of WST regulations by DOGGR. These include threshold values for acid volume used, disclosure requirements of chemical composition of well stimulation fluids, and source and volume information of all water used, be it base or waste fluid (California Environmental Law and Policy Center, 2015).

Third, SB4 requires public disclosure of WST fluid composition. The composition must be provided online within 60 days of the termination of treatment on a well. This information is to be posted on the DOGGR website beginning in January 1, 2016. Currently, the information is required to be posted via FracFocus.org (California Environmental Law and Policy Center, 2015)

Fourth, SB4 ends the ability of operators and suppliers to claim trade secret protections on many of their products. It requires that the supplier disclose all chemical additives or constituents used in well stimulation treatment to DOGGR, even if the information is claimed as trade secret. If DOGGR finds that a trade secret claim is invalid, it may release the information to the public. Under the New Public Resources Code section 3160(J)(2) the following may no longer be protected as a trade secret:

1. The identities of the chemical constituents of additives
2. The concentration of additives in the well stimulation treatment fluid
3. Air or other pollution monitoring data
4. Health and safety data associated with WST fluids; and
5. The chemical composition of flowback fluid

Fifth, SB4 creates a permitting process for WST operations. A well operator must provide in the well permit application the time and location of the WST, a complete list of chemicals to be used, water management and groundwater monitoring plans, and the source and disposal method of fluids used in the operation. The permit is valid for one year from

DOGGR's approval date. Permits are made available online by DOGGR five days after approval date (California Environmental Law and Policy Center, 2015).

Sixth, SB4 requires that landowners within 500 feet of a horizontal project of a WST or within a 1500 foot radius of the wellhead be notified of treatment. Operations may not commence until 30 days after notification of nearby landowners.

Last, SB4 directs the SWRCB to develop regional or well specific groundwater monitoring criteria by July 15, 2015. DOGGR along with industry and agriculture stakeholders are responsible for providing input into the monitoring plan (California Environmental Law and Policy Center, 2015)

Environmental groups withdrew support of SB4 when a provision was added that would allow the continuance of WSTs while DOGGR finalizes its comprehensive fracturing regulations. In addition, Section 3161, which requires DOGGR to complete an Environmental Impact Report (EIR) on WST across the state by July 1, 2015 allowed some local governments, namely Kern County, to attempt to complete their own independent EIRs before the statewide report could be finalized (California Environmental Law and Policy Center, 2015).

Kern County has not yet released an approved EIR. In August 2013, however, Kern County released a notice of preparation of a draft EIR. This EIR will be programmatic, that is environmental conditions of the entirety of Kern County will be considered, not conditions specific to each well. Should a Kern County oil and gas EIR be approved, DOGGR must consider only Kern's EIR instead of the statewide EIR when approving WST permit applications (Kern County Planning and Community Development Department, 2013).

B. Hazardous Material Release Regulations

The federal law that regulates hazardous materials spills is the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA). It requires hazardous materials spills which exceed minimal reportable amounts to be reported to the National Response Center by any responsible parties (U.S. EPA, 2006).

In California, hazardous material spills are regulated by two pieces of law: the California Water Code section 13271 and the California Code of Regulations Title 19, Division 2, Chapter 4, Hazardous Material Release Reporting (California Water Code, 2015; California Code of Regulations, 2008)

The California Water Code section 13271 requires that any release of hazardous substances or sewage to the waters of the state must be verbally reported immediately to the California Emergency Management Agency, or once knowledge of the discharge is available or notification is possible without impeding cleanup and emergency measures (California Water Code, 2015). The California Emergency Management Agency is responsible for notifying the local health officer and director of environmental health of the spill. If the spill is of high enough concern to the health board, the public will be notified. Failure to comply with the notification requirements will result in misdemeanor charge or a fine of up to $20,000 to involved parties. Substances that are listed as hazardous wastes in Section 25410 of the Health and Safety code are assigned reportable quantities by the department of Toxic Substances Control (California Water Code, 2015). Sewage is assigned reportable quantities by the California State Water Board.

The California Code of Regulations chapter on hazardous materials expands on the reporting requirements to include the minimum information required in the release report (California Code of Regulations, 2008). This includes the

1. Exact location of the release or threatened release;
2. The name of the person reporting the release or threatened release;
3. The hazardous materials involved in the release or threatened release;
4. An estimate of the quantity of hazardous materials involved; and
5. If known, the potential hazards presented by the hazardous material involved in the release or threatened release;

Reporting is to be made to the Office of Emergency Services and a telephone number is provided. Interestingly, the California Code adds to the Water Code by clarifying that the immediate reporting of a hazardous material spill to land is only required in there is "reasonable belief" that the spill may pose a threat to public health, property, or the environment. Written reporting is only sometimes required, pursuant to 42 U.S.C. section 11004(c). If required, the written notice is sent to the Chemical Emergency Planning and Response Commission no later than 30 days after the release. The written notice form can be found on the next page figure 4 (California Code of Regulations, 2008).

The reportable quantities of chemicals can be found on two lists (California Office of Emergency Services, 2014a). The first is the Extremely Hazardous Substances list. The second is the more detailed Consolidated List of Chemicals. However, besides these two lists, according to California Hazardous Materials Spill / Release Notification Guidance, if the responsible parties are doubtful of whether or not the release should be reported, the release should be reported (California Office of Emergency Services, 2014a).

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