Comments on
Draft Environmental Impact Report (DEIR)
Analysis of Oil and Gas
Well Stimulation Treatments in California

State Clearinghouse No. 2013112046

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March 16, 2015

Table of Contents

Appendices

1. Introduction

In January 2015, the California Department of Conservation, through its Division of Oil, Gas and Geothermal Resources, issued Draft Environmental Impact Report (DEIR) Analysis of Oil and Gas Well Stimulation Treatments in California.[1] The DEIR defines the Project being reviewed as activities associated with well stimulation treatments:

> For the purposes of this EIR the "project" is defined as all activities associated with a stimulation treatment that could occur either at an existing oil and gas well, or at an oil and gas well that is drilled in the future expressly for the purposes of a stimulation treatment.[2]

The DEIR analyzes an alternative (Alternative 1) that would prohibit well stimulation treatments anywhere in California, and this prohibition is estimated to significantly affect future crude oil production in the State.

> The No Future Well Stimulation Treatments Alternative (Alternative 1) would prohibit all current well stimulation activities and prohibit future use of well stimulation treatments anywhere in the State.[3] [...] [T]he immediate effect of the No Future Well Stimulation Treatments Alternative would be an expected decrease around 25 percent of oil production in California.[4]

The DEIR also analyzes a second alternative (Alternative 2) that would prohibit well stimulation treatments in some areas of California, but the DEIR does not quantify how it would affect future crude oil production in the State.

> The No Future Well Stimulation Treatments Outside of Existing Oil and Gas Field Boundaries Alternative (Alternative 2) […] would prohibit well stimulation outside of existing fields and their buffer areas […] this alternative would not reduce the amount of oil produced in California to the same extent as the No Future Well Stimulation Treatments Alternative, which would enact a State-wide ban.

[1] Draft Environmental Impact Report, Analysis of Oil and Gas Well Stimulation Treatments in California, State Clearinghouse No. 2013112046, prepared for California Department of Conservation by Aspen Environmental Group, January 2015 ftp://ftp.consrv.ca.gov/pub/oil/SB4DEIR/EIR/SB4_DEIR_Vol1.pdf
ftp://ftp.consrv.ca.gov/pub/oil/SB4DEIR/EIR/SB4_DEIR_Vol2.pdf
ftp://ftp.consrv.ca.gov/pub/oil/SB4DEIR/Mapbook/SB4_mapbook_ALL.pdf
[2] DEIR, p. ES-2.
[3] DEIR, p. ES-5.
[4] DEIR, p. 8-7-8-8 [footnote 2 in original omitted].

> However, it is not possible at this time to quantify the precise amount of oil and gas resources that would be lost.[5]

The DEIR also analyzes three other alternatives, but these alternatives are not expected to significantly affect future well stimulation treatments and crude oil production in the State.[6]

The DEIR then assumes that, without well stimulation,

- there would be less California crude production;
- this foregone production would be offset by additional oil produced outside of the State and delivered to California; and
- there would be indirect environmental impacts associated with exploration and production activities in the areas where the oil would be produced and impacts associated with transportation of the oil into California, primarily by tanker and rail:.

The DEIR evaluates the environmental impacts associated with the Project and Alternatives and concludes that the Project is considered to be the Environmentally Superior Alternative.[7]

These Comments were prepared by Ian Goodman[8] and Brigid Rowan[9] of The Goodman Group, Ltd. (TGG), a consulting firm specializing in energy and regulatory economics.[10] TGG was retained to provide a Market Analysis to evaluate the DEIR analysis.[11]

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5 DEIR, p. ES-6.

6 As explained in the DEIR:

> The Well Pad Consolidation Alternative (Alternative 3) would apply primarily outside of existing oil and gas fields in areas where resources would potentially become recoverable due to advances in well stimulation technologies and increased understanding of California's geology in the Monterey Formation. [DEIR, p. ES-6] [...] It would not limit the amount of well stimulation in the future, so overall oil and gas production is not expected to change as a result of this alternative. [DEIR, p. 8-11]
> [...]
> The Urbanized Area Protection Alternative (Alternative 4) would prohibit future oil and gas well drilling for the purposes of stimulation within the boundaries of any established Urbanized Area not included within an existing oil and gas field's boundaries or its buffer area. [DEIR, p. ES-7-ES-8] [...] [T]his alternative is likely to minimally impact future oil production in the State. [DEIR, p. 8-13] [...] [T]he majority of the Monterey Formation is outside of the Urbanized Areas [DEIR, p. 8-13]
> [...]
> The Active Fault Zone Restrictions Alternative (Alternative 5) would prohibit future oil and gas well stimulation treatments within the earthquake study zone boundaries of a known active earthquake fault outside of existing oil and gas field boundaries and their buffer areas. [DEIR, p. ES-8] [...] While some areas outside of the existing oil and gas fields would not be available for well stimulation, much of the area would be available for use, so this alternative is likely to minimally impact future oil and gas production in the State. [DEIR, p. 8-12]

7 DEIR, p. ES-46, p. 14-12.

8 Resume of Ian Goodman is provided as Appendix A to these Comments.

9 Resume of Brigid Rowan is provided as Appendix B to these Comments.

10 www.thegoodman.com

11 These Comments were co-authored by Ian Goodman and Brigid Rowan, co-authors of "Comments on
(footnote continued on next page)

The DEIR touches upon a very wide range of issues regarding rapidly evolving crude markets. Petroleum markets are large, complex, and highly interconnected. In turn, petroleum market analysis can be highly complex, with significant interrelationships between its various elements. Petroleum markets are also highly dynamic and interactive. Given the limited time, information, and other resources available for these Comments, it is impractical for TGG to undertake a full independent analysis.

In light of these constraints, TGG has provided a sound alternative analysis that offers useful guidance to policymakers. The TGG Market Analysis reviews the DEIR analysis and provides an alternative analysis focusing on:

- the effects of the Project and DEIR Alternative 1 (and 2) on production and supply of oil for California,
- the GHG and air quality impacts associated with this production and supply, and
- the DEIR Comparison of Alternatives and rationale for selection of the Project as the Environmentally Superior Alternative, in regard to GHGs and air quality.

In particular, these Comments focus on the No Future Well Stimulation Treatments Alternative (Alternative 1). This is the only Alternative estimated and quantified by the DEIR to significantly affect future crude oil production in the State.

These Comments also provide some guidance in regard to the No Future Well Stimulation Treatments Outside of Existing Oil and Gas Field Boundaries Alternative (Alternative 2). This Alternative could also affect future crude oil production, but these impacts are a subset of those for Alternative 1 and are not quantified by the DEIR.

Section 2 of these Comments discusses California crude production and supply. Section 3 discusses Greenhouse Gas (GHG) emissions. Section 4 discusses Air Quality.

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Initial Study/Mitigated Negative Declaration (IS/MND) Valero Crude by Rail Project Benicia, California Use Permit Application 12PLN-00063" that was filed July 1, 2013 as an attachment to the Comments of NRDC http://www.ci.benicia.ca.us/vertical/sites/%7B3436CBED-6A58-4FEF-BFDF-5F9331215932%7D/uploads/Report_by_the_Goodman_Group.pdf with appendices at http://www.ci.benicia.ca.us/index.asp?SEC={FDE9A332-542E-44C1-BBD0-A94C288675FD}; and "Report evaluating the Keystone XL (KXL) Draft Supplemental Environmental Impact Statement (DSEIS) Market Analysis" filed April 22, 2013 as an attachment to the DSEIS Comments jointly submitted by the Sierra Club, NRDC, and 14 other environmental and public interest organizations: http://switchboard.nrdc.org/blogs/aswift/Comments%20of%20Sierra%20Club%2C%20et.%20al.%2C%20on%20the%20Keystone%20XL%20DSEIS.4.22.13.pdf

2. Impacts on California Crude Production and Supply

Section 2.1 discusses DEIR estimates regarding well stimulation impacts on California crude production and supply. Section 2.2 focuses on the time pattern of these impacts. Section 2.3 reviews the basis of the DEIR estimates. Section 2.4 discusses the implications of lower crude prices. Section 2.5 provides a Summary.

2.1. DEIR Estimates

The DEIR assumes that, without well stimulation,

- there would be less California crude production, and
- that this foregone production would be offset by additional oil produced outside of the State and delivered to California, primarily by tanker and rail.

Specifically, the DEIR estimates that with no well stimulation [No Future Well Stimulation Treatments Alternative (Alternative 1)], California crude production will be lower by 25%:

> Approximately 25 percent of drilled oil wells in California use hydraulic fracturing (Halliburton, 2014). As such, the immediate effect of the No Future Well Stimulation Treatments Alternative would be an expected decrease around 25 percent of oil production in California. [footnote 2 in original: The decrease in oil production cannot be calculated precisely without knowing the estimated production level of each well that would have been hydraulically fractured and whether the well owner would proceed with the drilling despite the fracturing restrictions. The actual loss of production may be more or less than 25 percent.][12]

The DEIR then estimates that, with California crude production lower by 25%, an additional 57 million barrels per year would have to be sourced from outside of California:

> In 2009, California produced almost 230 million barrels of oil from over 52,000 producing wells (DOC, 2010). That same year, California used over 600 million barrels of oil, importing 15 percent of its oil from Alaska and 45 percent from foreign sources, with Saudi Arabia (25 percent), Iraq (19 percent), Ecuador (17 percent), and Brazil (9 percent) accounting for 70 percent of the imported oil (CEC, No Date; CEC, 2010). Since 2009, the percent of foreign oil imports to California has increased to 50 percent of the oil used and imports from domestic sources other than Alaska have also increased (CEC, No Date). A loss of 25

[12] DEIR, p. 8-7-8-8 (emphasis underlining added).

> percent of the California-produced oil would require an additional 57 million barrels per year be purchased from another source.[13]

In turn, the DEIR then estimates that, with additional oil being imported into California, there would be indirect environmental impacts associated with exploration and production activities in the areas where the oil would be produced, including impacts associated with transportation of the oil into California, primarily by tanker and rail:

> [A]dditional oil and gas would need to be imported to continue to supply California's fuel needs and offset the foregone production. Additional future imported oil and gas would be delivered to California's refineries primarily via rail or tanker. Under Alternative 1, production of hydrocarbon resources outside of California and subsequent delivery of these resources to the State would result in indirect environmental impacts. These would include impacts associated with exploration and production activities in the areas where the petroleum would be produced and impacts associated with transportation.[14]

But, as this Section demonstrates, for multiple reasons, restrictions on well stimulation may have only a much smaller impact on California crude production and supply, especially in the near term.

2.2. Time Pattern of Impacts

Even if it is assumed that 25% of drilled oil wells in California use hydraulic fracturing, the immediate effect of the No Future Well Stimulation Treatments Alternative would not be an immediate 25% decrease in crude production. Instead, it would take at least 5 years (and likely longer, possibly up to 7-10 years or more) for the decrease in crude production to be as high as 25%.

Wells typically produce crude over a number of years, albeit at declining rates. So production in a given year is affected not just by drilling in that year, but also by ongoing production from wells drilled in previous years. Thus, any change in drilling practices (such as restrictions on well stimulation) will have only a limited impact on production in the near term. Put another way, it will likely take several years, or even longer, for a change in drilling practices to affect large numbers of wells and reach its maximum effect on overall crude production.

Various factors affect the time pattern of impacts relating to well stimulation.

There is only a limited amount of drilling that could and will take place each year.[15]

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[13] DEIR, p. 8-8.

[14] DEIR, p. ES-6.

Even absent restrictions on well stimulation, some drilling will not make use of well stimulation.[16] This drilling (and the associated crude production) will not be affected by restrictions on well stimulation.

Absent restrictions on well stimulation, some drilling will involve well stimulation. If well stimulation is restricted, this drilling (and the associated production) might not take place. And even if this drilling does still take place without well stimulation, it would likely result in lower production than it would have in combination with well stimulation.

Thus, in a scenario with well stimulation vs. a scenario without well stimulation, well stimulation in previous years has a cumulative impact on production in current and future years. And that increase in production will be incremental, and the overall impact on crude production will be greater in later years.

So for example, overall impacts in year 2 will include incremental production due to well stimulation applied in year 2, as well as in year 1. Likewise, overall impacts in year 3 will include incremental production due to well stimulation applied in year 3, as well as in years 1 and 2.

The DEIR fails to estimate how long it would take for restrictions on well stimulation to have their maximum effect to lower crude production vs. a scenario absent restrictions on well stimulation. But based on the information in the DEIR, as well as from other sources, it would take at least 5 years for the restrictions on well stimulation to reach their maximum impact on crude production and it might well take 7-10 years, and perhaps even longer.[17]

(footnote continued from previous page)

[15] A variety of factors affect and constrain the amount of drilling in each year. Drilling is a complex, high cost, physical activity requiring extensive and highly specialized equipment, labor and services, as well as coordination and permits. Moreover, especially in California's mature fields, drilling of new wells is (in part) related to the ongoing depletion and abandonment of existing wells. Thus, it is more feasible and cost-effective for drilling to be spread out over time, rather than happen all at once. That said, the pace of drilling activity can accelerate or slow, notably in response to changes in crude prices and drilling technology. [DEIR, especially Section 7]; http://ccst.us/publications/2015/2015SB4-v1.pdf , especially pp. 31-41. Also see footnote 21 regarding this source; and Section 2.4, specifically footnote 32.

[16] As defined in California law and the DEIR, enhanced oil recovery techniques such as steam flooding and cyclic steaming are not well stimulation treatments. DEIR, pp. 1-1, 4-1.

[17] It will take at least several years for restrictions on well stimulation to reach their maximum impact, with various factors influencing the timing of impacts. The DEIR (pp. 7-23-7-25, 10.3-32-10.3-33) assumes that almost 90% of well stimulation will be at new wells. But even when crude prices and drilling activity were relatively high in 2014, the new production from the new wells drilled each month was less than 1% of total California crude production (see footnotes 27 and 32). And this new production was being offset by declines in output from existing wells, such that overall California production was stable/very slowly increasing (see footnote 27). This time pattern of impacts suggests that it might take approximately 10 years for restrictions on well stimulation to reach their maximum impact on crude production.

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2.3. Basis of DEIR Estimates

As discussed in Section 2.1, the DEIR analysis assumes that well stimulation enables 25% of California crude production. But this assumption appears to be inconsistent with other information in the DEIR, as well as other available information. Moreover, this assumption is based on a personal communication that is unreviewable, as well as potentially prone to bias.

The DEIR assumption about prevalence of well stimulation is based on "Halliburton, 2014". But the DEIR is not consistent in characterizing information from this source.

In support of its assumption that well stimulation enables around 25% of California crude production, the DEIR states that approximately 25% of drilled oil wells in California use hydraulic fracturing:

> Approximately 25 percent of drilled oil wells in California use hydraulic fracturing (Halliburton, 2014). As such, the immediate effect of the No Future Well Stimulation Treatments Alternative would be an expected decrease around 25 percent of oil production in California.[18]

But elsewhere, the DEIR states that fewer than 25% of wells are hydraulically fractured:

> Fewer than 25 percent of all wells drilled within the State are hydraulically fractured (Halliburton, 2014).[19]
> [...]
> [F]ewer than 25 percent of all wells within California were hydraulically fractured in recent years.[20]

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And it could take even longer for restrictions to reach their maximum impact. According to the DEIR (p. 7-25), production wells are generally planned for a 20-30 year life, and some existing California wells are much older. On the other hand, some of the crude production enabled by well stimulation may be relatively short-lived.

Hydraulic fracturing in California is often applied to injection wells, notably to facilitate enhanced oil recovery. Thus, hydraulic fracturing at new injection wells may enable crude output at existing production wells, and it may have a different time pattern of impacts compared with other crude production. [DEIR, pp. 7-22-7-24; see footnotes 41, 42, and 43; and http://crc.com/images/documents/IR/Financials/CaliforniaResourcesCorporationAnalystDayPresentationOctober2014Rev10302014.pdf pp. 11, 13, 35, 39. 42-56]

Well stimulation applied in any given year may enable increased production in future years. Thus, well stimulation applied in any given year may have a cumulative lifetime impact on production that is larger than the impact in the first year.

[18] DEIR, p. 8-7-8-8 [footnote 2 in original omitted].

[19] DEIR, Section 7.4.1, p. 7-25.

[20] DEIR, p. 10.3-30, which in turn references "EIR Section 7.4.1" quoted above (footnote 19).

Meanwhile, the CCST SB4 Well Stimulation study[21] concluded that only about 20% of California crude production involves hydraulic fracturing:

> [A]bout 20% of the total oil production in the state is facilitated by hydraulic fracturing, with most of this occurring in the San Joaquin Basin.[22]

None of the above information is definitive as to how much of the state's crude production is enabled by well stimulation and specifically hydraulic fracturing. That said, the 25% figure assumed in the DEIR seems to be at (or above) the high end of the range based on historical experience; a figure of 20% appears to be more consistent with this historical experience.

Moreover, the DEIR's reliance on information from "Halliburton, 2014" is problematic given the nature of this source. The DEIR's rather key assumption as to prevalence of well stimulation and its impact on crude production is based on a personal communication and is thus difficult (if not impossible) to review and validate:

> Halliburton (Halliburton Company). 2014. Personal communications between James Melrose (Halliburton Business Development Manager), et al., and Hedy Koczwara (Aspen Environmental Group). April 15, 2014.[23]

Halliburton is a pioneer and leading company involved in developing and selling hydraulic fracturing and other well stimulation services and materials. Thus, Halliburton has a strong interest in promoting and facilitating utilization of well stimulation. It is likely in Haliburton's economic self-interest to estimate that well stimulation has a larger impact on crude production, and it is certainly in Haliburton's self-interest that well stimulation not be prohibited or otherwise severely restricted.

The DEIR is based on an assemblage of data and other information from multiple sources. While it is not uncommon for analysis of complex energy and economic issues to rely upon disparate sources, great care is needed to ensure that the overall analysis is objective, coherent, internally consistent, and will provide useful and meaningful results. The need for

[21] CCST (California Council on Science and Technology), An Independent Scientific Assessment of Well Stimulation in California, Volume 1: Well Stimulation Technologies and their Past, Present, and Potential Future Use in California. Prepared by Long, Jane, et al (CCST, Lawrence Berkeley National Laboratory, Pacific Institute, and Dr. Donald Gautier, LLC), January 2015 http://ccst.us/projects/hydraulic_fracturing_public/SB4.php
DEIR (p. 11.13-21) states:

> CCST's Independent Scientific Study pursuant to SB 4 is in progress and will contain three volumes. […] Results from this study were not available for incorporation in the Draft EIR, yet could be important.

[22] http://ccst.us/publications/2015/2015SB4-v1.pdf p. i; see also pp. iii, 10, 87, 111-112, 150 for related and similar findings that about 20% of California crude production involves hydraulic fracturing; see also pp. i-ii, v-vi, 2-4, 9-21, 88- 119, 157, 250-253 for related findings regarding the extent to which well stimulation enables oil and gas production in California and elsewhere in the US; see footnote 21 regarding this source.
[23] DEIR, p. 17-6.

great care is increased when the data are (in many cases) derived from industry sources and analyses. Especially when there can be very substantial financial and other self-interest involved, data and other information should not be assumed to wholly objective; to the extent practical, inputs to the analysis should be carefully reviewed and verified for consistency and accuracy.

2.4. Lower Crude Prices

The DEIR assumptions regarding prevalence of well stimulation and impact on crude production are based on historical information that may not be representative of future conditions. In particular, the DEIR relies on information provided by Halliburton Business Development in April 2014. This predates, and thus does not take into account, the major changes since mid-2014 in terms of dramatically lower crude prices.

Likewise, the CCST SB4 Well Stimulation study[24] relies upon data from 2002-2013, and in limited cases into 2014. Put simply, the data in the CCST SB4 study also predate, and thus do not take into account, the major changes since mid-2014 in terms of dramatically lower crude prices. Crude prices remained at consistently high levels from 2011 to mid-2014, but have since dropped by half or more.[25]

With crude prices high for several years until recently, producers had strong incentives to maintain and expand production. US crude production increased very rapidly, but this growth was mainly outside of California from shale/tight oil plays including Bakken, Eagle Ford, and Permian.[26] California crude production, which had declined by half since peaking in 1985, bottomed out around 2011 and has since been stable/very slowly increasing.[27]

This historical experience, both outside and inside California, is relevant for evaluating the amount of California crude production enabled by well stimulation.

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[24] Discussed in Section 2.3, see footnote 21 .

[25] Crude prices vary somewhat based on quality and location, but the pattern of pricing from 2011 onward is broadly similar for the various crudes produced in California, as well as for crudes produced elsewhere (and in some case imported into California) http://www.eia.gov/dnav/pet/pet_pri_dfp2_k_m.htm
http://www.eia.gov/dnav/pet/pet_pri_spt_s1_m.htm
http://www.eia.gov/dnav/pet/pet_pri_land2_k_m.htm
See also Plains Price Bulletins with coverage for a wide variety of California and other US crudes
http://paalp.com/customer-center/crude-oil-price-bulletins-1363.html

[26] See footnote 32; http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm

[27] Crude production supplying California includes State onshore and offshore, as well as Federal offshore (PADD 5). In recent years, about 90% of total production is State (onshore and offshore) and about 10% is Federal offshore.
http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm
ftp://ftp.consrv.ca.gov/pub/oil/annual_reports/2009/PR06_Annual_2009.pdf
ftp://ftp.consrv.ca.gov/pub/oil/annual_reports/2012/PR03_PreAnnual_2012.pdf

Outside of California, well stimulation, in combination with high crude prices, has enabled large amounts of crude production from shale/tight oil plays.[28] Thus, outside of California, restrictions on well stimulation might have a large impact on crude production. In particular, restrictions on well stimulation could sizably impact production in a context of high crude prices which would otherwise enable high levels of drilling activity and extensive use of well stimulation.

In California, well stimulation, in combination with high crude prices, has not enabled large amounts of crude production from shale/tight oil plays.[29] Thus, in California, restrictions on well stimulation might have only a limited impact on crude production, even in a context of high crude prices.

Instead, in California, well stimulation, in combination with high crude prices, has enabled a limited amount of crude production from higher permeability conventional oil plays.[30] Thus, in California, restrictions on well stimulation might have only a limited impact on crude production, even in a context of high crude prices.

In combination with high crude prices, well stimulation has enabled a production boom in some areas outside of California, but not in-state. Instead, well stimulation may have helped to stabilize California production that had been declining. But high prices were also important (and perhaps much more important) in justifying activities to maintain production from California's mature and relatively high cost fields.

It remains to be seen how crude prices will evolve and how this will affect California crude production. In particular, it is uncertain how lower crude prices might affect usage and impact of well stimulation. But it is likely that lower crude prices (vs. higher crude prices) will result in lower California crude production and lower usage of well stimulation (in scenarios where well stimulation is not highly restricted). But if well stimulation is highly restricted, there will be little or no well stimulation, regardless of whether crude prices are high or low.

Put more simply, if crude prices are low and there is much less drilling in California (compared with recent years when crude prices were high and there was substantial drilling activity in California), then restrictions on well stimulation may not have a big impact on production.

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[28] See footnotes 22 and 32. Outside of California, well stimulation has also enabled large amounts of natural gas (and natural gas liquids) production from shale/tight gas plays including Marcellus, Utica, and Haynesville.

[29] See footnotes 22 and 32. In California, well stimulation has not enabled large amounts of natural gas (and natural gas liquids) production from shale/tight gas plays, but it has enabled some associated gas production (from wells that primarily produce crude).

[30] In California, well stimulation is applied in mature fields, sometimes in combination with enhanced oil recovery methods (such as steam flooding and cyclic steaming), which are not included in the definition of well stimulation. (See footnotes 41, 42, and 43) Well stimulation in California has also enabled some associated gas production (from wells that primarily produce crude). See footnote 22 and 32.

As just noted, it remains to be seen how crude prices will affect California drilling and crude production. But substantial information is provided by analysis from the Rice University Baker Institute Center for Energy Studies.[31] A recent Center for Energy Studies report demonstrates that recent low crude prices have resulted in a very large drop in California drilling and that crude production from newly drilled wells is also now much lower than previously; new drilling and crude production in January 2015 have decreased by about 90% compared with May-November 2014.[32]

The Center for Energy Studies report does not address well stimulation per se. But this report does identify the area and type of crude production that have been most affected by low crude prices: Kern County heavy crude production. As further discussed in Sections 3 and 4, this is also where well stimulation is most widely used.

So lower crude prices will very likely result in much less well stimulation activity than had been occurring when crude prices were high.[33] Lower crude prices are also likely to delay (and quite possibly forestall) extensive development of new oil fields and Monterey shale resources.[34]

The combination of historical experience and recent much lower crude prices is also relevant for evaluating both Alternative 1 and 2. In the short-term and possibly longer, lower crude prices will very likely result in much less well stimulation activity than had been occurring when crude

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[31] Located in Houston (a global center of the oil and gas industry), the Rice University Baker Institute Center for Energy Studies is internationally-recognized for work in energy policy and forecasting. http://bakerinstitute.org/center-for-energy-studies/about-energy-studies/

[32] In the May 2014-January 2015 period, for new onshore wells, total new oil production brought onstream in a given month was over 500,000 bpd (barrels/day) for the entire US, but California's share was less than 1%. Recent low crude prices have resulted in less well drilling and less new production being added nationally, but the cutbacks in California have been particularly fast and deep. Monthly new production has fallen by about 10% for the entire US (from around 600,000 bpd down to 525,000 bpd), but monthly new production is down by about 90% in California (from around 5000 bpd down to 600 bpd).
Source: Krane, Jim and Agerton, Mark, Effects of Low Oil Prices on U.S. Shale Production: OPEC Calls the Tune and Shale Swings, Rice University Baker Institute for Public Policy Center for Energy Studies, February 2015 http://bakerinstitute.org/files/8823/ pp. 6-7, 14-16; see also the entire Center for Energy Studies report regarding the effects of crude prices on production in California and elsewhere.

[33] The Center for Energy Studies report (pp. 14-16, see footnote 32) also demonstrates that recent low crude prices have resulted in a very large drop in new drilling and related crude production in California outside of Kern County, and specifically in Fresno and Los Angeles County (where the DEIR assumes there will be a small amount of well stimulation treatments; see footnotes 71, 72, and 83).

[34] In response to lower crude prices, producers will focus drilling and other development activities on the locations where these activities may still be profitable even with lower crude prices. In part, this involves focusing on the sweet spots where productivity is high and/or costs are low within fields. It also means focusing on existing vs. new fields. Developing new fields can be costly and risky. New fields typically have little or no pre-existing infrastructure (such as gathering lines and pipelines) in place, so there can be sizable up-front costs to develop this infrastructure. Developing new fields can also entail very sizable up-front costs to obtain mineral rights. And as compared with existing fields, there is less information and more uncertainties for new fields. [DEIR, pp. 6-15, 7-17-7-20]; see also footnote 32.

prices were high. Thus, in a context of lower crude prices, the amount of crude production enabled by well stimulation will be lower and slower to accumulate over time (as compared with a higher crude price context),

So instead of the immediate 25% drop in production claimed by the DEIR for Alternative 1, any impact on crude production from Alternative 1 may be very small at first and will (at most) grow only slowly over a long period.

Meanwhile, Alternative 2 may not (in practice) have a sizable impact on crude production, especially in the near-term. Alternative 2 would prohibit well stimulation outside of existing fields and their buffer areas. As explained above, development of new oil fields will likely be much lower, slower, and possibly forestalled in a context of lower crude prices. Thus, Alternative 2 would only prohibit well stimulation in locations (outside of existing fields and their buffer areas) where there might be little or no well stimulation in a context of lower crude prices.

2.5. Summary

The DEIR analysis assumes that well stimulation enables 25% of California crude production, and that Alternative 1 (No Future Well Stimulation) would result in an immediate 25% drop in production. But for multiple reasons, restrictions on well stimulation may have only a much smaller impact on California crude production and supply, especially in the near term.

First, the DEIR assumes that restrictions on well stimulation would immediately have their full impact on production; however, this is not a realistic reflection of the time pattern for drilling and production. Wells typically produce crude over a number of years, albeit at declining rates. So production in a given year is affected not just by drilling in that year, but also by ongoing production from wells drilled in previous years. Thus, any change in drilling practices (such as restrictions on well stimulation) will have only a limited impact on production in the near term. It will likely take several years, or even longer, for a change in drilling practices to affect large numbers of wells and reach its maximum effect on overall crude production.

Second, the DEIR assumes that well stimulation enables 25% of California crude production, but this 25% figure is high relative to historical experience and other available information. Moreover, this 25% figure is based on a personal communication that is unreviewable, as well as potentially prone to bias.

Third, the 25% figure assumed by DEIR does not take into account the major changes since mid-2014 in terms of dramatically lower crude prices. Lower crude prices (vs. higher crude prices) will result in lower California crude production and lower usage of well stimulation. In California, new drilling and crude production in January 2015 have decreased by about 90%

compared with May-November 2014.[35] Lower crude prices are also likely to delay (and quite possibly forestall) extensive development of new oil fields and Monterey shale resources

Thus, restrictions on well stimulation may not have a big impact on production. So instead of the immediate 25% drop in production claimed by the DEIR for Alternative 1, any impact on crude production from Alternative 1 may be very small at first and will (at most) grow only slowly over a long period.

Meanwhile, Alternative 2 may not (in practice) have a sizable impact on crude production, especially in the near-term. Alternative 2 would only prohibit well stimulation in locations (outside of existing fields and their buffer areas) where there might be little or no well stimulation in a context of lower crude prices.

[35] See footnote 32.

3. Greenhouse Gas Emissions

Section 3.1 discusses Direct Emissions from Well Stimulation Treatments. Section 3.2 discusses GHG Emissions from Crude Supply (Production and Transport).

3.1. Direct Emissions from Well Stimulation Treatments

The DEIR estimates of Greenhouse Gas (GHG) emissions from well stimulation treatments fail to include emissions from new well drilling.

For criteria and precursor air pollutant emissions from well stimulation treatments, the DEIR provides two sets of separate and additive estimates:
a) for hydraulic fracturing equipment (1926 maximum projected wells statewide),[36] and
b) for new well drilling equipment (1690 maximum projected wells statewide).[37]

But for GHG emissions from well stimulation treatments, the DEIR provides only a single set of estimates, for hydraulic fracturing (1926 maximum projected wells statewide).[38]

Based on the assumptions provided in the DEIR, GHG emissions from well stimulation treatments should also include the following for new well drilling (1690 maximum projected wells statewide):[39]

	CO_2	CH_4	CO2e
MT per year	126,919	7	126,926

3.2. GHG emissions from Crude Production and Transport

3.2.1. Introduction

Crude supply (production and transport to California refineries) accounts for a sizable portion of total California GHG emissions. The DEIR provides extensive and useful information regarding GHG emissions, but the DEIR does not properly analyze and interpret this information. The DEIR substantially understates GHG emissions for the supply from California production enabled by well stimulation, while overstating emissions for alternative crude supply from production outside California.

36 DEIR, Table 10.3-26, pp. 10.3-32 -10.3-33.
37 DEIR, Table 10.3-27, p. 10.3-33.
38 DEIR, Table 10.12-12, p. 10.12-25.
39 (Typical GHG Emissions per Well Drilling event (from DEIR, Table 10.12-11, p. 10.12-25)) * (Maximum projected # new wells (from Table 10.3-27, p. 10.3-33)).

California crude production has substantial combustion-related emissions, especially in the San Joaquin Valley Air Basin where well stimulation treatments are most extensively applied.[40] In particular, much of this production is heavy crude from mature fields with thermal recovery such as steam flooding and cyclic steaming.[41] As a result, California crude production results in sizable fuel combustion (notably natural gas for steam generation), greenhouse gas emissions, and criteria and precursor air pollutant emissions.

As defined in California law and the DEIR, steam flooding and cyclic steaming are not well stimulation treatments.[42] Rather, well stimulation treatments are used to enable crude production, which in many cases also involves steam flooding and cyclic steam.[43] So in effect, well stimulation enables use of steam flooding and cyclic steam.

Without a proper evaluation of crude supply and associated emissions from California production, the DEIR in turn does not provide a proper Comparison of Alternatives based on GHG emissions. Moreover, the DEIR Air Quality analysis is also flawed (as will be discussed in Section 4).

As described in the DEIR,[44] California has a complex regulatory setting in regard to GHG emissions. This setting includes a Low Carbon Fuel Standard (LCFS) being implemented by the ARB (Air Resources Board) to reduce the full fuel-cycle, carbon intensity of transportation fuels.[45] As part of the LCFS, CI (Carbon Intensity) values are estimated for crude oil production

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[40] The San Joaquin Air Basin includes a large amount of crude production and well stimulation in Kern County (DEIR Study Region 4), as well as a smaller amount of crude production and well stimulation in Fresno County (DEIR Study Region 5). DEIR, pp. 5-6-5-7, 6-8, 7-23-7-26.

[41] Sources: DEIR, pp. 6-13-6-14, A-14; CCST SB4 Well Stimulation study (see footnotes 21 and 22), pp. 4, 12, 88, 95, 97, 109, 131, 153, 207, 210, 305.

[42] DEIR, pp. 1-1, 4-1.

[43] As explained in CCST SB4 Well Stimulation study (see footnotes 21 and 22), p. 95, 97:

> The ratio of injection to production well records indicating hydraulic fracturing increases from 1:5 in 2002-2006 to 1:2 in 2007-2013, […] suggesting a shift toward greater use of hydraulic fracturing for enhanced oil recovery […]. This contrasts with the expansion of hydraulic fracturing for primary oil production in many other parts of the country.
>
> […]
>
> **Hydraulic Fracturing of Injection Wells Used for Enhanced Oil Recovery**
>
> Enhanced oil recovery (EOR) techniques typically involve modifying fluids in the reservoir to promote additional flow of oil to a well. In California, the most common EOR technique involves injection of steam and hot water to increase the temperature and pressure in the reservoir. The first lowers the viscosity of the oil and the second increases the force driving it to production wells. Hydraulic fracturing is not generally classed as an EOR technique because it alters the solids (rocks), rather than the fluids (oil, gas and water) in the reservoir, in order to increase the reservoir permeability. Hydraulic fracturing of injection wells can contribute to an EOR campaign by allowing more water or steam to be injected.

[44] DEIR, pp. 10.12-5-10.12-14.

[45] DEIR, pp. 10.12-11-10.12-12.

and transport. These CI values are for the fuel cycle from production field to California refinery gate. Thus, these CI values do not include downstream GHGs from refining, distribution, and combustion at end-use, but they do include GHG emissions outside of California from production and transport of crudes imported into California.[46] CI values are separately calculated for each oil field/crude providing supply to California, including production in-state, elsewhere in the US, and outside the US.

The LCFS CI values show that California crude production has a relatively high average carbon intensity. As presented in the DEIR, average carbon intensity is higher for California production (12.9 g CO2e/MJ) than for all crude supply (11.4 g CO2e/MJ for all supply to California, including both in-state production and imports):

> For California's use of crude oil, ARB determined that the overall average carbon intensity in 2010 was 11.39 grams of CO2e for the production and transport of each mega-joule (MJ) of energy from crude to the refinery gates (ARB, 2012), and for 2012 ARB estimated the average crude carbon intensity was 11.36 g CO2e/MJ (ARB, 2014c).
>
> Crude production in California had an average carbon intensity of 12.9 g CO2e/MJ (ARB, 2012) in 2010, which was higher than that of the average barrel of crude used in California at about 11.4 g CO2e/MJ (ARB, 2012; ARB, 2014c).[47]

The DEIR analysis of GHG emissions for Alternative 1 (No Future Well Stimulation) relies on these average CI values to compare the carbon intensity of California crude production and replacement supply from imports. The DEIR estimates that GHG emissions for 57 million barrels of crude supply would be around 4.6 MMTCO2e (million metric tons of CO2 equivalent) for California production and 4.1 MMTCO2e for replacement supply from imports:

> Because this alternative would cause some future oil and gas production to be lost, California end users of oil and gas would need to rely on a replacement supply. Using a replacement crude supply could result in an incremental change in life-cycle GHG emissions of California's crude supply, which could be an increase or decrease depending [on] the carbon intensity of the replacement supply. The carbon intensity for production and transport of an average unit of crude used in California (about 11.4 g CO2e/MJ) is lower than that of an average crude produced in California (12.9 g CO2e/MJ) (ARB, 2012). Life-cycle GHG from the production and transport of 57 million barrels of crude at the average carbon intensity for crude produced in California are around 4,600,000 MTCO2e,

[46] Likewise, the GHG emissions considered in the DEIR are for the fuel cycle up to the California refinery gate and do not include downstream GHG emissions, from refining, distribution, and combustion at end-use. DEIR, p. 10.12-2.

[47] DEIR, p. 10.12-12.

> and depending on the field-specific factors of the replacement supply imported, life-cycle GHG for the same amount of average supply used in California is around 4,100,000 MTCO2e. [48]

To provide some context, the California GHG Emissions Inventory for all sectors of the economy is around 459 MMTCO2e in 2012.[49] Thus, the GHG emissions estimated by the DEIR (4.6 MMTCO2e for 57 million barrels of in-state crude production and transport to refineries) are about 1% of total California GHGs (around 459 MMTCO2e). Put very simply, based on the DEIR analysis, the GHG emissions from the California crude production enabled by well stimulation would be a very significant component of overall statewide emissions.

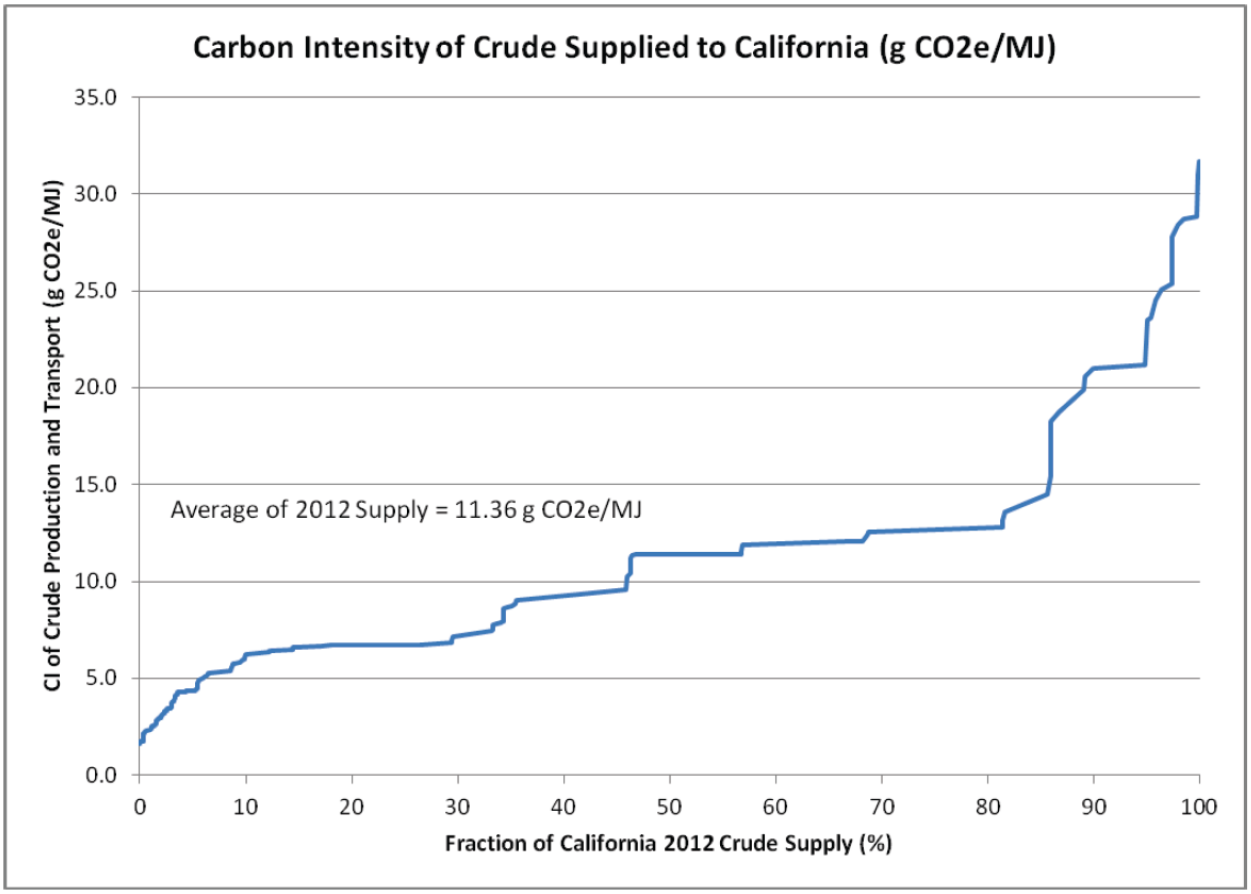
But the DEIR analysis substantially understates GHG emissions for the supply from California production enabled by well stimulation. As will be demonstrated in Sections 3.2.2 and 3.2.3, California production enabled by well stimulation has a substantially higher carbon intensity, relative to other California crude production and relative to replacement supply from imports.

3.2.2. Carbon Intensity of California Crude Production

Figure 1 shows the carbon intensity of crude supplied to California; this figure reproduces DEIR Chart 10.12-1 illustrating the LCFS CI values for 2012 crude supply (including both in-state production and imports).

[48] DEIR, p. 12.2-37-12.2-38.
[49] DEIR, p. 10.12-17.

Figure 1: Carbon Intensity of Crude Supplied to California[50]



For 2012 crude supply, carbon intensity for all supply averages 11.36 g CO_2e/MJ, and California crude production has a relatively high carbon intensity, averaging 13.06 g CO_2e/MJ.[51] But as shown in Figure 1, carbon intensity for individual fields varies dramatically, ranging from less than 2 to over 30 g CO_2e/MJ.[52]

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[50] Reproduced from DEIR Chart 10.12-1, p. 10-12-13; "Source: ARB 2014c (Calculation of 2012 Crude Average CI Value; March 17, 2014)" http://www.arb.ca.gov/fuels/lcfs/crude-oil/2012-crude-ave-ci.pdf

[51] The DEIR (p. 10.12-12) specifies that crude production in California had an average carbon intensity of 12.9 g CO2e/MJ in 2010, but does not provide an average for 2012. Average carbon intensity for California crude production in 2012 was calculated by TGG by weighting the carbon intensity for each crude by the volume (barrels) supplied to California refineries in 2012. CI values are reported for all California fields that produced at least 10,000 barrels during 2012. These fields comprise about 36% of all crude supply with reported CI values; the remaining 64% of crude supply with reported CI values is produced outside California and delivered to in-state refineries. http://www.arb.ca.gov/fuels/lcfs/crude-oil/2012-crude-ave-ci.pdf

[52] DEIR, p. 10.12-12:

> The ARB initially developed the LCFS with crude supply data from 2006, and subsequently found a growing fraction of the crude supply being provided by thermal methods and other energy-intensive methods of recovery. Between 2006 and 2010, the carbon intensity of the crude produced for and transported to California refineries had grown. […]

(footnote continued on next page)

Carbon intensities are very high (up to and exceeding 20 g CO2e/MJ) for some high-production California fields, representing about 25% of total California production (and about 10% of California supply). And carbon intensities are relatively high (around 15 g CO2e/MJ) for another 12% of California production (about 5% of California supply). But for much of California crude production (especially outside the San Joaquin Valley), carbon intensities are relatively low (ranging from 2 to 10 g CO2e/MJ).

There is a wide variation in carbon intensity for individual California fields, and this has important implications for analysis of California production and well stimulation. In recent years, over 90% of hydraulic fracturing operations have been in the San Joaquin Valley, virtually all at a small number of high-production fields.[53] California fields with the following attributes have high to very high carbon intensity:

- extensive use of well stimulation
- heavy crude
- thermal and other energy intensive recovery methods
- San Joaquin Valley/Kern County (Study Region 4)/Fresno Country (Study Region 5).

California fields that do not have the above attributes have lower and sometimes very low carbon intensity. In part, this reflects the locational advantage of California production. The carbon intensity values are for the fuel cycle from production field to California refinery gate, so they include crude transport as well as production. California production is delivered to California refineries over relatively short distances, typically by pipeline.[54] Thus, California production will tend to have relatively low energy use and GHGs for associated crude transport, vs. imports to California that are shipped over long distances. But despite this locational

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(footnote continued from previous page)

> Crude production in California had an average carbon intensity of 12.9 g CO2e/MJ (ARB, 2012) in 2010, which was higher than that of the average barrel of crude used in California at about 11.4 g CO2e/MJ (ARB, 2012; ARB, 2014c). This is because the carbon intensities for some high-production California fields, representing about 10 percent of California's supply, approach and exceed 20 g CO2e/MJ. Plotting the carbon intensity of each field that produces and transports crude to California refineries against each field's fraction of the supply shows that about 80 percent of California's crude supply has a carbon intensity less than 12.9 g CO2e/MJ. Chart 10.12-1 shows the carbon intensity of the 2012 supply.
>
> The carbon intensity varies drastically depending on field-specific conditions. Figures 10.12-1, 10.12-2, and 10.12-3 provide maps of the DOGGR Study Regions 1 through 6 and the ARB-calculated carbon intensity for each active field (ARB, 2014c).

[53] Hydraulic fracturing has been most prevalent at Belridge South and North, Lost Hills, Elk Hills, Midway-Sunset, Round Mountain, and Buena Vista fields in Kern County, and Coalinga in Fresno County. CCST SB4 Well Stimulation study (see footnotes 21 and 22), pp. 88, 109.

[54] DEIR, pp. 6-16, 7-19.

advantage, a sizable portion of California production has relatively high carbon intensity owing to high energy use and GHGs associated with crude extraction.

In evaluating the Project, the DEIR assumes that over 95% of future well stimulation treatments will be in Kern County, but also assumes treatments at a small number of wells elsewhere in California, notably at the Wilmington, Inglewood, and Sespe Fields.[55] As discussed by the DEIR, these fields (in Study Regions 1 and 2) have relatively low carbon intensity.[56]

Within the context of the current Comments, it is not feasible for TGG to undertake an extensive study to estimate the carbon intensity of California crude production enabled by well stimulation. Instead, to provide useful guidance on this important issue, TGG has developed estimates based on a reasonable range for carbon intensity. Given that well stimulation will enable crude production that is significantly more carbon intensive than average, it is reasonable to estimate that carbon intensity ranges between 15.9-19.6 g CO2e/MJ.[57] Thus, the carbon intensity of

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[55] See Section 4.2, and specifically footnotes 71, 72, and 83.

[56] The DEIR (pp. 11.12-3, 11.12-4, 11.2-6) notes that the carbon intensity of these specific fields is lower than average: Wilmington 6.36 g CO2e/MJ; Inglewood 8.74 g CO2e/MJ; Sespe 2.91 g CO2e/MJ.

[57] TGG's methodology for estimating the range for carbon intensity of crude production enabled by well stimulation (15.9-19.6 g CO2e/MJ) is explained below.

In recent years, over 90% of hydraulic fracturing operations have been in the San Joaquin Valley, virtually all at a small number (8) of high-production fields (see footnote 53). At these 8 fields where well stimulation has been most prevalent, carbon intensity for individual fields varies dramatically, ranging from 5 to almost 29 g CO2e/MJ, based on the LCFS CI values for 2012. Carbon intensity for these fields averages 16.0 g CO2e/MJ, as calculated by TGG by weighting the carbon intensity for each crude by the volume (barrels) supplied to California refineries in 2012. http://www.arb.ca.gov/fuels/lcfs/crude-oil/2012-crude-ave-ci.pdf

The LCFS CI values are being revised as models and data are updated. Based on the most recent (November 13, 2014) Draft (Table 8) CI values (see the second California Air Resource Board hyperlink below for the values in Table 8), carbon intensity now ranges from 5 up to almost 33 g CO2e/MJ for the 8 fields where well stimulation has been most prevalent. And carbon intensity for these fields now averages 19.6 g CO2e/MJ, as calculated by TGG by weighting the carbon intensity for each crude by the volume (barrels) supplied to California refineries in 2012.
http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/111314presentation.pdf
http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/111314handout1_crudeoil.pdf

The DEIR assumes that over 96% of future well stimulation treatments will be in San Joaquin Valley, but also assumes treatments at a small number of wells elsewhere in California, notably at the Wilmington, Inglewood, and Sespe Fields, which have relatively low carbon intensity (see footnotes 55 and 56).

For carbon intensity of crude production enabled by well stimulation, TGG thus estimated the low end of the range (15.9 g CO2e/MJ) from the average carbon intensity of the fields where well stimulation has been most prevalent, based on the LCFS values for 2012 (16.0 g CO2e/MJ), adjusted downward to reflect that some well stimulation might occur at other fields, which are less carbon intensive.

TGG estimated the high end of the range (19.6 g CO2e/MJ) based on typical carbon intensity values for California fields with extensive well stimulation in combination with thermal oil recovery of heavy crude (see Figure 1, and footnotes 43 and 52). The high end of the range estimated by TGG is also consistent with the average carbon intensity of the fields where well stimulation has been most prevalent, based on the most recent (November 13, 2014) Draft (Table 8) CI values (19.6 g CO2e/MJ), assuming that this would be representative for all fields where well stimulation was applied.

California crude production enabled by well stimulation is 22-50% higher than the average for all California production (13.06 g CO2e/MJ for 2012 crude supply).

The DEIR assumes that well stimulation enables 57 million barrels of California crude production. Based on the range of carbon intensity for California crude production estimated by TGG (15.9-19.6 g CO2e/MJ), GHG emissions for 57 million barrels of crude supply would range between 5.7 to 7.0 MMTCO2e. Thus, the GHG emissions for crude production enabled by well stimulation (5.7 – 7.0 MMTCO2e for 57 million barrels of in-state crude production and transport to refineries) are about 1.2-1.5% of total California GHGs (around 459 MMTCO2e).

3.2.3. Carbon Intensity of Crude Imports

As discussed in Section 3.2.1, the DEIR assumes that replacement supply from imports could have a carbon intensity of about 11.4 g CO2e/MJ, based on the carbon intensity for average crude supply to California.[58] This estimate of carbon intensity is based on the LCFS CI values for all crude supply to California, including both in-state production and imports. And as discussed in Sections 3.2.1 and 3.2.2, in-state crude production has an average carbon intensity (12.90 g CO2e/MJ in 2010 and 13.06 g CO2e/MJ in 2012) that is significantly higher than the average for all crude supply (11.39 g CO2e/MJ in 2010 and 11.36 g CO2e/MJ in 2012). Thus, the portion of California crude supply from imports (production outside of California delivered to in-state refineries) has to have an average carbon intensity that is significantly lower than the average for all crude supply.

Average carbon intensity for all foreign imports (from production outside the US) is 9.8 g CO2e/MJ in 2012.[59] Thus, while the DEIR assumes that replacement supply from imports could have a carbon intensity of about 11.4 g CO2e/MJ (based on the carbon intensity for average crude supply to California), replacement supply might have a substantially lower carbon

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[58] DEIR, p. 12.2-37-12.2-38; see footnote 48.

[59] The DEIR does not provide data on carbon intensity of imports. Average carbon intensity for foreign imports was calculated by TGG by weighting the carbon intensity for each crude by the volume (barrels) supplied to California refineries in 2012. 51% of total California crude supply with reported CI values is produced outside the US and delivered to in-state refineries in 2012. Foreign imports to California have relatively low average carbon intensity, but there is sizable variation in values for individual crudes. Some foreign imports, notably from Canadian tar sands production, have relatively high reported CI values (up to and exceeding 20 g CO2e/MJ, similar to carbon-intensive California crude production). http://www.arb.ca.gov/fuels/lcfs/crude-oil/2012-crude-ave-ci.pdf

Average carbon intensity for all imports (from production elsewhere in the US, as well as outside the US) is 10.4 g CO2e/MJ in 2012. Average carbon intensity for imports was calculated by weighting the carbon intensity for each crude by the volume (barrels) supplied to California refineries in 2012. 64% of total California crude supply with reported CI values is produced outside California and delivered to in-state refineries in 2012.

Total imports include a sizable component of Alaskan crude production, that has a relatively high carbon intensity (12.81 g CO2e/MJ, similar to the carbon intensity of average California crude production). Alaskan production is in decline and is unlikely to be source of replacement crude supply for California. Thus, carbon intensity for foreign imports (vs. for all imports including Alaskan production) appear to be more representative of carbon intensity for replacement crude supply for California.

intensity, notably about 9.8 g CO2e/MJ (based on the carbon intensity for foreign imports to California).

The DEIR assumes that Alternative 1 (No Future Well Stimulation) would require 57 million barrels of replacement supply from imports. Based on the carbon intensity for foreign imports (9.8 g CO2e/MJ), GHG emissions for 57 million barrels of crude supply would be about 3.5 MMTCO2e.

3.3. Summary and Comparison of Alternatives

As demonstrated in Section 3.1, the DEIR substantially understates direct GHGs from well stimulation treatments. Based on the assumptions provided in the DEIR, GHG emissions from well stimulation treatments should also include about 127,000 MTCO2e per year for new well drilling.

As demonstrated in Section 3.2, the DEIR substantially understates GHG emissions for the supply from California production enabled by well stimulation, while overstating emissions for alternative crude supply from production outside California.

The DEIR assumes California crude production enabled by well stimulation has a carbon intensity of 12.9 g CO2e/MJ, while replacement crude supply has a carbon intensity of about 11.4 g CO2e/MJ. But the TGG analysis in Section 3.2.2 demonstrates that California crude production enabled by well stimulation has a carbon intensity ranging between 15.9-19.6 g CO2e/MJ, 23-52% higher than assumed by the DEIR.

Likewise, the TGG analysis in Section 3.2.3 shows that replacement crude supply from imports has a carbon intensity of 9.8 g CO2e/MJ, 14% lower than assumed by the DEIR.

Taken together, the carbon intensity values from the TGG analysis in Sections 3.2.2 and Section 3.2.3 demonstrate that California production enabled by well stimulation has a much higher carbon intensity, compared with alternative crude supply from production outside California.

California crude production enabled by well stimulation has a carbon intensity ranging 15.9-19.6 g CO2e/MJ, while replacement crude supply from imports has a carbon intensity of only 9.8 g CO2e/MJ. Thus, California crude production has a carbon intensity that is 62-100% greater than the carbon intensity of replacement supply. Put another way, California crude production enabled by well stimulation could up to twice as carbon intensive as replacement crude supply from imports.

The DEIR assumes that Alternative 1 (No Future Well Stimulation) would require 57 million barrels of replacement supply from imports. Based on the carbon intensity values from the TGG analysis, GHG emissions for 57 million barrels of crude supply would be 5.7 – 7.0 MMTCO2e for California crude production enabled by well stimulation, compared with about 3.5 MMTCO2e for replacement crude supply. Thus, GHG emissions for California crude production would be 2.2 – 3.5 MMTCO2e higher than for replacement crude supply.

Meanwhile, the DEIR estimated that California crude production might have GHG emissions that were 0.5 MMTCO2e higher than for replacement crude supply.[60]

For Greenhouse Gas Emissions, the DEIR Comparison of Alternatives assigns a ranking of 1 [tied] to the Project and a ranking of 3 to No Future Well Stimulation (Alternative 1):

The Project

- Ranking = 1 [tied]
- Significant and unmitigable (Class I) GHG emissions during oil and gas production.

No Future Well Stimulation Practices (Alternative 1)

- Ranking = 3
- Greater impacts from increased oil and gas imports that cause significant and unavoidable GHG emissions from out-of-state oil and gas producers (Class I).
- Indirect impacts associated with additional conventional wells and abandonment activities to make up for lost production, and potentially increased well stimulation in areas under federal or tribal jurisdiction.[61]

In turn, the DEIR selects the Project as the Environmentally Superior Alternative, and bases this selection (in part) on the DEIR's assessment that Alternative 1 would have greater impacts from increased oil and gas imports that cause GHG emissions from out-of-state oil and gas producers.[62]

In support of its judgment that increased imports are problematic, the DEIR makes note of California's complex regulatory setting and how it differentially affects production that is inside California vs. out-of-state. Specifically, the DEIR explains that all crude production supplying California is subject to the LCFS, but only in-state production is subject to the Cap-and-Trade

[60] DEIR, p. 12.2-37-12.2-38.

[61] Excerpted from DEIR, Table 14.4-1, p. 14-17

[62] DEIR, p. 14-13:

> much greater impacts to greenhouse gas emissions from the importation of oil and gas from out of the State that would result if Alternative 1 were implemented. […] Alternative 1 is not considered to be environmentally superior overall.

Program; thus, increased imports would increase GHGs from sources that are not required to offset the GHGs to comply with California's cap.[63]

Put simply, the DEIR's rationale appears to create a preference for in-state crude production vs. imports, based on in-state production being more fully subject to California regulation, notably in regard to GHGs. This type of preference for in-state production could have broad ramifications, and an extensive consideration of these issues is beyond the scope of these Comments. But it is relevant here to consider how such a preference should operate given the relative carbon intensity of in-state production and imports.

The flawed analysis in the DEIR assumes that California crude production enabled by well stimulation is only moderately more carbon intensive than replacement crude supply from imports (12.9 vs. 11.4 g CO2e/MJ). But the analysis in Section 3 demonstrates that California production enabled by well stimulation is much more carbon intensive than imports (15.9-19.6 vs. 9.8 g CO2e/MJ).

Given that California crude production enabled by well stimulation could up to twice as carbon intensive as replacement crude supply from imports, there does not seem to be sound basis for the DEIR to rank the Project higher than Alternative 1 (or Alternative 2), based on GHG emissions. Even if in-state production should be somewhat preferenced based on being more fully subject to California regulation, this preference should be carefully applied so as to lessen the risk of perverse outcomes. Notably, it would seem problematic if California crude production that was highly carbon intensive was preferenced over imports that were much less carbon intensive, based on an interpretation of the state regulatory setting, notably in regard to GHGs.

[63] DEIR, pp. 12.2-36 – 12.2-38.

4. Air Quality

4.1. Introduction

This Section considers air quality (criteria and precursor air pollutant emissions), as opposed to GHG emissions (which were considered in Section 3). A key issue for the DEIR is whether air quality impacts have been properly analyzed. This Section demonstrates that the DEIR is seriously flawed in regard to air quality impacts.

The DEIR does consider air quality impacts from well drilling and stimulation, but it only selectively and inaccurately considers air quality impacts from crude production and transport. The DEIR understates adverse air quality impacts for the Project and overstates adverse impacts for Alternative 1 (and 2). The consideration of air quality impacts in the DEIR is thus incomplete and unbalanced.

Section 4.2 discusses emissions from crude production. Section 4.3 discusses emissions from crude transport. Section 4.4 discusses Comparison of Alternatives.

4.2. Emissions from Crude Production

The DEIR estimates for emissions from crude production are incomplete and potentially misleading. California crude production results in substantial emissions from both combustion and non-combustion sources.[64] Only a portion of these emissions (notably those from non-combustion sources) are explicitly considered by the DEIR. By failing to consider combustion sources, the DEIR fails to account for a sizable portion of the overall emissions associated with California crude production. In particular, the DEIR fails to account for virtually all of the emissions for criteria and precursor pollutants other than ROG (reactive organic gases).

The DEIR analysis relies upon the ARB emissions inventory data. In the ARB emissions inventory, Oil and Gas Production is divided into two components:

- Oil and Gas Production (Combustion), a subcategory within the Fuel Combustion source category);
- Oil and Gas Production (Non-combustion), a subcategory within the Petroleum Production and Marketing source category.

[64] As explained in Section 3.2 and further explained in this Section (4.2), California crude production results in sizable fuel combustion (notably natural gas for thermal oil recovery steam generation). The air emissions considered in the DEIR are for the fuel cycle within California up to the California refinery gate and do not include downstream air emissions, from refining, distribution, and combustion at end-use. DEIR, p. 10.3-2.

The data provided in the DEIR[65] for oil and gas production emissions are from the Petroleum Production and Marketing source category and from the Oil and Gas Production (Non-combustion) subcategory (within the Petroleum Production and Marketing source category). These are primarily ROG emissions, notably from fugitive losses.

But the DEIR does not provide emissions data from the Oil and Gas Production (Combustion) subcategory (within the Fuel Combustion source category). The DEIR acknowledges that combustion emissions from oil and gas production are categorized separately in the ARB emissions inventory:

> Emissions of criteria air pollutants are inventoried by ARB into five different stationary source subcategories, with all mobile sources and areawide sources derived separately. The stationary source category of Petroleum Production and Marketing includes oil and gas production along with pipeline transmission and distribution of petroleum products, primarily ROG emissions. **All combustion emissions from fuel used by stationary sources as part of the production process**, and all other downstream processes**, are categorized separately as Fuel Combustion.**[66]

But the DEIR then fails to consider these combustion emissions from oil and gas production and does not provide any rationale for this omission.

The failure by the DEIR to consider these combustion emissions is a significant omission. Without consideration of the emissions data from the Oil and Gas Production (Combustion) subcategory, the DEIR fails to account for a sizable portion of the overall emissions associated with in-state Oil and Gas Production, notably in regard to criteria and precursor pollutants other than ROG.

As discussed in Section 3.2, California crude production has substantial combustion-related emissions, especially in the San Joaquin Valley Air Basin where well stimulation treatments are most extensively applied.[67] In particular, much of this production is heavy crude from mature fields with thermal recovery such as steam flooding and cyclic steaming.[68] As a result, California crude production results in sizable fuel combustion (notably natural gas for steam generation), greenhouse gas emissions, as well as criteria and precursor air pollutant emissions.

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[65] DEIR, pp. 10.3-15 – 10.3-24.

[66] DEIR, p. 10.3-15 (emphasis added).

[67] The San Joaquin Air Basin includes a large amount of crude production and well stimulation in Kern County (DEIR Study Region 4), as well as a smaller amount of crude production and well stimulation in Fresno County (DEIR Study Region 5). DEIR, pp. 5-6-5-7, 6-8, 7-23-7-26.

[68] Sources: DEIR, pp. 6-13-6-14, A-14; CCST SB4 Well Stimulation study (see footnotes 21 and 22), pp. 4, 12, 88, 95, 97, 109, 131, 153, 207, 210, 305.

As defined in California law and the EIR, steam flooding and cyclic steaming are not well stimulation treatments.[69] Rather, well stimulation treatments are used to enable crude production, which in many cases also involves steam flooding and cyclic steam.[70] So in effect, well stimulation enables use of steam flooding and cyclic steam.

California crude production (and related air emissions) are primarily located in Kern County, where well stimulation is much more prevalent than elsewhere in the state:

> The Description of the Project indicates fewer than 25 percent of all wells within California were hydraulically fractured in recent years, and 80 to 90 percent of hydraulically fractured wells occurred in Kern County (EIR Section 7.4.1). This indicates that the majority of existing emissions from hydraulic fracturing activities probably occur within Kern County, in the SJVAPCD. Approximately 69 percent of statewide (2012) oil and gas production ROG emissions occur within the San Joaquin Valley Air Basin, amounting to 25 tons per day of ROG (Table 10.3-5). The fraction of these emissions that occurs from wells that have been subject to hydraulic fracturing is unknown.[71]

In evaluating the Project, the DEIR assumes that over 95% of future well stimulation treatments will be in Kern County.[72] The DEIR assumes that well stimulation would be applied to around 50% of new wells in Kern County, as well as to some existing wells:

> annually over the next 25 years, up to 3,300 new production, injection, and other miscellaneous wells would be drilled and approximately 1,100 would be abandoned. Hydraulic fracturing would be used for well completion on

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[69] DEIR, pp. 1-1, 4-1.

[70] As explained in CCST SB4 Well Stimulation study (see footnotes 21 and 22), p. 95, 97 (emphasis in original):

> The ratio of injection to production well records indicating hydraulic fracturing increases from 1:5 in 2002-2006 to 1:2 in 2007-2013, […] suggesting a shift toward greater use of hydraulic fracturing for enhanced oil recovery […]. This contrasts with the expansion of hydraulic fracturing for primary oil production in many other parts of the country.
>
> […]
>
> **Hydraulic Fracturing of Injection Wells Used for Enhanced Oil Recovery**
>
> Enhanced oil recovery (EOR) techniques typically involve modifying fluids in the reservoir to promote additional flow of oil to a well. In California, the most common EOR technique involves injection of steam and hot water to increase the temperature and pressure in the reservoir. The first lowers the viscosity of the oil and the second increases the force driving it to production wells. Hydraulic fracturing is not generally classed as an EOR technique because it alters the solids (rocks), rather than the fluids (oil, gas and water) in the reservoir, in order to increase the reservoir permeability. Hydraulic fracturing of injection wells can contribute to an EOR campaign by allowing more water or steam to be injected.

[71] DEIR, p. 10.3-30.

[72] For hydraulic fracturing equipment, 1926 maximum projected wells statewide, with 1850 (96%) in Study Region 4 (DEIR, Table 10.3-26, pp. 10.3-32 -10.3-33). For new well drilling equipment, 1690 maximum projected wells statewide, with 1650 (98%) in Study Region 4 (DEIR, Table 10.3-27, p. 10.3-33).

approximately 40 to 55 percent of new production wells and 40 to 62 percent of new injection wells. Well stimulation treatments would also be used on up to 200 already existing wells per year.[73]

Thus, based on the DEIR assumptions, well stimulation would enable a sizable portion of Kern County crude production. In turn, there would be sizable air emissions associated with this crude production, from both combustion and non-combustion sources. But only the non-combustion emissions associated with crude production are explicitly considered by the DEIR.

Table 1 provides the ARB emissions inventory for all San Joaquin Valley sources.

Table 1: San Joaquin Valley, Emissions for 2012 (average tons per day)[74]

Source Category	ROG	NOx	PM10	PM2.5	CO	SOx
Stationary Sources						
Fuel Combustion	3.6	29.2	5.5	5.3	23.8	4.3
Oil and Gas Production (Combustion)	1.3	1.9	1.7	1.7	4.8	1.1
Other	2.3	27.3	3.8	3.6	19	3.2
Waste Disposal	21	0.3	0.2	0.1	0.5	0.1
Cleaning and Surface Coatings	20.3	-	0.1	0.1	0	-
Petroleum Production and Marketing	33.6	0.3	0.2	0.1	0.6	0.1
Oil and Gas Production (Non-combustion)	25.2	0.2	0	0	0.3	0
Other	8.4	0.1	0.2	0.1	0.3	0.1
Industrial Processes	15.7	6.7	8	3.2	0.8	3.4
— Total Stationary Sources	94.2	36.4	14	8.8	25.7	7.9
Areawide Sources						
Solvent Evaporation	47.6	-	-	-	-	-
Miscellaneous Processes	128.6	13.2	250.2	54	186.8	1.3
— Total Areawide Sources	176.2	13.2	250.2	54	186.8	1.3
Mobile Sources						
On-Road Motor Vehicles	48.5	177.9	10.8	6.7	437.6	0.7
Other Mobile Sources	39	97.6	6.6	6.1	252.5	0.5
— Total Mobile Sources	87.5	275.5	17.4	12.8	690.1	1.2
Grand Total for San Joaquin Valley Air Basin	357.9	325.2	281.6	75.6	902.6	10.4

[73] DEIR, p. 10.3-44.

[74] DEIR, Table 10.3-16, p. 10.3-21; http://www.arb.ca.gov/app/emsinv/2013/emssumcat_query.php?F_YR=2012&F_DIV=-4&F_SEASON=A&SP=2013&F_AREA=AB&F_AB=SJV

Table 1 breaks out Oil and Gas Production as a separate subcategory.[75] In particular, this table provides emissions data for Oil and Production (Combustion) [as a subcategory under Fuel Combustion] and Oil and Gas Production (Non-combustion) [as a subcategory under Petroleum Production and Marketing]. Emissions for the two subcategories relating to Oil and Gas Production are additive; together they comprise the total emissions inventory for Oil and Gas Production.

As Table 1 demonstrates, Oil and Gas Production results in sizable emissions of all criteria and precursor air pollutants. For ROG, most of these emissions are assigned to Oil and Gas Production (Non-combustion) [under the Petroleum Production and Marketing source category]. For pollutants other than ROG, virtually all of the emissions are assigned to Oil and Gas Production (Combustion) [under the Fuel Combustion source category]. The DEIR fails to explicitly consider emissions for Oil and Gas Production (Combustion) and thus fails to account for virtually all of the emissions for pollutants other than ROG.

This is an important omission in regard to the Project. As discussed above, the DEIR assumes that well stimulation would be applied to around 50% of new wells in Kern County, as well as to some existing wells.[76] Thus, based on the DEIR assumptions, well stimulation would enable a sizable portion of Kern County crude production. The air emissions from crude production enabled by well stimulation would be sizable, perhaps in the order of half of the overall emissions in Table 1 for Oil and Gas Production.[77]

Table 2 provides estimates for the air emissions from crude production enabled by well stimulation, as well as the air emissions from well stimulation equipment. Air emissions from crude production enabled by well stimulation are estimated to be half of the emissions in Table 1 for Oil and Gas Production.[78] The air emissions from well stimulation equipment are assumed to equal those estimated in the DEIR.[79]

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[75] The DEIR (Table 10.3-16, p. 10.3-21) also provides a table showing the San Joaquin Valley emissions inventory, but the table in the DEIR does not break out Oil and Gas Production as a separate subcategory.

[76] See footnote 73.

[77] As discussed in this Section (4.2) and specifically footnotes 68 and 70, and Section 3.2.2 and specifically footnotes 52 and 53 , much of the production enabled by well stimulation has higher than average combustion and emissions (notably due to prevalence of heavy crude, mature fields, and thermal recovery). Thus, even if well stimulation enables somewhat less than half of total San Joaquin Valley crude production, the production enabled by well stimulation could account for half of total San Joaquin Valley emissions from oil and gas production.

[78] See footnote 77.

[79] See footnote 80. For this report, TGG did not provide an alternative estimate of the air emissions from well stimulation equipment, but TGG did provide an alternative estimate of the GHGs from new well drilling equipment (see Section 3.1).

Table 2: San Joaquin Valley, Increased Emissions from Well Stimulation (tons per year)[80]

Source Category	ROG	NOx	PM10	PM2.5	CO	SOx
Well Stimulation Treatments	153.1	2,049.50	60.4	60.4	606.3	3.3
Hydraulic Fracturing Equipment	97.9	1,268.70	37.7	37.7	372.8	1.9
New Well Drilling Equipment	55.2	780.8	22.7	22.7	233.5	1.4
Crude Production Enabled by Well Stimulation	4,830.80	377.8	315.7	315.7	927.1	208.1
Combustion	235.4	346.8	312.1	312.1	874.2	204.4
Non-Combustion	4,595.40	31	3.7	3.7	52.9	3.7
Total: Well Treatments + Crude Production	4,983.90	2,427.30	376.1	376.1	1,533.40	211.4

Table 2 demonstrates that the emissions from crude production would be a sizable impact in addition to the sizable emissions impact from the equipment used in the well stimulation treatments.

As acknowledged by the DEIR, the emissions directly associated with well stimulation would occur in a non-attainment region at levels that could violate an air quality standard:

> Table 10.3-26 shows .the emissions caused by equipment projected to occur in Study Region 4 as a result of hydraulic fracturing at 1,850 wells each year, and Table 10.3-27 shows the emissions from 1,650 new wells drilled each year. These emissions would occur in a region that is nonattainment for ozone, PM10, and PM2.5, and would occur at levels that could violate an air quality standard or contribute substantially to an existing or projected air quality violation.[81]

As shown in Table 2, for some pollutants (such as PM10/PM2.5), the air emissions from crude production enabled by well stimulation could be much larger than the emissions from the equipment used in the well stimulation treatments. But the DEIR fails to explicitly consider emissions for Oil and Gas Production (Combustion) and thus fails to account for most of the emissions for pollutants other than ROG.

As previously discussed, the large majority of California well stimulation is in Kern County.[82] Nonetheless, there is some well stimulation elsewhere in California.[83] In order to provide meaningful input for decisionmaking, the air quality analysis must properly account for air

[80] Sources: Well Stimulation Treatments: DEIR Table 10.3-26, pp. 10.3-32 -10.3-33; Table 10.3-27, p. 10.3-33 Crude Production Enabled by Well Stimulation: (emissions for Oil and Gas Production (Combustion + Non-combustion), as provided in Table 1 (see footnote 74)) * (.05, see footnote 77)
[81] DEIR, p. 10.3-44.
[82] See footnotes 71 and 72.
[83] The DEIR (Table 10.3-26, pp. 10.3-32 -10.3-33; Table 10.3-27, p. 10.3-33) assumes well stimulation treatments would be applied at a small number of wells in Study Region 1 (Wilmington and Inglewood Fields), Study Region 2 (Sespe and other Fields), and Study Region 5.

emissions from crude production enabled by well stimulation, in Kern County and elsewhere in California. The DEIR has not provided a sound basis for evaluating the Project and Alternatives in regard to air quality.

4.3. Emissions from Crude Transport

The DEIR analysis of emissions from crude transport focuses on marine deliveries via tankers:

> By halting well stimulation activities in areas under State jurisdiction, this alternative would restrict future oil and gas activity in California. This would avoid emissions that otherwise would occur during well stimulation treatments in areas under State jurisdiction, and it would also lead to a decrease in California oil production. To replace the decrease in California production, an additional 57 million barrels of crude per year would need to be supplied from fields outside of California (EIR Section 8.3.1), which currently supply about 380 million barrels annually (ARB, 2014c). The replacement supply would cause California import receipts to increase by about 15 percent. This would increase the activity of tanker ships delivering Alaskan and foreign oil to California via ports and marine terminals in Los Angeles, Long Beach, and the San Francisco Bay Area, and it would increase the activity of rail trains hauling crude oil primarily from North Dakota and Canada. In-state emissions from oil and gas production could occur at lower levels; however, these lowered emissions would be offset by increasing levels of emissions from tanker ships and locomotives delivering crude to California and from terminal facilities necessary to offload and handle the imports. The vast majority (more than 95 percent) of California's crude oil imports arrive by marine vessels at proprietary marine terminals in Los Angeles, Long Beach, and the San Francisco Bay Area. Emissions from ocean-going vessels that visit California seaports are subject to emissions control requirements and low-sulfur fuel requirements, when operating near the coast; and newer locomotive engines are subject to emission standards, and fuel requirements provide some level of control over these sources. Tanker vessels, as a subset of ocean-going vessels, produce about 22 tons NOx per average day according to the statewide inventory (ARB, 2013a). For tanker vessels, an increase of 15 percent could add over 3 tons NOx per day statewide or about 1,200 tons NOx per year, primarily in the South Coast and San Francisco Bay Area air basins.[84]

The DEIR estimates for tankers substantially overstate emissions relating to crude oil transport.

[84] DEIR, p. 12.2-12.

The DEIR cites ARB statewide inventory data ("about 22 tons NOx per average day according to the statewide inventory") as a basis for the DEIR estimate ("an increase of 15 percent could add over 3 tons NOx per day statewide").[85]

The ARB statewide inventory data (cited in the DEIR) includes emissions within 115 miles of the California coastline.[86] These emissions are not primarily in the South Coast and San Francisco Bay Area air basins; tanker NOx emissions in the South Coast and San Francisco Bay Area air basins are together less than 5 tons per day, or about 20% of the total in the statewide inventory.[87]

On the basis of the emissions inventory data for the air basins, a 15% increase in tanker vessels would add less than 160 tons NOx per year in the South Coast and less than 100 tons NOx per year in the San Francisco Bay Area air basins.

But **the ARB emissions inventory data (including the data cited in the DEIR) are not just for transport of crude oil into California; they also include emissions from tankers transporting other liquid bulk commodities.**[88] Thus, any emissions estimates based on ARB inventory data (for all tankers) will tend to overstate emissions for the subset of tankers transporting crude oil into California.

The NOx emissions estimated in the DEIR for tankers are also dramatically higher than those estimated in the Valero Benicia Crude by Rail Project DEIR.[89] The Benicia Project was estimated to displace 25.55 million barrels per year of marine deliveries into the Valero Benicia refinery, in turn displacing 91.84 tons NOx per year in the San Francisco Bay Area air basin.[90]

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[85] ~22 tons * 0.15 = ~3.3 tons.

[86] http://www.arb.ca.gov/regact/2011/ogv11/ogv11appd.pdf
The ARB inventory for ocean-going vessels includes emissions within 100 nautical miles of the California coastline; 1 nautical mile = 1.1508 miles.

[87] http://www.arb.ca.gov/app/emsinv/2013/emseic_query.php?F_YR=2012&F_DIV=-4&F_SEASON=A&SP=2013&SPN=2013_Almanac&F_AREA=CA&F_EICSUM=833
2012 NOx emissions from tankers (Emission Inventory Categories # 833-847-1210-9972 - 833-847-1210-9994):

Statewide	21.52 tons/day	7855 tons/year
South Coast Air Basin	2.86 tons/day	1044 tons/year
San Francisco Bay Area Air Basin	1.75 tons/day	639 tons/year.

[88] http://www.arb.ca.gov/regact/2011/ogv11/ogv11appd.pdf
Tankers are defined as vessels designed to transport liquids in bulk, including vessels transporting refined petroleum products and other non-crude oil liquid commodities; emissions data for tankers includes calls to ports (such as Avalon and Stockton) which are not crude oil import terminals.

[89] ESA, Valero Benicia Crude by Rail Project , Draft Environmental Impact Report, SCH # 2013052074
Use Permit Application 12PLN-00063, Prepared for City of Benicia, June 2014
http://www.ci.benicia.ca.us/vertical/Sites/%7B3436CBED-6A58-4FEF-BFDF-5F9331215932%7D/uploads/Valero-Benicia-DEIR-CD.pdf

[90] Ibid, pp. 4.1-18-4.1-19, Appendix E-2.

Thus, the Valero Benicia Crude by Rail Project DEIR estimated 3.6 tons NOx per year per million barrels of marine deliveries into the San Francisco Bay Area air basin.[91]

On the basis of the Valero Benicia Crude by Rail Project DEIR analysis, it can be estimated that a 15% increase in crude oil tanker vessels would add less than 130 tons NOx per year in the South Coast and less than 80 tons NOx per year in the San Francisco Bay Area air basins.[92] These more realistic estimates are dramatically lower than those in the DEIR, which claim that a 15% increase in tankers could add 1,200 tons NOx per year, primarily in the South Coast and San Francisco Bay Area air basins.

4.4. Summary and Comparison of Alternatives

For Air Quality, the DEIR Comparison of Alternatives assigns a ranking of 2 [tied] to the Project and 4 to No Future Well Stimulation (Alternative 1):

The Project

- Ranking = 2 [tied]
- Significant and unmitigable (Class I) air quality impacts caused by well stimulation treatments and new well drilling.

No Future Well Stimulation Practices (Alternative 1)

- Ranking = 4
- Greater impacts from increased oil and gas imports.
- Increased levels of emissions from tanker ships and locomotives delivering crude to California and from terminal facilities necessary to offload and handle the imports (Class I).
- Indirect impacts associated with additional conventional wells and abandonment activities to make up for lost production and potentially increased well stimulation in areas under federal or tribal jurisdiction.[93]

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[91] 3.6 tons NOx per year per million barrels of marine deliveries =
(91.84 tons NOx per year)/(25.55 million barrels per year of marine deliveries).

[92] Basis of estimates: 57 million barrels per year of added marine deliveries, with 35 million barrels (61% of the total) to the South Coast and 22 million barrels (39% of the total) to the Bay Area; 3.6 tons NOx per year per million barrels of marine deliveries into either destination air basin. The basis of these estimate is broadly consistent with available data, including tanker emissions in each destination air basin (footnote 87), and crude supply for Bay Area and all California refineries (http://www.energy.ca.gov/2014_energypolicy/documents/2014-06-25_workshop/presentations/01_Schremp_Final_2014-06-25.pdf pp. 11, 20, 24).

[93] Excerpted from DEIR, Table 14.4-1, p. 14-14

Based on the DEIR air quality analysis, it is unclear why the Project would be ranked higher than Alternative 1. As noted in the DEIR Comparison of Alternatives, the Project has significant and unmitigable impacts caused by well stimulation treatments and new well drilling. The impacts estimated by the DEIR for well stimulation and drilling include over 2,000 tons NOx per year.[94] Meanwhile, the impacts estimated by the DEIR for Alternative 1 include increased emissions of about 1,200 tons NOx per year from tanker ships.[95]

Thus, the DEIR Comparison of Alternatives (which ranks the Project higher than Alternative 1) is not consistent with the DEIR air quality analysis (which estimates that the Project would result in higher emissions than would Alternative 1).

Moreover, as discussed in Section 4.2, the DEIR fails to account for a sizable portion of the overall emissions associated with crude production, notably in regard to criteria and precursor pollutants other than ROG. So to the extent that well stimulation enables crude production, there are very sizable air emissions associated with this production.

And as discussed in Section 4.3, the DEIR estimates for tanker emissions substantially overstate emissions relating to crude oil transport.

The DEIR understates adverse air quality impacts for the Project and overstates adverse impacts for Alternative 1 (and 2). Thus, the DEIR consideration of air quality impacts is incomplete and unbalanced.

The DEIR Comparison of Alternatives is flawed in multiple ways in regard to air quality. The Comparison of Alternatives is not consistent with the DEIR air quality analysis. And the DEIR Comparison of Alternatives is further contradicted by the analysis provided in these Comments demonstrating that the DEIR understates adverse air quality impacts for the Project and overstates adverse impacts for Alternative 1 (and 2).

A proper consideration of air quality impacts would thus result in a Comparison of Alternatives that differs very substantially from that provided in the DEIR. Given the size and importance of these air quality impacts, it is essential that a proper consideration of these impacts be undertaken. The DEIR has not provided a sound basis for decisionmaking in regard to air quality, and more broadly in terms of the Project and Alternatives, and DEIR's selection of the Project as the Environmentally Superior Alternative.

[94] Table 1; DEIR, Table 10.3-26, pp. 10.3-32 -10.3-33; Table 10.3-27, p. 10.3-33.
[95] DEIR, p. 12.2-12.

APPENDICES

A: Resume of Ian Goodman

B: Resume of Brigid Rowan

APPENDIX

A. Resume of Ian Goodman

Ian Goodman

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Professional Profile

Ian Goodman is President and founder of The Goodman Group, Ltd. He has conducted research and consulted in energy regulation and economics for over 35 years. His practice has addressed a broad range of issues, including evolving North American oil, gas and electric markets, and economic development and environmental impacts of various energy supply and transportation options. Mr. Goodman has a particular expertise in the planning and operations of energy systems, as well as interjurisdictional energy trade in North America. Since 2011, his practice has focused on oil supply and transportation (notably Canadian tar sands, shale, pipelines and rail). Mr. Goodman has co-authored reports and expert testimony on the most controversial oil projects in North America.

He has provided expert evidence in almost 50 regulatory, environmental assessment, and legal proceedings in various North American jurisdictions including California, New York, three New England states, Florida, Manitoba, Ontario, Quebec, as well as the Federal Energy Regulatory Commission (FERC) in the US and the National Energy Board (NEB) in Canada. He has also assisted counsel in those and other proceedings. His clients have included energy sector companies (electric and gas utilities, marketers, project developers, and equipment providers), regulators, government, customer and environmental groups, and North American Native/First Nations organizations. Mr. Goodman is the author or co-author of over 60 publications and major reports relating to the energy industry. Ian Goodman co-authored an influential and widely publicized study on the employment impacts of the Keystone XL pipeline ("Pipe Dreams? Jobs Gained, Jobs Lost by the Construction of Keystone XL").

Professional Experience

1989 – present **President, The Goodman Group, Ltd.,**
Berkeley, California (formerly Boston, Massachusetts)

Collaborating with a team of associates to provide an array of expert consulting services such as expert testimony, reports, research, policy assessment and litigation support related to energy regulation and economics.

Specializing in the evolving North American oil, gas and electric markets, the economic development and environmental impacts of various energy supply and transportation options, and energy system planning and operations.

Major Projects:

Economic Development and Environmental Impacts of Energy Options

- Since 1991, has conducted over 20 national, regional, and state/provincial studies on the economic development impacts (notably jobs) and environmental impacts of various energy supply and transportation options in the US and Canada.

- Since 2011, has co-authored seven expert reports on the economic development impacts and environmental impacts of crude oil transportation (particularly interjurisdictional tar sands crude pipeline projects and crude by rail projects).

- Co-authored the "Economic Costs and Benefits of the Trans Mountain Expansion Project (TMX) for BC and Metro Vancouver" with Brigid Rowan in collaboration with Simon Fraser University's Centre for Public Policy Research. The report, released in November 2014 and re-released in February 2015, refutes Kinder Morgan's claims regarding the positive economic development benefits of its controversial pipeline project. Goodman and Rowan show that the benefits of the pipeline are very small and have been significantly overstated by Kinder Morgan, whereas the worst-case costs of a catastrophic spill are very large and have been vastly understated.

- Co-authored the "Economics of Transporting and Processing Tar Sands Crudes in Quebec" with Brigid Rowan in collaboration with Équiterre and

Greenpeace Canada. The January 2014 report demonstrates that the economic development benefits for Quebec of moving and refining tar sands crudes would be insignificant while the costs and risks are very high.

- Co-authored an "Analysis of the Potential Costs of Accidents/Spills Related to Crude by Rail" with Brigid Rowan on behalf of Oil Change International (OCI). The November 2013 report demonstrates that the economic costs of crude by rail accidents can be very large and concludes that a major crude by rail (CBR) unit train accident/spill could cost $1 billion or more for a single event. The report was incorporated into Comments filed by NRDC, Sierra Club and OCI before PHMSA as part of the Advance Notice of Proposed Rulemaking Hazardous Materials: Rail Petitions and Recommendations To Improve the Safety of Railroad Tank Car Transportation, December 5, 2013.

- Co-authored expert testimony, entitled "The Relative Economic Costs and Benefits of Enbridge's Line 9B Reversal and Line 9 Capacity Expansion Project" with Brigid Rowan. The expert report was filed in August 2013 at Canada's National Energy Board on behalf of the Équiterre Coalition, a coalition of Quebec- and Ontario-based environmental groups.

- Co-authored "Comments on Initial Study/Mitigated Negative Declaration (IS/MND) Valero Crude by Rail Project Benicia, California" with Brigid Rowan on behalf of NRDC. The July 2013 report provides a Market Analysis of a proposed crude by rail project for the Valero Benicia Refinery. Goodman and Rowan conclude that the proposed project could significantly affect crude supply (and thus quality) for the refinery, and recommend that a full Environmental Impact Report be undertaken. The report was included as an attachment to NRDC's Comments on Notice of Intent to Adopt a Mitigated Negative Declaration for the Valero Crude by Rail Project, filed with the City of Benicia on July 1, 2013.

- Co-authored a “Report evaluating the adequacy of the Keystone XL (KXL) Draft Supplemental Environmental Impact Statement (DSEIS) Market Analysis” with Brigid Rowan, and filed as an attachment to the Comments on KXL DSEIS jointly submitted by the Sierra Club, NRDC, and 14 other environmental and public interest organizations in April 2013. Based on their evaluation of the early 2013 market conditions (including emerging crude markets, factors driving tar sands expansion, availability and cost of crude oil transportation, and tar sands breakeven costs), Rowan and Goodman concluded that (i) the US State Department's DSEIS Market Analysis was deeply flawed and not a sound basis for decision-making; and (ii) KXL, and specifically its impact on tar sands logistics costs and crude prices, would have a significant impact on tar sands expansion under a very broad range of conditions and assumptions.

- Co-authored an influential and widely publicized study of the Keystone XL pipeline employment impacts ("Pipe Dreams? Jobs Gained, Jobs Lost by the Construction of Keystone XL") with Brigid Rowan and the Cornell Global Labor Institute. Goodman and Rowan provided economic impact analysis to demonstrate that TransCanada Pipelines Ltd had substantially exaggerated the US job numbers related to the KXL project. The report was originally released in September 2011 and updated in January 2012.

- Co-authored "Employment Impacts of Air-Pollution Controls at North Dakota Coal Plants" with Brigid Rowan. This November 2011 study for Sierra Club National estimated the employment impacts of Air-Pollution Controls at North Dakota Coal Plants.

- Provided expert testimony on behalf of The Greenlining Institute on economic development impacts (focusing on job creation and stimulus) of capital expenditures and rate increases proposed by the Pacific Gas & Electric Company in its 2011 General Rate Case.

- Co-authored the Avoided Energy Supply Costs in New England: 2009 Report, prepared for Avoided-Energy-Supply-Component (AESC) Study Group, which represents all major electric and gas utilities in New England, as well as efficiency program administrators, state energy offices and regulators. TGG's contribution to this report was an analysis of the economic development impact of Massachusetts electricity and gas energy efficiency programs.

- Co-developed E^{3}AS (Energy, Economic, and Environmental Analysis System) software on behalf of the US EPA in 1996 and made it available to assist government agencies in evaluating the economic and environmental impacts of energy supply and efficiency programs, and in considering both the benefits and costs of energy alternatives.

- Has incorporated E^3AS model analysis in all studies of economic and environmental impacts since 1996.

Manitoba Hydroelectric System Planning, Operations, Project Assessment, and US Exports

Wuskatim Generating Station and Transmission Project (1999-2005)

On behalf of the Pimicikamak Cree Nation (PCN):

- Evaluated Manitoba Hydro system planning, environmental review, and disclosure relating to the Churchill-Nelson hydro project
- Assessed the environmental and other impacts from existing hydro and the proposed 200 MW Wuskwatim hydro project
- Analyzed the need for comprehensive assessment of the entire Churchill-Nelson project (existing, proposed, and future)
- Reviewed precedents regarding comprehensive assessment of existing major hydro projects
- Submitted comments to the Minnesota Public Utilities Commission on Northern States Power's supply requirements in relation to Manitoba energy exports from Wuskatim.

Conawapa Generating Station (1990, 1992)

On behalf of a coalition of citizens', conservation and environmental groups:

- Filed expert evidence in the 1992 Conawapa Project Environmental Assessment concerning:
    - the need for environmental reviews to evaluate the justification of design alternatives to the 1290 MW Conawapa hydro project
    - a description of the changes in the utility industry and new supply source options affecting the design alternatives included in an environmental review
    - a review of the treatment of the project justification in North American environmental assessments.

- Filed expert evidence before the Manitoba Public Utilities Board in the context of the 1990 Manitoba Hydro Submission for the Conawapa generating station, which included:
    - a review of the Manitoba Hydro submission; a review of Manitoba Hydro load forecasting; an estimation of economic and attainable conservation potential; development of principles of conservation program design and delivery; a critique of the utility's proposed demand-side management program, an evaluation of supply-side alternatives and analysis of avoided costs; an assessment of

employment and economic development effects of hydroelectric development and conservation; and an analysis of profitability and risks of the proposed power sales contracts.

Hydro-Québec System Planning, Operations, Project Assessment, and US Exports

Great Whale Project (1989-1994)

Submitted evidence and testified before various regulatory and legal bodies in the US and Canada on behalf of the Grand Council of the Crees (of Québec) and/or a coalition of environmental groups to assess the economic and environmental impacts of the proposed 3160 MW Great Whale Project, as well as the long-term US export contracts based on the project.

Mr. Goodman's wide-ranging efforts were instrumental in Hydro-Québec's eventual cancellation of the Great Whale Project. Key interventions included:

- Submitting evidence between 1989 and 1991, before the Vermont Public Service Board, including a review of a proposed thirty year, 450 MW purchase by twenty-four Vermont utilities of Hydro-Québec power derived from the development of the Great Whale Project; and an analysis of planning and operation of Hydro-Québec power supply and modeling of hydro reservoir levels.

- Testifying in 1991 before the State of Vermont Supreme Court regarding the same 450 MW purchase and providing a summary of changes concerning load forecasts and supply-side alternatives and an analysis of the cost effectiveness of the contract.

- Submitting an analysis of the nexus between New York Power Authority purchases and the construction of specific Hydro-Québec facilities (notably Great Whale), as well as the operation of fossil fuel electric generation before the State of New York Supreme Court in 1990.

- Presenting a review of Hydro-Québec's proposed export contracts to Vermont (450 MW) and New York State (1000 MW) before Canada's National Energy Board in 1990.

- Analyzing confidential risk-sharing electric supply contracts between Hydro-Québec and large industrial customers, including an assessment of the resulting implications for Hydro-Québec and its ratepayers in 1991.

- Submitting evidence in 1992 for the Canadian and Québec governments' Environmental Review of the Great Whale Project including a discussion of changes in the utility industry and new supply resource options affecting design alternatives included in an environmental review.

- Assessing an 800 MW seasonal diversity contract in the context of the 1994 energy market before the State of New York Assembly Standing Committees on Energy and Conservation.

1986 – 1989 Consulting Associate, PLC, Inc., Boston, Massachusetts

Research and consulting in various aspects of utility regulation and economics. Advised utilities and regulatory commissions on electric and gas least-cost planning. Assessed potential for conservation, non-utility generation, and other supply alternatives. Reviewed prudence of power supply investment decisions. Analyzed rate design and allocation issues. Developed end-use demand estimates. Evaluated district heating system management. Analyzed markets and rates of regulated transportation services.

1981 – 1986 Consulting Associate, Analysis and Inference, Inc., Boston, Massachusetts

Research and consulting in various aspects of utility regulation and statistical applications. Reviewed prudence of utility power plant construction programs with emphasis on cost and schedule of nuclear plants. Researched utility rate design and allocation issues. Reviewed demand forecasts. Analyzed taconite industry economics and electricity supply. Analyzed causal factors for statistical theft estimation of fuel oil overbilling and diversion of parking meter and transit revenue.

1978 – 1987 Consultant, Salgo & Lee, Boston, Massachusetts

Research and consulting in electric utility regulation and civil damage litigation. Reviewed nuclear construction programs and alternatives, demand forecasts, transmission line proposals, and state rate-making policies. Analyzed effects of regional power pool rules on independent power producers. Evaluated damage claims arising from power plant equipment outages.

Education

1977	S.B., Civil Engineering, Massachusetts Institute of Technology

Advisory Assignments to Regulatory and Investigatory Commissions and Staff

1996	Commission of Inquiry on Hydro-Québec's Purchase Policy for Electricity from Independent Power Producers (*Commission d'enquête sur la politique d'achat par Hydro-Québec d'électricité auprès de producteurs privés*), Commission Staff.
1993 – 2000	Maine Public Utilities Commission Staff, Docket Nos. 92-331, 95-598, 98-791, 2000-441, and 2000-47; Special Industrial Rate Contracts
1993	Maine Public Utilities Commission Staff, Docket No. 93-147; Certificate of Public Convenience to Erect a Transmission Line
1987 – 1988	District of Columbia Public Service Commission, Docket No. 834 Phase II; Least-cost Planning Procedures and Goals.

Appointments

1991 – 1995	Committee to Review the Glen Canyon Environmental Studies, National Research Council Water Science and Technology Board
1978	New England Energy Congress, Regulatory and Institutional Process Committee.

Publications and Major Reports

Economic Costs and Benefits of the Trans Mountain Expansion Project (TMX) for BC and Metro Vancouver in collaboration with The Centre for Public Policy Research, Simon Fraser University, *November 10, 2014* (co-author with B. Rowan, re-released *February 4, 2015*).

Report on the Economics of Transporting and Processing Tar Sands Crudes in Quebec in collaboration with Équiterre and Greenpeace Canada, *January 2014* (co-author with B. Rowan).

Analysis of the Potential Costs of Accidents/Spills Related to Crude by Rail, *November 8, 2013* (co-author with B. Rowan) on behalf of Oil Change International (OCI), incorporated as Attachment 3 to Comments filed by NRDC, Sierra Club and OCI before The Pipeline and Hazardous Materials Safety Administration, U.S. Department Of Transportation as part of the Advance Notice of Proposed Rulemaking Hazardous Materials: Rail Petitions and Recommendations To Improve the Safety of Railroad Tank Car Transportation, *December 5, 2013*.

Comments on Initial Study/Mitigated Negative Declaration (IS/MND) Valero Crude by Rail Project, Use Permit Application 12PLN-00063, Benicia, California, *July 1, 2013* (co-author with B. Rowan) on behalf of NRDC, included as an attachment to NRDC's Comments on Notice of Intent to Adopt a Mitigated Negative Declaration for the Valero Crude by Rail Project, filed with the City of Benicia Community Development Department on *July 1, 2013*.

Report evaluating the adequacy of the Keystone XL (KXL) Draft Supplemental Environmental Impact Statement (DSEIS) Market Analysis, *April 22, 2013* (co-author with B. Rowan), filed as an attachment to the Comments on KXL DSEIS jointly submitted by the Sierra Club, NRDC, and 14 other environmental and public interest organizations.

Pipe Dreams? Jobs Gained, Jobs Lost by the Construction of Keystone XL, *September 28, 2011* (co-author with B. Rowan, TGG, and L. Skinner and S. Sweeney, Cornell Global Labor Institute; *revised January 18, 2012*).

Employment Impacts of Air-Pollution Controls at North Dakota Coal Plants, prepared for Sierra Club, *November 21, 2011* (co-author with B. Rowan).

The Economics of Supplier Diversity Examining Areas of Potential Interest for GLI with respect to GRC 2011 and Potential Amendments to GO 156, prepared for The Greenlining Institute, *August 6, 2010* (co-author with B. Rowan).

Avoided Energy Supply Costs in New England: 2009 Report, prepared for Avoided-Energy-Supply-Component (AESC) Study Group, *August 21, 2009* (co-author with R. Hornby, P. Chernick, et al.; *revised October 23, 2009*).

Reallocation of Funds from National Grid's Current Energy Efficiency Programs to Other Uses, prepared for National Grid USA, *October 24, 2006*

National Grid's Energy Efficiency Programs: Benefits for Rhode Island's Economic Development and Environment, prepared for National Grid USA, *July 28, 2006*.

Comment of Pimicikamak Cree Nation (PCN) on Minnesota Draft State Energy Planning Report, sponsored by Minnesotans for an Energy-Efficient Economy (ME3), *November 21, 2001.*

Proposal for PV and Energy Efficiency at State Facilities: Benefits for California's Economic Development and Environment, prepared for PowerLight Corporation, *November 15, 2001.*

Narragansett Electric's Energy Efficiency Programs: Benefits for Rhode Island's Economic Development and Environment, prepared for Narragansett Electric Company, *August 14, 2001.*

Comment Submitted By Pimicikamak Cree Nation on An Investigation Into Environmental And Socio-Economic Costs Under Minnesota Statute §216B.2422, Subd. 3, submitted in Minnesota Public Utilities Commission Docket No. E999/CI-00-1636, *January 16, 2001* (co-author with P. Chernick and A. Orkin).

Comment Submitted By Pimicikamak Cree Nation on Northern States Power's 1999 Request for Proposals for Supply Resources Needed Starting 2001-2005, submitted in Minnesota Public Utilities Commission Docket No. E002/M-99-888, *March 1, 2000,* Supplemental Comment *August 18, 2000* (co-author with R. McCullough, A. Orkin, A. Stewart, et al.).

Analysis of Special Industrial Rate Contracts: Maine Public Service Company with McCain Foods (Docket 2000-441) and J.M. Huber (Docket 2000-47), prepared for Maine Public Utilities Commission Staff, *July 2000.*

Energy, Economic, and Environmental Analysis System (E3AS) User’s Guide: Version 2, prepared for the US Environmental Protection Agency, *July 1998* (co-author with R. Carlson and B. Krier).

Employment, Earnings, and Environmental Impacts of Regional Improvements in Energy Efficiency, the Southern States Energy Board, *December 23, 1996* (co-author with B. Krier and P. Kelly-Detwiler).

North Carolina State Energy Supply Plan for Use with E3AS, prepared for North Carolina Department of Commerce Energy Division, *November 27, 1996* (co-author with R. Carlson).

Energy, Economic, and Environmental Analysis System (E3AS) User's Guide, prepared for the Southern States Energy Board, *May 1996* (co-author with R. Carlson and B. Krier).

Preliminary Results of Mohave Competitiveness Analysis, prepared for the Hopi Tribe, *March 11, 1996.*

River Resource Management in the Grand Canyon, Committee to Review the Glen Canyon Environmental Studies, National Research Council Water Science and Technology Board (Washington: National Academy Press, *1996*) (co-author with W. Lewis, et al.).

Submission of the Grand Council of the Crees (of Québec) and the Cree Regional Authority, Addressed to the Consultation of the Public Debate on Energy: Complement, prepared for Grand Council of the Crees (of Québec), *August 1995* (co-author with P. Raphals, et al.).

"Energy Efficiency and Employment: Recent Findings and Directions for Future Research," Third International Energy Efficiency & DSM Conference: Charting the Future, (Bala Cynwyd: SRC International, *1994*) (co-author with B. Krier).

"A Win/Win Approach to Commercial/Industrial DSM: Making DSM Work for All Utility Customers," The Electricity Journal, Vol. 7, No. 9, *November 1994* (co-author with H. Lachman, P. Cillo, and P. Kelly-Detwiler).

Conformity Analysis of Hydro-Quebec's Great Whale Project Feasibility Study, prepared by the Great Whale Environmental Assessment Office of the Grand Council of the Crees (of Québec)/Cree Regional Authority in consultation with Environmental Economics Intl., et al., *July 1994* (co-author with R. Torrie, et al.).

"DSM as Economic Development Strategy," The Electricity Journal, Vol. 7, No. 4, *May 1994* (co-author with S. Laitner and B. Krier).

Review of the Draft Environmental Impact Statement on Operation of Glen Canyon Dam, Committee to Review the Glen Canyon Environmental Studies, National Research Council Water Science and Technology Board (Washington: National Academy Press, *April 1994*) (co-author with W. Lewis, et al.).

Review of the Draft Federal Long-Term Monitoring Plan for the Colorado River Below Grand Canyon Dam, Committee to Review the Glen Canyon Environmental Studies, National Research Council Water Science and Technology Board (Washington: National Academy Press, *1994*) (co-author with W. Lewis, et al.).

A Comparison of New York State Employment Impacts from Expanded Demand-Side Management and Hydro-Québec Imports, prepared for Greenpeace USA, *February 16, 1994* (co-author with B. Krier and P. Kelly-Detwiler; *revised March 1, 1994*).

Employment Impacts of Electricity Efficiency in Florida, prepared for the Florida Energy Office, *November 18, 1993* (co-author with B. Krier and P. Kelly-Detwiler).

Economic Analysis of Mohave Generating Station Gas Conversion, prepared for the Alternative Coal Transport Study, Economic Analysis for the Hopi Tribe, *September 13, 1993.*

The Impact of Increased Coal Transportation Costs Upon Mohave Generating Station Customers, prepared for the Alternative Coal Transport Study, Economic Analysis for the Hopi Tribe, *July 27, 1993.*

Track II Position Paper on Behalf of the Grand Council of the Crees (of Québec) and PROTECT, submitted in New York Public Service Commission Case 92-E-1187 (Concerning Incorporation of Environmental Costs into Long-run Avoided Costs), *June 25, 1993* (co-author with J. Dumont and P. Kelly-Detwiler).

Review of the 1993 Hydro-Québec Development Plan, submitted to Québec Parliamentary Commission on the Economy and Employment, prepared for Grand Council of the Crees (of Québec), *March 11, 1993* (co-author with P. Kelly-Detwiler and E. Titus; also available in French as Analyse Critique du Plan de Développement 1993 d'Hydro-Québec).

Assessment of the Requirement and Rationale for Transmission Facilities Associated with the 1000 MW Electricity Purchase from Manitoba Hydro, submitted in Ontario Environmental Assessment Board Ontario Hydro Demand/Supply Plan Hearing, on behalf of Nishnawbe-Aski Nation/Grand Council Treaty #3/Teme-Augama Anishnabai, *December 1992.*

Economic Evaluation of Ontario Hydro's Proposed Moose River Basin Hydroelectric Projects, submitted in Ontario Environmental Assessment Board Ontario Hydro Demand/Supply Plan Hearing, on behalf of the Moose River/James Bay Coalition, *December 1992* (co-author with R. Carlson, R. McCullough, and W. Huddleston).

Energy Efficiency: Opportunities for Employment, prepared for Greenpeace U.K./International, *November 11, 1992* (co-author with B. Krier).

"Electricity Generation and Greenhouse Gases," Planning Our Electric Future Now, Conference Proceedings of Canadian Electric Association, *November 1992.*

Comments of Pace Energy Project; Natural Resources Defense Council, National Audubon Society; Vladeck, Waldman, Elias and Englehard; Environmental Defense Fund; Environmental Planning Lobby on the 1993-1994 Annual and Long Range Demand-Side Management and Integrated Resource Plans of the New York Utilities, submitted in New York Public Service Commission Case No. 28223, *September 14, 1992* (co-author with A. Gupta, J. Tripp, J. Vladeck, D. Wooley, et al.).

Employment Effects of Electricity Provision in Québec: The Great Whale Hydroelectric Project and Electricity Efficiency Alternative, prepared for Grand Council of the Crees (of Québec), *June 16, 1992* (co-author with B. Krier and M. Clark; *revised November 5, 1992;* abbreviated James Bay Publication Series version November 1994; full version and abbreviated versions also available in French as Effets de la fourniture d'électricité sur l'emploi au Québec: le projet d'aménagement hydroélectrique Grande Baleine et la solution de rechange axée sur l'efficacité énergétique).

A Comparison of the Employment Creation Effects of the AES-Harriman Cove Coal-Fired Generating Station and Maine Demand-Side Management, prepared for Conservation Law Foundation and National Resources Council of Maine, *May 15, 1992* (co-author with M. Clark, P. Kelly-Detwiler, and M. Anthony).

A Review of the Report on Gas Integrated Resource Planning for Submission to the Ontario Energy Board, on behalf of Ontario Metis and Aboriginal Association, *February 28, 1992* (co-author with B. Morse, M. Watkins, J. Stevenson, P. Kelly-Detwiler, and M. Clark).

"Electricity Imports from Quebec: The Current and Historical Context," Northeast Indian Quarterly, *Winter 1991.*

The Role of Non-utility Generation in Vermont, *December 12, 1991* (co-author with P. Messerschmidt).

Economic and Employment Impacts of Vermont State Energy Options, prepared for Northeast Alliance to Protect James Bay, *November 7, 1991* (co-author with P. Kelly-Detwiler and M. Anthony).

Comments on the Draft New York State Energy Plan 1991 Biennial Update, on behalf of PROTECT, Hudson Sloop Clearwater, and Grand Council of the Crees (of Québec), *October 7, 1991.*

"Energy Conservation vs. the James Bay Hydroelectric Project," Canadian Water Watch, Vol. 4, No. 5, *June 1991.*

Employment Impacts of New York State Energy Options, prepared for Grand Council of the Crees (of Québec), *June 2, 1991* (co-author with M. Tennis and M. Clark).

Comments on the Determination of the Supply Resources and Environmental Effects Affiliated with Ontario Hydro Proposed Export Sales, submitted in Canadian National Energy Board Order No. EW-3-90, on behalf of Moose River James Bay Coalition / Nishnawbe-Aski Nation / Grand Council Treaty No. 3, *January 28, 1991* (co-author with P. Kelly-Detwiler).

Comments of Sierra Club, Inc.; Atlantic States Legal Foundation, Inc.; PROTECT; and Grand Council of the Crees (of Québec) on Issues to be Addressed in the New York State Energy Planning Report 1991, *January 2, 1991* (co-author with P. Messerschmidt).

"Analysis of Residential Fuel-Switching as an Electric Conservation Option," Gas Energy Review, Vol. 18, No. 12, *December 1990* (co-author with P. Chernick and E. Espenhorst).

Comments of Center for Environmental Legal Studies; Natural Resources Defense Council, National Audubon Society; Vladeck, Waldman, Elias and Englehard; Environmental Defense Fund on the 1991-1992 Annual and Long Range Demand-Side Management Plans of the Major Electric Utilities, submitted in New York Public Service Commission Case No. 28223, *September 28, 1990* (co-author with J. Plunkett, et al.).

"Hydro-Québec's Long-Term Export Policy," Canadian Water Watch, Vol. 3, No. 7-8, *July-August 1990.*

Conservation and Capacity Optimization Alternatives to the PGT/PG&E Gas Pipeline Project, Tellus Institute Study No. 90-03, prepared for California Public Utilities Commission, *May 1990* (co-author with R. Hornby, S. Bernow, D. Marron, D. Nichols, D. Singh, and M. Tennis).

Complément Technique au Mémoire du Grand Conseil des Cris (du Québec) à la Commission de l'Économie et du Travail de l'Assemblée Nationale du Québec, prepared for Grand Council of the Crees (of Québec), *April 1990* (co-author with R. Mainville, et al.).

Analysis of Fuel Substitution as an Electric Conservation Option, PLC, Incorporated, prepared for Boston Gas Company, *December 22, 1989* (co-author with P. Chernick and E. Espenhorst).

Conservation Potential in the State of Minnesota, Volumes I and II, PLC, Incorporated, prepared for Minnesota Department of Public Service, *June 27, 1988* (co-author with P. Chernick).

The Excess Capacity Situation of Minnesota Power: Magnitude, Duration, and Origin, PLC, Incorporated, prepared for Minnesota Department of Public Service, *July 20, 1987* (co-author with P. Chernick; *revised August 12, 1987*).

Final Report, Phase I, Module IV, Rate Design/Analysis, Pacific Northwest Electric Power and Conservation Planning Council, *December 1981* (co-author with P. Chernick, S. Finger, and M. Meyer).

Regional and Commodity Price-Indices for the Trucking Industry, M.I.T. Center for Transportation Studies, CTS Report 77-13, *July 1977* (co-author with A. Friedlander)

Expert Testimony and Formal Submissions

Information is presented in the following order: jurisdiction and docket number; title of case; client; date testimony filed; and subject matter covered.

1. **Canadian National Energy Board Hearing Order OH-002-2013; Enbridge Pipelines Inc. Line 9B Reversal and Line 9 Capacity Expansion Project Application; Équiterre (Coalition); Joint Written Expert Testimony with Brigid Rowan; August 8, 2013.**
   Analysis of relative economic costs and benefits of Enbridge's Line 9B Reversal and Line 9 Capacity Expansion Project. Evaluation of the Project, which would transport a mix of tar sands dilbit, Bakken, and conventional WCSB crudes through Ontario and Quebec, crossing major waterways and Canada's most populous urban areas, (including Toronto and Montreal). Recommendation that the Enbridge Project be rejected, based on (i) the results of this relative economic cost-benefit analysis, demonstrating that the potential economic costs could exceed (and, under a range of malfunction/accident conditions, greatly exceed) the potential economic benefits; (ii) the highly uneven allocation of costs and benefits among the stakeholders, and across regions; and (iii) the conclusion of international pipeline safety expert, Richard Kuprewicz, that there is a high risk of pipeline rupture in the early years following Project implementation due to a combination of cracking and corrosion.

2. **California Public Utilities Commission Application No. 09-12-020; Pacific Gas & Electric Company General Rate Case 2011; The Greenlining Institute; May 19, 2010; Rebuttal Testimony June 4, 2010.**
   Analysis of economic development impacts (focusing on job creation and stimulus) of PG&E's proposed capital expenditures and associated rate increases. Consideration of the impacts of these expenditures and rate increases on customers and communities. Recommendation that PG&E increase its supplier diversity activities in order to offset adverse impacts on customers and communities while addressing equity concerns. Analysis of PG&E's Customer Retention and Economic Development (Load Attraction and Retention) activities. Analysis of the direct testimony of other intervenors with respect to economic development impacts of the proposed capital expenditures and quantification of these impacts in the Rebuttal Testimony.

3. **Manitoba Clean Environment Commission Public Registry Files 4724/4725; Wuskwatim Generating Station and Transmission Project; Pimicikamak Cree Nation (PCN); August 8, 2003 (joint affidavit with R. McCullough).**
   Evaluation of Manitoba Hydro system planning, environmental review, and disclosure relating to the Churchill-Nelson hydro project. Consideration of environmental harm and other impacts from existing hydro and proposed 200 MW Wuskwatim project. Analysis of need for comprehensive assessment of the entire Churchill-Nelson project (existing, proposed, and other future). Discussion of precedents regarding comprehensive assessment of existing major hydro projects.

4. **United States District Court, Northern District of New York Case 01-CV-0951; Pogliani, et al. v. Army Corps of Engineers; Stand Together Oppose Power Plant (STOPP); June 29, 2001.**
   Analysis of need for proposed 1080 MW gas combined cycle power plant in Athens, New York. Consideration of locational requirements for supply. Evaluation of potential for other in-state sources and imports.

5. **Vermont Public Service Board Docket 6300; Proposed Sale of Vermont Yankee Nuclear Power Station; New England Coalition on Nuclear Pollution and Vermont Public Interest Research Group; April 14, 2000.**
   Consideration of power supply planning in the context of risk and uncertainly. Evaluation of whether the proposed plant sale is consistent with sound utility planning, regulatory oversight, and electricity restructuring.

6. **Maine Public Utilities Commission Docket 98-791; Bangor Hydro-Electric Company; Maine Public Utilities Commission Staff; May 4 1999 (Bench Analysis joint with A. Monroe and M. Force).**
   Assessment of request for extension and amendment of special industrial rate. Analysis of the economic and physical viability of paper mill self-generation options. Evaluation of whether the contract extension would be beneficial for other utility ratepayers. Development of recommendations for amended contract termination provisions.

7. **California Public Utilities Commission A. 96-03-031; Southern California Gas Company; The Utility Reform Network (TURN); December 30, 1998; Rebuttal Testimony February 26, 1999.**
   Review of claims by gas utility and other parties that economic development would be promoted by allocating transition costs away from large industrial and other noncore gas customers. Evaluation of how economic development will be impacted by the period selected for

amortization of these transition costs. Provision of recommendations regarding consideration of economic development issues by the Commission.

8. **California Public Utilities Commission A. 97-12-048; Southern California Gas Company; The Utility Reform Network (TURN); April 17, 1998; Rebuttal Testimony May 4, 1998.**
   Review of claims by gas utility and other parties that economic development would be promoted by allocating transition costs away from large industrial and other noncore gas customers. Provision of recommendations regarding consideration of economic development issues by the Commission.

9. **Ontario Energy Board E.B.O. 177-17; Union Gas Ltd./Centra Gas Ontario, Inc. Application to Transfer Appliance Businesses to Union Energy; Pollution Probe; January 19, 1998.**
   Review of gas utilities' proposal to transfer their appliance sales, financing, renting and servicing businesses to an unregulated subsidiary. Evaluation of costs and benefits for gas consumers. Assessment of impacts upon competition, DSM, and the environment. Discussion of precedents regarding large-scale divestiture of utility assets, tender processes, and market-based valuation. Provision of recommendations regarding the future of the appliance businesses and development of competitive markets.

10. **United States Federal Energy Regulatory Commission Dockets ER97-1079-000 and OA97-237-000; New England Power Pool; Grand Council of the Crees (of Québec) and New England Coalition for Energy Efficiency and the Environment; July 1, 1997 (joint affidavit with R. Carlson).**
    Review of the market power analysis and market power mitigation principles submitted by New England Power Pool. Development of applicable standard for market power analysis. Evaluation of the potential for exercise of horizontal and vertical market power by Hydro-Québec. Assessment of possible market power mitigation measures.

11. **State of Vermont House Commerce Committee and House Judiciary Committee; April 30, 1997.**
    Review of a contract for purchases of Hydro-Québec power by Vermont utilities. Analysis of how changes in load forecasts, supply-side alternatives, and the wholesale power markets affect contract cost-effectiveness. Evaluation of decisions by Vermont utilities and state agencies to approve the contract. Discussion of implications for utility restructuring.

12. **United States Federal Energy Regulatory Commission Docket ER97-851-000; Petition of H.Q. Energy Services (U.S.) Inc. for Order Accepting Initial Rate Schedule, Authorizing Market-Based Rates, and Granting Certain Waivers and Blanket Approvals; Grand Council of the Crees (of Québec) and New England Coalition for Energy Efficiency and the Environment; March 27, 1997; Affidavit August 19, 1997 (joint affidavit with R. Carlson); Supplemental Affidavit September 25, 1997 (joint affidavit with R. Carlson).**
    Review of Hydro-Québec subsidiary's request for power marketer status. Assessment of Hydro-Québec transmission tariff and conformity with FERC Transmission Pricing Principles and Order 888. Development of applicable standard for market power analysis and critique of applicant's analysis under traditional Hub-and-Spoke and Merger Policy Statement frameworks. Identification of potential affiliate abuse, anti-competitive behavior, and environmental impacts. Assessment of possible market power mitigation measures. Discussion of reciprocal access to Québec markets.

13. **Massachusetts Department of Public Utilities 96-25; Massachusetts Electric Restructuring Proposal; Wheeled Electric Power Company; November 21, 1996.**
    Review of Massachusetts Electric's proposed Restructuring Settlement. Analysis of effects upon the utility's financial position and retail competition. Evaluation of the financial and rate reduction implications of an alternative proposal for Standard Offer retail prices to be market-based, rather than pre-specified.

14. **Commission d'enquête sur la politique d'achat par Hydro-Québec d'électricité auprès de producteurs privés; Commission Staff; September 16, 1996.**
    Analysis of Hydro-Québec's cycle of electricity surpluses and sales promotion in domestic and export markets. Evaluation of the relationship between sales promotion and the utility's independent power program. Review of mechanisms used elsewhere to acquire independent power. Discussion of transfer of utility small hydro projects to independent producers.

15. **Ontario Energy Board E.B.R.O. 493/494; Union Gas Ltd./Centra Gas Ontario, Inc. 1997 Rates Hearing; Pollution Probe; September 6, 1996 (joint testimony with R. Carlson).**
    Evaluation of the utilities' gas avoided cost methodology, and avoided cost estimates used in their 1997 DSM Plan. Review and verification of the utilities avoided cost analysis. Development of recommendations for future avoided cost submissions.

16. **Ontario Energy Board HR 24; Ontario Hydro 1997 Rate Proceeding; Green Energy Coalition; June 11, 1996 (joint testimony with R. Carlson).**
Examination of social and economic consequences affiliated with Ontario Hydro's existing and proposed industrial, residential, and commercial optional rates. Specific analysis of load retention/expansion, surplus power, real time, and aggregation rates, with reference to the Board's stated concerns regarding transparency, consideration of environmental impacts, and due diligence to prevent free ridership.

17. **Vermont Public Service Board Docket 5870; Tariff filing of Green Mountain Power requesting authority to implement its Customer Pilot Pricing Program; Grand Council of the Crees (of Québec), New England Coalition for Energy Efficiency and the Environment, and Vermont Public Interest Research Group; March 19, 1996.**
Review of a proposed rate discount for incremental sales to residential and small commercial customers. Analysis of impacts upon sales, energy efficiency, and net revenues. Evaluation of program design, evaluation plan, equity considerations, environmental impacts, and potential for free ridership.

18. **Maine Public Utilities Commission Docket 95-598; Central Maine Power Company's Annual Demand-Side Management Targets; Maine Public Utilities Commission Staff; June 26, 1995 (joint testimony with J. Raab).**
Discussion of the rationale for Central Maine Power Company's continued acquisition of demand-side management resources and the need for utility efficiency programs. Review of Central Maine Power Company's 1996 DSM targets and presentation of alternative efficiency targets and associated budgets. Evaluation of CMP's DSM proposal in the context of basic program design principles.

19. **Ontario Energy Board HR 23; Ontario Hydro 1996 Rate Proceeding; Green Energy Coalition; June 16, 1995 (joint testimony with R. Carlson).**
Examination of social and economic consequences affiliated with Ontario Hydro's existing and proposed industrial discount rates. Specific analysis of load retention and risk-sharing rates, with reference to the Board's stated concerns regarding transparency, consideration of environmental impacts, and due diligence to prevent free ridership.

20. **Ontario Energy Board E.B.L.O. 251; 1995/96 Trafalgar Facilities Expansion Program of Union Gas Limited; Pollution Probe; May 5, 1995; Supplemental Testimony February 8, 1996 (joint testimony with R. Carlson).**
Evaluation of Union Gas Ltd.'s application for a natural gas pipeline expansion. Verification of its discounted cash flow analysis. Critique of Union's expected energy cost savings to participants from displacement of alternative fuels, and development of alternative energy cost savings estimates. Verification and validation of its long-term transmission facilities expansion model and its total resource cost savings analysis.

21. **Ontario Energy Board E.B.R.O. 486; Union Gas Ltd. 1995 Rate Hearing; Pollution Probe; December 5, 1994 (joint testimony with R. Carlson).**
Evaluation of Union Gas Ltd.'s gas avoided cost methodology and avoided cost estimates used in its 1995 DSM Plan. Review of Union's avoided cost analysis. Verification of Union's results. Discussion of the limitations inherent in the utility's avoided cost modeling approach, and provision of an alternative perspective to that approach. Development of recommendations for future avoided cost submissions.

22. **New York Public Service Commission Case 94-E-0334; Consolidated Edison Company of New York Rate Proceeding; Enersave, Inc., Natural Resources Defense Council, Pace Energy Project, and New York Energy Efficiency Council; September 23, 1994; Revised Testimony October 11, 1994 (joint testimony with J. Peters).**
Assessment of proposed changes to Consolidated Edison's demand-side management programs, focusing on the Commercial & Industrial Lighting Program. Analysis of the impacts on rates, revenue requirements, and societal costs associated with demand- and supply-side resources. Discussion of the interaction between electricity rates and economic competitiveness. Provision of recommendations concerning changes to the utility's proposed DSM program.

23. **Maine Public Utilities Commission Docket 92-345, Phase II; Central Maine Power Company's Proposed Increase in Rates; Office of the Maine Public Advocate; June 15, 1994 (joint testimony with R. Carlson).**
Discussion of Central Maine Power Company's load-building programs, including fuel-switching, within the context of Maine's economic and regulatory environment. Assessment of short-run and long-run risks associated with Central Maine Power Company's flexible pricing proposal. Review of pricing flexibility impacts from surplus energy auctions. Provision of recommendations concerning appropriate cost-effectiveness

tests for load-building activities, limitations to auction of surplus electricity, and the insulation of residential rates from the impact of commercial/industrial sector promotional activities.

24. **Ontario Energy Board HR 22; Ontario Hydro 1995 Rate Proceeding; Grand Council Treaty #3; June 2, 1994.**
Summary of First Nation concerns relating to the proposed corporate restructuring of Ontario Hydro and potential impacts on price of electricity and quality of service. Discussion of the potential impact of restructuring on the settlement of outstanding grievances.

25. **Ontario Energy Board HR 22; Ontario Hydro 1995 Rate Proceeding; Nishnawbe Aski Nation and Grand Council Treaty #3; June 2, 1994 (joint testimony with R. Carlson).**
Review of First Nation concerns related to Ontario Hydro's ratesetting policies and orientations, including proposed discount rates and market-based pricing. Assessment of the potential impacts of rate restructuring on rural rates and equity. Critique of Ontario Hydro's cost allocation process and its potential impacts on rural customers.

26. **Ontario Energy Board HR 22; Ontario Hydro 1995 Rate Proceeding; Green Energy Coalition; June 2, 1994 (joint testimony with R. Carlson).**
Summary of general considerations relating to discounted industrial rates. Outline of the problems inherent in Ontario Hydro's proposed strategy of offering discount rates to industrial customers. Description of the applicable standard for granting special discount rates. Recapitulation of Hydro-Québec's experiences and financial difficulties associated with a strategy promoting discount rates.

27. **Florida Public Service Commission Case Nos. 930548-EG to 930551-EG; Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards by Florida's Investor-Owned Utilities; Florida Department of Community Affairs; April 29, 1994 (joint testimony with B. Krier).**
Discussion of precedents for utility commission consideration of employment and economic development issues. Summary of the role of energy efficiency programs in Florida's economic development. Interpretation of the qualitative findings contained in a companion Goodman Group report entitled The Employment Impacts of Electricity Efficiency in Florida. Comparison of this analysis with standards and practices utilized in similar studies in other jurisdictions.

28. **Ontario Energy Board E.B.L.O. 246 Amended; 1994/95 Trafalgar Facilities Expansion Program of Union Gas Limited; Pollution Probe; April 4, 1994; Supplemental Oral Direct Testimony April 22, 1994 (joint testimony with R. Carlson).**
Assessment of utility's demand-supply framework. Review of gas use projections and potential impacts of DSM and greenhouse gas restrictions. Critique of utility's application of cost-benefit test. Evaluation of fuel-switching analysis. Critique of fuel price forecasts utilized. Analysis of economic risk associated with proposed facility expansion.

29. **State of New York Assembly Standing Committee on Energy and Assembly Standing Committee on Environmental Conservation; March 2, 1994.**
Assessment of 800 MW Hydro-Quebec/New York Power Authority seasonal diversity contract in the context of reduced load forecasts, increased projections for independent power production and demand-side management, and the changing wholesale power markets. Analysis of the contract's cost-effectiveness. Analysis of risk, reliability, and economic development considerations.

30. **Maine Public Utilities Commission Docket No. 93-147; Central Maine Power Company Petition for a Certificate of Public Convenience and Necessity to Erect a Transmission Line Carrying 100 Kilovolts or More in York County; Maine Public Utilities Commission Staff; September 21, 1993 (joint testimony with R. Carlson and W. Scott).**
Assessment of peak load forecasts through 2008 for York County. Economic analysis of the need for a transmission line. Cost-effectiveness analysis of alternative line routes.

31. **Maine Public Utilities Commission Docket No. 92-331; Airco Industrial Gases Request for Interruptible Load Retention Service Rate with Central Maine Power Company; Maine Public Utilities Commission Staff; July 9, 1993; Supplemental Testimony August 10, 1993 (joint testimony with R. Carlson and R. McCullough).**
Assessment of request for a special industrial rate. Review of supply and demand trends in the industrial gases industry. Analysis of production scheduling and transportation cost models. Calculation of internal rates of return based on alternative assumptions. Development of recommendations for the framework, evidentiary standards, and evaluation criteria to be used in consideration of special industrial tariffs.

32. **Ontario Energy Board 169-III; Integrated Resource Planning for Ontario's Local Gas Distribution Companies; Ontario Metis and Aboriginal Association; November 20, 1992.**
Identification of importance of considering environmental and social externalities in energy planning generally and in Ontario natural gas industry specifically. Formulation of recommendations for incorporating externalities into the planning process. Consideration of externalities from the standpoint of the Aboriginal population.

33. **Government of Canada and Government of Manitoba; Conawapa Project Environmental Assessment; Concerned Citizens of Manitoba, Sierra Club of Western Canada (Manitoba Branch), Manitoba Naturalists Society, Inc., Manitoba Branch of the Canadian Parks and Wilderness Society, and Time to Respect Earths' Ecosystems (TREE) Inc.; June 4, 1992 (joint testimony with C. Goodwin and W. Marcus).**
Discussion of the need for environmental reviews to evaluate justification of design alternatives to the proposed 1290 MW Conawapa Project. Description of changes in the utility industry and new supply resource options that will affect the design alternatives included in an environmental review. Review of the treatment of project justification in North American environmental assessments.

34. **Government of Canada and Government of Québec; Great Whale River Project Environmental Review; Grand Council of the Crees (of Québec); March 18, 1992 (joint testimony with R. McCullough).**
Discussion of the need for environmental reviews to evaluate justification of design alternatives to the 3160 MW Great Whale River Project. Description of changes in the utility industry and new supply resource options that will affect the design alternatives included in an environmental review. Review of the treatment of project justification in North American environmental assessments.

35. **New York Public Service Commission Case 90-E-0775; Petition to Reopen Proceeding and Determine the Prudence of the Contracts for Delivery of Hydro-Quebec Power; Environmental Defense Fund, Center for Environmental Legal Studies of the Pace University School of Law, Natural Resources Defense Council, National Audubon Society, Sierra Club, (Atlantic Chapter), Greenpeace U.S.A., Environmental Planning Lobby, and Hudson River Sloop Clearwater; November 25, 1991.**
Review of the need for a contract for purchases of Hydro-Québec power by New York utilities. Summary of declining load forecasts and changes in the supply outlook. Analysis of the cost-effectiveness of the proposed purchase. Discussion of risk, reliability, and other considerations.

36. **State of Vermont Supreme Court and Public Service Board; In re: Application of Twenty-Four Electric Utilities for a Certificate of Public Good Authorizing Execution and Performance of a Firm Power and Energy Contract with Hydro-Québec and a Hydro-Québec Participation Agreement, and Specifically Concerning Motions for a Remand to the Board for a New Trial; October 15, 1991; Reply Affidavit October 28, 1991.**
Review of a contract for purchases of Hydro-Québec power by Vermont utilities. Summary of changes concerning load forecasts and supply-side alternatives. Analysis of how these changes affect the cost-effectiveness of the contract.

37. **State of New York Assembly Energy Committee Senate Environmental Conservation Committee; September 30, 1991 (updated October 7, 1991).**
Assessment of Hydro-Quebec contract in the context of reduced load forecasts, increased projections for independent power production, and the changing wholesale power markets. Analysis of the contract's cost-effectiveness. Estimation of risk, reliability, and economic development considerations.

38. **New York Public Service Commission Case 91-E-0462; Consolidated Edison Company of New York Rate Proceeding; City of New York; September 6, 1991.**
Review of Consolidated Edison's demand-side management programs. Analysis of program delivery mechanisms and incentive levels. Identification of additional cost-effective efficiency measures. Discussion of opportunities for increased cooperation between Consolidated Edison and the City of New York to achieve greater efficiency.

39. **New York Public Service Commission Case 91-E-0462; Consolidated Edison Company of New York Rate Proceeding; Environmental Defense Fund, National Audubon Society, Greenpeace, and Center for Environmental Legal Studies; September 6, 1991.**
Analysis of Consolidated Edison's resource planning process with respect to demand-side management programs and the 482 MW Hydro-Québec purchase. Evaluation of demand-side management and the Hydro-Québec purchase in context of long run avoided cost estimates. Determination of cost-effectiveness of Hydro-Québec contract. Discussion of risk, reliability, environmental and economic development considerations relating to the Hydro-Québec purchase.

40. **New York Public Service Commission Case 90-E-1185; Long Island Lighting Company Rate Proceeding; Vladeck, Waldman, Elias and Englehard, Natural Resources Defense Council, and Center for Environmental Legal Studies; June 3, 1991 (joint testimony with C. Komanoff).**
    Evaluation of Long Island Lighting Company's proposed 20 year, 218 MW purchase of electricity from Hydro-Québec. Comparison of Long-Run Avoided Cost and the Hydro-Québec purchase. Review of supply and demand options as alternatives to the purchase. evaluation of risk, reliability, environmental, and economic development considerations.

41. **Québec Access to Information Commission No. 90-04-07; Risk-Sharing Contracts; Grand Council of the Crees (of Québec); May 3, 1991.**
    Analysis of confidential risk-sharing electricity supply contracts between Hydro-Québec and thirteen large industrial customers. Description of participants by company ownership, location, principal activities, and business relationships. Estimation of energy and capacity required to service contracts. Assessment of resulting implications for Hydro-Québec and its ratepayers. Review of treatment of electricity contracts for aluminum smelters and other large industrial customers in North American jurisdictions.

42. **Massachusetts Department of Public Utilities 90-261-A; Massachusetts Electric Fuel Switching; Massachusetts Division of Energy Resources; April 17, 1991.**
    Evaluation of fuel switching as a demand-side management option. Review of current status of fuel-switching technologies. Formulation of cost and benefit allocation algorithms to optimize program participation and maximize societal benefits by incorporating fuel choice options, including renewables and active and passive solar, as part of utility least-cost planning.

43. **State of Vermont, Chittenden County Superior Court, Docket S518-91 CnC; March 5, 1991 Burlington Municipal Election Question 8; Grand Council of the Crees (of Québec); March 28, 1991.**
    Analysis of Burlington Electric Department Assessment provided as "voter information" in referendum concerning power purchase contract with Hydro-Québec. Evaluation of accuracy and impartiality of information concerning cost estimates, alternative sources of supply, environmental effects, and economic benefits.

44. **Manitoba Public Utilities Board; Manitoba Hydro Submission in Respect to Major Capital Projects; Concerned Citizens of Manitoba, Sierra Club of Western Canada (Manitoba Branch), and Conservation Strategy Association of Manitoba; July 23, 1990; Surrebuttal Testimony August 30, 1990 (joint testimony with W. Marcus).**
Review of Manitoba Hydro's submission and the proposed: construction of 1290 MW Conawapa generating station and other northern hydro projects; 100 MW demand-side management program; twenty-two year, 1000 MW power sale to Ontario Hydro; and two 150 MW seasonal diversity exchanges. Review of Manitoba Hydro load forecasting. Estimation of economic and attainable conservation potential. Development of principles of conservation program design and delivery. Critique of utility's proposed demand-side management program. Evaluation of alternative supply-side resources. Analysis of avoided costs. Assessment of employment and economic development effects of hydroelectric development and conservation. Analysis of profitability and risks of proposed power sales contracts.

45. **State of New York Supreme Court; Application of Sierra Club, Inc. et al. For Judgment Under Article 78 Against the Power Authority of the State of New York, et al.; April 18, 1990; Reply Affidavit August 6, 1990; Supplemental Reply Affidavit September 13, 1990.**
Analysis of nexus between New York Power Authority purchases and construction of specific Québec hydro facilities and operation of fossil fuel electric generation. Evaluation of power imports in New York State Energy Plan. Assessment of energy conservation as a potential substitute for hydro and fossil generation. Comparison of employment and economic development impacts of power purchase and conservation options.

46. **Canadian National Energy Board Hearing Orders No. EH-3-89 and AO-1-EH-3-89; Application of Hydro-Québec for Export License for Firm Power and Energy Contracts with Vermont Joint Owners and New York Power Authority; Grand Council of the Crees (of Québec); February 14, 1990 (joint testimony with W. Marcus).**
Review of a proposed thirty year, 450 MW sale of Hydro-Québec power to twenty-four Vermont utilities and review of a proposed twenty year, 1000 MW sale of Hydro-Québec power to the New York Power Authority. Analysis of planning and operation of Hydro-Québec power supply. Modeling of hydro reservoir levels. Determination of marginal supply resources associated with sales to Vermont and New York. Estimation of acid rain and greenhouse gases emissions from fossil and hydro generation. Analysis of reliability including adequacy of energy, capacity, and transmission supply. Estimation of achievable conservation potential

in Québec. Analysis of the profitability of the proposed power sales on both a private cost and social cost basis.

47. **Vermont Public Service Board Docket 5330; Application of Vermont Utilities for Approval of a Firm Power and Energy Contract with Hydro-Québec; Grand Council of the Crees (of Québec) and New England Coalition for Energy Efficiency and the Environment; December 19, 1989; Supplemental Testimony January 18, 1990 (joint testimony with W. Marcus). Docket 5330-A; Testimony April 30, 1991.**
Review of a proposed thirty year, 450 MW purchase of Hydro-Québec power by twenty-four Vermont utilities. Analysis of planning and operation of Hydro-Québec power supply. Modeling of hydro reservoir levels. Determination of marginal supply resources associated with sales to Vermont. Estimation of acid rain and greenhouse gases emissions from fossil and hydro generation. Analysis of risk and reliability including supply diversity, and adequacy and security of energy and transmission supply. Estimation of achievable conservation potential in Québec. Development of proposal for exports to Vermont based on conservation and alternative supply resources in Québec. Evaluation of costs and benefits of Vermont Joint Owners' proposed Waiver and Release to extend the date for cancellation of export contracts without penalty.

48. **Massachusetts Department of Public Utilities 89-72; Statewide Towing Association, Police-Ordered Towing Rates; Massachusetts Automobile Rating and Accident Prevention Bureau; September 13, 1989 (joint testimony with P. Chernick).**
Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison with competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing.

APPENDIX

B. Resume of Brigid Rowan

Brigid Rowan

The Goodman Group, Ltd.

Mobile: (514) 962-0318	682 Morin St
Citizenships: Canadian, Irish (EU)	Ottawa, ON, K1K 3G9
Email:	brigid@thegoodman.com
Skype:	brigidrowan

Professional Profile

Brigid Rowan is an energy economist with over 20 years of experience in the areas of energy and regulatory economics, energy efficiency and renewables. Ms. Rowan's practice addresses the economic development and environmental impacts of various energy supply and transportation options, interjurisdictional energy trade in North America, as well as the regulation of natural gas and electricity distributors (with a particular expertise in energy efficiency for lower-income consumers). She also has extensive experience in marketing and communications in the energy field. Ms. Rowan has provided consulting services in energy economics and regulation in Quebec, Ontario, Manitoba, British Columbia, California, Nevada, North Dakota, South Dakota, New York and New England. Brigid has worked with public interest, environmental and indigenous groups, start-ups, large corporations and governments in consulting, senior management and public affairs positions throughout Canada and the US, and internationally.

She has provided testimony in over 25 regulatory proceedings before the *Régie de l'énergie du Québec* (Quebec Energy Board) and co-authored expert evidence at the National Energy Board (NEB) in Canada. Since 2011, her practice has focussed on oil supply and transportation (notably Canadian tar sands, shale, pipelines and rail). She has co-authored reports and expert testimony on the most controversial oil projects in North America, including “Pipe Dreams? Jobs Gained, Jobs Lost by the Construction of Keystone XL.” "Pipe Dreams" is an influential and widely publicized study on the employment impacts of the Keystone XL pipeline. More than three years after its release, the study continues to be cited by the Obama administration and the media as evidence that KXL will not be a major creator of American jobs.

Energy Economics and Energy Industry Experience

2006 – present **Senior Energy Economist, The Goodman Group, Ltd., Berkeley, California**

Provide energy consulting services including expert reports, testimony, policy assessment, research, intervenor and litigation support related to energy regulation and economics.

Specialize in the evolving North American oil, gas and electric markets, the economic development and environmental impacts of various energy supply and transportation options, and the regulation of natural gas and electricity distributors.

Major Projects:

Economic Development and Environmental Impacts of Energy Options

- Since 2006, has co-authored or collaborated in 15 national, regional, and state/provincial studies on the economic development impacts (notably jobs) and environmental impacts of various energy supply and transportation options in the US and Canada.

- Since 2011, has co-authored seven expert reports on the economic development impacts and environmental impacts of crude oil transportation (particularly interjurisdictional tar sands crude pipeline projects and crude by rail projects).

- Co-authored the "Economic Costs and Benefits of the Trans Mountain Expansion Project (TMX) for BC and Metro Vancouver" with Ian Goodman in collaboration with Simon Fraser University's Centre for Public Policy Research. The report, released in November 2014 and re-released in February 2015, refutes Kinder Morgan's claims regarding the positive economic development benefits of its controversial pipeline project. Goodman and Rowan show that the benefits of the pipeline are very small and have been significantly overstated by Kinder Morgan, whereas the worst-case costs of a catastrophic spill are very large and have been vastly understated.

- Co-authored the "Economics of Transporting and Processing Tar Sands Crudes in Quebec" with Ian Goodman in collaboration with Équiterre and Greenpeace Canada. The January 2014 report demonstrates that the economic development benefits for Quebec of moving and refining tar sands crudes would be insignificant while the costs and risks are very high.

- Co-authored an "Analysis of the Potential Costs of Accidents/Spills Related to Crude by Rail" with Ian Goodman on behalf of Oil Change International (OCI). The November 2013 report demonstrates that the economic costs of crude by rail accidents can be very large and concludes that a major crude by rail (CBR) unit train accident/spill could cost $1 billion or more for a single event. The report was incorporated into Comments filed by NRDC, Sierra Club and OCI before PHMSA as part of the Advance Notice of Proposed Rulemaking Hazardous Materials: Rail Petitions and Recommendations To Improve the Safety of Railroad Tank Car Transportation, December 5, 2013.

- Co-authored expert testimony, entitled "The Relative Economic Costs and Benefits of Enbridge's Line 9B Reversal and Line 9 Capacity Expansion Project" with Ian Goodman. The expert report was filed in August 2013 at Canada's National Energy Board on behalf of the Équiterre Coalition, a coalition of Quebec- and Ontario-based environmental groups.

- Co-authored "Comments on Initial Study/Mitigated Negative Declaration (IS/MND) Valero Crude by Rail Project Benicia, California" with Ian Goodman on behalf of NRDC. The July 2013 report provides a Market Analysis of a proposed crude by rail project for the Valero Benicia Refinery. Goodman and Rowan conclude that the proposed project could significantly affect crude supply (and thus quality) for the refinery, and recommend that a full Environmental Impact Report be undertaken. The report was included as an attachment to NRDC's Comments on Notice of Intent to Adopt a Mitigated Negative Declaration for the Valero Crude by Rail Project, filed with the City of Benicia on July 1, 2013.

- Co-authored a "Report evaluating the adequacy of the Keystone XL (KXL) Draft Supplemental Environmental Impact Statement (DSEIS) Market Analysis" with Ian Goodman, and filed as an attachment to the Comments on KXL DSEIS jointly submitted by the Sierra Club, NRDC, and 14 other environmental and public interest organizations in April 2013. Based on their evaluation of the early 2013 market conditions (including emerging crude markets, factors driving tar sands expansion, availability and cost of crude oil transportation, and tar sands breakeven costs), Goodman and

Rowan conclude that (i) the US State Department's DSEIS Market Analysis was deeply flawed and not a sound basis for decision-making; and (ii) KXL, and specifically its impact on tar sands logistics costs and crude prices, would have a significant impact on tar sands expansion under a very broad range of conditions and assumptions.

- Co-authored an influential and widely publicized study of the Keystone XL pipeline employment impacts ("Pipe Dreams? Jobs Gained, Jobs Lost by the Construction of Keystone XL") with Ian Goodman and the Cornell Global Labor Institute. Goodman and Rowan provided economic impact analysis to demonstrate that TransCanada Pipelines Ltd had substantially exaggerated the US job numbers related to the KXL project. The report was originally released in September 2011 and updated in January 2012.

- Co-authored "Employment Impacts of Air-Pollution Controls at North Dakota Coal Plants" with Ian Goodman. This November 2011 study for Sierra Club National estimated the employment impacts of Air-Pollution Controls at North Dakota Coal Plants.

- Collaborated in the preparation of expert testimony on behalf of The Greenlining Institute on economic development impacts (focusing on job creation and stimulus) of capital expenditures and rate increases proposed by the Pacific Gas & Electric Company in its 2011 General Rate Case; co-authored an analysis of the Economics of Supplier Diversity with Ian Goodman, as supplementary evidence for the same case.

- Collaborated in the analysis for the Avoided Energy Supply Costs in New England: 2009 Report, prepared for Avoided-Energy-Supply-Component (AESC) Study Group, which represents all major electric and gas utilities in New England, as well as efficiency program administrators, state energy offices and regulators. TGG's contribution to this report was an analysis of the economic development impact of Massachusetts electricity and gas energy efficiency programs.

- Co-authored several national and regional analyses with Ian Goodman for SunPower Corporation (an international solar electric manufacturer based in California) focussing on the economic development and environmental benefits of solar manufacturing and reduction of coal use.

2004 – 2013 **Senior Energy Economist,**
Econalysis Consulting Services,
Montreal, Quebec

Provided written evidence and/or testified in over 25 regulatory proceedings before the *Régie de l'énergie du Québec* (Quebec Energy Board) on behalf of Option consommateurs in energy regulatory proceedings. The cases involved Quebec gas distributors (Gaz Metro and Gazifère), as well as Hydro-Québec Distribution (the electricity distributor) and Hydro-Québec Transport (the electricity transmission company).

Offered strategic advice and analytical expertise to public interest intervenors and their counsel in energy regulatory proceedings through the preparation of interrogatories, testimony, cross-examination, and final argument.

Actively participated in working groups, negotiations and consultations related to energy stakeholder issues in Quebec.

Hired, coordinated and collaborated with subject-matter experts in various energy regulatory proceedings.

Coordinated Econalysis' team of Quebec-based energy analysts from 2005-2007.

Major Projects:

- Prepared evidence and coordinated expert participation on behalf of Option consommateurs in Gaz Métro’s 2013 case with respect to the renewal of its Distribution Incentive Mechanism.

- Prepared evidence and testified on behalf of Option consommateurs in Gaz Métro’s 2013 rate case with respect the Supply Plan, a Gas Procurement Incentive Mechanism, operating costs and other rate issues.

- Prepared evidence and testified on behalf of Option consommateurs in Gaz Métro’s 2012 rate case with respect to the profitable development of the residential market, cost allocation and rate strategy.

- Prepared evidence and testified on a range of regulatory issues (notably energy efficiency programs for lower-income consumers) on behalf of Option consommateurs in 2004-2007 regulatory hearings relating to Hydro-Québec and Gaz Métro.

2001 – 2004 **Principal, Energy and Communications Consultant, Just Brigid Energy & Communication Montreal, Quebec**

- Provided comprehensive English communications and website production services with a specialization in energy and the environment
- Clients included: Quebec Ministry of the Environment, Équiterre, Quebec Centre for Action on Climate Change, Madinina Software
- Managed the redesign, production and relaunch of a new website for Équiterre, Québec's largest environmental group (www.equiterre.org) and advised on the web strategy for the Quebec Centre for Action on Climate Change.

1998 – 1999 **Energy Consultant, Econalysis Consulting Services Toronto, Ontario**

- Assisted in the preparation of expert testimony in English and French and conducted research for public interest intervenors in Quebec, Ontario and Manitoba energy regulatory proceedings.

1998 **IBM Canada, Client Manager, Utility & Energy Services Industry Toronto, Ontario**

- Managed IBM client relationships at Canada's largest energy utilities via the direct marketing channel.

1996 – 1997 **IBM Canada, Direct Marketing Specialist, Industry Solutions Unit, Toronto, Ontario**

- Managed diverse teams (database specialists, graphic designers, copywriters, translators, ad agencies, direct mail houses) to implement Quebec-based B2B direct marketing campaigns for the energy and telecommunications industry, including pioneering web campaigns
- Successfully implemented five campaigns, three of which generated response rates of 10-35% and respective revenues of over $2.5 million.

1995 – 1996 **Energy Analyst, The Goodman Group, Ltd., Boston, Massachusetts**

- Collaborated in the preparation of expert testimony regarding Hydro-Québec's cycle of electricity surpluses and sales promotion in domestic and export markets on behalf of Commission Staff for a Quebec Government Commission on Hydro-Québec's purchasing policies with respect to independent power producers

- Assisted with the research and writing of various expert reports on energy economics for environmental and indigenous groups.

1992 – 1993 Energy Analyst, Stephen Graham Associates, Ottawa, Ontario

- Prepared a series of documents for policymakers on the economic, political and technical feasibility of various alternative energy options in developing countries.

Marketing, Communications and Management Consulting Experience

1999 – 2001 Acting CEO and Co-Founder
Sites.com, New York, NY and Toronto, Ontario

- Oversaw operations for this New-York-based search engine/publishing start-up including web content development, book production (circulation 15,000 copies), sales and marketing, human resources, finances, facilities, telecommunications, information technology
- Developed marketing strategy including branding, advertising, marketing channels and media relations; managed the development of offline and online marketing communications
- Participated in all aspects of strategy and business plan development.

1995 – 1995 Director of Communications,
International Children's Institute, Toronto, Ontario

- Created and presented several successful proposals to obtain government and foundation funds in excess of $500,000 for this Canadian NGO, which assists traumatized refugee children
- Managed the production of communications materials for Institute pilot projects in Toronto and Croatia.

1993 – 1994 Management Consultant, Groupe SECOR, Ottawa, Ontario

Selected Projects:
Republic of BENIN

- Co-produced a study in French on public sector reform in Benin as a member of a team assisting the President of Benin in strengthening government systems to support the political transition to democracy

Marketing Communications for the World Bank

- Developed a marketing package for Groupe SECOR to familiarize World Bank officials with the firm’s capabilities and experience.

1988 – 1989 **IBM Canada,**
Co-operative Education Positions
Vancouver, BC, Ottawa and Toronto, Ontario

- Marketing Representative (1989): Promoted IBM PCs at trade shows across Western Canada.
- Public Affairs Specialist (1988): Produced an IBM position paper encouraging high tech initiative in Canada; prepared political briefing material for company executives.

1988 **IBM Europe,**
Public Affairs Specialist
Brussels, BELGIUM

- Wrote an article on the effects of the 1988 US Trade Bill on American subsidiaries in Europe for *Commerce in Belgium*, a business journal.
- Prepared a report on broadcast advertising in a united Europe and the effects of EU advertising directives on IBM's business.
- Researched the potential effects of the Montreal Protocol on IBM Europe and recommended that IBM Europe not align itself with companies opposing the Protocol.

Education

Master of Arts, International Affairs, International Political Economy (Environmental Specialization),
Norman Paterson School of International Affairs,
Carleton University, Ottawa, Ontario, 1996.

Thesis examines how the Cree of Northern Quebec (a Canadian First Nations group) used economic arguments and energy regulation to successfully oppose Hydro-Québec's construction of the Great Whale dam.

Bachelor of Arts, Honours Economics, Computer Science Minor
(Cooperative Education Program),
University of Waterloo, Waterloo, Ontario, 1990.

Other: Financial Literacy Program for Directors and Executives,
Rotman School of Management, University of Toronto, 2007.

Languages: English, French, Spanish, Italian.

Appointments, Achievements and Awards

Greenpeace Canada (2006 – present): Board member; Treasurer and Chair of the Finance Committee

Quebec Centre for Action on Climate Change (2004): provided pro-bono web strategy advice and website production oversight

Équiterre (2003-2004): managed the redesign, production and relaunch of a new website for Équiterre, Québec's largest environmental group (www.equiterre.org)

Humber School for Writers (2002): scholarship for a fiction-writing workshop

Sites.com (2000): edited and published *best of the best sites.com*, a 210-page guide to the Internet's top sites

IBM Canada Team Success Award (1997 and 1998) and **IBM Canada Public Affairs Award** (1988): presented for an outstanding contribution to the Public Affairs Department

Canadian Club at Harvard University (1996): participated in a round table discussion on energy exports with former Quebec Premier, Robert Bourassa

Ottawa Co-Director, Pollution Probe (1993): co-directed the 1993 Ottawa fund-raising drive for this Ontario-based ENGO

Ontario Public Interest Research Group (1992): co-organized a panel discussion at the Canadian Parliament Buildings on hydro projects in the Canadian North for Indigenous and federal politicians and members of the public

Carleton University Grant for Graduate Studies (1991-93):
grant requirements included conducting tutorials for undergraduate Economics courses

University of Waterloo Nordic Ski Team (1988-90): competed at the provincial level

Competitive Cycling (1986-89): competed at the national and provincial levels.

Publications, Major Reports and Expert Testimony

Economic Costs and Benefits of the Trans Mountain Expansion Project (TMX) for BC and Metro Vancouver in collaboration with The Centre for Public Policy Research, Simon Fraser University, *November 10, 2014* (co-author with Ian Goodman, re-released *February 4, 2015*).

Report on the Economics of Transporting and Processing Tar Sands Crudes in Quebec in collaboration with Équiterre and Greenpeace Canada, *January 2014* (co-author with Ian Goodman).

Analysis of the Potential Costs of Accidents/Spills Related to Crude by Rail, *November 8, 2013* (co-author with Ian Goodman) on behalf of Oil Change International (OCI), incorporated as Attachment 3 to Comments filed by NRDC, Sierra Club and OCI before The Pipeline and Hazardous Materials Safety Administration, U.S. Department Of Transportation as part of the Advance Notice of Proposed Rulemaking Hazardous Materials: Rail Petitions and Recommendations To Improve the Safety of Railroad Tank Car Transportation, *December 5, 2013*.

The Relative Economic Costs and Benefits of Enbridge's Line 9B Reversal and Line 9 Capacity Expansion Project, *August 8, 2013* (co-author with Ian Goodman), expert testimony filed at Canada's National Energy Board on behalf of the Équiterre Coalition, a coalition of Quebec- and Ontario-based environmental groups.

Comments on Initial Study/Mitigated Negative Declaration (IS/MND) Valero Crude by Rail Project, Use Permit Application 12PLN-00063, Benicia, California, *July 1, 2013* (co-author with Ian Goodman) on behalf of NRDC, included as an attachment to NRDC's Comments on Notice of Intent to Adopt a Mitigated Negative Declaration for the Valero Crude by Rail Project, filed with the City of Benicia Community Development Department on *July 1, 2013*.

Report evaluating the adequacy of the Keystone XL (KXL) Draft Supplemental Environmental Impact Statement (DSEIS) Market Analysis, *April 22, 2013* (co-author with Ian Goodman), filed as an attachment to the Comments on KXL DSEIS jointly submitted by the Sierra Club, NRDC, and 14 other environmental and public interest organizations.

Pipe Dreams? Jobs Gained, Jobs Lost by the Construction of Keystone XL, *September 28, 2011* (co-author with Ian Goodman, TGG, and L. Skinner and S. Sweeney, Cornell Global Labor Institute; *revised January 18, 2012*).

Employment Impacts of Air-Pollution Controls at North Dakota Coal Plants, prepared for Sierra Club, *November 21, 2011* (co-author with Ian Goodman).