COMMUNITIES FOR A BETTER ENVIRONMENT

1 May 2015

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Office of the Governor
State of California
c/o State Capitol, Suite 1173
Sacramento, CA 95814

Re: **Emergency need for a moratorium on new infrastructure for extreme oil; followup information requested in our discussion on 13 April 2015**

Dear Mssrs. Rechtschaffen and Alex,

Thank you, again, for considering the unprecedented flood of extreme oil infrastructure that now threatens severe and potentially irreversible statewide impacts. This responds to your request during our 13 April 2015 meeting for additional information regarding the possible interaction of a statewide moratorium on new infrastructure for extreme oil, such as tars sands oil, with the Governor's planned transportation fuel goal. We understand that Ken Alex asked:

> **Assuming that California succeeds in reducing the statewide use of petroleum-based transportation fuels by 50% in the year 2030, how much of what type of crude oil do you envision would be refined statewide in 2030?** Could you say what you envision California refineries would process in terms of numbers?

This response outlines the (1) volume, (2) sources, and (3) quality (bulk refining properties) of crude feedstocks we envision that the California refining fleet could be processing in the year 2030, assuming California is using 50% less oil-based transport fuels by then.

In sum, it will depend on the policy decisions made about new oil infrastructure here. The amount of crude oil refined in California could be cut or not, crude imports could be cut or grow, and crude feed quality could remain similar or become far more hazardous and polluting to refine. Which of these outcomes is realized will more likely than not depend upon whether oil companies are allowed to build and profit from infrastructure in California to import, process, and export the products of low-quality 'extreme' oil.

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(1) Y-2030 Crude Feed <u>Volume</u>:

- **50–100% of current statewide crude feed volume (≈0.85–1.7 MM barrels/day);**
- **outcome depends on refined product exports, and new policy intervention.**

Refiners <u>should</u> process less oil here when we use less oil-based fuels here, but <u>will not</u> if their export sales replace their in-state sales gallon for gallon.

Reliable data demonstrate a recent trend of increasing refined product exports as West Coast gasoline sales have declined. *<u>See</u>* Chart 1. This trend is consistent with refiners' long-practiced export of products that are not used or are no longer used as much in nearby markets. Examples of this practice include West Coast refiners' petroleum coke exports to China and European refiners' gasoline exports to the U.S. East Coast.

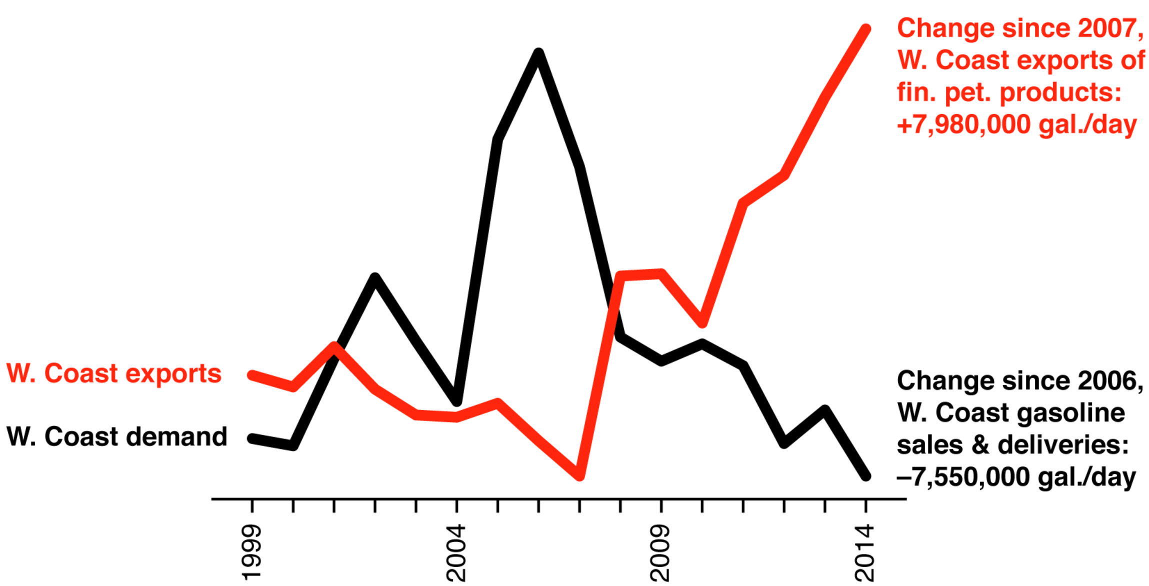

Chart 1. Gasoline sales in the West Coast v. finished petroleum products exports from the West Coast (PADD 5): 1999–2014. Data from US EIA (www.eia.gov/petroleum/data.cfm).

Increasing exports are explained, in large part, by a 'business as usual' response that avoids stranded assets through finding new markets. But this is not the whole story; recent changes in climate policy support refinery exports. Exports are exempt from all emission costs applied to gasoline and diesel sold in-state under the Low Carbon Fuel Standard (LCFS), so refiners that export gain that advantage over those that do not. Meanwhile, exports avoid costs under cap-and-trade by moving the end-use emissions out-of-state, while oil producer and refiner emissions get 'leakage[1] protection' credits free. The net effect is it is cheaper to emit when exporting product. This is presumably unintended on the State's part, and the incentive to avoid stranded assets has no doubt been the stronger influence thus far, but both supported the observed exports growth.

[1] The Air Resources Board defines 'leakage' as "a reduction in GHG emissions within the state that is offset by an increase in GHG emissions outside the state."

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It is reasonably foreseeable that absent new policy intervention, incentives to export California refinery products will strengthen between now and 2030, thwarting the promise of refinery capacity retirement here as Californians use less petroleum fuels.

As Julia May and I outlined in our 13 April meeting with you, the industry now plans an unprecedented statewide flood of projects for new infrastructure to deliver, process, and export products from the refining of ,‘extreme’ oil, such as tar sands dilbit. These new capital commitments (to port facilities, rail terminals, pipelines, storage tanks, refinery modifications, and more) would strengthen incentives to use that infrastructure through 2030. Indeed, the alternative hypothesis—that the oil companies are planning these projects so that they will lose money on stranded assets—must be rejected as absurd.

There is no credible evidence that currently planned market-based policies alone will counter these incentives for expanded refined product exports by 2030. The Low Carbon Fuel Standard does not cover any of the emissions associated with making and using refined products when the products are exported, and even if this exemption is changed, it is unlikely to cover all potential export markets over the next 15 years. Thus, the LCFS cost advantage for refined product exports must be considered reasonably likely.

Moreover, price discounts on the extremely low-quality tar sands oils enabled by the currently planned statewide infrastructure could further incent refined product exports. Using the new capital assets for that cheaper, dirtier oil would become the economic reality, despite plans to phase out free ‘leakage’ credits under cap-and-trade. In fact, refiners that export their products could save money on imported tar sands dilbit price discounts of $3.50 to $10 per barrel[2] unless cap-and-trade credit prices rise as high as $50 to $150 per metric ton of CO_2 equivalent (CO_2e).[3]

The moratorium on extreme oil infrastructure that CBE recommends would avoid these new capital commitments to cheaper and dirtier oil,[4] but whether it will be implemented in time remains uncertain, and additional new policy intervention may be needed.

For these reasons, we envision Y-2030 California refinery crude feed volume ranging from 50–100% of that refined here today (≈0.85–1.7 million barrels/day), with the low end of this range more likely if the moratorium we seek is implemented, and the high end of this range a reasonably foreseeable outcome of allowing tar sands to flood in now.

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[2] *Compare* ≤20.0 v. 25.1–30 ºAPI, 20.1–25 v. 25.1-30 ºAPI, and ≤ 20.0 v. 30.1–35 ºAPI prices from Feb 1999–Jan 2015, US EIA data (http://www.eia.gov/dnav/pet/pet_pri_imc3_k_m.htm).

[3] Based on an average refinery CO_2e emission increment of 0.069 tonnes/barrel from tar sands v. current average California refinery input (Karras, 2010; UCS, 2011; available on request), and price discounts ranging from $3.50 to $10 per barrel (*see* note above). Emissions from all parts of the fuel cycle are exempt from the LCFS for exported product, and when import oil is refined to export products, emissions from production and product end-use are outside the State.

[4] Please note that, though this response accepts your question’s assumption that California’s goal of halving petroleum fuel use by 2030 will be achieved, the moratorium we seek may be needed to reach that goal. As discussed in our 6 March letter, allowing extreme oil impacts would create an unfair subsidy that would undermine less polluting energy and transportation alternatives.

(2) Y-2030 Crude Feed <u>Sources</u>:

- **≈15–25% California oil and growing imports of low-quality ('tar sands') oil**
- ***<u>or</u>* ≈30–50% Cal. oil and shrinking imports of widely-sourced conventional oil;**
- **outcome depends on new policy intervention.**

As California supply declined, from 1995–2007 refiners here added sulfur capacity and boosted higher sulfur crude imports.[5] From 2004–2014 they imported crude from at least 7 U.S. states and from 36 countries on every continent.[6] Crude supply and infrastructure in California will continue to affect the volume, type, and sources of crude refined here.

Dwindling California oil supply: Intensively explored and exploited, despite expansion of harmful extreme extraction methods (e.g., fracking) the State's oil resources are in terminal decline. CEC data reveal a remarkably steady reduction in California-produced crude refined statewide. *<u>See</u>* Chart 2. This trend continued over three decades despite drastic changes in the prices of crude[7] and gasoline,[8] and despite increasingly intensive drilling and extraction methods.[9] It is reasonably foreseeable that this trend could continue for the next 15 years. The CEC has forecast that it will continue through 2030.[9] A straightforward linear forecast based on CEC data[10] falls into the same range as the CEC forecast,[9] and suggests that California crude could account for ≈ 106–150 million barrels per year (≈ 0.29–0.41 MM b/d) of the total statewide crude feed in Y-2030.

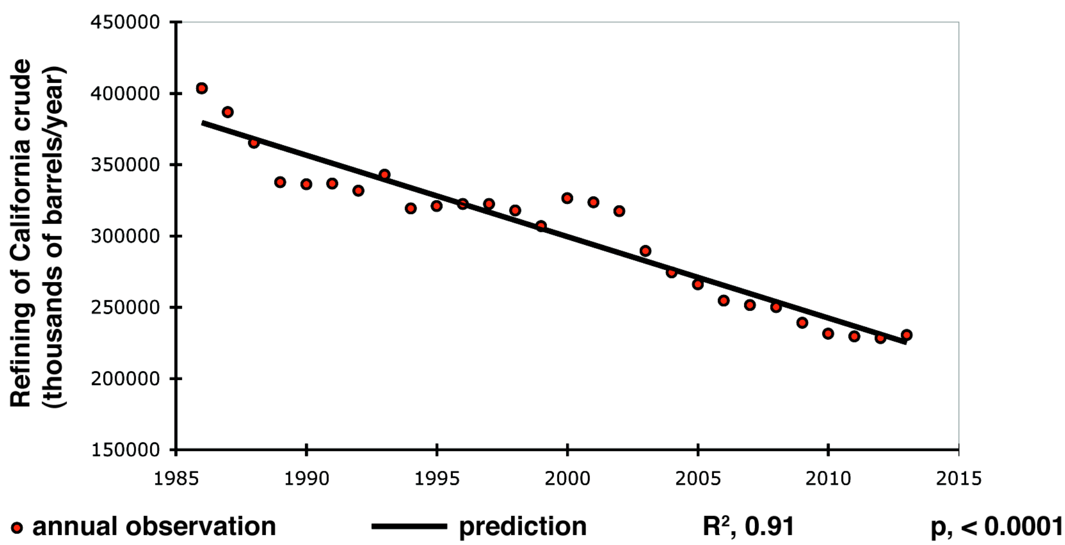

Chart 2. California-produced oil volume processed by California refineries 1986–2013. Data from CEC (http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts.html).

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[5] *<u>See</u>* Karras, May and Lee (2008); previously submitted to ARB, available on request.
[6] *<u>See</u>* CEC data, e.g., http://energyalmanac.ca.gov/petroleum/statistics/2014_crude_by_rail.html; and EIA data (http://www.eia.gov/petroleum/imports/companylevel/archive).
[7] *<u>See</u>* EIA data (http://www.eia.gov/dnav/pet/pet_pri_imc3_k_m.htm).
[8] *<u>See</u>* EIA data (http://www.eia.gov/dnav/pet/pet_pri_refmg_dcu_nus_m.htm).
[9] *<u>See</u>* CEC reports CEC-600-2010-002-SF; CEC-600-2011-007-SD (forecast shown in graphs).
[10] Based on 95% confidence of the mean predicted by linear regression on CEC data in Chart 2.

Oil imports grow, or shrink, depending on policy:

Currently, crude imports from out of state average ≈ 1.1 MM b/d.[11] Assuming the California crude supply forecast above (≈ 0.29–0.41 MM b/d), these imports could grow to ≈ 1.3–1.4 MM b/d in the the 'extreme oil'/products export scenario (1.7 MM b/d total crude feed). This imports growth is consistent with the CEC's 'high case' forecast.[12]

Alternatively, with policy intervention, in the 'moratorium' scenario (0.85 MM b/d total crude feed), the volume of imported oil refined in California by Y-2030 could be reduced by about half, to ≈ 0.44–0.56 MM b/d.

The type of crude refined changes without policy intervention:

In the extreme oil / products export scenario, infrastructure would be retooled for growing imports of low-quality crude. Imported tar sands oils (heavy oil and bitumen) could account for as much as roughly 75–85% of total statewide crude input by Y-2030.[13]

In the 'moratorium' scenario, policy intervention blocks retooling for cheap bottom-of-the-barrel crude oil, and crude imports could decline along with petroleum fuels demand. Declining refinery product sales and crude throughputs, gradual retirement of capacity assets, and the relative ease of supplying crude when only about half as much is needed, would support little capital investment in retooling for extreme oil feedstock. Thus, the quality of crude feed refined here could remain similar to that now. In this scenario, roughly 50–70% of the Y-2030 California refinery crude feed could be out-of-state oil imports, and similar types of crude oil could be imported then as now.

Sources of oil imports change without policy intervention:

In the moratorium scenario Y-2030 California refinery crude feeds would need much less of the same type of crude California now imports from 36 countries and every continent. California's Y-2030 crude imports could come from many more sources that are much less geographically limited than they might be in the extreme oil scenario. However, this moratorium scenario assumes policy intervention.

In the extreme oil scenario refineries could commit capital assets to tar sands oil. This would lock in that feedstock. They would then depend on a subset of the global oil resource—those heavy oil and bitumen deposits that are technically, financially, and politically feasible to commercialize at scale. Although it has been trying for at least 50 years,[14] the oil industry has commercialized large-scale tar sands production in only a handful of regions, primarily the Orinoco of South America and the Western Canadian Sedimentary Basin. In this scenario, California might become dependent on a smaller number of more geographically concentrated, higher-impact oil extraction sources.

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[11] Y-2013 CEC data, http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts.html.
[12] CEC-600-2011-007-SD at 203 (480 MM b/y or 1.315 MM b/d).
[13] Canadian imports are imminent but are not the only, or even necessarily the largest, potential source of 'heavy oil' and 'bitumen,' as defined by the USGS report noted in our 6 March letter.
[14] *See* e.g., the history reported by Speight (1991).

(3) Y-2030 Crude Feed Quality: much worse without policy intervention.

In the moratorium scenario, in 2030 California could import about half as much of the same types of oil from current sources as it does now, and statewide crude feed quality could remain roughly similar to that now. But this assumes policy intervention.

Chart 3 illustrates feed quality in the extreme oil scenario. By 2030 the statewide crude feed could have ≈ 2–3 times more sulfur, and its density could increase by ≈ 2–4 times the current difference between its density and that of the US average. This assumes it is 75–85% tar sands oil that ranges in average quality from that of heavy oil to bitumen.

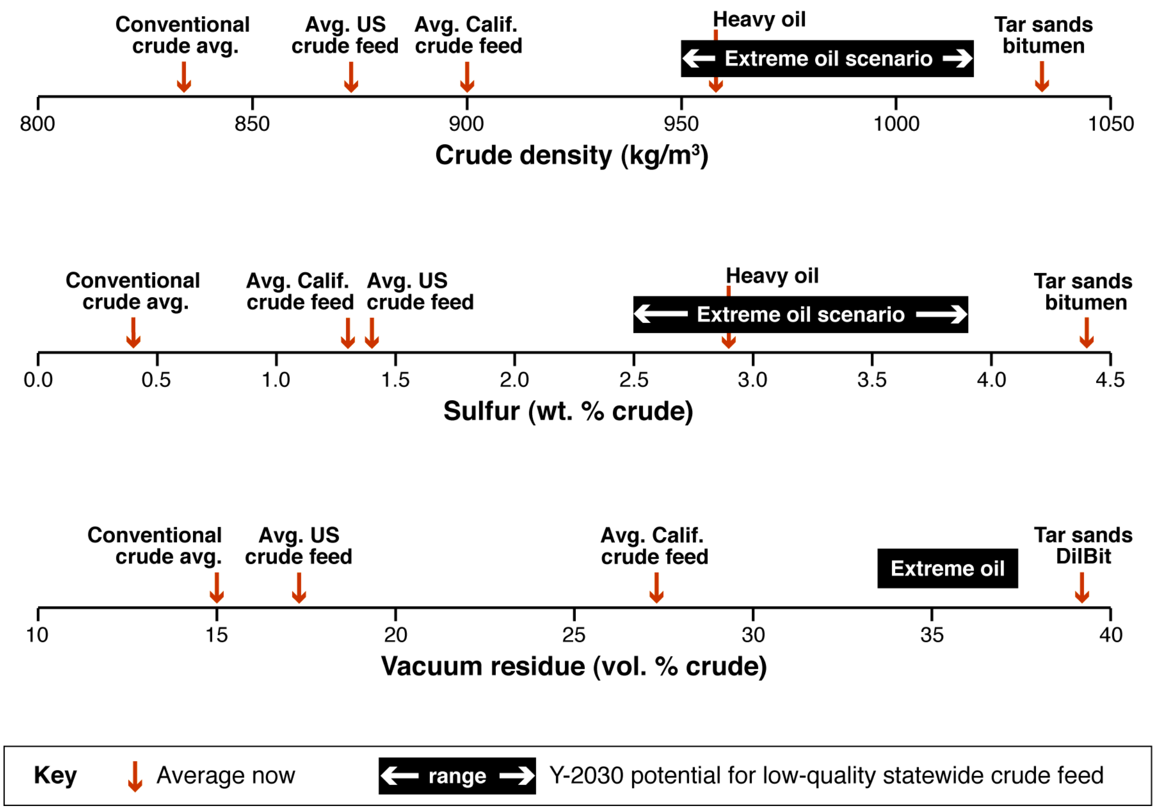

Chart 3. Estimated potential for tar sands oil to worsen three inherently hazardous refining characteristics of the average California crude feed by 2030 in the 'extreme oil' scenario.

Black horizontal bars: Y-2030 average California crude feed density, sulfur content, or (vacuum residue vol. %); range for 75–85% heavy oil/bitumen blends (Alberta dilbit blends) with remaining 15–25% comprised of the current avg. Calif. crude (current avg. estimated vacuum resid vol. %). ***Downward arrows:*** current average density, sulfur content or vacuum residue vol % reported for the type of crude oil or crude feed indicated. Note: density estimates exclude dilbit diluent.

Data: Conventional crude, heavy oil, and natural bitumen data from USGS Open-File Report 2007-1084, except conventional residue data from SCH# 2011062042 for 33.7 °API crude. US crude feed data from NRDC, 2015. Current California crude feed and California crude values are 2004–2009 averages from UCS (2011), except the resid value is estimated by CBE from EIA coking, visbreaking, ROSE capacity and coker yield data by the method used in NRDC, 2015.

The density, sulfur content, and vacuum residue fraction[15] of the statewide refinery crude feed could increase dramatically in this scenario. Abundant evidence links denser, higher sulfur, higher resid crude feeds to substantially increased toxic pollution and greenhouse emissions from refineries, increased frequency and magnitude of flaring, and recurrent catastrophic refinery spills, fires and explosions.[16] Increasing values for these 'bulk' characteristics of crude also suggest a general worsening of crude quality for other properties, such trace element and corrosive compound levels, and hydrogen content.

Chart 3 illustrates how far the extreme oil scenario crude feed could go in the wrong direction in terms of reported processing characteristics.[17] Predictions based on nationwide and statewide observations[18] illustrate how far this worsening of crude feed quality could go wrong in terms of its inherent effect on the average emission intensity of processing: Statewide emissions from oil refining alone (≈ 39.0 million metric tons/yr)[19] are now ≈ 46% of California's 85.2 million metric tons/yr target for statewide emissions of greenhouse gasses from <u>all</u> sources in Y-2050. In the extreme oil scenario, however, a predictive model developed for use with the available crude quality data suggests that average statewide refinery emissions could increase to ≈ 57.3–85.2 million metric tons per year, or ≈ 70–100% of that target, by the year 2030.[20]

These illustrations are meant to put the scale of crude feed quality change that is reasonably foreseeable assuming no new policy intervention into context, and should not be interpreted as a complete prediction of potential impacts. Refinery greenhouse gas emission impacts alone, though potentially severe and irreversible, do not represent a complete and accurate view of potential impacts in the extreme oil scenario. We outlined many severe and potentially irreversible impacts of allowing extreme oil infrastructure, including but by no means limited to increased refinery greenhouse gas emissions, in our 6 March letter to the Governor.

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[15] Crude oils with higher proportions of vacuum residue have more of the bottom-of-the-barrel, densest, most sulfur- and toxic metals-contaminated hydrocarbons that require severe, energy intensive, higher pollutant-emissions processing. Moreover, in addition to its larger volume percentage in tar sand oils, tar sands-derived vacuum residue tends to be much denser, more contaminated and more difficult to process than that of conventional crude oils.

[16] Citations omitted for brevity; documentation available on request.

[17] Many other tar sands oil properties are extreme but not well quantified for the South American imports in this scenario. Y-2030 shale oil/heavy oil blends are possible, but the severity of emulsion and coking problems those blends cause are not quantifiable by their density, sulfur content, or other standardized crude assays.

[18] Karras, 2010 and Union of Concerned Scientists (UCS), 2011; available on request.

[19] Average from 2004–2009 from UCS, 2011; includes all hydrogen production for refining.

[20] Based on the estimated average crude feed density (950–1,018 kg/m^3) and sulfur content (2.5–3.9 wt. %) range summarized in Chart 3 and central predictions from the average multi-plant CO_2 emission model reported by Karras (2010) and validated for California refineries by UCS (2011). Products, capacity utilization, and refinery fuel mix model inputs are estimated 2004–2009 statewide means. <u>*See*</u> Table 1-1 in UCS (2011) for non-oil-quality input and validation details.

Statewide Crude Feed in 2030?

Conclusion

Thank you, again, for your attention to this extreme oil infrastructure threat, and for valuing CBE's advice in this critically important matter. I hope you find this response helpful, will share it with the other State leaders who participated in our 13 April 2015 meeting, and will let me know if you have a question about this response.

We note and greatly appreciate Governor Brown's recent Executive Order for a 40% cut from 1990 levels in statewide greenhouse gas emissions by the year 2030—a goal that obviously is intertwined with the topic of this letter, moving away from oil-based fuels without moving toward even 'dirtier' oil. CBE's energy work is focused on organizing a just transition to sustainable energy and climate for environmental health and justice with good jobs for workers and everyone in our communities who wants one. As we continue in our community-based work for climate justice, please know that we look forward to continuing the development of policy support for replacing extreme energy with sustainable energy together.

In Health,

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Senior Scientist

Copy: Byron Gudiel, CBE
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