October 9, 2013
Ms. Barbara Radlein
SCAQMD
bradlein@aqmd.gov

Re: JMay Report on Phillips 66 LA Refinery Carson Plant-Crude Oil Storage Capacity Project Draft Negative Declaration (ND) – ND should be rejected, a full EIR is required

Dear Ms. Radlein,

This report provides my expert opinion regarding the Phillips 66 Los Angeles Refinery Carson Plant - Crude Oil Storage Capacity Project Negative Declaration (hereinafter the ND, or "the Project") provided on behalf of Communities for a Better Environment (CBE). I am a Senior Scientist at CBE and have provided engineering analysis on oil refinery project impacts, alternatives, and pollution prevention in California, and also outside the state as a consultant, for the last 25 years. A true and current copy of my CV is attached. I appreciate your review of these comments regarding major problems with the stated intent of Phillips 66 regarding this Project, which I found requires a full Environmental Impact Report. In summary (detailed later), I found that:

- **The direct impacts of the Project, even as narrowly described by the ND, have been underestimated and are significant**, including air impacts from new storage tank and pipeline cleaning, degassing operations, and other emissions;
- **Additionally, Phillips 66's Project description is incomplete,** failing to identify that the proposed changes to the refinery inputs to the crude unit, including expanded use of the brine stripper and added heat exchangers, which are exactly the increased desalting and temperature controls needed to enable processing of cheaper "Advantaged Crudes" which Phillips 66 has publicly announced it is bringing by rail and ship to California, including to the Los Angeles refinery. The brine stripper throughput and temperature increases also comprise an expansion beyond the refinery baseline;
- **Consequently Project impacts due to a type of debottlenecking of crude types that can be processed must also be evaluated,** including increasing risk of accidents due to corrosion associated with worsening crude quality (as determined by the U.S. Chemical Safety Board following the Chevron Richmond explosion on August 6, 2012), in addition to increased greenhouse gases and other significant impacts;
- **The Project would also enable other potential refinery expansions by providing a large increase in crude oil storage.** For example, Phillips has publicly stated its intention to add export capability to its West Coast refineries, to send product to China, India, and Brazil. Increased storage can be used in many different refinery projects. Storage tank emissions must not be piecemealed as a stand-alone project, since the tanks will be used in conjunction with many other refinery expansions.
- **This Project represents a piecemealing of a broader, publicly acknowledged Project by Phillips 66 to bring crude into California by rail and ship, and specifically to the Los Angeles refinery,** which has the potential to cause major risk increases and must be considered as a cumulative hazard.

Julia E. May, Senior Scientist, CBE, julia.e.may@gmail.com

Report of Julia E. May / CBE, on Phillips 66 LA Refinery Carson Plant
Crude Oil Storage Capacity Project Draft Negative Declaration (ND)
Comments to SCAQMD, 10/9/2013

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1. ***The redesign of desalting with new heat exchangers at the refinery front end is a necessary part of a switch to processing unconventional crude oil feedstocks, and is not an incidental modification.***

The Phillips66 Negative Declaration (ND) is misleading and incomplete in its Project Description. It is missing pieces of the picture that relate directly to the potential of the Project to enable a change in the crude types processed at the Los Angeles refinery to shale oils and tar sands crudes, causing significant environmental impacts.

First, the ND states incorrectly and in conclusory fashion that the Crude Unit heater firing rate is "considered" to be the baseline at the Refinery, and that because the Project does not include modifications to the Crude Unit throughput or heater firing rate, and does not include changes to process units downstream of the Crude Unit, the Project will not change the baseline operations of the Los Angeles refinery. The ND states:

> The current operations of the Crude Unit, including the heater firing rate at or near the permit limit, is considered to be the baseline at the Refinery and the proposed project does not include modifications to the Crude Unit throughput or heater firing rate. Therefore, current operations of the Crude Unit would not be expected to change as a result of the proposed project. Additionally, for the same reasons, the proposed project will not modify operations of process units located downstream of the Crude Unit. Therefore, the proposed project would not change the baseline operations of the refining processes or capacity at the LARC or the crude throughput of the Refinery. (1-10 to 1-11)

But the California Environmental Quality Act (CEQA) requires an analysis of actual potential environmental impacts, not a description of generalized perceptions of baseline operation. This analysis leaves out key details relating to switches in crude quality and their impacts at the refinery. Assuming, for the sake of argument, that there is no change to Crude Unit throughput or heater firing rates, this still does not preclude changes at the refinery due to the Project that cause significant environmental impacts.

To the contrary, the Project includes modifications occurring *at the input* to the Crude Unit that are key to enable the processing of heavier crude oils, and are especially key for Canadian heavy crudes, including tar sands. Processing dirtier crude oils can cause increased emissions and impacts even without substantially modifying downstream refinery operations; although the potential for such changes downstream are also discussed later in this comment.

Specifically, this project involves modifications to the desalting and heat exchanger operations associated with the Crude Unit. An industry paper, *Designing a crude unit heat exchanger network*, (2012)[1] describes the key role played by the desalter and heat exchanger "cold train," which is an *input* to the Crude Unit, and which itself is fed by the Project's new crude storage

[1] *Designing a crude unit heat exchanger network, Preheat train design for heavy Canadian crudes can be very , challenging, requiring an approach not normally required with other crudes,* Tony Barletta and Steve White, Process Consulting Services, Krish nan Chunangad Lummus, Technology Heat Transfer, Published in: Sour & Heavy 2012, www.eptq.com, "The refining, gas, and petrochemicals processing website," http://www.cbi.com/images/uploads/technical_articles/Crude-unit-heat-exchanger.pdf , Attached as Exhibit A

tanks. This paper highlights the crucial design and temperature requirements of desalting operations needed in order to process unconventional crudes:[2]

> The cold train heats the crude from the storage tanks to the desalter through seasonal changes in raw crude temperatures. For example, Canadian crude oil pipeline temperatures vary seasonally from 20-40°C, with the optimum desalter temperature varying from 120-140°C, depending on the crude blend. The amount of cold train duty that needs to be shifted to meet the wide range of desalter temperatures, while also handling the variable raw crude temperature, is very large. This is a major challenge because of the large amount of swing heat that must be moved before and after the desalter.

The paper finds that Canadian Crude oil, and tar sands oils or bitumen in particular, require adjustments to the desalter train design:

> Compared with other crudes, heavy Canadian crude processing requires more flexibility in the preheat train to adjust the desalter temperature in order to avoid asphaltene precipitation. Distillation column heat removal requirements require more flexibility because of seasonal diluents flow rates and variable crude compositions. The amount of required flexibility should be quantified as an objective of the preheat train design. (at 4)

The following ND excerpt describes water separation from incoming crude oil as merely a matter of moving the water draw from the Sour Water Stripper said to be operating "mostly" at capacity, instead to the new water draw surge tank, in order to allow treatment of the water <u>in the Brine Stripper</u> (a desalting operation). This involves three new heat exchangers "designed to raise the temperature of the water." This is exactly the type of change described by the paper above. The ND states:

> Crude oil received at the LARC contains small amounts of water, which are separated from the crude oil and accumulate in the bottom of the crude oil storage tanks. The accumulated water, referred to as water draw, is transferred from the crude oil storage tanks into a smaller water draw surge tank for processing prior to disposal. Currently, the water draw from all existing crude oil tanks is processed in the Sour Water Stripper, which mostly operates at maximum capacity. In order to consolidate and more efficiently manage water draw from crude oil tanks, the water draw from all existing crude oil tanks and new crude oil Tank 2640 is proposed to be routed to the new water draw surge Tank 2643. **The new 14,000 bbl water draw surge tank would allow LARC to treat the water in the Brine Stripper, which performs the same function as the Sour Water Stripper but has excess capacity.** No modifications are required to the Brine Stripper, but new equipment would be added to adjust the temperature of the water from Tank 2643 prior to entering the Brine Stripper. The new equipment would consist of three new heat exchangers **designed to raise the temperature of the water before entering the Brine Stripper,** and a steam trap to remove condensed steam after the heat exchangers. (at 1-9 to 1-10 (emphasis added).)

[2] Unconventional crudes are not strictly defined, but generally considered to include tar sands, shale oils, and deepwater crudes.

The ND discusses this as a benign matter of convenience. But in fact this is exactly the type of design change described in the paper above which specifically enables the processing of these heavier crude oils in the refinery. Furthermore, additional debrining (desalting) capacity is being added to the refinery, since the ND, as shown above, states that the Brine Stripper is not operating at capacity. The baseline is the current operation of the brine stripper, so this expanded use of debrining represents a type of debottlenecking allowing this change in crude feedstocks.

Another publication, a *Special Report: Refiners processing heavy crudes can experience crude distillation problems* (Oil and Gas Journal),[3] explores this same issue, again confirming that these key desalting and heat exchanger design modifications are needed to enable processing heavier crude feedstocks, necessitating increasing desalter temperatures as follows:

> **Processing tar sands crudes creates some unique challenges.** These crudes can have high sediment and clay contents and some blends also have high viscosity. **Desalter operations are more difficult and there is an increased likelihood of stable emulsion formation.** If desalter performance deteriorates, the corrosion rate in the atmospheric column Overhead system may increase and cause reliability problems.
>
> Crude blends with gravities <22° API require sufficient cold exchanger train preheat to achieve efficient desalting, which typically requires a desalter temperature between 270° and 300° F. **The desalter must separate the emulsion into low-salt crude and oil-free water. With a heavier crude feed, the desalter temperature can decrease by 30° to 40° F.,** if no additional surface area is added to the cold exchanger train. **The desalted crude's salt content can increase dramatically if the temperature is too low.** Many heavy crudes such as Zuata or Merey can have high salt contents depending on production field operations; therefore, good desalter performance is critical. **Poor cold exchanger train designs often cause low desalter temperatures, poor salt removal, and periodic upsets that send large quantities of brine to the atmospheric heater and column.** High chlorides to the atmospheric heater generate large quantities of hydrochloric acid (HCl). Severe fouling in the crude column's top, rapid fouling and corrosion in the atmospheric condenser system, and severe overhead line corrosion often reduce crude runs and unit reliability. (emphasis added throughout)

The Phillips 66 Project switch to processing through the Brine Stripper with additional heat exchangers to raise the temperature of the water, is again, exactly the kind of process design described by this report, and the ND has glossed over the purpose of this process change.

The ND does acknowledge at one point that the Project would provide "flexibility" in the types of crude oil the refinery may obtain. However inaccurately, the ND states in a conclusory way that the only thing that matters is the frequency of filling and emptying tanks, rather than also the modifications which allow changes in refinery feedstocks, or crude oil quality:

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[3] Oil and Gas Journal, Special Report: Refiners processing heavy crudes can experience crude distillation problems, 11/18/2002, available at http://www.ogj.com/articles/print/volume-100/issue-47/special-report/special-report-refiners-processing-heavy-crudes-can-experience-crude-distillation-problems.html , attached as Exhibit B

> **The increase in permitted throughput of the two existing storage tanks would provide flexibility for LARC to be able to blend multiple types of crude oil** in order to obtain the optimal crude oil properties for refining. Therefore, the proposed project would only increase the crude oil storage capacity and the frequency of filling and emptying of the tanks at the LARC. (ND, at p. 1-3)

There are differences in the levels of contaminants and other characteristics of these unconventional crudes that cause major impacts when refined, discussed later in this report.

A third article (*Innovative Solutions for Processing Shale Oils)* which is a second from Hydrocarbon Processing, discusses problems specific to shale oil processing including Bakken shale, as highly variable oils which can lead to asphaltene destabilization when blended with heavier crudes. This results in fouling of the cold preheat train, fouling of hot preheat exchangers and furnaces, problems in transportation, storage, refinery corrosion, and crude unit shutdowns:[4]

> The refining of shale oil (also known as tight oil) extracted through fracturing from fields such as Eagle Ford, Utica and Bakken has become prevalent in many areas of the US. Although these oils are appealing as refinery feedstocks due to their availability and low cost, processing can be more difficult.
>
> The quality of the shale oils is highly variable. These oils can be high in solids with high melting point waxes. The light paraffinic nature of shale oils can lead to asphaltene destabilization when blended with heavier crudes. These compositional factors have resulted in cold preheat train fouling, desalter upsets, and fouling of hot preheat exchangers and furnaces. Problems in transportation and storage, finished-product quality, as well as refinery corrosion, have also been reported. Operational issues have led to cases of reduced throughput and crude unit shutdowns. The problems encountered with shale oil processing and possible prediction and control strategies will be presented.

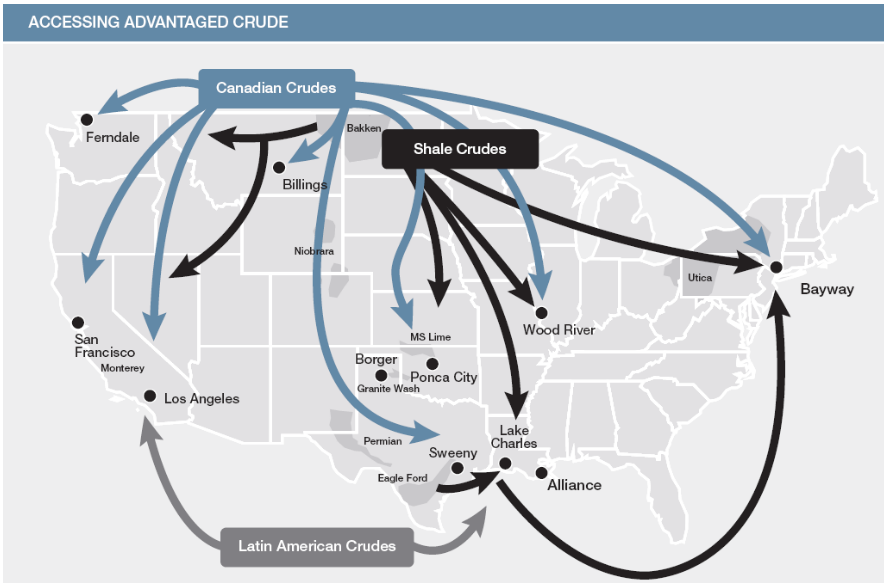
This article also identifies increased levels of extremely hazardous hydrogen sulfide that can be present, and other problems with shale oil. The likelihood of Phillips increasing use of tar sands and Bakken crude oils, and the associated impacts, are discussed below.

2. *Phillips has public plans to switch to an increasing percentage of these unconventional crudes, to be brought in by rail*

Phillips 66 showed in its Annual Report business plans emphasizing new use of "Advantaged Crudes," in other words, cheaper unconventional crude oils including Canadian tar sands crude, and Bakken Crude (from the Dakotas) and to bring them to West Coast refineries including the

[4] Innovative Solutions for Processing Shale Oils, Hydrocarbon Processing, 7/10/2013, http://www.hydrocarbonprocessing.com/Article/3223989/Innovative-solutions-for-processing-shale-oils.html, attached as Exhibit C

Los Angeles refinery by rail, as well as by marine vessel, as explained in the accompanying legal comments, and as shown in the report's map and statements below: [5]



For instance the annual report states:

> **In 2012, we reached an agreement with a railcar supplier to manufacture 2,000 crude oil railcars for the transport of shale crude to our East and West Coast refineries.**
>
> "Representatives from key areas of our business had been working on our crude-by-rail strategy." Said Joe Gallagher, director Commercial Truck and Rail. "We wanted to get a railcar order in quickly so we could get the cars in service and deliver cost-advantaged crude to our refineries as soon as possible."

The annual report also describes Phillips' business plan to *add export capability*, so that not only will its West Coast U.S refineries produce for the U.S. market, but they can also service China, India, and Brazil:

> Export Capability
>
> **The ability of U.S. refiners to access lower-cost crudes and natural gas provides a unique competitive advantage over many international refiners.** The United States has more than enough refining capacity to meet domestic demand and **studies show that much of the growth in demand for refined products will come from rapidly developing nations, such as China, India and Brazil,** with lower demand in the more developed regions of the world. The potential to export enables U.S. refineries to maintain high capacity utilization, resulting in lower per-unit costs and sustaining jobs at the facilities.

[5] Phillips 66, 2012 Summary Annual Report, at p. 20, available at: http://www.phillips66.com/EN/about/reports/Documents/Phillips-66-Summary-Annual-Report.pdf , attached as Exhibit D

> **Phillips 66 will continue to primarily serve domestic markets and will explore opportunities to meet growing demand overseas when opportunities exist.** At the end of 2012, we had the capability to export up to 285,000 BPD of refined products from our domestic refineries. **Several projects to further expand our export capability in our Gulf and West Coast refineries are expected to increase our total export capability to 370,000 BPD by the end of 2013.** This represents 30 percent of the clean products produced in our coastal refineries. We expect to be a key source of improving R&M margins over the next several years. (emphasis added)

Bloomberg also reported on the trend for West Coast refineries including Phillips 66 major shift toward rail shipment of cheap heavy crude oil, which it reports will drive cleaner oil out by 2014:[6]

> **The increasing volume of domestic oil making its way to the West Coast will drive light oil imports out of the region by the end of 2014,** Paul Y. Cheng, an analyst at Barclays Plc (BARC)'s investment-banking unit in New York, said.

It noted this increasing trend by rail in California, and that Phillips 66 is specifically planning rail offloading:

> **California, the world's ninth-largest economy, shipped via rail more oil than ever in February from North Dakota's Bakken formation,** while Russian imports to the region slid to 713,000 barrels from a June 2012 record of 6.53 million. . . .
>
> Tesoro, based in San Antonio, is already using rail to bring 50,000 barrels a day of Bakken to its Anacortes refinery in Washington and 5,000 barrels to the Golden Eagle plant in Northern California. Alon USA Energy Inc. (ALJ), **Phillips 66** (PSX), BP Plc (BP/) and Valero Energy Corp. (VLO) **are planning rail-offloading stations at their West Coast refineries**.

Tar sands crude developers in Canada are currently constrained by pipeline volume out of Canada (which is driving the crude by rail trend). Oil developers noted their target market of California in this press report: "Would it be beneficial to refiners to get this Canadian crude into the refineries in California and the West Coast?" said Charles Drevna, president of the American Fuel & Petrochemical Manufacturers trade group, this April. "The short answer is yes. The long answer is heck yes."[7]

CEO Greg Garland, has also been quoted on Phillips 66's webpage, as saying "We are looking at **pipe, rail, truck, barge and ship** -- just about any way we can get advantaged crude to the front end of the refineries." *See, e.g., Transcript of Dec. 13, 2012, Phillips 66 Analyst Meeting.*[8]

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[6] Bakken Boom Cutting West Coast Imports of Crude: Energy Markets, Bloomberg News, June 21, 2013, http://www.bloomberg.com/news/2013-06-21/bakken-boom-cutting-west-coast-imports-of-crude-energy-markets.html attached as Exhibit E

[7] Anchorage Daily News, April 21, 2013, http://www.adn.com/2013/04/21/2873796/pipeline-project-quietly-moving.html#storylink=cpy

[8] Available at: http://www.phillips66.com/EN/investor/presentations_ccalls/Documents/PSX_Investor_Transcript_12_13.pdf;

Phillips 66 defines this “advantaged crude” as including “heavy crude oil from Canada and Latin America, lighter Canadian grades, and West Texas Intermediate (WTI).” [9]

Moreover, Hydrocarbon Processing Magazine published an article stating that the oil industry no longer cares if the Keystone Pipeline gets built, because it now has other options for transporting the oil, such as those listed above.[10]

Fox Business News further reported last December that Phillips 66 Executive Vice President (VP) had specifically identified its Los Angeles refinery in these efforts:[11]

> . . . **So instead, local refiners are angling to bring in oil from places such as the Bakken fields** of North Dakota and the Eagle Ford and Permian Basin in Texas, **turning to railways** to tap into domestic production that is running at its highest in two decades. **The incentive is clear.** Bakken was priced at around $82 a barrel on Friday, while roughly similar quality ANS crude from Alaska was nearly $106, according to Reuters data. That's a steal, even accounting for the up to $15 a barrel cost of shipping the oil by rail from North Dakota to the West Coast.
>
> **Phillips 66, which runs refineries in Los Angeles and San Francisco, is "looking for everything we can find," says Tim Taylor,** executive vice president of commercial, marketing, transportation and business development. **Its West Coast plants already use rail to export refined fuels and have some capacity for unloading crude, he added.**

Notably, the VP was quoted stating that **the LA refinery already has some capacity for unloading crude by rail**. This shows that the Project identified in the ND enables Phillips 66 to immediately utilize different types of crude through changes at the refinery front end which increase desalting capacity. Because the ND is missing analysis about how this change modifies the type of crude that can be input, it is also missing a quantification of the volume of crude oil change that can be processed due to the increased capacity at the brine stripper, the added heat exchangers and the potential resulting impacts. This change needs to be analyzed in a full EIR.

Phillips 66 stated again on its website that it has a specific target for switching to advantaged crudes to reach an additional 500,000 bpd (barrels per day) from 2011 to 2017, which is an additional 28% of its entire U.S. refining capacity (of 1.8 million bpd), involving 2,000 railcars (757 barrels each, which is almost 32,000 gallons[12]), as shown in the following table from its website, entitled “**Advantaged Crude by numbers**:”[13]

Transcript of May 21, 2013, Phillips 66 Presentation at UBS Global Oil & Gas Conference, last accessed Aug 7, 2013;
http://www.phillips66.com/EN/investor/presentations_ccalls/Documents/2013%20UBS%20Oil%20and%20Gas%20Conference.pdf last accessed Aug 7, 2013.

[9] Available at: http://www.phillips66.com/EN/newsroom/feature-stories/Pages/AdvantagedCrude.aspx, last accessed Aug 7, 2013.

[10] Hydrocarbon Processing, 9/4/2013, http://www.hydrocarbonprocessing.com/Article/3251320/Blogs/US-refiners-dont-care-if-Keystone-XL-pipeline-gets-built.html

[11] December 10, 2012, http://www.foxbusiness.com/news/2012/12/17/analysis-california-refiners-dreamin-shale-oil-face-hurdles859141/

[12] 1 barrel = 42 gallons

[13] Phillips 66 website, “Advantaged Crude by the Number” January 2013, http://www.phillips66.com/EN/newsroom/feature-stories/Pages/AdvantagedCrudebytheNumbers.aspx

Global crude oil refining capacity	2.2 million BPD
U.S. crude oil refining capacity	1.8 million BPD
Average volume of advantaged crude oil processed at Phillips 66 U.S. refineries in the fourth quarter of 2012	1.1 million BPD
Targeted increase in new or increasingly advantaged crude oil processed from 2011 to 2017	500,000 BPD
Number of new crude oil rail cars to be delivered in 2013-2014	2,000
Capacity of each rail car/Total capacity of new rail car fleet	757 barrels/1.5 million barrels
Number of Jones Act Vessels under long-term charter to deliver advantaged crude oil	2
Brent crude price as of February 22, 2013	~$114/barrel
WTI price as of February 22, 2013	~$93/barrel

The trend toward crude by rail is driven by the price differential between more conventional foreign crudes, and cheaper crudes such as Canadian tar sands and Bakken. These prices do fluctuate, and a recent financial report described a slow-down of rail shipment due to the reduction in this price differential. However, the financial publication predicted that even if the price differential isn't quite as big as it had been and rail shipments may not grow as fast as they were, rail still remains attractive due to the flexibility it allows for oil refineries to switch feedstocks quickly with price changes:[14]

> **The bottom line**
>
> Looking ahead, however, I don't expect crude-by-rail shipment volumes to fall sharply, though I do suspect they probably won't grow as fast as they have over the past couple of years. **Rail still remains one of the most attractive alternatives to pipelines and, in some cases, the only viable option for shipping crude from remote oil-producing regions of the country.**
>
> When compared to pipelines, rail frequently offers greater flexibility since it allows shippers to more easily reroute oil based on price differentials, which are constantly in flux. It also offers a much speedier time to market, sometimes two or three weeks faster than pipelines. **Lastly, rail features shorter-term contracts than pipelines and lower regulatory risk -- factors prized by many customers.**

In addition to the price differential between conventional crudes and so called advantaged crude, these factors increase the incentive for oil companies to get the infrastructure in place for crude by rail now, in order to have this flexibility, and in order to take advantage of the price differentials when they become larger. Such infrastructure modifications include those identified for this Project; i.e., front end desalting and heat exchangers increases.

3. ***The switch to a higher percentage of unconventional crude oil processing includes increased crude contamination and higher energy use, causing major impacts***

[14] AOL Money and Finance, The Daily Finance, http://www.dailyfinance.com/2013/09/28/is-the-collapse-of-the-brent-wti-spread-a-threat-t/

While Phillips already processes many heavy crude oils, these differ from the unconventional crude oils that Phillips 66 has now targeted for major expansion at its refineries including the Los Angeles complex, including heavy Canadian tar sands crude and Bakken shale oil.

Although Bakken shale is generally light (meaning a relatively lower carbon content compared to heavy crude oil) and sweet (low sulfur), it is unlike conventional light sweet crude, in that there are still many problems with processing it, and it can cause severe wax buildups when transported and processed. This is discussed below in relation to another excerpt from the previously cited Hydrocarbon Processing article (*Innovative Solutions for Processing Shale Oils. . .*), and later in the section on rail transport.

The article found use of shale oils was particularly problematic when blended with heavy crudes, which is very likely to happen at the Los Angeles refinery complex, since it is designed for heavy crudes. (See below, where a variety of crudes are identified for this refinery.) This blending can cause agglomeration of large molecules onto surfaces inside refinery units which can crack and leave coke-like deposits if the surfaces are hot.[15] Coke deposits lead to poor operation and can cause shut down of units before planned maintenance periods. In addition, the article found shale oils to be highly variable in certain characteristics including for example, its solids content, and others.

Furthermore, shale oils can include high levels of extremely hazardous hydrogen sulfide (H2) gas, but when scavenging agents are used to reduce H2S presence, these can also cause corrosion and form solid deposits inside refinery processing units.

Specifically, the article states:

> Due to their paraffinic nature, mixing shale oil with asphaltenic oil leads to destabilization of the asphaltene cores. Asphaltenes are polar compounds that influence emulsion stability. Once the asphaltenes destabilize, they can agglomerate, leading to larger macro-molecules. On hot surfaces, agglomerated asphaltenes easily crack or dehydrogenate and gradually form coke-like deposits.
>
> **Several shale oil production locations have high H_2S loading.** To ensure worker safety, scavengers are often used to reduce H_2S concentrations. The scavengers are often amine-based products-—methyl triazine, for instance—that are converted into mono-ethanolamine (MEA) in the crude distillation unit (CDU). Unfortunately, these amines contribute to corrosion problems in the CDU. Once MEA forms, it rapidly reacts with chlorine to form chloride salts. These salts lose solubility in the hydrocarbon phase and become solids at the processing temperatures of the atmospheric CD towers and form deposits on the trays or overhead system. **The deposits are hygroscopic, and, once water is absorbed, the deposits become very corrosive.** These physical properties are responsible for the problems that are being experienced by refineries handling shale oils.

Unconventional crude characteristics can also include increased metal content. Of course, tar sands crude oil causes major environmental damage during its mining, as described by the World

[15] Coke is a petroleum product that is mostly the carbon leftover after making gasoline from crude oil. Coke is a fuel, and similar to coal, as an energy source that results in high GHG and criteria pollutant emissions, and significant heavy metal content.

Resources Institute, which rather mildly states the severe impacts:[16] *"The local and regional environmental impacts of heavy oil and tar sands production can include: significant water consumption, massive earth moving and ecosystem disturbance, increased criteria and other air pollution, and release of heavy metals and toxic materials."*

Canadian tar sands are even heavier than most heavy conventional crudes (higher carbon content, requiring additional energy to process and increasing emissions) and have higher sulfur content. Contaminants must be removed during refining, which increases hazardous materials present within the refinery and can lead to dangerous corrosion within refinery operations units. These also increase energy needed for refining, resulting in higher greenhouse gas and smog-precursor emissions.

Earlier I cited an Oil & Gas Journal article which identified the need for additional desalting and temperature controls in order to process unconventional crude oils. This and the other articles identified many problems with processing unconventional crudes, emphasizing that it is not just *volume* of crude throughput that determines environmental impacts, but also the characteristics or *quality* of the crude oils. The Oil and Gas Journal article (*Refiners processing heavy crudes can experience crude distillation problems)* also identified a number of differences in the content of unconventional crudes (such as tar sands and others):

> Heavy crudes have much higher microcarbon residue (MCR), asphaltenes, and metals. As mandated refinery gasoline and diesel pool sulfur specifications take effect, minimizing cat feed hydrotreater (CFHT) feed contaminants becomes more important. In some cases, vanadium in the CFHT feed has increased from less than 1 ppm to 5-10 ppm with heavy Venezuelan crudes.[1] **High feed-stream contaminants can reduce run length to less than half the planned turnaround interval.** Optimizing the atmospheric column flash-zone and wash section, and the vacuum unit design can reduce CFHT feed vanadium by 30-40%. . . .
>
> Heavy crudes have higher viscosities, some have higher salt content, several have high naphthenic acid content, and they are all more difficult to distill than lighter crude blends. Some upgrader crudes also have lower thermal stability than conventional crudes and higher fouling tendencies due to the increased likelihood of asphaltene precipitation. . . .
>
> High chlorides to the atmospheric heater generate large quantities of hydrochloric acid (HCl). Severe fouling in the crude column's top, rapid fouling and corrosion in the atmospheric condenser system, and severe overhead line corrosion often reduce crude runs and unit reliability.

A few of these problems are discussed in more detail below, but a complete inventory and evaluation of differences in the crude oils to be processed at the refinery due to the Project changes needs to be evaluated for environmental impacts.

a. Increased hydrochloric acid corrosion

Hydrochloric acid corrosion discussed above causes potential reliability problems and increases accident risk. Especially since the article above found that these contaminants can reduce the run

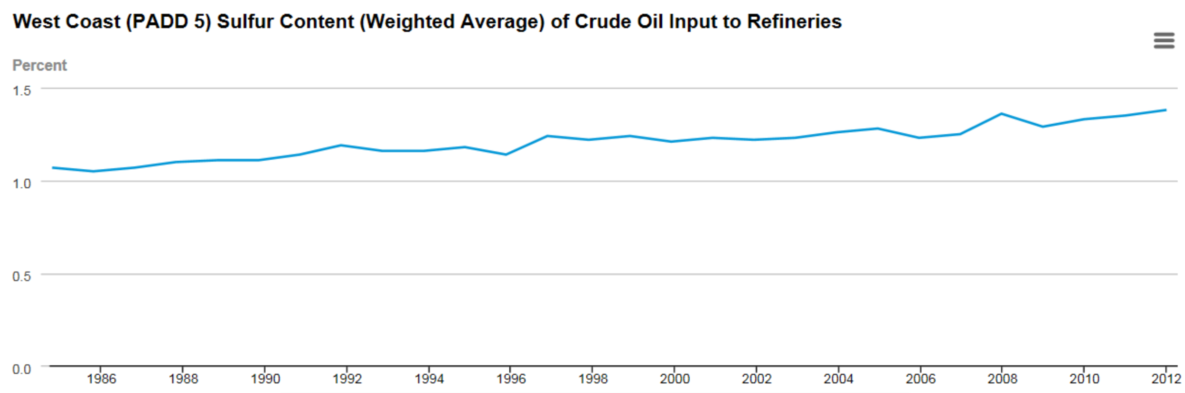
[16] http://www.wri.org/publication/content/10339

time of units to half of planned turnaround time (which means that process problems occur long before scheduled maintenance), this can result in upsets that at the least increase emissions and require unscheduled shutdowns, and at worst, are life-threatening to workers and dangerous to neighbors' health.

b. Increased sulfur compound corrosion

Another type of corrosion due to increased *sulfur* content in crude oil is a major increasing risk at oil refineries. Unconventional crudes, especially extremely high sulfur tar sands crude, can make this drastically worse. Increased sulfur content problem already caused a major explosion at a California refinery, indicating that we are moving to a very dangerous point in refinery operation in the state. Any increase in sulfur content in crude oil slates at California refineries should now be considered to cause a significant impact. (This problem was substantiated by the U.S. Chemical Safety Board report on the Chevron explosion; see discussion below.)

The U.S. Energy Information Administration (EIA) charted the trend in increased sulfur content, as in the chart on West Coast refinery crude oils, which were up from just over 1% to an average of about 1.4 percent in 2012: [17]



(The EIA also found this increase on a national basis.[18])

California refineries dominate the data in the chart above for the West Coast region called PADD5.[19] Only imported crude data is provided by the EIA for individual refineries, so domestic crude from California and Alaska are missing.

As bad as this trend already is, use of unconventional crude oils can make it much worse. For example, Western Canadian Select crude oil has a very high sulfur content (3.5%), far higher

[17] U.S. EIA, chart downloaded 10/8/2013, pdf of website page, available at: http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mcrs1p52&f=a

[18] US EIA, "The average sulfur content of U.S. crude oil imports increased from 0.9 percent in 1985 to 1.4 percent in 2005, and the slate of imports is expected to continue "souring" in coming years. Crude oils are also becoming heavier and more corrosive . . ." http://www.eia.gov/forecasts/archive/aeo06/pdf/0383(2006).pdf

[19] California made about 67% or 2.2 million barrels per day (bpd) in 2006 out of 3.2 million PADD5 total. (EIA does not provide such data separately for California in total.) From CBE report: *The Increasing Burden of Oil Refineries and Fossil Fuels in Wilmington, California and How to Clean them Up!,* at p. 10 and endnotes, available at http://www.cbecal.org/wp-content/uploads/2012/05/wilmington_refineries_report.pdf

than the state average.[20] Although the Phillips 66 Los Angeles refinery complex already processes high sulfur crude, it is the average of the total volume that would increase due to the use of unconventional crude oils. Based on my experience and review of Phillips crude oil domestic and imported crude oil, it is doubtful that the current average is this high.

My review of U.S. EIA data including reporting on Phillips 66 crude oil quantities, sulfur content, and API gravity, for the Phillips 66 Los Angeles refinery crude oil for 2012 (imports only) shows that its crude import sulfur content varied from about 0.79% to only a couple of instances with as high as 3.34% sulfur.[21] (Phillips also uses substantial domestic crude, but unfortunately this is not required to be reported to EIA, but should be reported in a full EIR.) The imported crude was made up of roughly half high sulfur and half lower sulfur crude oils. Most of the higher sulfur crudes still had much lower sulflur content than Western Canadian. It is these imported crudes that are likely to be replaced by "advantaged" crude oils from Canadian tar sands and Bakken shale at Phillips, so there is clearly a major potential for a significant increase in sulfur content.

The ND should have identified baseline crude slates and sulfur content data at the Phillips 66 Los Angeles refinery complex, in addition to the percent sulfur of the unconventional crudes which can potentially be processed due to the Project changes discussed, and volumes of the baselines and crude changes.

In addition to the overall sulfur compound percentage in crude oil, even light sweet Bakken crude (low sulfur), can have dangerously high levels of H2S along with the crude. A report by Bakkenshale.com found:[22]

> Is the Bakken producing higher volumes of H2S? That's the question you have to ask yourself when you see pipelines implementing H2S standards for the first time.
>
> On May 8, Enbridge submitted an emergency application to the Federal Energy Regulation Commission (FERC) asking to amend its conditions of carriage to 5 ppm of H2S or less. If accepted, Enbridge would have the right to reject crude with higher levels of H2S. . . .
>
> **Enbridge acted after it found concentrations of 1,200 ppm in a crude tank at its Berthold Terminal. 20 ppm is the limit allowed by OHSA and an average of 10 ppm of exposure is all that is allowed over an 8-hour work day.**
>
> Both Plains Marketing and Murex Petroleum objected to the FERC application, but it looks as if they solved their differences when Enbridge notified FERC it wasn't planning an outright ban on crude with higher H2S concentrations. The two companies weren't against the change, but were afraid they couldn't comply in the time frame planned.

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[20] Western Canadian Select (WCS) fact sheet, Cenovus Energy, http://www.cenovus.com/operations/doing-business-with-us/marketing/western-canadian-select-fact-sheet.html, attached as Exhibit F

[21] 2012 US EIA data, for Phillips 66 Los Angeles refinery, available at: http://www.eia.gov/petroleum/imports/companylevel/archive/

[22] May 30, 2013, http://bakkenshale.com/pipeline-midstream-news/bakken-producing-sour-gas-h2s-problem-in-north-dakota/ attached as Exhibit G

Thus hazardous and corrosive sulfur compounds can either be part of the crude characteristic, but also can be transported with otherwise low sulfur crude oil. The Chemical Safety Board report also identified that H2S was a particularly aggressive corrosive agent.[23] These issues must be evaluated through a full EIR to prevent severe safety risks associated with crude slate changes.

The problem of sulfur corrosion increasing accident risk was unfortunately born out at Chevron Richmond in California last August, when a major explosion barely avoided killing 19 workers, but did send 15,000 neighbors to the hospital, after a huge black plume traveling many miles through the Bay Area resulted from the crude unit explosion, which burned for many hours. The same kind of sulfur corrosion found at the Richmond refinery was identified at the Chevron El Segundo refinery in Southern California by the U.S. Chemical Safety Board report regarding the Richmond explosion. Steelworkers also testified at the U.S. Chemical Safety Board hearing on the Chevron explosion that such sulfur corrosion is a statewide problem at California oil refineries.[24] The Chemical Safety Board found the Richmond accident was caused by sulfur corrosion that Chevron had been aware of, and had repeatedly ignored, and the report showed that sulfur content had increased. The photos below show the heavy impact not only in Richmond, but across the San Francisco Bay Area due to this accident.

Please also see a full discussion of corrosion issues at oil refineries due to increased sulfur content in crude oil, and other important related issues in the attached report of Greg Karras on the Phillips 66 *Rodeo* refinery EIR,[25] where a new rail project is also in the works. This report demonstrates in further detail the impacts of sulfidation corrosion demonstrated by the US Chemical Safety Board, causing the massive explosion in August of 2012 in the Chevron Richmond refinery, pictured below. The U.S. Chemical Safety Board report is also available.[26] The significance of the air pollution impacts are evident in the photos below.


[23] *Id.* at p. 33
[24] U.S. Chemical Safety Board transcript of public hearing on Chevron Richmond, CA August 2012 explosion and fire, page 225, http://www.csb.gov/assets/1/19/0503CSB-Meeting.pdf
[25] Expert Report of Greg Karras, CBE, 4 September 2013, Regarding the Phillips 66 Company Propane Recovery Project Draft Environmental Impact Report released in June 2013 by the Contra Costa County Department of Conservation and Development, Attached as Exhibit H
[26] Interim Investigation Report, Chevron Richmond Refinery Fire, (which as adopted at the July public hearing) available at: http://www.csb.gov/assets/1/19/Chevron_Interim_Report_Final_2013-04-17.pdf Attached as Exhibit I

c. Increased heavy metal emissions

As identified in the Oil and Gas Journal report, unconventional crudes contain higher metal content. Because there were so many issues missing from the ND, it is difficult to document all the missing issues in this report, but increased toxic heavy metals should be evaluated through a full EIR. Please see the report of Dr. Phyllis Fox for a discussion of increased metals, and many other issues that directly apply here, related to the use of tar sands crude oil proposed to be brought in by rail at the Valero Benicia, California refinery.[27]

d. Increased emissions and risk of accidents from rail and other transport of unconventional crudes

The July 6, 2013 crash of a train ferrying 73 tanker-cars carrying Bakken crude oil crashed in Lac Mégantic, Quebec and ensuing explosion leveled a town, killing dozens and injuring hundreds. Energy news reported the following statements regarding risk of rail transport (*Bakken crude makeup faces scrutiny in rail car explosion)*:[28]

> "Oil, even at very low pressures … still has some natural gas dissolved in it, and that gas will try to form a gaseous state every time there's a pressure drop," University of Texas, Austin, petroleum engineering professor Paul Bommer said in an interview.
>
> Loading the ill-fated crude into tank cars that rode the Montreal, Maine and Atlantic Railway Ltd. to Lac-Mégantic likely caused a small pressure drop, Bommer added, leaving room for "a fairly minor gaseous phase" to remain. "And gas, we all know, is extremely combustible."
>
> The Federal Railroad Administration warned the oil industry three weeks after the derailment that it had concerns about widespread misclassification of crude on the tracks as well as the potential for chemicals used in hydraulic fracturing to corrode rail cars used for shipping oil.

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[27] Comments on the Initial Study / Mitigated Negative Declaration, Valero Benicia Crude by Rail, June 1, 2013, Dr. Phyllis Fox, attached as Exhibit J

[28] Posted 9/10/2013, by Energy Wire, Midwestern Energy News, E&E Publishing, LLC, http://www.midwestenergynews.com/2013/09/10/bakken-crude-makeup-faces-scrutiny-in-rail-car-explosion/ Attached as Exhibit K

As a result of the accident (which was close to Maine), U.S. Congressional Members Pingree and Michaud met with federal agencies to review hazardous materials transport by rail, and provided the following report:[29]

> "After the accident in Quebec, there have been a number of safety concerns raised—both specifically in response to it and others that are longstanding. While it is still too early in the investigation to determine exactly how this tragedy could have been prevented, the design flaws of DOT-111 tank cars are well documented. We appreciate the Pipeline and Hazardous Materials Safety Administration's efforts to advance a rule to update the design of these cars, but progress is frustratingly slow given the initial delay. The federal rulemaking process is a cumbersome one, but we need to avoid any further delays, especially given the exponential growth of hazardous material shipments. Whether its oil, ethanol, or some other hazardous material travelling on our nation's tracks, the American people deserve to know that these shipments are being carried in tanker cars that are designed to the highest safety standards," said Michaud and Pingree.

Obviously there is a potential for increased accidents whenever there is increased rail transport of crude oil. This should have been evaluated in a full EIR due to the Projects' design changes facilitating unconventional crude import, and Phillips' stated intent to use such transport.

Please also see the attached *Future of Crude by Rail to the West Coast Part 2,* which identifies the many ways that crude can be transported to the West Coast by rail, either directly to oil refineries, or to centralized shipping centers being proposed, or to Bakersfield or other inland areas for input into existing pipelines. This indicates that a variety of transport methods will be used including rail, ship, and pipeline to get Canadian and Bakken crudes to California and the West Coast in general.[30] A full EIR is needed to evaluate the increases of all of these transportation modes, since Phillips will not exclusively rely on any one means.

In addition to accident potential, other transportation problems have been identified due to rail, truck, pipeline, ship and even truck transport and storage of shale oils, again from the Hydrocarbon Processing Article (Innovative Solutions …) due to paraffinic (wax) buildup:

> Another challenge encountered with shale oil is the transportation infrastructure. Rapid distribution of shale oils to the refineries is necessary to maintain consistent plant throughput. Some pipelines are in use, and additional pipelines are being constructed to provide consistent supply. During the interim, barges and railcars are being used, along with a significant expansion in trucking to bring the various shale oils to the refineries. Eagle Ford production is estimated to increase by a factor of 6—from 350,000 bpd to nearly 2 MMbpd by 2017; more reliable infrastructures are needed to distribute this oil to multiple locations. Similar expansion is estimated for Bakken and other shale oil production fields.
>
> **The paraffin content of the shale oils is impacting all transportation systems. Wax deposits have been found to coat the walls of railroad tank cars, barges and trucks.**

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[29] Federal Agencies to Review Hazmat Rail Rules Wednesday, July 31, 2013 Michaud, Pingree meet with Pipeline and Hazardous Materials Safety Administration, Attached as Exhibit L http://pingree.house.gov/index.php?option=com_content&task=view&id=1070&Itemid=24#sthash.m65A8kjB.dpuf

[30] RBN Energy LLC, 10/6/2013, Attached as Exhibit M, http://www.rbnenergy.com/coast-bound-train-the-future-of-crude-by-rail-to-the-west-coast-part-2

> Waxy deposits in pipelines regularly require pigging to maintain full throughput. Bakken shale oil is typically transported in railcar, although pipeline expansion projects are in progress to accommodate the long-term need. **These railcars require regular steaming and cleaning for reuse.** Similar deposits are being encountered in trucks being used for shale oil transportation. **The wax deposits also create problems in transferring the shale oils to refinery tankage. Fig. 4** shows samples of deposited wax collected from pigged pipelines[31] in shale oil service.

The article provided a photo ("waxy deposits removed from shale oil buildup"):

The article also identified multiple chemical dispersants used to mitigate these problems not only during transportation, but also within refineries where these shale oils are processed. Such chemicals must be identified in a fuel EIR in order to assess the impacts of their use. The article also found that steam cleaning is used to remove such deposits from railcars. Such activities should be identified and associated impacts evaluated.

(Such waxy building within the refinery should also be evaluated for safety risks.)

e. Increased unconventional crude processing greatly increases greenhouse gas emission

The ND discusses only two types of increased greenhouse gas emissions (GHGs) due to the project – emissions due to third-party power (electricity), and GHG emissions due to construction. The ND did not evaluate the major increase in GHG emissions due to the switch to dirtier crude feedstocks.

Regarding third party power use, the ND states that emissions will by definition all be taken care of by the state's Cap and Trade program. It finds that because this program exists, therefore there will be no increase in GHG emissions above the SCAQMD threshold. (Unfortunately, the efficacy of this program is far from demonstrated, in fact, substantial evidence of its ineffectiveness[32] is part of the regulatory record, but for now, let us leave this aside.) The ND states that no change in GHG operational emissions is expected at the LARC:[33]

[31] A "pig" is launched through a pipeline until it reaches a receiving trap, in order to clean and inspect pipeline
[32] The efficacy of California's Cap and Trade program is by no means a demonstrated fact. The Cap and Trade program and particularly its offsets provisions are highly controversial and not demonstrated to succeed in reducing greenhouse gas emissions. In fact, substantial evidence has been submitted into state regulatory proceedings showing that all pollution trading programs failed in the early years, and many never succeeded in reducing pollution even after years: 34 Colum. J. Envtl. L. 395 (July 17, 2009), Overallocation Problem in Cap-and-Trade:

> Sources regulated by the cap must reduce their GHG emissions or buy credits from others who have done so. This means that the additional power utilized at the LARC as a result of the proposed project cannot result in an increase in GHG emissions from the increased use of third-party power, compared to GHG emissions at the time of issuance of the NOP. The proposed project does not affect compliance with the requirements of AB32, **since no change in GHG emissions at LARC from operation of the proposed project are expected**. Therefore, the proposed project would not conflict with AB32, the applicable GHG reduction plan, policy, and regulations that have been adopted to implement AB32.
>
> Thus, the SCAQMD's GHG significance threshold for industrial sources would not be exceeded. Based on the preceding analysis, implementing the proposed project is not **expected** to generate significant adverse cumulative GHG air quality impacts. (emphasis added)

The ND finds only 63 metric tons/year in emissions (from purchased power), and 43 metric tons per year from "30-year Amortized Construction" are expected:

TABLE 2-6

Estimated GHG Emissions for the Proposed Project
(metric tons/year)

Source	CO_2e
Third-Party Power[(1)]	63
30-Year Amortized Construction	43
Total GHG w/ Construction	**106**
Significance Threshold	**10,000**
Significant?	**No**

(1) Anticipate less than 25 kW increase in purchased power from SCE.

If 30-year Amortized construction means that the GHG emissions are averaged over 30 years, more specifics should be provided on the actual peak emissions in the shorter time frame, especially relating to GHGs other than CO2 and methane that have strong short term impacts, but which are under- or un- regulated .

But beyond these problems, the main issue with the gross underestimation of GHG emissions due to the Project is related to the processing of unconventional crude oils (shale and tar sands), which have different qualities from conventional crude oil, and can require far more energy to refine. The ND states categorically that there will be no changes in downstream refinery processing, but does so without providing any evidence to demonstrate the existing baselines for the downstream units and crude oil transportation facilities (including rail, ship, and pipeline baselines).

This flies in the face of the evidence because: 1) the Project redesign is the same kind needed to allow increased processing of unconventional crude oils, 2) Phillips has stated it plans such a switch, 3) such a switch requires increased processing to remove sulfur contaminants, to crack

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Moving toward Stringency, The; McAllister, Lesley K., http://www.columbiaenvironmentallaw.org/assets/pdfs/34.2/7._McAllister_34.2.pdf.
The European Trading program srepeatedly failed to meet its emission reduction goals.

[33] At p. 2-28

heavy hydrocarbons, and for coking operations. Under these circumstances, the ND has a major gap, in the failure to provide any evidence but conclusory statements that there will be no changes.

Furthermore, an expert report submitted relating to the Valero Benicia, California refinery rail project of this year found that refineries have a price incentive to purchase heavy, sour Canadian tar sands over Bakken light sweet crude. Canadian tar sands crude oils require greatly increased energy to process.

A CBE peer-reviewed study (Karras, CBE, Environmental Science and Technology 2010[34]) documented that crude oil density or API gravity (heaviness of crude oil) and sulfur content (which usually accompanies heavy crude) strongly predicts high energy intensity, meaning it takes a lot of energy to refine this crude oil. High energy use means high carbon dioxide emissions from this processing. This high energy intensity drove a 39% increase in greenhouse gas emissions across regions and years at oil refineries.

Although it took a rigorous study to prove it, this result makes common sense, because oil refineries must do more intensive cracking when crude oils contain a higher percentage of heavy, long-chain hydrocarbon molecules, in order to produce shorter molecules that make up gasoline and diesel liquids, and they must strip sulfur compound contamination out of this high sulfur crude, requiring high amounts of hydrogen.[35]

It is essential that a full EIR be provided that fully discloses actual refinery baselines (not just permitted levels of operation, but also actual levels of operation). In addition to crude unit baselines (including heaters), this should include hydrotreaters (which strip sulfur), cracking units (which break up long chain hydrocarbons found in heavy crude oil), coking (which processes the heaviest bottom of the barrel fraction of crude, which is a higher percentage of heavy crude oils), hydrogen unit production (needed for stripping sulfur compounds and make-up hydrogen), and outside hydrogen purchases. These will provide the evidence regarding whether the downstream baselines will increase or not.

Further, a full EIR should be prepared which identifies the refinery modifications of the last few years and planned modifications, in order to identify their relationship to this Project.

4. *The major new tank capacity enables large future refinery expansions*

[34] Greg Karras, CBE, Combustion Emissions from Refining Lower Quality Oil: What Is the Global Warming Potential?, *Environ. Sci. Technol.* **2010,** *44*, 9584–9589, http://pubs.acs.org/doi/abs/10.1021/es301915z Attached as Exhibit N

[35] Stripping sulfur compounds requires making large amounts of hydrogen. Also, "make up" hydrogen is required to be added when cracking long hydrocarbons. New hydrogen plants at oil refineries have been shown to add a million tons per year of CO_2 emissions to a single refinery. In addition to vastly increasing energy needed to make gas and diesel, dirty crude oil means a great increase in processing acutely hazardous sulfur gases such as hydrogen sulfide. This can be released during accidents.

The Negative Declaration (ND) states:[36]

> **Description of Nature, Purpose, and Beneficiaries of Project:** Phillips 66 is proposing to increase crude oil storage capacity at its Los Angeles Refinery Carson Plant by installing one new 615,000 barrel crude oil storage tank with a geodesic dome, increasing the annual permit throughput limit of two existing 320,000 barrel crude oil storage tanks, and installing geodesic domes on the same two existing 320,000 barrel crude oil storage tanks.

Later, the ND finds that the reason for this major crude storage increase is to reduce the time in-port for tankers offloading large crude quantities:

> The current capacity of the existing storage tanks limits vessel delivery volumes to Panamax vessels (400,000 bbl capacity), which are the size limits of vessels that can travel through the Panama Canal. For larger vessels, such as Aframax (720,000 bbl capacity) or Suezmax (1,000,000 bbl capacity), the current capacities of the existing storage tanks require two ship calls to unload the entire volume of a larger vessel, resulting in seven to 10 days when the ship remains in the port area. When a ship larger than Panamax calls, LARC accepts delivery of the first portion of the crude oil into the existing tanks then processes the crude oil through LARC to make room in the receiving tanks to accommodate the second discharge from the larger vessel. In order to avoid the extra wait time, which increases costs and creates additional vessel hoteling emissions, LARC needs more crude oil tankage storage capacity to accommodate the larger vessels so the entire volume of crude oil can be unloaded in one ship call.

While it is true that these new tanks can enable reducing expensive port-time for large tankers, this storage capacity also massively increases one piece of the refinery's overall crude oil processing capacity at the front end. The company stated above that it plans to expand in the future into the business of *exporting* refinery products to other countries, including from its West Coast refineries. Adding this tankage provides one major piece of such a project that should not be separated from future refinery projects that enable such expansions. This major tankage increase must be evaluated as part of such future expansions. It may also be that the refinery plans to separate storage of unconventional crude oils with varying characteristics from other storage. These issues need to be evaluated in a full EIR.

5. *Even emissions associated with the limited Project description were undercounted*

VOC (Volatile Organic Compound) emissions from operation of the Project were calculated in the ND at 50.83 lbs/day (rather close to the threshold of 55 lb/day), and during construction were estimated at 65.3 lbs/day (not far from the SCAQMD 75 lb/day CEQA construction threshold). Only minor increases in emissions would put the Project over the CEQA significance thresholds. The following emissions sources were not assessed in the ND. Not only is there a fair argument that these have the potential to cause operation emissions to exceed the SCAQMD 55 lb/day CEQA threshold, due to the number of these missing sources, it is very likely these would cause exceedance of the threshold:

[36] at 2nd page of Notice of Intent to Adopt a Draft Negative Declaration (ND)

- Oil layer in water draw surge tank: VOC emissions from the ongoing presence, and from collection and removal of crude oil accumulation in the water draw surge tank which were not provided and should be calculated, related to identified conditions in the ND:[37]

  > "Over time, a thin layer of crude oil is expected to form in the water draw surge tank. Accumulated crude oil from the water draw surge tank would be collected and transferred back to the new crude oil storage tank."

  These may be uncontrolled emissions, and should be described and quantified.

- Tank cleaning and degassing: Storage tanks must be periodically cleaned. Emissions from tank cleaning operations for preparation for the modifications of the existing tanks, and later tank cleaning during ongoing operation of both existing and new tanks, was not identified and assessed. Because refinery crude oil storage tanks are very large, and over time crude storage results in accumulation of heavy sludge (called tank "bottoms"), this must periodically be cleaned and removed. SCAQMD Rule 1149 (Storage Tank and Pipeline Cleaning and Degassing) controls but does not eliminate these emissions from the extremely large volumes of hydrocarbon product in these tanks.[38] Tank cleaning and degassing protocols and frequency should be identified and emissions calculated.

  In addition, the Hydrocarbon Processing article (Innovative Solutions) identified storage tank waxy buildup and sludge as a specific problem with shale oil storage, with a solution to use chemicals to break up the waxes. The impacts, effects on tank operation and cleaning, and impacts of solutions such as chemicals used to break up waxes, should also be evaluated in an EIR process.[39]

- Pipeline cleaning and degassing: Pipelines are also periodically cleaned and degassed, and in this case, emissions would likely occur not only during future pipeline operation and maintenance activities, but also during the construction connection process with the new tanks. Again, Rule 1149 applies, but does not eliminate all emissions. Further, shorter runs of pipe are exempt, as described in the SCAQMD staff report, and so would not be controlled.[40] Identification of the pipeline lengths, connectors, construction activities, operation, and maintenance activities, including cleaning and degassing, and fugitive emissions from connectors should be specifically described and emissions quantified.

- Flaring of tank and pipeline gases: If flares are used to control degassing emissions for tanks and pipelines, the gas volumes, flare hydrocarbon destruction efficiency, and

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[37] At p. 1-9

[38] Final Environmental Assessment: Proposed Amended Rule 1149 – Storage Tank and Pipeline Cleaning and Degassing, April 2008, SCAQMD, Attached as Exhibit O, http://www.aqmd.gov/ceqa/documents/2008/aqmd/finalEA/FEA1149.pdf

[39] *"Due to the variation in solids loading and their paraffinic nature, processing shale oils in refinery operations offers several challenges. Problems can be found from the tank farm to the desalter, preheat exchangers and furnace, and increased corrosion in the CDU. In the refinery tank farm, entrained solids can agglomerate and rapidly settle, adding to the sludge layer in the tank bottoms. Waxes crystalize and settle or coat the tank walls, thus reducing storage capacity. Waxes will stabilize emulsions and suspend solids in the storage tanks, leading to slugs of sludge entering the CDU. Waxes will also coat the transfer piping, resulting in increased pressure drop and hydraulic restrictions."*

[40] At p. 1-13

remaining VOC emissions from flaring should be identified (as well as NOx, SOx, particulate matter, and other emissions).

- Crude diluent emissions: Additional emissions during the transport, piping, tank loading, and continued operation from volatile diluents used with expanded unconventional crude oils that Phillips has stated as its plans for the refinery have not been identified, and should be, with emissions quantified. Diluents can be very volatile and include BTEX compounds (Benzene, Toluene, Ethylbenzene, and Xylene, which are both toxic, and smog precursor VOCs).[41] In addition to the highly reactive ozone-precursor quality of such diluents, they need to be identified and evaluated as toxic air contaminants, due to carcinogencity and other health impacts.
- Rail transport emissions: In addition, potential VOC and other emissions from rail transport of the crude oil must be evaluated, since the refinery *currently* has rail capacity to unload unconventional crudes. Not only do these crudes have the potential to be unconventional, the company has specifically announced its intention to import such crude by rail, but has not discussed this within the ND. The potential for expanded rail transport for the purpose of delivering crude to the greatly expanded tanks must also be evaluated (also see section on rail transport).
- Unplanned process shutdowns: Because unconventional crude oils can reduce run-time to half that of planned turnarounds (planned maintenance schedules) as identified in the earlier-cited Oil & Gas Journal article, this means additional air emissions. Unplanned refinery shutdowns increases startup / shutdown and maintenance emissions include increased flaring emissions, potential pressure relief device venting to atmosphere, and also increase the risk of fires and explosions with many associated emissions (not only VOCs, but particulate matter, hydrogen sulfide, all the criteria pollutants, toxics including PAHs (polycyclic aromatic hydrocarbons), and many more). They also increase safety risks for workers and neighbors)

6. *Conclusion – a full EIR should be prepared*

My conclusion is that there is an abundance of evidence of significant environmental impacts due to this Project, requiring the preparation of a full EIR as discussed above. Because the ND incorrectly portrayed this Project as relatively a minor change, there were numerous environmental impacts missing. While I identified a number of these, the full range of impacts were too numerous to provide in a relatively short report. An EIR would rectify this problem by providing a full scoping and evaluation of these numerous issues. Furthermore, implications for the associated Wilmington portion of Phillips' Los Angeles operations must be fully identified.

[41] Please see the details in the comments of NRDC on the Notice of Intent to Adopt a Mitigated Negative Declaration for the Valero Crude by Rail Project, July 1, 2013, Attached as Exhibit P, which provide a detailed discussion of impacts of diluents used with Canadian Crude oil, and other important impacts related to the Valero Benicia crude by rail project in common with the Phillips 66 Los Angeles refinery complex.

List of Exhibits:

- Exhibit A Designing a crude unit heat exchanger network
- Exhibit B Oil and Gas Journal Heavy Crudes and Distillation Unit problems
- Exhibit C Innovative Solutions for Processing Shale Oils - Hydrocarbon Processing
- Exhibit D Phillips-66-Summary-Annual-Report
- Exhibit E bakken-boom-cutting west coast imports of crude - Bloomberg
- Exhibit F Western Canadian Select Fact Sheet
- Exhibit G bakken-producing H2S
- Exhibit H Karras Exp Rpt P66 Rodeo
- Exhibit I Chevron_Interim_Report_Final_2013-04-17
- Exhibit J Report by Dr. Phyllis Fox Valero Benicia Crude by Rail
- Exhibit K bakken-crude-makeup faces scrutiny in explosion
- Exhibit L Federal Agencies to Review Hazmat Rail Rules
- Exhibit M coast-bound-train-the-future-of-crude-
- Exhibit N Karras Combustion Emissions from Refining Low Quality Oil
- Exhibit O FEA1149 SCAQMD tank and pipe cleaning and degas
- Exhibit P NRDC comments NOI Mit ND Valero Crude by Rail

// Julia E. May

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Experience

1989-present

Industrial & energy use planning for pollution prevention / Science team manager / Environmental engineering consultant and regulatory analyst: Identification and quantification of industrial air pollution sources including criteria pollutants, toxics, and greenhouse gases, especially in the oil industry. Identification of pollution prevention methods and engineering solutions related to episodic and ongoing chemical releases. Also electrical power plant, long term electricity planning, and evaluation of alternative energy options. Research of best and worst industrial and energy use practices and chemical phase-out. Compiling health and environmental impacts data, analyzing air monitoring and permitting data. Evaluation of technical basis of regulatory compliance with environmental laws. Working through practical issues of regulation, negotiating with industry and government agencies to craft health-protective regulatory language. Translating inaccessible technical information into lay language educational materials. Technical assistance for communities on impacts and solutions on environmental health protection regulation, permitting, and policy. Managed four-person science department for statewide environmental organization. Hired by regulatory agency as technical advisor to community members to identify feasible air pollution controls not previously adopted. Consultant to various environmental organizations outside California on environmental permitting issues.

- **Evaluation of air emission and other impacts from proposed permits for individual U.S. fossil fuel industry expansions including refineries, oil drilling, pipelines, and coal gasification:** Evaluation of oil industry emissions and solutions regarding permitting of feedstock switches to Canadian tar sands crude oil at ConocoPhilips Wood River, BP Whiting, Detroit Marathon, and proposed new MHA Nation, North Dakota, refineries, as well as dozens of refinery expansions in Northern and Southern California. Evaluation of oil drilling operations, air impacts, public safety hazards, earthquake and subsidence hazards, public nuisance hazards and solutions in residential neighborhood in Southern California. Evaluation of pipeline transport impacts of crude oil, hydrogen, and other oil industry feedstocks in California and the Midwest. Evaluation of coal gasification plant air emissions. (1990s to present)
- **Development of model California oil industry criteria pollutant regulation, proposed greenhouse gas regulation and alternatives analysis:** Developed multiple proposals ultimately adopted for addition to ozone attainment plans in Northern and Southern California of model oil refinery regulations for flares, pressure relief devices, tanks, leakless fugitives standards, petroleum product marine loading, and others. Technical working group member in State of California regulation of greenhouse gas and co-pollutants (smog precursors and toxics). Developed recommendations for regulation of oil industry greenhouse emissions, sources, alternatives, and reporting; the State found these recommendations feasible and recommended regulation. (1990s to present)

- **Evaluation of emissions and phaseout opportunities for smaller industrial sources including metal finishing, foam manufacturing, wood finishing, electronics, consumer products, etc**.: Evaluation of air emissions and unnecessary use of ozone depletors, carcinogens, and reproductive toxins, direct negotiation with individual companies to identify specific chemical elimination options in lieu of penalties for environmental violations. For example, metal degreasing was replaced with benign alternatives (soap and water) or grease use eliminated, by talking through use with manufacturers. Phaseout of chemicals was over a million pounds of various substances from many sources. (1990s)

Education

1981 **B.S. Engineering**, University of Michigan, Ann Arbor

Engineering principles, mathematics, thermodynamics, physics, materials science, chemistry, electronic circuit design, solid-state physics, and others; majored in electrical engineering.

Positions

2004- present **Independent Environmental Consultant (2004 - ongoing) and Senior Scientist, Communities for Better Environment (2006 – present) --** Industrial pollution quantification, short and long term energy use evaluation, analysis of impacts and solutions to environmental problems including trends in oil industry crude feedstocks, electricity system planning, associated equipment changes, emissions of criteria pollutants, toxic emissions, and greenhouse gases. Technical consultant in community campaigns on industrial regulation and pollution prevention. Geographic areas include Southern & Northern California; multiple U.S. states.

2001-2003 **Statewide CBE Lead Scientist, CBE,** Oakland, CA

Responsible for accuracy and value of technical evaluations within community and environmental law enforcement campaigns, also led statewide technical staffing. Analysis and recommendations on adding regulation to Bay Area Ozone Attainment Plan (flares, pressure relief devices, wastewater ponds, storage tanks, and others) ultimately adopted. Identified underestimations in power plant expansion air emissions in communities with high asthma rates; identified alternatives options including conservation, non-fossil fuel energy, and transmission availability to prevent need for fossil fuel expansion, before California Energy Commission. Evaluated Environmental Impact Reports and Title V permits of refineries and chemical plants; identified potential community impacts and solutions. Frequently a primary negotiator during successful talks with industrial facilities and government agencies regarding environmental violations, identifying technical pieces for Good Neighbor Agreements and for bringing facilities into environmental compliance.

1990-2001 **Clean Air Program Director, Northern California Region, CBE**

Analysis of oil refinery, power plant, cement kiln, smelter, dry cleaner, consumer product, lawn mower, mobile source, and other air pollution sources, neighbor and worker health impacts, with pollution prevention policy development. Successfully advocated for national models of oil refinery regulation. Evaluated and documented root causes of industrial chemical accidents as part of community campaigns for industrial safety. Technical assistance to community members negotiating Good Neighbor Agreements with refineries. Successful advocacy for adoption of policies eliminating ozone depletors in favor of benign alternatives.

1987-1990 **Research Associate, CBE**

Led successful campaign working closely with maritime workers and refinery neighbors for adoption of strict oil refinery marine loading vapor recovery regulation, which became statewide and national model. Member of technical working group at BAAQMD evaluating emissions, controls, safety, and costs. Also analyzed school pesticide use and won policy for integrated pest management on school grounds.

1986 **Assistant Editor of appropriate technology publication, Rain Magazine**, Portland, OR -- Publication on innovative environmental success models around the U.S. and the world. Compiled, co-edited, wrote, and provided production for non-profit publication.

1981-1985 **Integrated Circuits Design Engineer, National Semiconductor Corp., Santa Clara, CA -** Electronics engineering design team member for analog-to-digital automotive engine controls for reducing air emissions. Troubleshooting hardware and evaluating fault-analysis software efficacy.

A few special activities

2002-2003 **Roundtable on Bay Area Ozone Attainment Progress** - Invited member of problem-solving group of decision makers including BAAQMD board members, City Council members, industry CEOs and trade group directors, California Air Resources Board (CARB) and US EPA officials, and others, for reviewing progress and proposing action to control San Francisco Bay Area regional smog.

1995-2003 **Negotiator for Optical Sensing Air Pollution Monitoring Equipment on oil refinery fenceline -** CBE signatory to enforceable Good Neighbor Agreement with Rodeo, California oil refinery, providing technical analysis for community negotiators, resulting in permanent installation of a state-of-the art air pollution monitoring system on the refinery fenceline, using optical sensing to continuously measure air pollution and broadcast data to a community computer screen. Reviewed manufacturer specifications, developed Land Use Permit language, and worked with refinery and manufacturer for better Quality Assurance/Quality Control. Worked with US EPA, Contra Costa County, and community groups evaluating the system and publishing a report.

1998-2002 **Program Administrator for Bucket Brigade air pollution monitoring**. Coordinated community groups of Contra Costa County Bucket Brigade project (funded by US EPA) who carried out training events in several communities surrounding major Bay Area refineries and chemical plants. The Bucket Brigade used low-tech air pollution monitors community members can build and operate, based on a standard air pollution sampling tedlar bags analyzed at certified laboratories. Provided community information on laboratory results, administered complex federal grant including quality assurance plan.

1997 **Installation of Photovoltaic Panels,** Solar Energy International, Colorado. Completed practical training on solar energy system design and installation for general electrical energy uses including water pumping, house cooling, etc, and applying energy conservation principles.

1993 **Chemistry of Hazardous Materials**, U.C. Berkeley Extension, for environmental professionals