The Proposed Negative Declaration by SCAQMD for the Tesoro Pipeline from its Long Beach Marine Terminal to New Wilmington Refinery Storage Tanks is Missing Major Expansion Plan Descriptions and Requires a Full EIR

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I. Introduction

This report evaluates the Tesoro Storage Tank Replacement and Modification Project (described hereafter as the “Project”) in Wilmington and finds that a Negative Declaration (ND) published by the South Coast Air Quality Management District should not be adopted, because the Project has broad implications for changing operations at the refinery, marine operations, in integration of the Wilmington with the Carson refinery, among other changes. These changes have significant impacts that need to be evaluated through a full Environmental Impact Report (EIR).

II. The Project Description is flawed – the Pipeline & Storage Tank Negative Declaration is contradicted by Tesoro’s Published Broader Plans

A. Project description

The ND\(^1\) describes the Project as merely a way to offload products faster, to speed getting ships out of harbor, unrelated to other transportation and refinery operations. For example, it states:

*Description of Nature, Purpose, and Beneficiaries of Project: The Tesoro Refining & Marketing Company LLC (Tesoro) is proposing a storage tank replacement and modification project at its Los Angeles Refinery – Wilmington Operations to increase the amount of crude oil that can be stored, and to increase the efficiency of the crude oil deliveries from ships.*

The ND describes very large storage expansion (440,000 bbls per day increase for two tanks, plus increased throughput of 150,000 bbls/month for one tank), and changes in materials stored:

<table>
<thead>
<tr>
<th>Tank Number</th>
<th>Description</th>
<th>Current Size</th>
<th>Proposed Size</th>
<th>Permitted Materials Stored</th>
<th>Proposed Materials Stored</th>
</tr>
</thead>
<tbody>
<tr>
<td>80035</td>
<td>Fixed to Internal floating roof</td>
<td>80,000 bbl</td>
<td>300,000 bbl</td>
<td>Petroleum materials including crude oil, hyrocracking unit (HCU) feedstock (a light gas</td>
<td>Light &amp; heavy crude oils of varying vapor pressures up to 11psi, light gas oils (such as</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>oil); currently primarily stores HCU feedstock (ND p. 1-1)</td>
<td>HCU feedstock &amp; FCCU Feedstock), &amp; heavy gas oils, but ND also states these will</td>
</tr>
<tr>
<td>80036</td>
<td>Fixed to Internal floating roof</td>
<td>80,000 bbl</td>
<td>300,000 bbl</td>
<td></td>
<td>primarily store crude oil</td>
</tr>
<tr>
<td>80038</td>
<td>Fixed roof w/out vapor recovery, connect to vapor</td>
<td>80,000 bbl</td>
<td>No size change</td>
<td>Petroleum distillate w/true vapor pressure &lt;0.5psi such as crude oil &amp; heavy gas oils,</td>
<td>Change types of materials stored to also include light gas oil</td>
</tr>
<tr>
<td></td>
<td>recovery</td>
<td></td>
<td></td>
<td>currently primarily stores vacuum gas oil (heavy)</td>
<td></td>
</tr>
<tr>
<td>80079</td>
<td>Internal floating roof tank</td>
<td>80,000 bbl</td>
<td>Same size, but</td>
<td>Petroleum distillate w/true vapor pressure &lt;7.6psi such as crude oil, heavy gas oils,</td>
<td>No change in types of materials permitted to be stored</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>increased throughput from 350,000 to 500,000 bbls/month</td>
<td>light gas oils, diesel fuel, primarily stores crude oil</td>
<td></td>
</tr>
</tbody>
</table>

\(^1\) Negative Declaration at p. 2-1, and Notice of Intent to Draft a Negative Declaration, Tesoro Storage Tank Replacement and Modification Project, at 2nd page.
No specific baseline data is provided on the current materials actually stored in the tanks.

The description also proposes greatly increased pipe sizing (from a 12-inch diameter pipe, to a 42-inch pipe) for delivery of crude oil and other materials from the Marine Terminal to these storage tanks. The volume of material that can be delivered through a pipe is dependent on cross-sectional area; the 42-inch pipe would allow a delivery increase of over 12 times the volume currently able to be delivered.\(^2\)

\[\text{Over 12 twelve-inch pipes would fit into one 42-inch pipe, so the volume of crude oil & other petroleum liquids that can be offloaded through the new pipe is over 12 times higher than the existing pipe}\]

The description incorrectly concludes there will be no significant impacts, and counter to Tesoro’s public statements documented later, there will be no changes in materials delivered:

\(\text{No changes to the type of materials delivered to the Wilmington Operations are proposed. The following environmental topic areas were identified as having the potential to be affected by the proposed project: air quality and greenhouse gas emissions; energy; geology and soils; hazards and hazardous materials; hydrology and water quality; noise; solid and hazardous waste; and transportation and traffic. However, the analysis of these environmental topic areas in the Draft Negative Declaration (ND) concludes that the proposed project would not generate any significant adverse environmental impacts.}\)

But the changes described above have the potential for major operational debottlenecking and changes in materials (e.g. crude oil) delivered, with associated impacts described below. Furthermore, Tesoro has publicly announced such changes outside of the ND process.

The following graphic of the project was provided in the ND (at p. 1-10):

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\(^2\) A 12 inch diameter = 6 inch radius, a 42 inch diameter = 21 inch radius. Volume of material delivered depends on the pipe cross-section area. The cross-sections of the two pipes’ areas are: For 12 inch pipe the area = \(\pi r^2 = 3.14 \times (6 \times 6)\) sq inches, or 3.14 x 36; For 42 inch pipe the area = 3.14 x (21 x 21) or 3.14 x 441. Thus the 42 inch pipe cross-section area is larger than the 12 inch pipe by a factor of 441/36, or 12.25.
The difference in the physical locations of the Marine Loading terminal and the refinery shown in the graphic above and the satellite images below illustrates that there will be a large increase in petroleum materials piped in the range of a mile from the terminal to the refinery. This in itself increases the risk of spills, especially during earthquakes. The ND states that there will not be a physical change at the Marine Terminal itself, but it fails to evaluate the major increase in volume of materials that will be present in the pipes at any one moment.

The Pier B Tesoro facility (Port of Long Beach, 820 Carrack Ave, Long Beach 90813, Facility ID 172878, Tesoro Logistics Operations LLC) was identified by the SCAQMD by telephone as the marine loading facility involved in the Project, although Tesoro Logistics now owns three marine loading facilities in Los Angeles. Different magnifications are inserted below, including Pier B, and the Wilmington refinery (on the order of a mile away):
The map below, excerpted from the ND (at p. 1-6), depicts the long path of the new pipeline across the refinery to the new refinery tanks. (This map has been rotated 90 degrees to make wording readable.) It also shows that the pipe goes beyond the new tanks, to the corner of the Wilmington property.

B. Tesoro has published plans to increase throughput, yields, transport alternative crude types by rail to Washington then by ship to Long Beach, and to integrate the Wilmington refinery with the adjacent Carson refinery

Both industry literature and Tesoro statements reveal that Tesoro has been planning the following:
- Increased throughput at its California refineries (including its Wilmington and Carson complex),
- Increased product yield,
- Integration of the Wilmington and Carson refineries,
- Changes in crude oil type delivery and processed in favor of cheaper crudes (“advantaged” or “discount” crudes which can have negative impacts when transported and refined),
• Use of rail to transport crude to Tesoro’s Vancouver Washington shipyard, and then by ship to California refineries (from Bakken oil fields in North Dakota but also potentially from Canadian tar sands fields),
• Use of its facilities by Third parties and for export, and
• Increased coking operations.

The alternative crude would be offloaded from marine vessels, sent through the greatly expanded pipeline described in the ND, and stored in the massively expanded storage tanks proposed. Importantly, the Wilmington and Carson refinery operations share a fenceline.

These publicly acknowledged projects are clearly related to the storage tank expansion, and demonstrate that the proposed Project goes far beyond simple ship offloading efficiency. Even if we had no knowledge of these plans, such storage expansion would have the potential to allow expanded activities at the refinery and the Marine Loading dock, and to change operations through integration with Tesoro’s Carson refinery. These operations cannot be “piecemealed” from the storage project, and must be evaluated together through a full EIR.

1. Industry literature identified these plans

An example of an industry literature report on Tesoro plans is provided by Morningstar Inc. (a multinational, multi-billion dollar research and investment management firm\(^3\)), which published the following analysis in July of 2013:\(^4\)

*Tesoro aims to increase throughput of domestic crude over the next few years*

* Tesoro has embarked on a multiyear plan to improve its profitability, including increasing spending to support larger income improvement projects. The most significant of those, including capacity expansions and rail facilities, aim to take advantage of domestic crude discounts. . . .

*We think, however, the biggest area of opportunity for Tesoro to improve its profitability is by increasing processing of discount crude, particularly in its primary market of California, where operating conditions remain challenging. The company is highly leveraged to developments within the state and that will only increase with its proposed acquisition of BP’s BP Carson refinery. Operating in California can be advantageous because West Coast margins typically fetch a premium given the state's relative isolation from outside sources of refined product and specialized gasoline blends. . . .

*The increased availability of discount crude bolsters the potential for the Carson acquisition despite the increased exposure to California. Specifically, Tesoro can dramatically improve the performance of Carson by optimizing its crude slate with light crude from the Bakken. Also, on its face the deal looks like a winner for Tesoro given the relatively attractive valuation of the refinery and the collection of associated


midstream assets that can be dropped down to Tesoro Logistics TLLP. **Tesoro should gain further advantages from integrating Carson with the Wilmington refinery.** . . .

The addition of Carson and its integration with Tesoro's Wilmington refinery should lower costs and better position the company to deal with increasing environmental regulation. . . . [Emphasis added throughout and below]

Discount crudes generally have negative impacts as described below. For example, Canadian tar sands crude oil is very heavy, with high sulfur, requiring more intensive refining, and Bakken crude oil from the Dakotas has high paraffinic content (wax) and is explosive. These require specialized handling or more intensive refining with environmental and safety impacts (described later). The article also identifies the potential for Tesoro to import either Bakken or Canadian heavy tar sands crude.

Increasing throughput of light and heavy discount crude from the Mid-Continent and Canada via rail will likely benefit Tesoro more, though. To this end, Tesoro recently entered an agreement to develop a 120 mb/d crude by rail and marine facility in Washington. The facility should be operational in 2014 and affords Tesoro the flexibility to send light or heavy crude to its California refineries. Tesoro’s California refineries should realize higher margins and improved returns through lower feedstock costs and **improved yields** while expending little capital.

(Note that this project was updated and expanded from the 120,000 barrel/day figure to 360,000 barrel/day, to be completed in 2015.5) The Morningstar webpage also explained in July of 2013 why oil companies are incentivized to change operations to accommodate such cheap crude oil:

**Success in the refining business is primarily a function of the difference in the amount the refiner pays for oil and the amount at which it sells the refined product.** As such, the short- and long-term risks are dependent on movements in the prices of crude oil and gasoline or diesel. Supply interruptions or increased demand that drive up oil prices, as well as demand destruction or economic slowdown that depress gas prices, are the primary risks. **Additionally, the recent strong operating performance is attributable to wide crude differentials.**

Such crude differentials are available for both Bakken and Canadian tar sands crude. The costs can fluctuate, so many refiners, including Tesoro, are looking at both these sources depending on the most current price fluctuations and logistics. Tesoro has evaluated both Bakken and Canadian crude sources, and both these sources are booming compared to existing Tesoro crude sources, which have been dropping.6

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6 California’s Oil Refiners Double Crude-by-Rail Volumes (1), Lynn Doan May 02, 2014, Bloomberg Business Week, [“U.S. West Coast refiners including Tesoro Corp. (TSO:US) and Valero Energy Corp. (VLO:US) are developing projects to bring in more oil by rail from reserves across the middle of the U.S. and Canada to displace more expensive supplies. Crude production in PADD 5, which includes California and Alaska, has dropped every year since 2002 while drillers are extracting record volumes from shale in states including North Dakota and](http://www.businessweek.com/news/2014-05-02/california-oil-refiners-double-crdue-by-rail-volumes)”
The Morningstar report also identifies other refinery processes such as vacuum distillation, increased coking, increased product export, and increased yields, as related to the Project. For instance, the analysis identifies a recent Wilmington refinery vacuum distillation unit project allowing increased coking. The vacuum distillation tower was also reported in Bloomberg news in late 2012, with further allusions to Tesoro’s plans to integrate Wilmington and Carson operations, which could result in shutdown of Tesoro’s fluid catalytic cracking unit (FCC), unit. This further stresses the changes to overall refinery balancing and design which can occur as a result of the changes in crude oil which would be brought in as a result of the ND’s pipeline and storage Project.

Heavy, bottom of the barrel portions of crude oil are a much higher proportion in heavier crudes, which result in production of petroleum coke in higher quantities, which the storage project would also enable. The evaluation states:

To address these challenges, Tesoro is focusing on improving yields and lowering operating costs at its facilities while increasing export volumes to higher value markets. To improve yields, Tesoro replaced a vacuum distillation unit at its Wilmington facility, which should allow it to upgrade petroleum coke to clean products.

In the Pacific Northwest, Tesoro's two refineries, which account for almost 30% of total capacity, are at a disadvantage because of their lack of cokers, resulting in poor yields and large amounts of fuel oil. However, Tesoro's recently completed project to rail upward of 50,000 bpd of discount, light Bakken crude to its Washington refinery, should lead to reduced dependence on waterborne crude and improved margins.

Increased coking means increased emissions from coking operations. Increased exports have the potential to increase emissions due to refining, storing, and loading products for export. Increased yields of individual product units within the refinery have different characteristics, and must be evaluated specifically, rather than looking at the overall crude oil throughput, since different units have different chemical use and different emissions, which can be impacted even without an increase of crude throughput. All of these are related operations with potentially major impacts not evaluated in the ND.

The Morningstar literature identified the lack of cokers at Tesoro’s Pacific Northwest refineries as increasing the need for taking advantage of available coking facilities in California refineries:

Tesoro's refining capacity is concentrated in California. Second, it has invested in rail facilities to move 50 mb/d of Bakken crude west to its Anacortes, Wash., refinery, which has resulted in improved yield and margins. Finally, we expect the imbalance between light and heavy crude in the Mid-Continent will create an opportunity and

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economic incentive to rail both types of crude to its three California refineries, increasing their throughput of cost-advantaged crude. In fact, Tesoro already has plans in place to do so. . . .

2. Tesoro also published these plans

Tesoro has confirmed these industry findings. For example, a February 2014 Tesoro slideshow on Tesoro’s “Presentations” webpage states “Los Angeles acquisition [BP Carson and terminals and coking] transforms our capabilities,” providing flexibility in yield, access to “advantaged” crude oil, integrated logistics infrastructure, etc. (Slide 7).

Another slide below (12) identifies the “Los Angeles Refinery Integration Project” (integrating Carson and Wilmington refineries) as optimizing processing capability and “product flexibility”:

California Synergy Capital Expenditures

This is followed by a slide describing Tesoro’s “Advantaged” feedstock opportunity, “Extending the advantaged crude oil to the West Coast,” and changing the Los Angeles operations crude oil feedstock from 15% California Heavy crude to “Potentially up to 50% California Heavy and Bakken” crude oil (at Slide 13).

The slideshow also evaluates the cost of crude by rail directly to West Coast refineries, including Los Angeles, in the following (slide 15), but also states that the cost of rail to the state of Washington, and then by ship to California, is “Competitive with direct rail cost to California” (at Slide 17). Slide 17 also finds that its Washington rail to ship project provides “Flexibility to deliver to all West Coast refineries.”

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Another key point on Slide 15 as shown below is the massive increase in “West Coast Unloading capacity” from 218 barrels per day (bpd) in 2013, to 395 bpd estimated in 2014, to 910 bpd estimated in 2015. California is the largest share of West Coast Tesoro capacity, and Los Angeles is the largest share of Tesoro California capacity.

Crude oil unloading capacity is the subject of this ND, by unloading crude oil from ship to the expanded pipeline, to the expanded storage tankage. As a result, it is clear that Tesoro’s West Coast plans for bringing Bakken crude into LA will require the increased unloading and storage identified in the Negative Declaration.

Another very similar version of this slideshow presented a month earlier by Tesoro (January 2014) elucidates further that “Terminaling, Transportation, and Storage” will “Consolidate Tesoro volumes in Southern California distribution system” (and identifies additional impacts in Southern California). Storage capacity is an essential requirement for terminal, transportation, and refining operations. None of the required evaluation of relationships of storage capacity changes to these other processes have been evaluated in the negative declaration, as they should have been.

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Slide 34 in this second presentation also mentions a plan to decommission the Wilmington refinery’s FCC (Fluid Catalytic Cracker) unit. Again, such a change should be identified as part of the whole broad project, either directly, or as part of a cumulative impacts evaluation.

The Slides and previous reports above show that Tesoro has considered different options for transporting crude from North Dakota and Canada to the Los Angeles complex, including rail transport directly to California (despite the ND’s dismissal of rail as potentially connected to this Project). Tesoro has lately settled on the rail to Washington and ship to Long Beach option. However, if conditions change (for example, if the Washington hub does not proceed due to public opposition), Tesoro could instead take advantage of the new Tankage’s proximity to the nearby rail line that traverses both its LA refineries. For example, the new Tesoro pipeline continues past the new storage tanks, and ends next to the railway that transects the refinery, as discussed later.

III. Potential impacts of the Project are large

A. Changes in crude oil feedstock facilitated by the Project have significant impacts

1. Waxy Bakken crude oil requires special handling and creates problems of transfer in both marine vessels and refinery storage tanks and requires chemical dispersants
An article from Hydrocarbon Processing -- *Innovative Solutions for Processing Shale Oils*\(^\text{10}\) -- identifies problems in processing oils such as Bakken shale, due to high variability in crude qualities, waxy buildup (paraffinic content), etc. This article specifically identified transfer to refinery tankage as problematic:

**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. 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\(^\text{11}\) in shale oil service. [emphasis added]

The article provided photos (entitled “waxy deposits removed from shale oil buildup”) which graphically depict the more obvious problems with Bakken crude:

![Waxy Deposits Removed](image)

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.

*To control deposition and plugging in formations due to paraffins, the dispersants are commonly used. In upstream applications, these paraffin dispersants are applied as part of multifunctional additive packages where asphaltene stability and corrosion control are also addressed simultaneously.*

These chemicals must be identified in a full 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. Impacts within the refinery must also be evaluated for safety risks.

2. **Bakken crude oil also causes fouling of preheaters, heat exchangers, and furnaces, refinery corrosion, and can shutdown refinery units**


\(^\text{11}\) A “pig” is launched through a iline until it reaches a rece...
The Hydrocarbon Processing article found that asphaltene destabilization can occur when blending shale oil with heavier crudes. This is precisely the kind of blending that could occur due to the Project, since Tesoro has stated it plans to change the crude slate in California from 15% California Heavy crude to “Potentially up to 50% California Heavy and Bakken” (see earlier in this comment).

These problems result in fouling of the cold preheat train, fouling of hot preheat exchangers and furnaces, problems in transportation, storage, refinery corrosion, and crude unit shutdowns. These oils are also extracted through fracturing, which have additional and major impacts on water, air, and the global climate. The article finds:

*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.*

[Emphasis added throughout and below]

The article found use of shale oils was particularly problematic when blended with heavy crudes, which is admittedly planned by Tesoro for its California refinery operations. 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.\(^\text{12}\) Coke deposits lead to poor operation and can cause shut down of units before planned maintenance periods. All these problems require special handling and planning at the refinery. In addition, the article found shale oils to be highly variable in certain characteristics including for example, its solids content, and others. 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.*

\(^\text{12}\) 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.
3. Bakken crude is volatile and explosive and these characteristics were not evaluated in the ND.

Unfortunately, Bakken crude oil has been fatally demonstrated as very volatile and explosive, as in the case of the tragic explosions at Lac Megantic in Canada, and in other instances.

The U.S. Department of Transportation Pipeline and Hazardous Material Safety Administration issued a safety alert regarding the transport of this type of crude oil in January of 2014, finding that whether it was transported in railcar or other mode of transport, it represents unique hazards of explosion, fire, and corrosivity, requiring additional testing, handling, and public information for first responders. Entrained gases require additional testing.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is issuing this safety alert to notify the general public, emergency responders and shippers and carriers that recent derailments and resulting fires indicate that the type of crude oil being transported from the Bakken region may be more flammable than traditional heavy crude oil.

Based upon preliminary inspections conducted after recent rail derailments in North Dakota, Alabama and Lac-Megantic, Quebec involving Bakken crude oil, PHMSA is reinforcing the requirement to properly test, characterize, classify, and where appropriate sufficiently degasify hazardous materials prior to and during transportation. Proper characterization will identify properties that could affect the integrity of the packaging or present additional hazards, such as corrosivity, sulfur content, and dissolved gas content. These characteristics may also affect classification.

PHMSA stresses to offerors the importance of appropriate classification and packing group (PG) assignment of crude oil shipments, whether the shipment is in a cargo tank, rail tank car or other mode of transportation. Emergency responders should remember that light sweet crude oil, such as that coming from the Bakken region, is typically assigned a packing group I or II. The PGs mean that the material’s flashpoint is below 73 degrees Fahrenheit and, for packing group I materials, the boiling point is below 95 degrees Fahrenheit. This means the materials pose significant fire risk if released from the package in an accident.

. . . Based on initial field observations, PHMSA expanded the scope of lab testing to include other factors that affect proper characterization and classification such as Reid Vapor Pressure, corrosivity, hydrogen sulfide content and composition/concentration of the entrained gases in the material. The results of this expanded testing will further inform shippers and carriers about how to ensure that the materials are known and are properly described, classified, and characterized when being shipped. In addition, understanding any unique hazards of the materials will enable offerors, carriers, first responders, as well as PHMSA and FRA to identify any appropriate mitigating measures that need to be taken to ensure the continued safe transportation of these materials.

This is a major problem with the Project, at the Marine Terminal in Long Beach, in the expanded pipeline to the refinery, in the storage tanks at the refinery, and in the refinery where it will be...

used. It was a major failure of the ND to ignore these impacts, which even without the other impacts, would require an EIR.

4. Bakken crude refining can also increase levels of acutely hazardous and corrosive Hydrogen Sulfide in the refinery

The Hydrocarbon Processing article also identified increased levels of extremely hazardous hydrogen sulfide (H2S) gas as a problem associated with shale oil. Furthermore, when scavenging agents are used to reduce H2S presence, these can cause corrosion and form solid deposits inside processing units. The article states:

*Several shale oil production locations have high H2S loading. To ensure worker safety, scavengers are often used to reduce H2S 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.*

Hydrogen sulfide is deadly, corrosive, causes odor complaints when released, and its increase in the refinery certainly requires specific evaluation that was absent in the ND.

A report by Bakkenshale.com found: 14

*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.*

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. 15 These issues must be

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15 *Id.* at p. 33
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.

Steelworkers 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.\textsuperscript{16} 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.

A discussion of corrosion issues at oil refineries due to increased sulfur content in crude oil, and other important related issues was provided in the attached report of Greg Karras on the Phillips 66 Rodeo refinery EIR.\textsuperscript{17} Also refer to the previously cited report of Dr. Fox on impacts of use of “advantaged” crude are also in process.

These reports demonstrate in further detail the impacts of 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.\textsuperscript{18} The significance of the air pollution impacts caused by the Chevron explosion are self-explanatory, in the photos below of the August 2012 explosion caused by the refinery corrosion.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{chevron-explosion.jpg}
\caption{August 2012 explosion caused by the refinery corrosion.}
\end{figure}

\textsuperscript{16} U.S. Chemical Safety Board transcript of public hearing on Chevron Richmond, CA August 2012 explosion and fire, page 225, \url{http://www.csb.gov/assets/1/19/0503CSB-Meeting.pdf}
\textsuperscript{17} 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
\textsuperscript{18} Interim Investigation Report, Chevron Richmond Refinery Fire, (which as adopted at the July public hearing) available at: \url{http://www.csb.gov/assets/1/19/Chevron_Interim_Report_Final_2013-04-17.pdf}
5. Another “advantaged” crude oil from Canadian Tar Sands that Tesoro plans to import also causes major impacts

As previously identified, Tesoro plans to bring cost advantaged crude oil to Los Angeles, both light and heavy, including heavy Canadian tar sands crude. Canadian tar sands crude is even cheaper than Bakken, as discussed by Bloomberg about Tesoro’s plans to use the cost advantage of Canadian heavy crude in California.

_U.S. West Coast refiners including Tesoro Corp. (TSO) and Valero Energy Corp. (VLO) are developing projects to bring in more oil by rail from reserves across the middle of the U.S. and Canada to displace more expensive supplies._ Crude production in PADD 5, which includes California and Alaska, has dropped every year since 2002 while drillers are extracting record volumes from shale in states including North Dakota and Texas.

_The surging flows of domestic oil to California “reflect a continuing improvement in crude-by-rail receiving facilities here,”_ David Hackett, president of Stillwater Associates, an energy consultant, said by phone from Irvine, California.

**Lower Costs**

_Crude from North Dakota and Canada trades at a discount to Alaska North Slope oil, which rose 36 cents to $107.78 a barrel at 9:09 a.m., data compiled by Bloomberg show. Western Canada Select, a heavy, sour blend, gained 36 cents to $82.88. North Dakota’s Bakken crude also gained 36 cents to $95.28. It costs $9 to $10.50 a barrel to send North Dakota’s Bakken oil by rail to California, according to Tesoro, the West Coast’s largest refiner._

Of course, tar sands crude oil causes major environmental damage during its mining in Canada, as described by the World Resources Institute, which rather mildly states the severe impacts: 19

_“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.”_

But the ND must account for the local Los Angeles region, and global impacts. 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

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19 [http://www.wri.org/publication/content/10339](http://www.wri.org/publication/content/10339)
also increase energy needed for refining, resulting in higher greenhouse gas and smog-precursor emissions. The corrosion hazard is increased due to the higher sulfur content, increasing refinery accident risk identified by the US Chemical Safety Board in the last section.

The ND failed to evaluate the obvious increases in desulfurization processes within the refinery due to higher sulfur content, as well as additional cracking, coking, and additional use of hydrogen, all of which require more energy and increase criteria and toxic pollutant emissions. This is a major and obvious area of impacts that was completely ignored in the ND, especially without any baselines provided.

An Oil & Gas Journal article *Special Report: Refiners processing heavy crudes can experience crude distillation problems* (Oil and Gas Journal), also 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 crude oils 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 from heavy Venezuelan crudes 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 crude oils 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 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.

Additional emissions during the transport, piping, tank loading, and in refinery operation from volatile diluents used with expanded tar sands crude oils have not been identified, and should be, with emissions quantified. Diluents can include volatile and toxic compounds such as BTEX.

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VOCs (Benzene, Toluene, Ethylbenzene, and Xylene). 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 carcinogenicity and other health impacts, as well as any potentially explosive compounds.

6. The Project Description failed to provide baseline data on the current crude oil slate, to compare it to the “advantaged” crudes the Project allows, and to identify the potentially significant impacts of such changes

The ND did not provide baseline information about the crude oil slate. This is a major omission especially given Tesoro’s public acknowledgement of the key nature of its planned switch to cost-advantaged crude oils such as Bakken crude (or Canadian tar sands). The ND assumes that if general types of crude oil and products remain the same, then the Project cannot cause changes with significant impacts. But this is demonstrably false – changes in the crude slate can cause major impacts regardless of existing AQMD permit conditions, even if volumes don’t change. Tesoro should have provided this baseline information.

Through outside sources we can find some very basic information about the recent crude slate at Tesoro’s Wilmington and Carson refineries:

- The Alaska Business Monthly stated that the Carson refinery formerly owned by BP has recently (2012) processed significant levels of Alaska North Slope crude (ANS).22
  “According to Chuck Coulson, BP’s manager for midstream operations, BP refines “virtually” all of its Alaska crude at its two West Coast refineries: Cherry Point in Puget Sound and Carson refinery in L.A. County. BP runs a mix of Alaska North Slope crude and crude from other countries at both facilities.

- The BP website stated in 2013 that the Carson facility processed ANS, Middle Eastern, and West African crude:23
  “It processes crude oil from Alaska’s North Slope, the Middle East and West Africa.”

- Tesoro’s SEC report identified in California refineries:24
  “Our California refineries run a significant amount of South American heavy crude oil ("Oriente"), San Joaquin Valley Heavy ("SJVH") and light crude oil from Iraq ("Basrah"), which continued to be priced at a discount to Brent throughout 2013.”

21 Comments of NRDC on the Notice of Intent to Adopt a Mitigated Negative Declaration for the Valero Crude by Rail Project, July 1, 2013, on impacts of diluents and other important impacts related to the Valero Benicia crude by rail project in common with the Phillips 66 Los Angeles refinery complex, http://switchboard.nrdc.org/blogs/dbailey/NRDC%20comments%20letter%20on%20Notice%20of%20Intent%20to%20Adopt%20a%20Mitigated%20Negative%20Declaration%20for%20the%20Valero%20Crude%20by%20Rail%20Project.pdf
24 http://biz.yahoo.com/e/140224/tso10-k.html
Tesoro’s 2013 SEC report\textsuperscript{25} also provides a general picture of Tesoro’s crude slate in California from 2011 to 2013 (but not at the individual refineries):

*Our refineries process both heavy and light crude oil.* Light crude oil, when refined, produces a greater proportion of higher value transportation fuels such as gasoline, diesel and jet fuel, and as a result is typically more expensive than heavy crude oil. In contrast, heavy crude oil produces more low value byproducts and heavy residual oils. These lower value products can be upgraded to higher value products through additional, more complex and expensive refining processes.

Throughput volumes by feedstock type and region are summarized below (in Mbpd):

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2012</th>
<th>2011</th>
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<tr>
<td></td>
<td>Volume</td>
<td>%</td>
<td>Volume</td>
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<tr>
<td>California</td>
<td>422</td>
<td>100</td>
<td>242</td>
</tr>
<tr>
<td>Heavy crude</td>
<td>178</td>
<td>42</td>
<td>151</td>
</tr>
<tr>
<td>Light crude</td>
<td>206</td>
<td>49</td>
<td>67</td>
</tr>
<tr>
<td>Other feedstocks</td>
<td>38</td>
<td>9</td>
<td>24</td>
</tr>
<tr>
<td>Total</td>
<td>422</td>
<td>100</td>
<td>242</td>
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</tbody>
</table>

Tesoro’s chart shows Heavy Crude feedstock lowering from 65 to 42%, with Light Crude increasing from 25 to 49%, and other unidentified feedstocks remaining about the same. It appears that at least half of 2013 did not include the BP purchase, which increased the throughput greatly.

The US EIA (Energy Information Administration) provides data on foreign crude imports, but not on refineries’ domestic crude use. The following table provides an example of US EIA Tesoro data for the month of March 2014. The ND should provide current baseline information from 2010 to the present, including both imported and domestic crude slate for each of the Wilmington and Carson refinery portions.

\textsuperscript{25}Tesoro’s US Securities and Exchange Commission (SEC), Annual 10-K report, for 2013, at p. 5, http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=3&ved=0CDIQFjAC&url=http%3A%2F%2Fphx.corporate-ir.net%2FExternal.File%3Fitem%3DUGFyZW50SUQ9NTM1NDc5fENoaWxkSUQ9ODg4ODk5fFR5cGU9MTk5MjIzMDUyNTQzNjUyMjQwNzExNjM5ODEwNTIyODc1&ei=UuGUU7CZO8qOqAhW7ILgAg&usg=AFQjCNGfro71fQanqMTIBnFVK-mEduvJPQ&sig2=-yTQ5qevA3RSmO-yIlD9qQ&bvm=bv.68445247,d.b2k
The data above shows that out of crude imports, almost 38% of the Wilmington refinery in March was already from Canada, with a very high sulfur content – indicating that Wilmington is already importing substantial Canadian tar sands crude. However, the weighted average sulfur content for that month for imports of Tesoro was about 2.53% sulfur (for imports only, since the EIA data does not provide domestic crude use information by refinery), much lower than the Canadian crude (shown at 3.46%). Increasing the Canadian source further will increase the average sulfur content.

The Carson portion of the Los Angeles refinery complex on the other hand, had a much lower weighted sulfur average (1.82%), and lighter crude oil (API gravity is a reverse scale, so that higher gravity indicates lighter crude). The former BP Carson refinery is designed for a lighter feedstock compared to the Wilmington refinery. The location of the new storage tanks, with the proposed pipeline expansion through the refinery, and continuing to the corner of the Wilmington operation, could be used to source either the Wilmington OR the Carson operations.

Having a major increase in tankage and connection via rail to Washington and via ship to Long Beach, allows Tesoro to increase either lighter Bakken OR heavy Canadian tar sands, both “advantaged” crude oils, both with serious environmental impacts.

There is an array of public information available about the potential impacts at refineries using different crude oil slates. In one example, the International Council on Clean Transportation’s 2013 Report: Effects of Possible Changes in Crude Oil Slate on the U.S. Refining Sector’s CO2 Emissions, Final Report26 found not only that refinery CO2 emissions varied considerably

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depending on the type of crude oil processed, but identified the changes in yields of refinery products. Further, an excerpt from this report shows that Bakken shale oil (generally considered on average a light and low sulfur crude oil), can vary in quality, and can be heavy, so it should not be assumed that imported Bakken crude would always be lighter than the current slate.

The specific CO2 emissions in this study have been refuted by a peer reviewed CBE study published in Environmental Science and Technology which showed that the greenhouse gas emissions impacts of heavy crude oil are much higher than shown in this oil industry-sponsored study.

The CBE paper documented that the impacts of crude oil density or API gravity (heaviness of crude oil) and sulfur content (which usually accompanies heavy crude) on greenhouse gas emissions strongly predicts high energy use at oil refineries. 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.

However, even the industry study showed in the chart above that crude quality impacts the volume of individual products produced by the refinery. This is also a common-sense conclusion – it is obvious that lighter crude oils produce higher volumes of gasoline, and that heavier crude oils produce more bottoms and more coking. These changes cause a multitude of environmental impacts that the District is well aware of. But the ND assumes contrary to these fundamental principles, that because throughput is expected not to change, and heat input is expected to be the same at the crude unit at the front end, that no changes will occur downstream in the refinery. This is plainly incorrect and must be re-assessed (in addition to the problem of lack of baselines in the ND).

27 In the Table entitled Exhibit 3: Composition of Alternative Crude Slates, by Crude Type (K b/d), showed 720 thousand barrels per day of Bakken crude oil in the Heavy Crude designation column, 37th page.
If light, low sulfur Alaska North Slope (ANS) crude oil, which is continually lowering in production, is displaced with extremely heavy, high sulfur Canadian tar sands crude oil, clearly that would increase sulfur content in the refinery, increase corrosion hazard and potential impacts of H2S gas, and require additional energy to process the heavy crude.

If Bakken crude oil were to replace, for example, ANS at the Tesoro refineries, this may or may not be comparable to ANS crude in gravity and sulfur content. (since Bakken is acknowledged as extremely variable). However, even if the Bakken crude were light, its high paraffin content described above, can cause waxy, dangerous buildup in transport, in the refineries, can be accompanied by toxic diluents, and explosion hazards (a la Lac Megantic explosion in Canada).

If Bakken is mixed with heavy crudes, asphaltene destabilization, preheater fouling, desalter upsets, unwanted coking, etc., identified earlier in the Hydrocarbon Processing article, can occur. These impacts can cause dangerous shutdowns and accidents. The specific changes must be identified to provide an accurate Project Description, to enable a full evaluation of potential impacts.

If instead, which may be the most likely case, heavy Canadian Select would replace California heavy crude at the Wilmington facility, then sulfur content and API gravity goes up considerably, causing increased presence of H2S and increased energy use; while the Bakken imports would go to the Carson portion of the refinery complete, which is designed to handle lighter crude, but introducing the documented problems associated with Bakken characteristics that are not present in, for example, Alaskan crude.

Other impacts aside from CO2 emissions and energy use were also described in the International Council’s report on impacts of varying crude slates. The table entitled Exhibit 11 inserted on the next page from the International Council report described above, identified varying refinery product outputs caused by varying crude oil slate inputs. In other words, the amount of gasoline, diesel, jet fuel, coke, sulfur, light gases, naphtha, resid, and aromatics produced at the refinery varied depending on the variation of crude oils into the refinery.

That means that the impacts associated with each of these different operations change with different crude oil inputs, and these impacts must be evaluated for the Tesoro project, after providing the baseline crude slate, and comparing it to the proposed potential changes in crude slate facilitated that the new Project allows. Some refinery processes involve light ends (which may for example have high benzene content, a known carcinogen), others involve heavy refinery components (which may for example be associated with higher particulate matter emissions, which increase death rates in the population). Others have high levels of odorous and hazardous sulfur compounds, or may increase fire or explosion risk. The pieces of the refinery are not interchangeable, and modifications to crude slate have impacts on the individual components of the refinery which should have been identified.

A report by Dr. Phyllis Fox on a crude by rail project to the Valero Benicia California refinery identified many impacts due to switches to “advantaged” crude oils, including increased metals, increased use of toxic BTEX compounds, and many other impacts in transportation and at the
refinery due to use of changing crude slates. All the issues identified in this report should be evaluated for the Tesoro ND.

CEQA provides requirements for clear project descriptions and potential impacts. Even if Tesoro has permits that allow variations in crude oil types, if those variations can cause significant impacts, they still must be identified and evaluated under CEQA even if allowed by current limited permit conditions. CEQA provides additional protections not necessarily covered by AQMD permit conditions, and this kind of data must be available and transparent for the public CEQA process to be carried out.

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29 Comments on the Initial Study / Mitigated Negative Declaration, Valero Benicia Crude by Rail, June 1, 2013, Dr. Phyllis Fox, attached, [http://www.ci.benicia.ca.us/vertical/sites/%7B3436CBED-6A58-4FEF-BFDF-5F9331215932%7D/uploads/Report_by_Dr._Phyllis_Fox.pdf](http://www.ci.benicia.ca.us/vertical/sites/%7B3436CBED-6A58-4FEF-BFDF-5F9331215932%7D/uploads/Report_by_Dr._Phyllis_Fox.pdf)
B. Integrating the Wilmington and Carson refinery units and logistics operations is related to the Project, and has the potential to cause major impacts

This map from the Negative Declaration shows the close proximity of the **Tesoro Wilmington and Tesoro Carson refinery operations**, with many residences shown in pink surrounding these facilities (and with labels added for the new Tesoro storage tanks, and the Phillips 66 refinery, next door):

![Map of Wilmington and Carson refinery operations](image)

When Tesoro purchased the BP Carson refinery, it planned to take advantage of marine operations to allow changes in crude oil feedstock to feed into the whole refinery complex, and specifically planned to integrate the Carson and Wilmington refineries and the Tesoro and BP “logistics” assets (which provide transportation and storage of feedstocks and products).

Tesoro planned to transfer intermediate feedstock to Carson’s cokers and other changes, facilitated by the new storage tank expansions. Tesoro also planned to use BP terminals / “logistics” assets for its own materials, and even to use these terminals to sell excess capacity to
third parties (not even mentioned in the ND). Tesoro should have identified these operations for
the ND evaluation. Tesoro has further stated:30

Integrating the BP assets, specifically the logistics, is expected to drive significant value
throughout the West Coast system. The Carson refinery has the only very large crude carrier, or
VLCC, capable to dock on the West Coast. We will be able to leverage the broader crude oil
sourcing optionality and reduce long-haul shipping costs throughout the Tesoro West Coast
system.

VLCC freight economics on a per barrel basis typically reduce long-haul shipping costs by
between $1 and $2 per barrel. Having this capability will allow us to source more economic
alternatives to Alaska North Slope crude oil, which has been a significant component of that
Carson refinery's historical crude oil slate. We also anticipate benefiting from Carson’s two
additional cokers, allowing us to further optimize intermediate feedstock transfers between our
refineries. We expect feedstock optimization synergies to account for 40% to 45% of the fully-
realized synergies.

The primary focus of product synergies is delivering the combined regional production sales
volumes to end users in the most efficient way possible. Today, Tesoro uses third-party logistics
assets to distribute a significant amount of our product volume. Post close, we intend to drive
much of that volume through BP’s logistic asset, which have excess capacity. In fact, under the
operation of Tesoro Logistics, we feel we can drive additional third-party volume through the
combined, historically proprietary, logistics network. We expect these cost improvements to
account for 15% to 20% of the total synergies.

As we look at the potential for operating synergies, we are confident that significant value can
be created through the combination and reconfiguration of the Carson and Wilmington
refineries. One expected benefit is increased clean product yields and greater flexibility between
gasoline and distillate production, with a focus on distillates. We expect a combined shift of about
25% in our capability to supply market demand for diesel. With about 10% coming from
optimizing the combined assets and the remaining 13% resulting from capital investment. This
will allow Tesoro to meet the growing demand for distillate fuel on the West Coast. In addition to
our plan to lower manufacturing costs in California prior to the acquisition, we also plan to
lower costs as a result of the combined operations.

This discussion and others documented earlier in this comment also show that the overall
“logistics” capacity must be evaluated in total, since increased storage in one part of the Tesoro
properties can further free up capacity in other parts of its local complex, and also facilitate third
party activities and the “reconfiguration” of the two refineries described by Tesoro.

The previously cited Tesoro February 2014 report to the SEC also again identified the integration
of the refineries, the “Logistics” operations, and marketing operations.

30 Thomson Reuters Streetevents Edited Transcript, TSO - Tesoro Corporation to Purchase BP's Fully Integrated
Southern, California Refining and Marketing Business - Conference Call, August 13,
%2F%2Fphx.corporate-ir.net%2FExternal_File%3Fitem%3DUGFyZW50SUQ9NDc4MzEzEzIENoaWxkSUQ9NTExMDE5fFR5cGU9MQ%3D%3D%26%3D1&ei=ocCPU4zaB4iQag_A&usg=AFQjCNHQ0VQojMISfBGmaOGNaHN0-GBPvsw&sig2=XfnG0PAYBnf1Wz_ud2tnIA&bvm=bv.68235269,d.b2k
During 2014, we plan to continue to focus on our strategic priorities described above by:

- delivering the improved California synergies, resulting from our acquisition and integration of the Southern California refining, marketing and logistics business; . . .

Tesoro Logistics LP

TLLP was formed to own, operate, develop and acquire logistics assets to gather crude oil and distribute, transport and store crude oil and refined products. [Emphasis added throughout]

These plans, put forth so publicly, repeatedly, and recently, before and after the purchase of the BP properties, should have been disclosed in the ND as part of the Project. The ND is entirely at odds with this public description of Tesoro’s own plans. Existing permit conditions listed in the ND are not sufficient to prevent these major refinery changes for which the storage tanks are needed.

The ND identifies the following existing permit conditions and makes very generalized conclusory statements that the Project is not for other purposes, but the ND does not provide the baseline evidence necessary to substantiate these claims, that are so in conflict with the evidence of Tesoro’s own statements:

- The existing Tanks 80035 and 80036 are both currently permitted to store petroleum materials including crude oil, hydrocracking unit (HCU) feedstock (a light gas oil . . .
- The two new tanks are proposed to be permitted to store light and heavy crude oils of varying vapor pressures up to 11 pounds per square inch (psi), light gas oils such as HCU feedstock and fluid catalytic cracking unit (FCCU) feedstock, and heavy gas oil
- Tank 80038 is currently permitted to store petroleum distillate products with true vapor pressures less than 0.5 psi such as crude oil and heavy gas oils and is not connected to the vapor recovery system. Tank 80038 currently primarily stores vacuum gas oil, a heavy gas oil. The proposed modifications to Tank 80038 would change the type of commodity to be stored in the tank to also include light gas oil and connect Tank 80038 . . .
- All modifications associated with the proposed project will occur within the confines of the Wilmington Operations . . .
- . . . no modifications will occur at the Carson Operations.
- The proposed project was conceived, and the applications for the proposed project were submitted to the SCAQMD prior to Tesoro's acquisition of the Carson Operations.
- The overall amount of crude oil delivered to the Wilmington Operations will not change from current operations.
- The proposed project will not increase the total amount of crude oil delivered to the Wilmington Operations on an annual basis and will not alter the methods of
crude oil delivery because crude oil will continue to be delivered via ships and pipeline.

- No modifications are proposed to the existing crude oil delivery pipeline from the Marine Terminal. Further, no other pipelines that deliver crude oil or any other product to the Wilmington Operations will be modified as part of the proposed project.

- Further, Tesoro is not proposing to change the crude oil throughput of the Wilmington Operations or any downstream refining processes because crude oil storage capacity is not a limiting factor for the throughput and production at the Wilmington Operations.

- Refining operations fluctuate and are controlled by many factors, including but not limited to, equipment design parameters, market demand, equipment maintenance schedules, equipment permit limit conditions, and crude oil characteristics (e.g., sulfur content, acidity, specific gravity, etc.).

- Tesoro has operated the refining processes at the Wilmington Operations at the maximum capacity in the past and are expected to continue to operate up to or at maximum capacity in the future. Therefore, the baseline crude oil throughput rate and product output of the Wilmington Operations on a daily or an annual basis would not change as a result of implementing the proposed project.

- The refining capacity of the Wilmington Operations is constrained by a number of factors including equipment design parameters, market demand, equipment maintenance schedules, equipment permit limit conditions, and crude oil characteristics (e.g., sulfur content, acidity, specific gravity, etc.).

- The refining capacity is based on the overall design of the refining processes within the Wilmington Operations.

- The heat required to first separate crude oil into various intermediate products, which are later refined further, dictates the amount of crude oil that can be processed overall by the Wilmington Operations.

- Specifically, the Crude Unit, the first step in the refining process, receives the crude oil directly from storage (i.e., from both the existing and proposed storage tanks), has operating limits on the heater, which limits the amount of crude oil that can be processed.

- The Crude Unit operations fluctuate based on conditions of other process units within the Wilmington Operations, market demand, and crude oil characteristics.

- The Crude Unit heater routinely operates at various firing rates and will continue to operate at various firing rates, which is considered to be the baseline at the Wilmington Operations, and the proposed project does not include modifications to the Crude Unit throughput or heater firing rate.

The reasoning that no modifications will occur at the Carson refinery is conclusory, because the Project is currently self-defined as only including the pipe and storage tank increases.
The reasoning that operations “fluctuate” based on “conditions of other process units, market demand, and crude characteristics” is always true of every refinery. This general statement by no means precludes environmental impacts occurring.

No timeline or size of such fluctuations is identified in the ND, so they could be unlimited. Baseline periods and quantification of degree of fluctuations should be identified.

Such fluctuations in crude oil characteristics were identified in the literature previously cited as directly causing environmental impacts.

No baselines were provided for crude oil sulfur, metals, paraffin, or carbon content, or for any crude oil characteristics whatsoever.

Neither does the ND identify whether existing permit conditions for the tanks or other parts of the refinery include any limits on such characteristics.

The ND does not provide any information on the baseline “heat” provided in the crude unit heaters mentioned in the ND.

The ND does not provide any information about when in the past the refinery was operated at “maximum capacity,” how maximum capacity is defined, how long ago this occurred, for how long this occurred, and at what percentage of the capacity the refinery is currently running.

Further, the ND does not identify the baseline levels of any other process units within the Wilmington refinery, or within the Carson refinery.

The ND does not identify whether there is existing piping connected to, or close to the Wilmington tanks that could bring materials in the future to the Carson refinery.

The ND does not identify whether the tankage increase in Wilmington could free up other tankage at either refinery, or that could be connected in the near future.

The ND does not identify whether such changes could change the yields of different units within the Carson or the Wilmington refinery.

All these and more such details are essential to an evaluation of the Project and its impacts.

C. The new pipeline across the Wilmington refinery to the Project storage tanks continues past the tanks to the corner of the Wilmington property closer to the Carson property, and next to a railway

The ND states that the Project does not involve the Carson refinery, nor any transport by rail, or anything besides the pipeline and the storage tanks. But the new pipeline through the Tesoro facility is routed not only to the new tanks, but beyond them, to a corner of the refinery that is
close to the Carson portion of the refinery, and is also next to rail lines that traverse the length of
the refinery between the Carson and the Wilmington operations.

I have circled the end of the pipeline route which was identified in the refinery layout map
provided by the ND. The ND graphic shows an additional length of pipeline beyond the Project
tanks, to the corner of the Wilmington refinery property, but provides no explanation about the
potential for this extended pipeline to connect with additional refinery and logistics operations
(including the Carson refinery, the adjacent rail yard, other storage tanks, and potentially even to
trucking assets). There is also an extra leg of pipeline indicated without explanation, between
two tanks that were not identified as part of the Project.

Why does pipeline portion circled below continue past Project tanks, and end at the
corner of the Wilmington refinery?

The ND must be recirculated as a full EIR, and the potential for connections to the Carson
portion of the refinery must be identified. Existing nearby pipelines and connections, plans made
known to the AQMD of such connections, and the general potential for such connections that the
Project facilitates must be evaluated.

In addition to the potential that the storage tanks and pipeline are located in close proximity to
the Carson refinery, they are also next to a rail line which runs from top to bottom to the left of
the diagram above. The US Energy Information Administration website provides the following
charts showing the steady increase of alternative forms of crude oil delivery to oil refineries
instead of ship (rail, barge, and truck), including in California. The ND states that Tesoro does
not currently transport crude by rail to the Wilmington refinery (at 1-1), but that does not

31 http://www.eia.gov/todayinenergy/detail.cfm?id=12131

29
preclude the Project from facilitating such a project in the near future, especially given the proximity of the tanks to a rail line. The potential to connect in the future to other local rail should also have been discussed.

Further, Tesoro owns major truck terminal assets. The ND does not provide any information about any applications in process related to truck terminals, baseline activities, potential connections to other transport modes, or the potential for the increase in storage to be connected to Tesoro’s terminal. While ship is the more obvious choice at this time, the potential for flexibility of these storage tanks for Tesoro to connect with other transport such as rail and truck should also have been evaluated in the ND.

However, the most crucial omission was the failure to evaluate the Project’s role in the integration of the Wilmington and Carson portions of the refinery complex.

**D. Volumes and throughput are also publicly planned to increase at the Southern California Marine Terminals according to Tesoro**

As described earlier, and also in Tesoro’s May 1, 2014 earning call, Philip Anderson, President of Tesoro Logistics LP identified increases in the volumes that its terminals will handle (not just the speed of offloading), increasing throughput capacity:

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“We have two of our terminals are being expanded to handle additional capacity, and those expansions will come online this summer. And that will allow us to bump up volumes either very late in the second quarter or early in the third quarter.” . . .

“Our marine facility down there [Long Beach], 121, which is the large neighbor de-berth in Long Beach, stays pretty full. We have our legacy to Long Beach terminal [Marine Terminal] that is adjacent to our newly acquired, what we call, P-2 in Long Beach. And between P-2 and our legacy Long Beach terminal, we probably have an additional 100,000 plus barrels per day of throughput capacity.”

The ND can’t legitimately cut the baby in half – the reason for the increase in offloading through a much larger pipeline and into much larger tankage is admittedly a planned throughput increase in Tesoro’s marine terminals.

Tesoro will be enabled to offload over 12 times as fast from its marine loading operations to the new and expanded onshore storage tanks through the Project’s expanded 42-inch pipeline. Not only will this enable increased speed of offloading, it will free up the terminals to allow scheduling of additional ships to port for offloading at these large storage tanks.

As previously discussed, the US Department of Transportation found that all modes of transportation for Bakken crude need to assess the safety hazards it poses. Further, the AQMD must also evaluate the hazards involved with the transport by ship of heavy tar sands crude, and the diluents that come along with it.

E. The Project has the potential to increase coking

As identified above, there is a major potential to increase the proportion of heavy crude oil from Canada, which would increase coking. The AQMD performed source tests at South Coast refineries and found the following emissions (in lbs per coking cycle).\textsuperscript{33} Coking cycles at least once a day. While the AQMD adopted a regulation to reduce these emissions, final deadlines of the regulation are in 2019, so increased coking in the meantime will mean increased impacts from VOCs, particulate matter, sulfur compounds, and the greenhouse gas methane from these operations, which were not evaluated in the EIR. First the ND needs to provide information about the crude slate baseline and coking baseline so that the degree of increased coking can be identified.

\textsuperscript{33} Proposed Rule 1114 Working Group Meeting, September 27, 2012, Petroleum Refinery Coking Operations (staff presentation, Slide 4)
F. The increased Storage Tanks themselves have significant impacts, for example, due to the increased tank and pipeline size causing increased risk from fires and earthquakes

The Project treated earthquakes and fires as separate issues. This provides an unrealistic probability that oil and gas fires would occur. The Project instead should be considered to cause a significant increase in the probability of oil and gas fires due to the imminent earthquake hazard. Oil and gas fires are very difficult to extinguish, and could easily spread. Such fires can emit large clouds of hazardous black smoke over the region.

Obviously, the risk of explosion and fire due to Bakken crude oil represents much increased risk, as previously discussed. However, just the increased size of the tankage increases the volume of material vastly, which of course increases the impacts when a fire or explosion occurs, regardless of the type of crude oil present.

A major earthquake is not just a theoretical possibility. The risk of a major earthquake in the region is imminent and severe. A September 2005 Los Angeles Times article, 34 Katrinas Aftermath, California Earthquake Could Be the Next Katrina, reported:

“A state study published last year on hazard reduction paints a sobering picture of California's earthquake danger. About 62% of the population lives in a zone of high earthquake danger, including 100% of the population of Ventura County, 99% of Los Angeles County and 92% of Riverside County. . . .

“Researchers at the Southern California Earthquake Center said there is an 80% to 90% chance that a temblor of 7.0 or greater magnitude will strike Southern California before 2024.”

The Southern California Earthquake Center (at the University of Southern California) earlier found:

“The last official estimate of earthquake potential in southern California was the 1988 report of the Working Group on California Earthquake Probabilities. The report estimated the probabilities of large "characteristic" earthquakes on major faults, like the San Andreas and San Jacinto faults. The report concluded that there is a 60% chance of at least one large earthquake (M=>7) on the San Andreas fault before the year 2018. The report concluded that the probability is even higher, 80-90%, when other faults are included.” Such an earthquake could occur today. Severe ground shaking will occur during the inevitable major earthquake in Los Angeles area. Los Angeles’ soil types cause increased ground shaking.

The Uniform Building Code does not prevent significant and even severe earthquake damage. In an Environmental Impact Report performed for Industrial Service Oil Company, Inc. (ISOCI) of Los Angeles, the potential for damage to structures (including oil treatment and storage structures) was identified, despite the fact that the facility stated it would comply with the Uniform Building Code.

Based on the historical record, it is highly probable that the Los Angeles region will be affected by future earthquakes. Research shows that damaging earthquakes will be likely to occur on or near recognized faults showing evidence of recent geologic activity. The impacts of an earthquake on the site are considered to be greater than the current conditions since additional structures will be constructed including new treatment and storage facilities. Impacts of an earthquake could include tank and other structural failure.

Additional structures at the site must be designed to comply with the Uniform Building Code . . . The goal of the code is to provide structures that will:

1) Resist minor earthquakes without damage;
2) Resist moderate earthquakes without structural but with some non-structural damage; and

35 SCEC (at the University of Southern California) gathers and combines new information about earthquakes in Southern California, is supported by the National Science Foundation and the U.S. Geological Survey, and coordinates efforts of over 50 institutions
37 “Another project in progress will update this map by showing a higher level of shaking for soft-soil sites. This will lead to a higher rate of damaging shaking because the more common smaller earthquakes will produce greater shaking in soft soil. The result will be to increase slightly the rates for the sedimentary basins such as the Los Angeles basin and the San Gabriel, Ventura and San Bernardino Valleys.” Seismic Hazards Map for Southern California, Southern California Earthquake Data Center, http://www.data.scec.org/general/PhaseII.html
Thus, the ISOCI EIR found that an earthquake in the region could cause tank and other structural failure, and also found that the Uniform Building code does not preclude all damage from earthquakes. It found that the Code is only meant to cause resistance to earthquake damage and collapse. These same risks exist at the proposed Oxy site.

A discussion of remaining risks which exist after compliance with the Uniform Building Code was provided in a publication by Dr. Robert J. Kuntz, President of the California Engineering Foundation, and Daniel L. Tanner, the California Engineering Foundation’s Economic Consultant. This document found:

> The California Building Code offers only minimal protection from seismic damage, i.e., a structure should not be damaged in a minor earthquake, damaged beyond repair in a moderate earthquake, nor collapse in a major earthquake. However new technologies, such as seismic isolation, can mitigate both structural and building contents damage and are becoming available to government and industry. There is a need for design professionals, building officials, planners, and building owners to become aware of these new technologies, the criteria for their use, and how to incorporate them into practice.

> The Uniform Building Code provides minimal seismic protection determined acceptable by local governments, but Code specifications do not prevent structural damage nor ensure the use of a building after an earthquake.

Such limited protection is not consistent with the needs of commerce or emergency facilities, which must remain operational after an earthquake, nor does it protect the contents of a building. Two earthquakes which struck near the Lawrence Livermore National Laboratory in California, within two days of each other in January of 1980, caused a total of $10 million in damage. Nearly half of the damage was to laboratory equipment, testing systems, and other building contents.

As an illustration of the potential damage that can occur in an industrial area during a major earthquake, the 1999 earthquake in Turkey was evaluated by the Pacific Earthquake Engineering Research Center. An excerpt of a report on this study is provided below. The report found “The earthquake struck the industrial heartland of Turkey.” It found that complete structural failures due to earthquake were few in number, but severe damage short of complete structural failure did occur. One example was the failure of floating roofs in crude oil tanks.

Such fracturing and crumpling of support structures and other earthquake damage to industrial equipment not only cause leaks and spills, but could easily cause fires. Even in residences, fires during earthquakes are a known common hazard due to leaking natural gas, broken structures and electrical systems, ignition sources, etc. When damage occurs during major earthquakes to heavy industrial facilities that store, transfer, and process combustible materials, there is even more potential for dangerous fires. The Turkish example included a fire during the 1999

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39 Disaster Recovery Journal, 1999, [http://www.drj.com/drworld/content/w2_066.htm](http://www.drj.com/drworld/content/w2_066.htm)
earthquake when a refinery cooling tower failed, and also when eight naphtha-storing fuel tanks burned.

A publication funded by the Earthquake Engineering Research Institute and the Washington Emergency Management Division (2005) found severe damage due to earthquakes, including long-term environmental impacts of hazardous material releases. The Report found:

Fire following the earthquake caused severe damage to the Tüpras refinery. Other observed structural failures in the refinery were to a 115-m-tall smokestack, floating roofs in crude oil tanks, and piles supporting a jetty. Substations and one power generation facility suffered damage ranging from overturned transformers to fractured porcelain switches.”

Another publication described the Kocaeli fire, the tank structural damage, fire and collapse, and oil spilled into the sea, and major equipment including a large boiler knocked off its foundation.

Fig. 5. Fire damage to naphtha tanks at Tüpras refinery.

In addition to the risk of fires associated with earthquakes well known to California regulators (as well as those documented after the Turkish earthquake), a publication of the University of Patras, Greece -- Safeguarding Hydrocarbons Inside Local Earthquake Defense Systems --

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found major fire risks from earthquakes associated with burning hydrocarbons to be a general problem around the world:

“Hydrocarbons, particularly gas, also create a much increased risk of fire as a major secondary consequence following earthquake damage. There is a growing danger that major Greek cities may experience fire damage after a strong earthquake, enhanced by the increased supply of gas into urban areas. Fires following the earthquake at Kobe in Japan 1995 and Turkey 1999 (Fig.1,2) provided a salutary example of impact even in a well-regulated, modern and earthquake conscious country. Longer memories recall the conflagration in Tokyo that followed the 1923 Kwanto earthquake.”

The new tanks could be used for Bakken or Canadian Tar Sands crude oil according to Tesoro’s plans. Bakken crude oil has been shown to be explosive (as in the tragic Lac Megantic rail explosion). It is indisputable that fires and explosions, especially due to earthquake must be evaluated in a new ND related to Tesoro’s and Tesoro Logistic’s plans to bring Bakken crude oil into its facilities and crude oil tanks.

http://seismo.geology.upatras.gr/shields/SHIELD20003.htm
But even with heavy Canadian Tar Sands crude that Tesoro may switch to, an earthquake or other impact could cause a major oil fire. (And that is without considered the addition of volatile diluents added to tar sands crude, which should have been considered.)

An example of severe fires at a facility processing heavier grades of oil includes the Third Coast Industries fire in Houston Texas. The U.S. Chemical Safety and Hazard Investigation Board came to the conclusion that higher flash point (“non-ignitable”) materials such as heavy oils can represent major fire hazards. This agency concluded after evaluation of the huge 2002 automotive fluid blending plant fire in Texas, that oils with flash points greater than 200°F classified as “Combustible IIIB” (including motor oils) should be treated with more care regarding fire safety. The Texas fire under investigation could not be put out, and completely destroyed the facility.

In the Texas case, the Chemical Safety Board found that while most of the material onsite at this facility had higher flash points (meaning they were heavier, less volatile materials), the presence of small amounts of some liquids which were more easily combustible with lower flashpoints, could have caused the fire to start, and then combusted the bulk of the higher flashpoint materials. The Chemical Safety Board found that such higher flash point oils burn “fiercely” once a fire is started.

The Board concluded that fire codes and workplace safety regulations should apply more controls to combustible liquid storage and handling. In the aftermath of the Third Coast fire, the Board communicated its concerns in correspondence to the U.S. Occupational Safety and Health Administration (OSHA). The Chemical Safety Board also found:

... the facility was not designed to contain the contaminated runoff that could result from fighting the fire with water. Fire officials therefore decided they had no choice but to let the plant burn, and they focused on protecting nearby homes from destruction.

A 2005 oil depot fire in the Hertfordshire in the United Kingdom also illustrates how severe offsite impacts from smoky oil fires can be. The inefficient burning of petroleum products at this site caused huge smoking plumes similar to smoking which could occur at the Warren facility if a fire were to break out, due to earthquake or other reasons.

The Hertfordshire Oil Terminal fire showed that such fires cause huge smoky plumes due to poor combustion of hydrocarbon materials. Smoke from an oil fire and/or hazardous materials burning could cause major emissions of particulate matter, PAHs (Polycyclic Aromatic Hydrocarbons), sulfur oxides, heavy metals including lead, mercury, and chromium, chlorinated compounds including deadly dioxins, and many other hazardous compounds.

Smoky fires and gas plumes from such an event could reach nearby residential areas and impact workers offsite and onsite, and could billow for miles. Even a moderate fire could heavily impact

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44 http://en.wikipedia.org/wiki/2005_Hertfordshire_Oil_Storage_Terminal_fire#Causes
neighbors and schoolchildren, especially people with respiratory problems, asthma, or heart conditions, but could also significantly impact healthy adults. The impact would depend on fire size, availability of the fire department (which may not be the case in an earthquake), and how long it takes to put out the fire. In the event of an earthquake, the public has been repeatedly informed that emergency services may not be available for some time, due to obstructions on roadways, and broken water supplies.

The potential of such hazards due to a major earthquake must be evaluated in an EIR.

G. The approximate mile-long expanded pipeline from the Marine Terminal to the Wilmington refinery tanks increases earthquake risks

The ND fails to evaluate the increased volume of crude oil present in the pipeline at any one time, and the increased risk of spill this would cause, especially due to earthquakes. It relies on a stated assumption that annual transport would stay the same (which is also contradicted by Tesoro’s published plans, and not inherently true unless specific new conditions are set).

See the discussion above about risks of fires and explosions related to Bakken and Canadian Tar Sands Crude oil in the new expanded storage tanks. The same concern applies due to the large amount of petroleum material that would be added to the approximately mile-long pipeline from the marine terminal to the tanks. Compliance with building codes is meant to reduce risks, but is not considered to eliminate earthquake risk. The ND was wrong in its failure to consider the combination of fire and explosion from earthquakes, which would obviously be increased due to the higher volumes of materials that would be present. The smoky black plumes caused by oil fires contain particulate matter, PAHs (Polycyclic Aromatic Hydrocarbons) and many other harmful compounds that should have been evaluated in the ND with regards to oil fire risk that will certainly be significantly elevated due to the Project increases.

H. Other Potential Project Impacts

Evaluation of the following should be added, especially given the changes in crude slate planned by Tesoro:

- **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.\(^\text{45}\) 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. Furthermore, impacts related to tar sands storage and tank cleaning, including heavy tank bottoms, and use of diluents must be addressed.

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

- **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.

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46 “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.”

47 At p. 1-13
IV. Conclusion – Potential Impacts are large, have not been mitigated, no alternatives or Cumulative Impacts were analyzed, and an EIR must be developed

My conclusion is that there is an abundance of evidence on the deficiencies in the Project Description and the missing significant environmental impacts due to the full actual Project. Accordingly, AQMD is required to prepare a full EIR. Because the ND incorrectly portrayed this Project as relatively a minor change, numerous impacts are either understated or missing. Mitigation, Cumulative Impacts and Project Alternatives to avoid these significant impacts were not evaluated.