VALERO

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April 11, 2013

Crude by Rail Project, Facility B2626
S-97 TK-1776, S-253 Railcar Unloading
NSR Permit A/N 25242
Response to Questions 3 - 13

PUBLIC VERSION

Ms. Thu Bui
Senior Air Quality Engineer
Engineering Division
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Dear Ms. Bui:

Thank you for the expeditious review and response to Valero ATC Application for its Crude by Rail project, A/N 25242. Attached are Valero's responses to information request items 3 thru 13 outlined in the BAAQMD March 20, 2013 incomplete letter.

Items contained in the responses that are Confidential Business Information have been redacted from this version.

We anticipate that submittal of this documentation will allow for a timely completion of the subject permit application. Please do not hesitate to contact me at (707) 745-7203 or Don Cuffel at (707) 745-7545 if you have any questions or comments.

Sincerely,

Susan K. Gustofson
Staff Environmental Engineer

SKG/tac

Enclosures

ecc: Tim Morgan, ESA
Charlie Knox, City of Benicia

Document # 23729

VALERO
BENICIA REFINERY

CRUDE BY RAIL PROJECT

VALERO REFINING COMPANY – CA

BENICIA REFINERY

BAAQMD A/N 25242

RESPONSE TO BAAQMD 3/20/2013

PROJECT QUESTIONS

APRIL 11, 2013

PUBLIC VERSION

Document # 23703

1. **A soft copy of the spreadsheet for all emissions calculations (fugitives, ships and rails, etc...) that Valero submitted.**

   A compact disk containing the emissions calculation spreadsheets have been forwarded separately.

2. **A completed form "Appendix H".**

   Completed Form Appendix H has been forwarded separately.

3. **What is the proposed Tier for rail cars in your calculation?**

   While Valero has no control over the types/tiers of locomotive engines used by UP to haul freight to and/or from the facility that might serve this project, UP has invested in significant fleet improvements since 2000. These improvements include the purchase of more than 3,500 locomotives that meet the newer tier guidelines, new Tier 3 locomotives scheduled for delivery in 2013, retirement of over 2,500 older locomotives, and overhaul or rebuild of over 4,100 locomotives. The types/tiers of locomotive engines used to haul railcars on any given day is determined by the logistics of the rail yard, the railroad company, the freight to be transported, and the transportation route.

   UP has been working cooperatively with CARB to modernize their fleet to reduce overall emissions. Two examples of these cooperative agreements are outlined below.

   In 1998, participating railroads and CARB entered into an agreement, commonly referred to as the "1998 Memorandum of Mutual Understanding" or MOU, whereby the participating railroads accelerated the introduction and use of cleaner, lower-emitting locomotives used in the South Coast air basin. This emissions reduction is attained voluntarily on a fleet-average basis. UP manages approximately 8,300 locomotives nationwide. Because the railroads must consider a multitude of factors to manage their fleet of locomotives to efficiently deliver freight, the area-wide fleet-average agreement was deemed to be the most effective avenue to achieve CARB's goals.

   In cooperation with the MOU agreement, beginning in 2005 UP purchased only Tier 2 or better locomotives. Beginning 2013 new locomotives purchased must be at least Tier 3. Tier 4 locomotive technology is still in the testing stages. Beginning in 2015 according to the agreement, new locomotives purchased must be Tier 4. Though Tier 4 locomotives are currently not commercially available, UP is scheduled to test a prototype later this year.

   In addition to the MOU agreement, in 2005 participating railroads and CARB entered into an agreement to reduce particulate matter (PM) emissions at California rail yards. Emissions reduction methodologies include using ULSD on-highway diesel fuel supplied to locomotives fueled in California, reducing visible emissions by implementing a plan to expeditiously repair locomotives exhibiting excessive visible emissions, and reducing non-essential idling time both inside and outside of rail yards. All new UP locomotives have automatic stop-start equipment, and older locomotives are being retrofitted with

this same equipment. Over 70% of their current locomotive fleet is now equipped with this technology. UP has also voluntarily chosen to utilize the UP-pioneered Genset switchers in their rail yards to further reduce emissions.

Since these cooperative agreements were implemented, significant emissions reductions have been and continue to be achieved.

Emission factors for estimating locomotive exhaust emissions due to the proposed rail car activity for this project were obtained from the EPA document – "Emission Factors for Locomotives, Technical Highlights", EPA-420-F-09-025, April 2009 (See Attachment 1). Emission factors for NOx, PM10, and hydrocarbons, in grams per gallon of fuel consumed by type of engine and operation, were obtained from Tables 5, 6, and 7 of this EPA document. Emission factors for other criteria pollutants and GHGs were converted from the units of g/bhp-hr to g/gallon fuel using various conversion factors provided in this document. Emission factors for the year 2014, when the project first becomes operational, were chosen for the calculations.

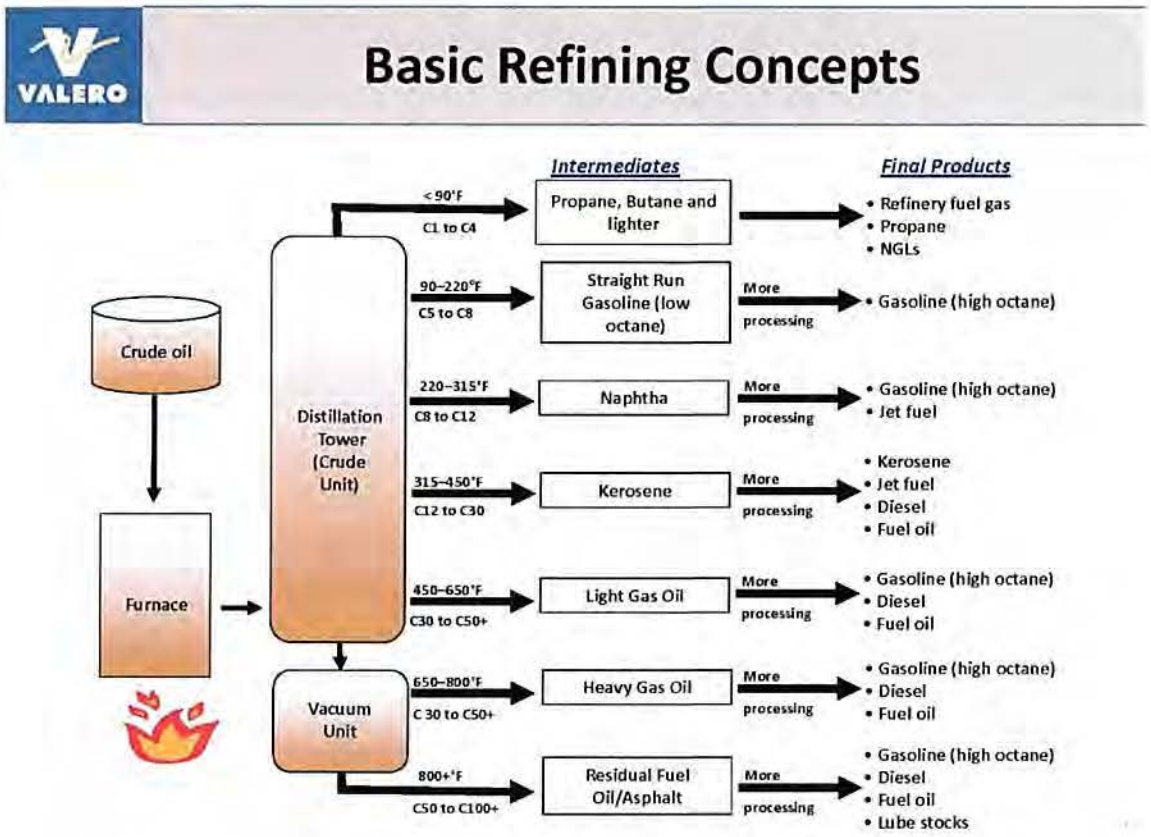
As stated in the section titled "Projected Future Emission Factors" on page 5 of this EPA document, the emission factors in Tables 5, 6, and 7 are an average of the emission factors of a projected/expected composite fleet in a calendar year. The composition of the fleet (number of engines by tiers) will vary over time and depends on several factors, such as useful life of engines, scrapping of engines, inclusion of newer engines in the fleet and regulatory drivers.

In conjunction with responses to **Questions 4 through 8**, please review the Refinery Processes discussion below. This discussion explains where and how emissions are generated in refinery processes, where and how components undesirable in transportation fuel products are removed, and the conversion of certain components to a more beneficial form that is used as a valuable commercial product and that is less hazardous and more easily handled.

The North American sourced crudes proposed to be received by railcar are similar to crudes currently supplied by marine vessel - Alaskan North Slope (ANS) look-alikes or sweeter. The North American sourced crudes will be transported in unheated railcars and will be stored in an unheated storage tank. This prohibits transport of heavier gravity crudes because they are too viscous to pump at ambient temperatures. The Valero Refinery processes a mixture of crudes from throughout California, the United States and the world. These crudes are blended together at the refinery to assure safe and compliant processing utilizing current refinery hardware and within permitted limits. Because there will be no change to the units that process the crude as a result of the proposed method of crude receipt, the refinery's 'diet' of crudes must also remain within existing parameters.

Refinery Processes

The Valero Benicia Refinery process heaters and boilers consume internally-produced refinery fuel gas which may contain purchased natural gas as a supplement to meet total fuel demand. The primary source of refinery fuel gas is the light ends, or low boiling point hydrocarbons, naturally occurring in crude oil that are generated in the refining process. As depicted in the simplified process flow diagram below, the lightest hydrocarbons in the C1 (methane) to C2 (ethane) range are directed toward refinery fuel gas while C3s and C4s (propanes and butanes) are preferentially sent to commercial products such as propane, butane, and natural gas liquids.



Refinery fuel gas is initially produced during the atmospheric and vacuum distillation processes, the first processes that the crude (or mixture of crudes known as the "crude slate") encounters. Hydrocarbon cracking processes in the Hydrocracker, Fluid Catalytic Cracker (FCCU) and Fluid Coker produce additional light-ends, some of which fall in the

boiling point range for refinery fuel gas (C1s & C2s). Seasonal motor gasoline blending changes required by the California Air Resources Board (CARB) specifications and facility-wide refinery fuel gas balances can result in some normal butane being directed to refinery fuel gas as well.; However, for economic reasons this normal butane blending is minimized because the normal butane has more value when converted to isobutane and blended into commercial products. In every scenario, purchased natural gas, which is predominately methane, is minimized.

Because refinery fuel gas is constrained to contain methane (C1) and ethane (C2) as the primary components, the mixture is indifferent as to where the methane or ethane was generated. Thus, C1s and C2s from cracking processes such as the FCCU or Coker are identical to C1s and C2s from basic distillation at the crude unit. Cracking processes do introduce some additional sulfur compounds into the raw refinery fuel gas steam, but these are removed by treatment before the fuel is used. The treatment of sulfur compounds is addressed below.

Combustion of refinery fuel gas produces NOx, SO_2, CO and sulfuric acid mist (SAM) in well-understood and documented processes. The Refinery's Title V permit regulates NOx and CO for every process heater and boiler by establishing emissions limits under Federal and BAAQMD regulations including source-specific permit conditions. The production of NOx is driven by excess oxygen (O_2), burner type, firebox temperature, residence time and any abatement such as selective catalytic reduction (SCR) or ammonia injection (selective non-catalytic reduction-SNCR). During normal operations, heat transfer demand from the fired source to the process is controlled by throughput (feed to the heater) and other production variables (such as catalyst activity) to maintain relatively stable combustion of refinery fuel gas. Because the refinery fuel gas is consistently a combination of C1s and C2s distilled or cracked from the crude slate with purchased natural gas added as needed, the refinery fuel gas combustion emissions for NOx are unchanged by changes in the crude slate.

NOx and CO vary inversely as excess O_2 is adjusted. Simply put, increasing excess O_2 typically increases NOx and decreases CO for given combustion source fired condition because complete combustion is promoted with ample excess oxygen. For energy conservation, excess oxygen is minimized to just above the point where CO production could become unstable beyond acceptable limits. This combustion tuning procedure minimizes NOx as well. This balance between NOx and CO is not dependant on the crude slate or refinery fuel gas qualities other than maintaining the refinery fuel gas heating value (HHV) within a reasonable range to promote good and stable combustion in a well-tuned furnace.

North American sourced crudes are typically characterized as "sweet" meaning they contain less than 0.5 wt% sulfur. The North American sourced crudes currently available to the Valero Benicia refinery are expected to have sulfur below 0.5 wt% which is well below the

typical crude slate average of 1.4 wt%. Therefore, these crudes directionally sweeten the crude slate and reduce the amount of refinery fuel gas sulfur treatment required.

EPA and the BAAQMD impose sulfur limitations on refinery fuel gas, both total reduced sulfur (TRS) and H_2S, with specific concentration and averaging periods as documented in the Title V permit. For this facility the Title V permit contains 7 unique permit limits for sulfur in refinery fuel gas with 5 different averaging periods. Short term limits such as 162 ppm H_2S for 3-hours and 155 ppm TRS in a calendar day do not reflect the degree of control required on a daily basis that the longer term limits impose such as the Cogen unit's limit of 35 ppm TRS in a rolling 365-day period.

No matter what the sulfur content might be in any crude oil or crude slate, the refinery fuel gas sulfur content is controlled to meet permit limits by treating the fuel gas with MEA to remove H_2S and with "sponge oil" to remove TRS constituents other than H_2S. The refinery fuel gas treatment systems monitor and analyze for sulfur content (TRS & H_2S) on a real-time basis to adjust treatment as needed to maintain compliance. Consequently, the sulfur-based emissions associated with combusting refinery fuel gas are essentially unaffected by changes in crude slate. In fact, any increase in refinery fuel gas sulfur concentration actually results in increased sulfur recovery during the fuel gas treatment processes which translates to increased commercial sales of molten elemental sulfur. But as stated above, the crude slate is expected to be sweeter with the introduction of North American sourced crudes.

Sometimes source-specific sulfuric acid mist limits are imposed on newer sources like the Cogeneration facility; however, the production of sulfuric acid mist is driven by the sulfur content in the refinery fuel gas (producing SO_2) and the stack temperature (driving dissociation of sulfuric acid mist into SO_2 and water). As explained above, the sulfur content of refinery fuel gas is not expected to change with changes in crude slate because sulfur recovery increases whenever refinery fuel gas treatment increases. Thus the input to the formation of sulfuric acid mist is not expected to change beyond the current performance boundaries.

In fact, the Benicia Refinery has reduced sulfuric acid mist emissions significantly with the operation of the Flue Gas Scrubber (FGS). While this abatement system is not associated with refinery fuel gas directly, it removes SO_2 from previously unabated flue gas which exited the Main Stack. Toxic Release Inventory (TRI) records show that sulfuric acid mist emissions were reduced in by 85% in the first year of FGS operation from annual averages near 80k lbs/year to only 12k lbs/year. Of that amount, less than 2k lbs/year is estimated to result from refinery fuel gas combustion.

A summary of criteria pollutant emissions impacts from the North American sourced crudes appears below:

Pollutant	Current Limits	Expected change in emissions	Comments
SO_2	Set by TRS and H_2S limits in Refinery fuel gas (refinery fuel gas)	No change expected because treatment for H_2S and TRS will continue to achieve compliant refinery fuel gas	North American sourced crudes are expected to be sweeter than existing average crude slate
NOx / CO	Set by Title V applicable Federal and BAAQMD Regulations and source-specific permit conditions	No change is expected because the refinery fuel gas composition (C1s, C2s) is indifferent to changes in crude slate	Tuning furnaces for energy conservation and NOx minimization will continue as primary compliance practice
Sulfuric Acid Mist (SAM)	Set by TRS and H_2S limits in Refinery fuel gas (refinery fuel gas) and selected source-specific permit conditions (e.g. Cogen)	Sulfuric acid mist will not increase by introducing North American sourced crudes into the crude slate	North American sourced crudes are characterized as sweet and are expected to have sulfur content lower than current crude slate sulfur average

Conclusion: Processing North American sourced crudes will not increase emissions of criteria pollutants or sulfuric acid mist.

4. **The toxic air contaminant composition of the North American crude.**
5. **Provide the toxic air contaminant composition of the crude slate that is being fed into the crude units at Valero refinery and/or Asphalt Plant.**

4 & 5 Response: The proposed North American sourced crudes contain elemental compounds similar to or lower than the existing crude mixture processed at this facility. These compounds can vary even within a certain crude production field. Metals that are inherent in all crudes are primarily removed in hydrofining processes to meet CARB product specifications. There will be no change in this operation, and product specifications will continue to be met.

Because the crudes that are proposed to be received by railcar will be transported and stored in unheated equipment, the crudes must have low viscosity at ambient temperatures. Therefore, they are lighter in gravity and are expected to have metals content equal to or lower than the crudes they will replace.

Individual crudes purchased for refinery processing are often outside the range of design feedstock criteria, but are blended with other crudes to meet those criteria prior to processing at the refinery. Factors that contribute to the design feedstock criteria that require the refinery to operate within its range include sulfur processing capacity, limits on SO2 and other emissions, metallurgical constraints, and process unit sizing and configuration constraints for the crude gravity it is designed to process.

The graph below identifies Padd V historical data, the blended crude feedstock criteria for the Valero refinery (green box), and historic crudes processed at this refinery from 2007 through 2012. The crudes proposed to be brought in by rail are those that fall into the lower right corner of the graph, which would be lighter in gravity and lower in sulfur than the average Padd V or average Valero crude slate.

6. **Specify if there would be any air pollutant, NOx, SO2, H2S, sulfuric acid mist, and other toxic metal emission increases or decreases from downstream processes due to the blending of North American crude in the crude slate. Please identify each process in the refinery beginning with the crude unit to downstream processes, including the SRU, Hydrogen Plant, amine systems, boilers and furnaces that use the refinery fuel gas. Please show the before and after comparison including detail analyses and calculations.**

   In addition to the background discussion above, because the proposed North American-sourced crudes are expected to be ANS look-alikes or sweeter, and because the mechanism for generation and scrubbing or removal of these emissions will not change, there is not expected to be any difference in emissions generated compared to existing operations. To summarize:

   NOx generation is primarily independent of crude slate. NOx is generated in process heaters and is based on heater configuration, burner type, firebox temperature, residence time, excess oxygen, and available abatement mechanisms such as NH3 injection or SCR. Next to crude, energy is a primary component in the cost of manufacturing transportation fuels. Therefore, optimizing heater performance is a high priority for refinery operations. Optimized heater performance also benefits by minimizing NOx generation.

   SO2, H2S, and Sulfuric Acid Mist (SAM) are primarily generated from combustion of refinery fuel gas. The refinery's operating permit tightly regulates sulfur-related emissions. The permit contains 7 unique permit limits and 5 different averaging periods to control sulfur-related emissions from refinery fuel gas. Because sulfur is recovered or scrubbed from the refinery fuel gas stream in the sulfur recovery unit and amine scrubbing system prior to being combusted in refinery processes, sulfur-based emissions associated with combusting refinery fuel gas are essentially unaffected by changes in crude slate.

   Metals: Metals that are inherent in all crudes are primarily removed in hydrofining processes to meet CARB product specifications. There will be no change in this

operation, and product specifications will continue to be met. Because the crudes that are proposed to be received by railcar will be transported and stored in unheated equipment, the crudes must have low viscosity at ambient temperatures. Therefore, they are lighter in gravity and are expected to have metals content equal to or lower than the crudes they will replace.

7. **If Valero is not able to compare the before and after project emissions at this time, please prepare the refinery average emission inventory (type and quantities of criteria pollutants, toxic air contaminants, and greenhouse gases for all continuous, intermittent, predictable and accidental air releases) in the past three years for toxic purposes.**

The refinery inventory of Criteria Pollutants is prepared annually by the BAAQMD and is included in the refinery's Permit to Operate. Valero prepares the annual Criteria Pollutant estimates (NOx, SO2, PM, VOC, CO) and forwards this information to the BAAQMD for inclusion in the Annual Inventory.

TAC's are evaluated project by project and are maintained in BAAQMD inventory. TAC's from this project have been estimated and have been provided in the permit application. This project does not expect to have any effect on TACs. The increased emissions from the tank seals from the repurposed storage tank will be decreased by reduced utilization of crude storage in the currently permitted crude storage tanks. Because BAAQMD Reg. 2-2 requires permitted projects to evaluate only emissions increases, the netted decrease was not included in the TACs provided in the permit.

For the calendar year 2010, the refinery prepared data requested in the EPA Refinery Information Collection Request (Refinery ICR). The Refinery ICR contains estimated criteria pollutant emissions by source. This information was also provided to the BAAQMD for use in updating the emissions factors used in calculating the Annual Inventory update. Rate and capacity information contained in the ICR was also provided to the BAAQMD and this is considered Confidential Business information. Valero does not anticipate any changes in emissions values other than those driven by production rates.

Beginning with the calendar year 2010, greenhouse gas (GHG) emissions inventory is prepared annually for CARB. 2012 data is currently being collected and is required to be validated by September 1, 2013. 2010 and 2011 refinery GHG emission inventory is available on the CARB website.

8. **The PSD analysis for NOx, SO2, sulfuric acid mist and other PSD pollutants as a result of blending North American crude at the affected equipment.**

There is not anticipated to be any quantifiable difference in PSD pollutants from this project based on the following: 1. North American-sourced crudes proposed to be received by railcar are ANS look-alikes or sweeter, 2. there will be no change to the

process units; only the method of crude receipt will change, 3. the refinery's diet of crudes processed will remain within existing parameters, 4. the mechanism for producing and removing undesirable components from the process streams remains unchanged.

9. **Identify the routine or non-emergency flaring frequency of each refinery process. How will this project affect the flaring frequency of each process? Will the Flare Minimization Plan be updated?**

Flaring will be unaffected by the proposed project. The Benicia refinery processes a mixture of crudes from throughout California, the United States, and the world. These crudes are blended together at the refinery to assure safe and compliant processing utilizing current refinery hardware and within permitted limits. Because there will be no change to the process units as a result of the proposed method of crude receipt, the refinery's diet of crudes processed must also remain within existing parameters.

The refinery operates in compliance with BAAQMD Regulation 12-11 Flare Monitoring at Petroleum Refineries, Regulation 12-12 Flares at Petroleum Refineries, the EPA 114 Consent Decree, and EPA regulations. The refinery controls and minimizes flaring activity as outlined in the Flare Minimization Plan (FMP). The FMP documents improvements to continue to reduce frequency and intensity of flaring events and is updated annually. A key goal in routine refinery operations requires no routine flaring. An example of this operating requirement is controlling the balance of refinery fuel gas produced and consumed. During periodic elevated ambient air temperatures, refinery process rates are adjusted to maintain the refinery fuel gas production/consumption balance to eliminate flaring of unconsumed refinery fuel gas.

The reports listed below provide information on all flaring activity at the facility.

REGULATION	ITEM	FREQUENCY	AGENCY
BAAQMD 12-11	Flare Report	Monthly	BAAQMD
BAAQMD 12-11, BAAQMD 12-12	Flare Causal Analysis	Flare Events > 500 MSCF/d, SO2 flare emissions > 500 lbs/day	BAAQMD
EPA 114 Consent Decree	Flare Causal Analysis	SO2 flare emissions > 500 lbs/24 hrs	EPA
BAAQMD 12-12	Flare Minimization Plan	Updated Annually	BAAQMD

10. **Identify the route or provide the map that shows BNSF and/or UP uses to bring the crude from Canada or other locations into Valero.**

Route maps are provided in the Appendix.

11. Update the District on the CEQA progress for this project and provide a copy of the EIR, when it is available.

CEQA progress and EIR will be provided to the BAAQMD when available.

12. Identify the crude oil name(s) that will be brought in by rail (Bakken, etc …)

(Confidential Business Information)

13. Specify if there would be any locomotive activity within Valero's railyard.

(Confidential Business Information)

Appendix

Figure 1 – UPRR Route from Roseville Rail Yard to Valero Benicia Refinery

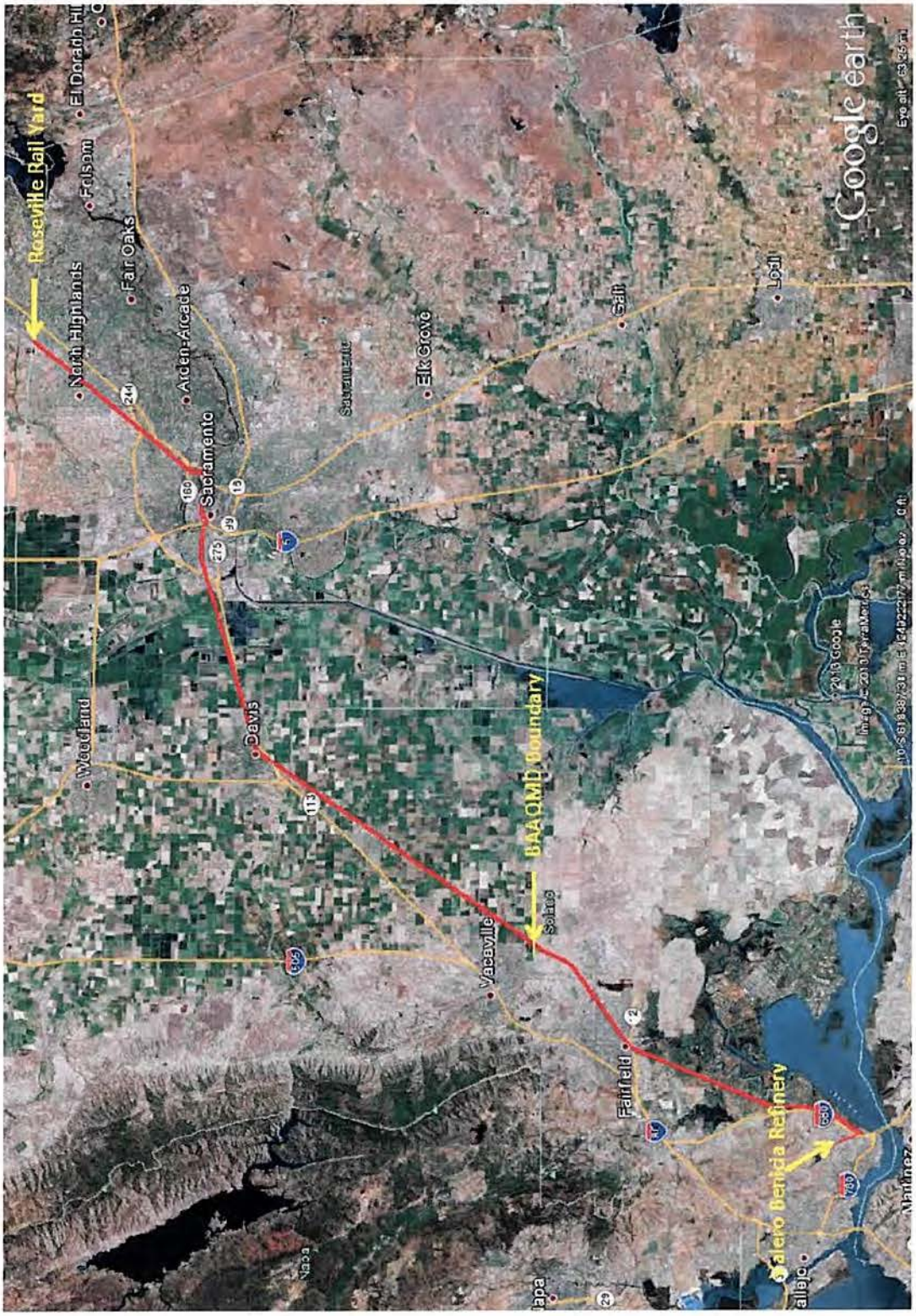


Figure 2 – UPRR Route from BAAQMD Boundary to Valero Benicia Refinery

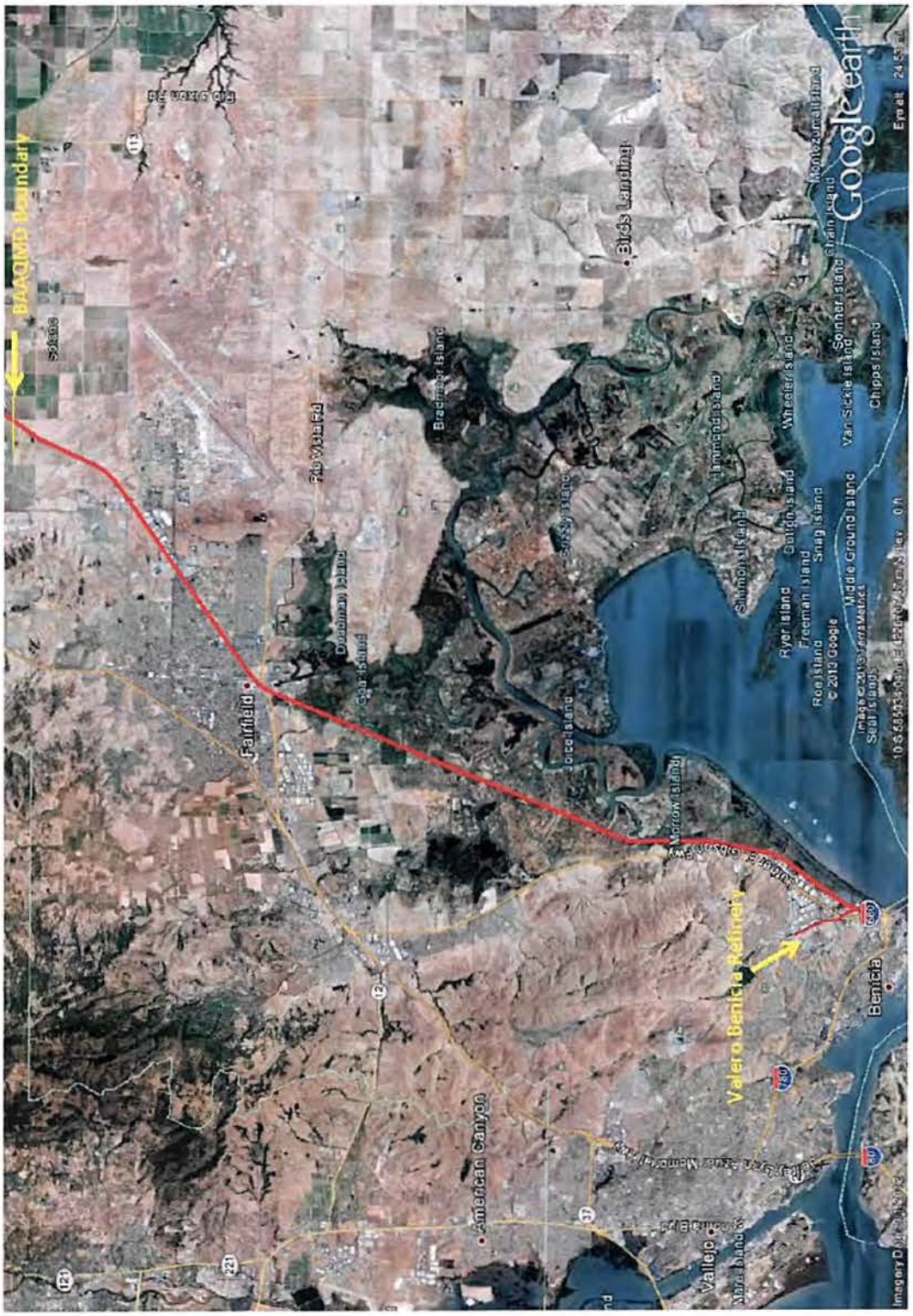


Figure 3 – UPRR Route at Valero Benicia Refinery