Comments

on

Draft
Environmental Impact Report

CHEVRON PRODUCTS COMPANY
EL SEGUNDO REFINERY
HEAVY CRUDE PROJECT

Prepared by

J. Phyllis Fox, Ph.D., P.E.
Consulting Engineer
Berkeley, CA

June 8, 2006

CHEVRON HEAVY CRUDE PROJECT
COMMENTS

2-140 Chevron is proposing modifications to its El Segundo Refinery ("Refinery") to allow it to process heavier crude than it currently processes. These modifications include increases in the capacity of and other changes to the No. 4 Crude Unit, the Delayed Coker, the No. 6 H_2S Plant, and the Coke Handling System. Collectively, these modifications constitute the project.. The Draft Environmental Impact Report ("DEIR")[1] underestimated the increase in nitrogen dioxides ("NOx"), sulfur dioxide (SO_2), particulate matter with an aerodynamic diameter less than 10 microns ("PM10"), volatile organic compounds ("VOCs"), and carbon monoxide ("CO") emissions that would result from these changes and thus failed to identify and mitigate all significant air quality impacts.

I. THE PROJECT WOULD RESULT IN SIGNIFICANT INCREASES IN OPERATIONAL EMISSIONS

2-141 The proposed modifications are required to process increased amounts of heavier, higher sulfur crude than is currently processed. The DEIR estimated emissions only from coke drum depressurization and fugitive sources -- new pumps, valves, and flanges in modified processing equipment. DEIR, Table 4.1-7, p. 4-20. Coke drum depressurization emissions were underestimated. Further, the DEIR did not include increases in emissions from existing units that would operate at a higher rate than during the baseline period to support the project.

2-142 The project would increase emissions by increasing the utilities required to operate the Delayed Coker, No. 4 Crude Unit, No. 6 H_2S Plant, and other downstream units including Hydrotreaters, the Hydrogen Plant, and Sulfur Recovery Units, among others. The increased use of this equipment would increase emissions from existing boilers, cooling towers, heaters, the cogeneration unit, flares, compressors, and fugitive components. These additional emissions from existing equipment, relative to the CEQA baseline, would be higher than the emissions from existing equipment. Thus, the DEIR has substantially underestimated emissions by excluding emissions from

[1] South Coast Air Quality Management District (SCAQMD), Draft Environmental Impact Report, Chevron Products Company – El Segundo Refinery, Heavy Crude Project, April 2006.

2-142 (cont.)

supporting utilities. Further, the DEIR failed to disclose the basic information required to estimate these increases.

A. Coker Emissions Were Underestimated

2-143

The Coker processes heavy vacuum residuum produced by the crude units into lighter products that are further refined in downstream units. The vacuum residuum is heated to 900 to 940 F and fed into coke drums, where it cracks into lighter materials under pressures of 30 to 60 psig. These lighter materials boil off and are separated into raw gasoline, raw jet fuel, raw diesel fuel, and gas oil. These separate byproducts are further refined in downstream units. Coke is left behind in the coke drums, reclaimed, and exported. DEIR, p. 2-11.

This process results in emissions from a number of sources. These include combustion emissions from increased firing of the feed heaters, depressurization steam venting, decoking the drums, and fugitive emissions from pumps, valves and flanges, etc.

2-144

The Project would increase the capacity of the Coker from 60 MBD (million barrels per operating day) to 80 MBD, or by about 33%. DEIR, p. 2-12. This would increase coke production from 3,950 ton/day to 4,460 ton/day or by 15%. DEIR, p. 2-12. It would also increase the amount of liquid coking byproducts, e.g., naphtha, raw gasoline, but the DEIR did not disclose which or by how much.

1. <u>Increase in Combustion Emissions From Increased Firing of Coker Feed Heaters</u>

2-145

The Coker uses three identical heaters -- F501A, F501B, and F-501C -- rated at 176 MMBtu/hr each to heat up the residuum.[2] These heaters were retrofit with a selective catalytic reduction ("SCR") unit in 1992 to comply with Phase II of Rule 1109. The project would require increased firing of these heaters to accommodate the increase in vacuum residuum. The proposed modifications to the Coker unit, of which the feed heaters are a part, increase the Coker's throughput, which would increase emissions from these three Coker heaters. It would further increase the amount of ammonia that slips through the SCR catalyst and is emitted to the atmosphere. Ammonia is a PM10 precursor.

---

[2] Facility Permit to Operate, Chevron Products Co., El Segundo, CA, Facility I.D. # 800030, March 8, 2005, System 2: Coker Heating System, p. 15.

2-146 Chevron understood that the heater emissions would be analyzed in any EIR for the project. According to Chevron's notes from the CEQA kickoff meeting with the District in January 2005: "there may be an increase in the actual fired duty from the No. 4 Crude Unit and/or coker furnaces." Chevron acknowledged that "[c]hanges in the actual firing rate of the furnaces in the No. 4 Crude Unit, the Coker and any fired steam boilers need to be analyzed as part of the CEQA review process. [3]

2-147 Further, the DEIR admits to "changes in emissions from the Coker feed heaters resulting from an increase in the fuel combustion rate by the heaters" and "the increase in vacuum residuum feed rate to the Coker will lead to an increase in the annual average firing rate (quantity of fuel burned per year) of the furnace…" DEIR, pp. 4-12, 4-13. In this same vein, an administrative draft of the DEIR stated: "Therefore, the proposed increase in the Coker feed heater firing rates will not cause an increase in CO, VOC, NOx or PM10 pollutant emission rate." The South Coast Air Quality Management District ("SCAQMD") wrote next to this sentence: "Cannot verify that there is no increase in CO, VOC, NOx, & PM10 emissions without technical support." 3/17/06 Mueller, Attach. C, p. 4-10.

2-148 Despite this evidence in the District permitting file that the project would increase facility-wide emissions, the DEIR did not disclose any emission increases from increased firing of these three heaters. Instead, it argued that the peak daily firing rates are not anticipated to increase beyond the maximum allowable daily firing rates achieved during a few days in the past. DEIR, p. 4-13. However, the peak daily firing rate is irrelevant for purposes of CEQA because these firing rates were not sustained and could not be sustained due to limitations of the equipment itself. The proper baseline is the average firing rate during the two years prior to initiation of the environmental review process, i.e., the average firing rate during 2004 and 2005. DEIR, pp. 4-12, 4-13. The DEIR did not disclose this information and we were unable to obtain it from the SCAQMD in time to prepare these comments.

2-149 The increase in average firing rate of these heaters can be estimated from typical utility requirements for delayed cokers published in standard industry reference texts. The total utility requirement for any delayed coker consists of two separate parts. The first is continuous utility demands and the second is intermittent utility demands. The typical continuous firing rate to supply heat to

[3] E-mail from Charlie Aarni, Chevron, to Pang Mueller and other, SCAQMD, Re: Notes from Chevron/AQMD Pre Meeting on High Sulfur Heavy Crude Project, January 26, 2005.

2-149- (cont.)

a coker is about 5.1 MMBtu/hr of fuel per 1,000 BPD of feed.[4] The project would increase the throughput of the Coker by about 20,000 BPD. Thus, about 102 MMBtu/hr of fuel must be combusted to heat the 20,000 BPD increase to coking temperatures. The resultant increase in emissions from combusting 102 MMBtu/hr of fuel in the three Coker heaters, based on a source test conducted on these heaters,[5] is summarized in Table 1.

Table 1
Increase in Emissions from
Increased Firing of Coker Feed Heaters

	Increase in Emissions (lb/hr)	Increase in Emissions (lb/day)	Increase in Emissions (ton/yr)	CEQA Significance Threshold[6] (lb/day)
CO	42.23	1013[7]	185	550
SO_2	1.64	39[8]	7.2	150
NOx	1.53	37[9]	6.7	55
PM	1.01	24[10]	4.4	150
VOC	0.68	16[11]	3.0	55

2-150

This table indicates the increase in CO emissions from increased firing of the Coker feed heaters alone would exceed the SCAQMD's daily CEQA

---

[4] Robert A. Meyers (Ed.), Handbook of Petroleum Refining Processes, 2nd Ed., 1996, Chapter 12.2. FW Delayed-Coking Process, p. 12.78 and Robert E. Maples, Petroleum Refinery Process Economics, PennWell Books, Tulsa, OK, 1993, Chapter 10. Delayed Coking, p. 112. 7.

[5] Application 448241, Furnace Repairs, August 16, 2005, Attachment captioned Permit to Operate, Air Pollution Control System Common to and Serving Coker Furnaces F-501A, F-501B and F-501C, September 16, 1992, pp. 2-3. The emission factors are 7 lb/MCFH for VOC; 16.9 lb/MCFH for SO_2; 0.414 lb/MMBtu for CO; 0.015 lb/MMBtu for NOx; and 1.75 lb/hr for the three heaters combined. The average heating value of the refinery fuel gas is 1050 Btu/ft^3.

[6] South Coast Air Quality Management District, Air Quality Significance Thresholds, January 2006.

[7] Daily increase in CO emissions: (0.414 lb/MMBtu)(102 MMBtu/hr)(24 hr/day) = 1013.5 lb/day.

[8] Increase in SO_2 emissions: (16.9 lb/MCFH)(102 MMBtu/hr)/(1050 Btu/CF)(24 hr/day) = 39.4 lb/day.

[9] Increase in NOx emissions: (0.015 lb/MMBtu)(102 MMBtu/hr)(24 hr/day) = 36.7 lb/day.

[10] Increase in PM emissions: (1.75 lb/hr per heater)/176 MMBtu/hr)(102 MMBtu/hr)(24 hr/day) = 24.3 lb/day.

[11] Increase in VOC emissions: (7 lb/MMCFH)(102 MMBtu/hr)/(1050 BTU/hr)(24 hr/day) = 16.3 lb/day.

2-150 (cont.)

significance threshold of 550 lb/day for CO by nearly a factor of two. Annual CO emissions exceed the Prevention of Significant Deterioration ("PSD") significance threshold of 100 ton/yr for CO, triggering PSD review and requiring a federal permit from the U.S. EPA. The DEIR did not disclose that a federal PSD permit would be required. DEIR, Table 2-3.

2-151

Table 1 also shows that the increases in PM10 and VOC emissions from the increase in firing of these two heaters plus other operational emissions reported in the DEIR, Table 4.1-7, exceed the CEQA significance thresholds for PM10 (128+24=152) and VOC (45+16=61). Finally, the increases in NOx and SO_2 emissions from increased firing of the Coker heaters, plus other operational emissions omitted from the DEIR discussed below, exceed the CEQA significance thresholds for these pollutants.

2-152

Thus, these increases in emissions from increased firing of the Coker feed heaters alone (CO) or combined with emissions from other sources (SO_2, NOx, PM, and VOC) are new significant air quality impacts that were not disclosed in the DEIR, and would not be mitigated by the project described in the DEIR.

2-153

Other continuous utility demands include up to 500 gallons per minute of cooling water, 17,850 gallons per day of raw water, and 3,000 kw of electricity. In addition to these continuous utility demands, intermittent utilities are required for the decoking and coke drum blowdown systems. These include about 695 kw of electricity and 125 gallons per minute of cooling water.[12] Providing these additional utilities would increase emissions of VOC, PM10, NOx, SO_2, and CO. The DEIR included the increase in emissions of PM10 from providing the cooling water (p. 4-14), but did not disclose the increase in emissions from providing the other utilities. The emissions associated with electricity demand are discussed below in Comment I.C.2.

2-154

2. Coke Drum Depressurization VOC and PM10 Emissions Were Underestimated

The vacuum residuum is heated in the feed heaters to 900 to 940 F and fed into coke drums. The residuum remains in the coke drums under a pressure of 30 to 60 psig for 12 hours. The lighter materials boil off and are separated into raw jet fuel, raw diesel fuel, and gas oil. The coke drums fill up with solid coke. At the end of the 12 hours, the drums are stripped with steam to remove

[12] Estimates based on Meyers 1996, pp. 12.78 to 12.79: Continuous utilities based on 150 kW of electricity per 1000 BPD; 25 gal/min of cooling water per 1000 BPD; and 35 gal/day of raw water per short ton per day of coke, assuming an increase of 20,000 BPD of residuum and 510 ton/day of coke.

2-154 (cont.) remaining hydrocarbons, cooled with water, and depressurized. DEIR, p. 2-11. When the coke drum pressure drops below 5 psig, the line from the coke drum to the coker blowdown section is closed and the coke drum vent line to atmosphere is opened, venting steam and reducing the drum pressure to 0. 4/3/06 Responses,[13] p. 3; 3/14/06 Responses, #2.

2-155 The SCAQMD permitting file indicates that the District has measured depressurization emissions from all refineries in the Basin and is proposing to initiate a rulemaking by December 2006 to control these emissions.[14] These emissions are viewed as considerable.[15]

2-156 The DEIR included coke depressurization emissions in the operational emission inventory (Table 4.1-7), assuming the project would increase the number of depressurizations from 4.8 per day currently to 6 per day with the project. DEIR, p. 4-13. The emissions that occur during these depressurizations were based on measurements made by the SCAQMD in 2003. *Ibid.*

2-157 The DEIR failed to disclose the nature and magnitude of depressurization air quality impacts. The DEIR underestimated both PM10 and VOC emissions, failed to disclose that the stack test it relied on reported minimum emissions and that actual emissions are higher, and did not consider the full increase in Coker capacity in its calculations.

2-158 The SCAQMD measured PM10 and VOC emissions during depressurization of Chevron's Coker on January 23, 2003. The measurements were made to collect Coker unit emission information for potential rule development. The results are reported in a Test Report.[16] The DEIR estimated the increase in Coker depressurization PM10 and VOC emissions by multiplying the test results, reported as pounds per single drum blowdown event, by the increase in the number of such events, or 1.2 events per day. DEIR, p. 4-13. However, the DEIR neglected to mention the caveats in the Test Report.

---

[13] E-mail from David R. Kennar, Chevron, to Bob Sanford, SCAQMD, Re: Response to final open action item from heavy crude project 031706 AI request, April 3, 2006, Heavy Crude AI Request (3/17/06).

[14] Telephone communication with Bob Sanford, May 11, 2006

[15] E-mail chain, Sanford to various parties, March 22, 2006. Aarni say to Sanford: "the magnitude of the emissions surprised me as well." And Sanford replies to Aarni: "The Magnitude of the PM and VOC emissions during coke drum depressurization caught me by surprise."

[16] South Coast Air Quality Management District, Volatile Organic Compound (VOC), Carbon Monoxide, and Particulate Matter (PM) Emissions from a Coke Drum Steam Vent, Source Test Report 03-194, Conducted at Chevron/Texaco Refinery, El Segundo, CA, January 23, 2003,

2-158 (cont.)

First, the Test Report summary table that the DEIR relied on is followed by a note: "All mass emissions results are biased low; See Test Critique." Test Report, p. 3. The Test Critique explains that "the reported emissions reflect an inherent low bias and potentially a large low bias... As such, the emissions should be considered as greater than reported. Furthermore...the emissions are at least that which was reported." Test Report, p. 12. The DEIR did not disclose that the coke drum emissions of 28.4 lb/day in Table 4.1-7 are biased low.

2-159

Second, the DEIR did not include all of the measured particulate matter in its emission inventory. Particulate matter consists of two components, filterable and condensable.[17] The filterable fraction is present as solid material in the exhaust stream and is collected on filter paper during the test. The condensable fraction is present as a gas in the exhaust stream and condenses out as a solid in the impingers during the test and in the atmosphere.[18] The District has long regulated total particulate matter, and SCAQMD Method 5, used to measure particulate matter, measures both. The Test Report separately lists filterable (1.25 lb/event) and condensable (12.50 lb/event) PM. A note to the table explains that the condensable fraction "meets both the SCAQMD Rule 102 definitions for PM and VOC." Test Report, Table 2, p. 3.

The DEIR PM10 emissions are based only on the filterable component of PM (1.5 lb/day) and exclude the condensable component (15.0 lb/day) reported in the same Test Report table.[19] Thus, the total PM10 from coke drum depressurization should have been 16.5 lb/day, not 1.5 lb/day. This increase in emissions (16.5 lb/day), plus the increase from increased firing of the Coker feed heaters (24.3 lb/day) and other operational emissions admitted in the DEIR (127.8 lb/day), results in total PM10 emissions of 168.6 lb/day. This new total exceeds the SCAQMD CEQA significance threshold of 150 lb/day. This is a new significant impact that was not discussed in the DEIR.

---

[17] U.S. EPA, Estimation of the Importance of Condensed Particulate Matter to Ambient Particulate Levels, NTIS PB84102565, April 1983.

[18] The EPA explained in the preamble in which it adopted a PSD significance threshold for PM10, a subset of PM, that: "Particulate matter" is the generic term for a broad class of chemically and physically diverse substances that exist as discrete particles (liquid droplets or solids)…. They may be emitted directly or formed in the atmosphere by transformations of gaseous emissions such as sulfur oxides, nitrogen oxides and volatile organic substances." 52 FR 24635 (July 1, 1987). The "liquid material" and material that forms in the atmosphere are condensible particulate matter.

[19] The emissions in parentheses are the increase in PM10 emissions from adding 1.2 cycles per day

2-160

The air quality impacts modeling in the DEIR only included the increase in PM10 emissions from Cooling Tower No. 9. This modeling shows that the Cooling Tower alone results in an increase in 24-hour PM10 at the property boundary of 2.36 μg/m³. DEIR, p. 4-30. The significance threshold is 2.50 μg/m³. DEIR, Table 4.1-1. The depressurization emissions should have been included. The revised depressurization emissions may result in exceedance of this threshold.

2-161

Third, the DEIR extrapolates the test results assuming the modifications to the Coker will increase the number of depressurization operations from 4.8 per day to 6 per day, or an increase of 20%. DEIR, p. 4-13. However, the project description indicates that Coker modifications would increase the capacity of the Coker from 60 MBD to 80 MBD, or by 33%. DEIR, p. 2-12. Thus, unless the air permit limits the number of depressurizations to 6, bottlenecking the capacity increase, the coke drum emissions should have been estimated by multiplying the emissions measured in the Test Report by 1.33, rather than 1.20. See Table – below.

2-162

Finally, the PM10 concentrations measured during the SCAQMD stack tests exceeded the permissible levels in SCAQMD Rule 404(a) at the time of testing. Thus, the project will contribute to an existing violation of Rule 404. This is a new significant impact that was not disclosed in the DEIR.

2-163

3. <u>Coke Drum VOC And PM10 Decoking Emissions Omitted</u>

After the coke drums are depressurized, the tops and bottoms of the drums are removed, water is drained from the coke, and high-pressure water drilling is used to break up and remove coke from the drums. Responses, p. 3. The DEIR did not disclose that there were emissions from this process even though it had relied on the depressurization Test Report that discloses such emissions.

The depressurization Test Report discussed above explains that the coke drums continue to emit after they have been depressurized:

> After the blow down period [which was tested], the top drum head is removed and continues to remain open for a period of time longer than the vent period to allow further cooling. After cooling, the coke is cut from the drum. It was observed that emissions occurred during these events similar to the blow down event, as indicated by a visible steam and an emissions plume comparable in appearance and odor to those that were tested during venting. These emissions were not tested nor included in the **<u>Results</u>** section of this report. Based on observation of these

2-163 (cont.)

> plumes, these emissions may be significant or possibly more significant than those that were tested.

Test Report, p. 13 (highlighting in original). These results, available since January 2003, should have put Chevron on notice that further cooling and decoking were significant emission sources. Chevron should have measured the emissions from further cooling and decoking and disclosed them in the DEIR.

2-164

Thus, PM10 and VOC emissions from further cooling and decoking could be roughly comparable to those from depressurization, the only coke drum emission source included in the DEIR. Making the corrections discussed above, further cooling and decoking could double or more the depressurization emissions disclosed in the DEIR. If the VOC emissions were only double those reported in the DEIR (56.8 lb/day), the increase in VOC emissions from the coke drums alone would exceed the SCAQMD's CEQA significance threshold of 55 lb/day for VOCs. This is a new significant impact that was not disclosed in the DEIR.

2-165

4. <u>Coke Drum Hydrogen Sulfide Emissions Omitted</u>

The coking process produces high concentrations of hydrogen sulfide (H_2S) and other reduced sulfur compounds. The coke drum vapors are about 5% H_2S by weight.[20] The depressurization, cooling, and decoking operations discussed above also emit hydrogen sulfide (H_2S) and other reduced sulfur compounds. Hydrogen sulfide and other reduced sulfur compounds are chronically and acutely toxic and cause malodors. The DEIR did not disclose that the coke drums would emit H_2S, nor evaluate its odor and public health impacts.

2-166

The SCAQMD attempted to measure sulfur compounds during depressurization but did not succeed because the sample was collected after the particulate matter sampling train, which would have removed these compounds. However, the presence of sulfur compounds in depressurization vent gases was confirmed by soluble sulfates in the impinger catches. Test Report, pp. 13, 16. These results should have alerted Chevron to the presence of H_2S in coker depressurization gases. Chevron should have measured these emissions and disclosed them in the DEIR.

---

[20] Tesoro Petroleum, Material Safety Data Sheet, Coke Drum Vapors, February 18, 2005; South Coast Air Quality Management District, Mobil Oil Corporation, Torrance Refinery, Reformulated Gasoline (RFG) Project, Environmental Impact Report, Risk of Upset, August 1993, Table 5.

2-167

Based on the SCAQMD's Test Report, the project would increase the emission of H_2S from depressurization by greater than 0.25 lb/day, assuming the measured sulfates are present as H_2S in the exhaust gases.[21] Alternatively, assuming that the depressurization vent gases contain the same weight percent H_2S as the coke drum vapors, or 5% by weight, H_2S emissions from coker depressurization would be greater than 1.6 lb/day.[22]

2-168

5. <u>Emissions From Increase In Steam Use In Compressor Omitted</u>

The compressor will be replaced with a new one to increase gas compression capabilities. DEIR, p. 2-12. This is confirmed by the SCAQMD Air Permit Application, which indicates that the "gas compression capability of the plant is also limited and will need to be upgraded." Ap.,[23] p. 4. Increasing the capacity of the compressor will increase steam demand, increasing the amount of fuel combusted in boilers in the steam plant. The DEIR and the SCAQMD file do not contain the information required to calculate the resulting increase in emissions. They could be substantial. For example, the steam demand for a 1561 hp Dresser-Rand turbine-rated compressor is 119,280 lb/hr. [24] The DEIR should be revised to disclose the type of compressor, the increase in steam demand for the new compressor, and the resulting emissions to generate the increase in steam.

2-169

B. No. 4 Crude Unit Emissions Were Underestimated

The No. 4 Crude Unit is a two-stage unit that separates crude into several components, including methane, ethane, liquid petroleum gas, naphtha, raw jet fuel, raw diesel fuel, gas oil, and residuum. The crude is first heated and separated under atmospheric conditions in a distillation column. The residuum from this process is then heated and separated in a vacuum distillation column. The products of these separations are further refined in downstream equipment

---

[21] The Test Report indicates 132 mg of sulfates and 3235 mg of particulate, excluding sulfates, was collected in the Method 5 sampling train. Test Report, p. 16. The amount of H_2S: [132/(3235+132)](13.75 lb PM/event)(34 lb-mole H_2S/96 lb-mole SO_4) = 0.19 lb/event. Assuming the project increases the number of events by 33%, the increase in H_2S emissions due to the project: (0.19)(1.33) = >0.25 lb/day.

[22] The increase in H_2S, assuming that 5% of the VOC emissions are H_2S: (12.50 + 11.16)(0.05)(1.33) = >1.57 lb/day.

[23] Chevron, Technical Support Documentation for SCAQMD Air Permit Application, Chevron El Segundo Refinery, Heavy Crude Project.

[24] Letter from M.T. Heller, ConocoPhillips, to Gerardo Rios, U.S. EPA, Re: Ultra Low Sulfur Diesel Project, PSD Permitting Exemption, Los Angeles Refinery – Wilmington Plant, August 17, 2004, Attached Dresser Rand Performance Date.

2-169 (cont.)

to produce final products -- gasoline, diesel, jet fuel, and others. DEIR, pp. 2-9 to 2-10.

2-170

1. <u>Increase in Combustion Emissions from Increased Firing of Crude Unit Heaters</u>

The project would increase the crude feed rate to the No. 4 Crude Unit from 195 MBD for a typical crude slate to 210 MBD of heavier crude. The unit may be able to run up to 230 MBD on a crude slate tailored to the modified unit. 1/16/06 Responses, #3. The project would also increase the vacuum residuum production rate (which is routed to the Coker) from 45 MBD to 57 MBD (DEIR, p. 2-9) or 58 MBD. 1/30/06 Responses, p. 4. The proposed increase in throughput will require an increase in the heating rate of crude oil entering the unit. DEIR, p. 2-10.

2-171

The operating permit indicates the crude feed is currently heated by two 315 MMBtu/hr heaters (F-1100A, F-1100B). The atmospheric residuum from this first step is next heated by a 219 MMBtu/hr heater (F-1160) and routed to the vacuum distillation unit for further separation. The DEIR claims that the firing rates (and thus the emissions) of these feed heaters will not change "substantially" from current rates because Chevron is proposing modifications to the heat exchangers to increase heat recovery from the vacuum residuum leaving the unit. DEIR, p. 2-10. Because the DEIR failed to define how it will gauge "substantially," the District's claim absent definition or substantive analysis is meaningless.

2-172

The meaning of "substantial" should be documented using a heat balance to determine the increase in heat required to distill increased crude throughput and to demonstrate that the increase in heat will be offset by the increase in heat exchange capacity. This unsubstantiated claim is likely not correct for the range of operating conditions contemplated. Chevron's notes from the January 2005 CEQA kickoff meeting with the District states: "there may be an increase in the actual fired duty from the No. 4 Crude Unit and/or coker furnaces."[25] They further state that "[c]hanges in the actual firing rate of the furnace in No. 4 Crude Unit, the Coker and any fired steam boilers need to be analyzed as part of the CEQA process." The DEIR did not analyze these emissions.

---

[25] E-mail from Charlie Aarni, Chevron, to Pang Mueller and other, SCAQMD, Re: Notes from Chevron/AQMD Pre Meeting on High Sulfur Heavy Crude Project, January 26, 2005.

2-173

The processing of additional amounts of crude (up to 35 MBD) and atmospheric residuum (19 MBD)[26] will require increases in the combustion of fuel to heat the feed, generate electricity, and generate steam. These amounts were calculated from typical utility requirements for atmospheric and vacuum distillation and are summarized in Table 2.

Table 2
Increase in Utilities
No. 4 Crude Unit[27]

	Electric Power (kW)	Fuel (MMBtu/hr)	Steam (lb/hr)
Atmospheric	729	146	36,500
Vacuum	238	79	39,600
Total	967	225	76,100

2-174

However, additional fuel still must be burned to generate electricity and steam even if the modified heat exchangers offset the increase in fuel required to heat up the increased crude throughput. About 1,200 Btu of fuel is required to generate a pound of steam.[28] Thus, 91 MMBtu/hr of fuel would have to be combusted to supply the increase in steam demand required to process increased amounts of crude. The emissions from generating this amount of steam may be as high as those shown in Table 1 for the Coker feed heaters. Steam is generated at the refinery in several steam boilers and a cogeneration plant, but I was unable to calculate the emission increases because the District did not produce any test results or emission factors for the steam boilers in response to our Public Record Act request before these comments were due.

2-175

2. Crude Unit Heat Exchangers Debottleneck Refinery

The proposed modifications to the No. 4 Crude Unit will increase the amount of crude processed at the refinery by about 35 MBD (230-195). The DEIR

---

[26] The increase in throughput of the vacuum distillation unit is calculated from the increase in vacuum residuum as reported in the DEIR and SCAQMD files (58-45=13 MBD), adjusted using the ratio of the input to the vacuum distillation column to residuum from the column, based on the process flow diagram for the No. 4 Crude Unit attached to the 1/16/06 Responses: 13 MPD of vacuum residuum x 3030 gpm/2120 gpm = 18.6 MBD.

[27] Maples 1993, p. 63. The calculations assume the project will increase crude throughput by 35 MBD and atmospheric residuum input to the vacuum distillation column by 19 MBD.

[28] James H. Gary and Glenn E. Handwerk, Petroleum Refining. Technology and Economics, 3rd Ed., Marcel Dekker, Inc., New York, 1994, p. 355.

2-175 (cont.)

claims that this will not increase the amount of refined products, e.g., gasoline, diesel, jet fuel, because heavy crude produces lower amounts of the light cuts that make up these products, in contrast to the lighter crudes currently processed. DEIR, p. 2-9. However, this is not supported, and is not true for all possible operating conditions.

2-176

The proposed project as described in the DEIR does not require processing of a heavier crude slate. Instead, the modified refinery will still be capable of processing the current slate of lighter crudes. If the modified refinery operates on the current slate or a lighter slate, the project, in essence, debottlenecks the entire refinery, increasing the throughput of downstream refining units, including the hydrogen plant, hydrotreaters, the alkylation unit, the fluid catalytic cracker, steam boilers, and sulfur recovery units. Thus, the project could potentially increase the emissions from every combustion source in the refinery. The DEIR did not disclose this possibility or evaluate its impacts.

2-177

C. Increase In Emissions From Increasing Throughput Of Higher Sulfur Crude

The project would increase the feed rate of the No. 4 Crude Unit from 195 MBD of a typical crude slate up to 230 MBD of heavier crudes or by 18%. Further, the sulfur content would increase from 2.43% for the existing slate to 2.59% or by 6.5%. 1/16/06 Aarni E-mail #2. These two increases combined will increase the firing rate and emissions from numerous units downstream of the Coker and No. 5 Crude Unit. Thus, the project, in addition to increasing the firing rates of heaters and boilers that support the No. 4 Crude Unit, Coker, and No. 5 H_2S Plant, which are directly modified, would also increase the firing rates of heaters and boilers that support downstream units, including Hydrotreaters and the Hydrogen Plant.

2-178

The DEIR did not analyze the increase in emissions from increased firing of downstream heaters and boilers. However, the air permitting file contains admissions that increases will occur. Chevron admits that the proposed modifications to the No. 4 Crude Unit would increase the offgases generated by the vacuum column from 500 MSCFD to about 900 MSCFD due to the higher cracking tendency of the Napo crude. This increased amount of offgas would be routed to the amine treating facilities. 1/16/06 Aarni E-mail #2, p. 7. Further, emissions from processing increased amounts of byproducts downstream of the No. 4 Crude Unit and Coker were not analyzed. The Coker produces naphtha and other products that are further refined to produce diesel and gasoline. These are routed to downstream Hydrotreaters to remove sulfur. 1/16/06 Aarni E-mail #2, pp. 17, 18. The project would increase the yield of these Coker products by 2-5%. 1/16/06 Aarni #2, p. 8.

2-179

1. Increase In Emissions From Increased Hydrotreating

The Project increases the amount of sulfur that must be removed from Coker and No. 5 Crude Unit products. This would require increases in hydrotreating, which in turn requires increases in heat production, steam production, electricity generation, cooling water, boiler feedwater, sour gas treatment, and sulfur recovery, among others. The DEIR included the increases in cooling water, sour gas treatment, and sulfur recovery required to support the project. However, the DEIR did not include the increases in heat production, steam production, and electricity generation.

2-180

In hydrotreating, sulfur in the feed is reacted with hydrogen in the presence of a catalyst at elevated temperature and pressure. The sulfur is converted to hydrogen sulfide (H_2S), which is separated from the product in a stripper and recovered in downstream processes. This process requires hydrogen, steam, electricity, and heat. The generation of hydrogen, steam, electricity, and heat requires the combustion of fuels in heaters, boilers, and turbines, which releases NOx, SO_2, CO, VOCs, and PM.

The sulfur removed from the feedstock is partitioned into gases and waters. This sulfur is removed in downstream processing units. The sour gas stream is treated in an amine treatment unit to remove and recover H_2S. The H_2S stream from the amine treatment unit is fed to a sulfur recovery unit to recover elemental sulfur. Sour water is treated in a steam stripper. The removal of increased amounts of sulfur in these units requires additional steam, electricity and heat, which requires the combustion of additional fuel and releases more pollutants.

See, for example, the U.S. EPA's discussion of these consequences of hydrotreating in *Petroleum Refinery Tier 2 BACT Analysis Report*.[29] This report notes: "Increases in hydrotreating, hydrogen production, sour gas treatment, and sulfur recovery can result in increases in criteria pollutant emissions at a refinery." *Id.*, p. 2-3 and Table 2-1. The DEIR did not include the increase in emissions that would result from increases in hydrotreating to support the Project.

---

[29] U.S. EPA, Petroleum Refinery Tier 2 BACT Analysis Report, Final Report, Prepared by Eastern Research Group, Inc., January 16, 2001.

2-181

2. Increase In Emissions From Increased Electricity Generation

The calculations in Comments I.A and I.B indicate that proposed modifications to the Coker and No. 4 Crude Unit would require at least 4,662 kW or 111,888 kWh/day of electricity. Significant additional electricity would be required to support other components of the project, but the DEIR does not contain sufficient information to estimate them. The air permitting file identifies some of them, but does not quantify them.

The project will increase the electrical supply to the Desalters to improve efficiency. DEIR, p. 2-11; 10/18/05 Meeting Slides.[30] The project will increase the capacity of the Coker compressor and install a new refrigeration unit. DEIR, p. 2-12. Both require electricity. The modifications to the No. 6 H_2S plant will require that power be run to a new substation to feed the unit, which is "essentially a new grass roots installation."[31] Heavier crude oils require heating to reduce their viscosity so they can be easily handled. This means the crude tanks must be maintained at a temperature of 130 F, which requires increased electricity to heat the tanks. Ap., p. 4; 10/18/05 Slides, p. 9. The coke handling system uses a bridge crane to remove coke from the Coker pit and transfer it to the conveyor system. These cranes are typically electrical. The amount of coke produced would increase by 13% (4460/3950). DEIR, p. 2-12. Thus, electricity demand to operate the bridge crane would increase by 13%. The new coke handling system includes two new blowers to ventilate the enclosed conveyors. Coke Handling Ap., p. 4-2. These blowers would use electricity. Finally, additional electricity would be required to process increased amounts of higher sulfur byproducts in refining units downstream from the Coker and No. 4 Crude Unit. Thus, my estimate of 4,662 kW for only two of the directly modified units is low.

2-182

This electricity could be generated anywhere on the grid. The grid includes many uncontrolled turbines of varying ages fired on a range of fuels. Thus, I report emissions for two cases to bracket the likely increase in emissions: (1) an uncontrolled turbine burning natural gas with a heat rate of 12,000 Btu/kW and (2) a controlled natural gas fired combined cycle plant with a lifetime average heat rate of 7030 Btu/kWh and a peak heat rate during duct firing of 9290 Btu/kWh.[32] Emissions were estimated using emission factors from

---

[30] Chevron Heavy Crude Project, Team C Meeting, October 18, 2005.

[31] High Sulfur Heavy Crude Project, Preliminary Permitting Meeting with AQMD Staff, January 11, 2005.

[32] Northwest Power Planning Council, Natural Gas Combined-cycle Gas Turbine Power Plants, August 8, 2002. http://www.westgov.org/wieb/electric/Transmission%20Protocol/SSG-WI/pnw_5pp_02.pdf

2=182 (cont.) U.S. EPA's *Compilation of Air Pollutant Emission Factors* ("AP-42").[33] The controlled case assumes the unit is equipped with an SCR that removes 90% of the NOx and an oxidation catalyst that removes 90% of the CO and 50% of the VOCs. The increases in NOx, PM10, and VOC emissions are as follows:

<u>(1) Uncontrolled natural-gas fired turbines:</u>

NOx:
55.9 MMBtu/hr× 3.2×10^{-1} lb NOx/MMBtu = 17.9 lb NOx/hr or 429.3 lb NOx/day

PM10:
55.9 MMBtu/hr × 6.6×10^{-3} lb PM10/MMBtu = 0.37 lb PM10/hr or 8.9 lb PM10/day

VOC:
55.9 MMBtu/hr × 2.1×10^{-3} lb VOC/MMBtu = 0.12 lb VOC/hr or 2.8 lb VOC/day

CO:
55.9 MMBtu/hr × 8.2×10^{-2} lb CO/MMBtu = 4.6 lb CO/hr or 110 lb CO/day

<u>(2) Controlled natural-gas fired turbines (based on peak day):</u>

NOx:
43.3 MMBtu/hr×3.2×10^{-1} lb NOx/MMBtux0.1 = 1.4 lb NOx/hr or 33.3 lb NOx/day

PM10:
43.3 MMBtu/hr×6.6×10^{-3} lb PM10/MMBtu = 0.29 lb PM10/hr or 6.9 lb PM10/day

ROG:
43.3 MMBtu/hr×2.1×10^{-3} lb VOC/MMBtux0.5 = 0.05 lb VOC/hr or 1.1 lb VOC/day

CO:
43.3 MMBtu/hr×8.2×10^{-2} lb ROG/MMBtux0.1 = 0.36 lb CO/hr or 8.5 lb CO/day

2-183 These calculations indicate that NOx emissions alone could be substantially higher than the SCAQMD significance threshold of 55 lb/day, depending upon the source of the electricity. The emissions of the other criteria pollutants do not individually exceed significance thresholds. However, when

2-183 (cont.)

added to other emission increases, they exceed the SCAQMD's CEQA significance thresholds. See Comment I.F. Further, they are cumulatively significant, requiring that the Project's contribution be mitigated.

2-184

D. Annual v. Daily Emissions

The DEIR omitted several sources of emissions from Table 4.1-7 because maximum daily emissions would not increase above peak levels met at undisclosed periods in the past. There are several problems with this approach, discussed in detail below for each unit where such a standard is claimed.

In general, the baseline is not the peak level that occurs on a few (unidentified) days, but rather the average that occurs in the one to two years prior to publishing the notice of preparation. Further, this ignores the fact that the project is increasing the capacity of various units, thus allowing them to operate at a higher rate for many more days per year than currently. The historic short-term excursions to a higher level cited in the DEIR (which is not supported with any actual data) likely cannot be routinely sustained without modifications to refinery equipment. Further, the DEIR did not disclose when these peaks occurred or the conditions under which they occurred. They may, for example, represent anomalous operating conditions, resulted in violations of permit limits, or occurred in the distant past and would thus be irrelevant for purposes of establishing a CEQA baseline. Regardless, the DEIR should evaluate not only daily emissions but also annual emissions.

2-185

1. Sulfur Export

The DEIR did not include increased emissions from sulfur trucks in its emission tabulation in Table 4.1-7. DEIR, p. 4-20. The DEIR excluded these trucks for two reasons.

First, the DEIR argues the project "is not expected to alter market demand for elemental sulfur on a daily basis. Therefore, the proposed project is not anticipated to change the maximum daily number of trips to export sulfur from the refinery." DEIR, p. 4-16. Market demand does not dictate emission increases. It is undisputed that the project will increase sulfur production by at least 19 ton/day. DEIR, p. 4-15. This sulfur will be either exported contemporaneously, stored and then shipped, or disposed. Regardless, it must be exported from the refinery, thus generating combustion emissions from the trucks, trains, or ships that transport it.

2-186

2-186 (cont.)

allowable daily sulfur production achieved in the past (baseline), because the Sulfur Recovery Units have operated at their maximum daily capacity on several occasions during the past two years." DEIR, p. 4-15. The Sulfur Recovery Units cannot routinely operate at these peak levels because they are constrained by the ability of the upstream H_2S plants. This project will debottleneck these units. Thus, the project will allow more sulfur to be produced on more days than at present. Thus, the emission increases from sulfur export must be evaluated in the DEIR.

2-187

The increase in SO_2 emissions, although omitted from the DEIR's analysis, can be estimated. The increase in SO_2 emissions is proportional to the increase in sulfur production. The DEIR estimated the project would result in an average increase in sulfur production of 19 tons per day. DEIR, p. 4-15. However, elsewhere, the DEIR states the increase in sulfur production will require an average of two additional truck trips per day. DEIR, p. 1-6. A truck holds about 26 tons of material, suggesting the increase in sulfur production is larger than disclosed. The increase in emissions from two sulfur trucks can be estimated using the same emission factors as used in the DEIR for coke trucks. DEIR, pp. B.2-30 to 32. The increase in emissions from this one additional truck would be:

- CO: 0.48 lb/day
- VOC: 0.12 lb/day
- NOx: 3.2 lb/day
- SO_2: 0.04 lb/day
- PM10: 0.14 lb/day

These emissions do not individually exceed significance thresholds. However, when added to other emission increases, they exceed the SCAQMD's CEQA significance thresholds. See Comment I.F. Further, they are cumulatively significant, requiring the Project's contribution to be mitigated.

2-188

This approach is inconsistent with the diesel exhaust risk assessment, which did evaluate the increase in emissions from sulfur trucks. DEIR, p. 4-28. The reliance on historic peaks does not justify ignoring emission increases for purposes of air quality analysis.

2-189

2-189 (cont.)

by smaller marine tankers. The DEIR calculated the increase in emissions from these 15 ship calls (p. B.2-28), but they were not included in the emission tabulation in Table 4.1-7 (p. 4-20) and their significance was not evaluated. The DEIR admits that annual emissions would increase, but argues daily emissions would not because the ESMT (the El Segundo Marine Terminal) only has two berths, offloading will require more than 24 hours so only two tankers can be offloaded at once, and both berths have been occupied at the same time by two vessels. DEIR, p. 4-19. There are at least two flaws in this argument.

2-190

First, the two-berth argument only applies to hoteling emissions, or the emissions that occur while the ship is docked in berths. The major source of tanker emissions is from cruising along the California coast and waiting off-shore to dock. These emissions are not limited by the presence of two berths. The project would increase the cruising and queuing emissions from 15 ships on days when these ships call. Thus, cruising and queuing emissions should be included in the daily inventory.

2-191

The cruising emissions were calculated in an appendix to the DEIR, but not disclosed in the text. DEIR, p. B.2-28. The cruising emissions alone exceed the daily significance threshold for every single criteria pollutant by large margins. Thus, the increase in tanker emissions alone is a significant impact that was not disclosed in the DEIR.

Second, the project would increase the number of days that both berths would be occupied, thus increasing annual emissions. The DEIR should have evaluated these increases in annual emissions.

2-192

3. Increased Emissions From Increased Utility Demand

The project modifies the No. 4 Crude Unit, the Coker, the No. 6 H_2S plant, and the Coke Handling System. These modifications would require increases in heat, steam, electricity, and other utilities. Providing the increases in utilities would increase emissions from heaters, boilers, and turbines. These increases are discussed in Comments I.A through I.C.

The DEIR dismisses these increases, arguing that they fall within the current permitted capacity of the units and that regardless, the higher levels have been reached in the past. DEIR, pp. 2-12, 2-13, 4-13, 4-15. This is the wrong

2-193

2-194

4. <u>Increased Emissions From Sulfur Recovery Units</u>

The project would increase the amount of sulfur entering the refinery by increasing the amount of crude that is processed and the amount of sulfur in the crude. About 99.9% of this sulfur is recovered by concentrating it into the acid gas stream in the H_2S Unit and then converting the acid gas into elemental sulfur in the Sulfur Recovery Units. The H_2S rich acid gas stream is burned with about one-third the stoichiometric quantity of air and the hot gases are passed over a catalyst to produce free sulfur. This process produces a gas stream that is vented to atmosphere and contains SO_2. DEIR, p. 4-15.

2-195

The increase in SO_2 emissions is proportional to the increase in sulfur production, which was underestimated. The DEIR estimated the project would result in an average increase in sulfur production of 19 ton/day. DEIR, p. 4-15. However, other information suggests the increase would be higher.

First, the DEIR states the increase in sulfur production will require an average of two additional truck trips per day. DEIR, p. 1-6. A truck holds about 26 tons of material. Thus, the trip estimate suggests an increase of about 52 ton/day.

2-196

Second, the sulfur content of the heavier crude would increase from 2.43% for the existing slate to 2.59%, or by 6.5%, and the crude throughput would increase from 195 MBD of a typical crude slate up to 230 MBD of heavier crudes, or by 18%. 1/16/06 Aarni E-mail #2. Thus, the amount of sulfur produced would increase by 26%.[34] The current sulfur production capacity is reported as 448 ton/day.[35] Thus, sulfur production could increase by up to 116 ton/day.

This increase in sulfur production should increase the SO_2 emissions from

2-197

2-197 (cont.)

daily capacity on several occasions during the past two years." Thus, it reasons, daily emissions will not increase beyond the current peak levels allowed by Chevron's current permit and that have occurred in the past. DEIR, p. 4-15. This reasoning is flawed, as discussed above for other processes.

2-198

First, this argument ignores the fact that the Sulfur Recovery Unit cannot currently routinely operate at the increased production levels due to physical constraints. Second, the District's assumptions ignore the fact that the project will allow the peak daily conditions to occur on many more days, up to every operational day. Third, the District's assumptions are flawed because they ignore annual impacts. Fourth, the DEIR has not disclosed any information about the alleged "several occasions" on which these peak levels were reached. Thus, the DEIR has failed to meet its burden to disclose pertinent information. Finally, the DEIR takes a different approach by analyzing the increase in PM10 emissions from sulfur trucks in the diesel exhaust risk assessment. DEIR, p. 4-28.

2-199

E. Emission Sources Were Omitted

The project would increase emissions from other sources that were not included in the DEIR. Each of these is discussed below. The DEIR should be revised to include these emissions.

1. Coke and Sulfur Truck Loading PM/PM10

The project would produce increased amounts of sulfur and coke. These materials are loaded into trucks and hauled offsite. The dumping of solid materials into trucks, referred to as drop emissions, would increase emissions of PM10. These drop emissions were not included in the DEIR.

2-200

2-201

2-201 (cont.)

(flare) and the LSFO Emergency Relief System Flare. 3/17/06 Mueller Memo,[36] p. 1; DEIR, p. 2-15.

The project will connect pressure relief valves on the new DEA regenerator to the LSFO emergency relief system flare to handle acid gas flaring from modifications. DEIR, p. 2-15; 3/17/06 Mueller, Attach. B, p. 2-14; 1/16/05 Aarni, p. 7. This will increase the frequency and amount of acid gases released to the flare. The air permit application indicates that a caustic scrubber will be added as a control device,[37] but the DEIR does not disclose this fact or evaluate its impacts. These two changes—connecting relief valves to the flare and the scrubber—are not described in the DEIR.

2-202

Chevron argues in correspondence with the SCAQMD that there will be no measurable increase in relief load from the No. 6 H_2S plant when the relief scrubber is in operation. 1/16/06 Aarni, p. 7. It also presents emission estimates that indicate the scrubber will remove 100% of the sulfur compounds, leaving only 65 lb/hr of VOC. *Id.*, p. 13. The DEIR does not include any increase in VOC emissions from increased flaring. Further, the files I reviewed do not disclose the conditions under which the relief scrubber would not be employed, the frequency of these events, and the emissions during these periods. Because the scrubber is used only in emergencies, it is likely that it is not normally operating and that it would have to be started up to respond to a release. Untreated acid gases could be flared during this startup time. The H_2S and SO_2 emissions during even a short period of acid gas flaring, which contains over 90% H_2S, could be quite high, causing nuisance odors and acute health impacts. These impacts were not disclosed in the DEIR.

2-203

2-204

a. Increase In Queuing Emissions From Crude Ships

Chevron imports and stores heavy crude from different sources at the same time. These different crudes must be kept in separate storage tanks due to differences in properties. Currently, marine tankers occasionally need to wait offshore or in the Port of Los Angeles before they offload at the ESMT because none of the heavy crude storage tanks is empty. The project would reduce the number of different types of heavy crude that Chevron can store at the same time, thus increasing the time that tankers must wait to unload. DEIR, p. 1-17. The DEIR did not include these queuing emissions in its emission inventory (Table 4.1-7) and did not evaluate the resulting air quality impacts. Shipping emissions from cruising, maneuvering, and hoteling are significant by themselves. The queuing emissions would further increase shipping emissions above the significance thresholds. The DEIR should be revised to include these emissions and the project alternative that would increase heavy crude storage capacity should be adopted as mitigation.

2-205

b. Increase In Ship Calls To Handle Increase In Coke

The project would increase the amount of coke exported from the refinery. The DEIR indicates that this coke is exported through the Port of Los Angeles or the Port of Long Beach. DEIR, p. 4-16. This would increase the number of ship calls per year to export coke. The DEIR did not include emissions from increases in ship calls to export the increased coke production.

F. Revised Emissions

2-206

2-207

Table 4
Emissions
(lb/day)

Source	**CO**	**VOC**	**NOx**	**SO_2**	**PM10**
DEIR, Table 4.1-7	4.7	45.7	31.1	0.3	129.5
Coker Heaters	1013	16	37	39	24
Coke Drum Depressurization		+			>15
Electricity Generation	>8.5	>1.1	>33.3	+	>6.9
Sulfur Trucks	0.5	0.1	3.2	0.04	0.1
Ships Cruising	679.5	388.8	6119.7	4118.6	751.2
Ships Hoteling	101.3	135.4	770.2	548.4	65.5
TOTAL	**>1808**	**>2485**	**>6994**	**4706**	**>992**
Significance Threshold	550	55	55	150	150

This table shows that emissions of CO, VOC, NOx, SO_2, and PM10 exceed the SCAQMD's CEQA significance thresholds by large amounts. The emissions from shipping alone exceed the significance thresholds for all pollutants, and the emissions of CO from increased firing of the Coker heaters exceed the CO significance threshold alone. These are new, highly significant impacts that were not disclosed in the DEIR and which must be mitigated.

2-208

In addition to these five pollutants, it is likely that the increase in H_2S emissions from the project would exceed the PSD significance threshold. The DEIR should be revised to include a complete tabulation of H_2S emissions.

2-209

2-209 (cont.)

DEIR imposes twelve mitigation measures for the construction phase of the proposed Project; nine measures to reduce combustion exhaust emissions, two measures to reduce fugitive dust emissions, and one measure to reduce VOC emissions from on-site surface coating. DEIR, pp. 4-32 – 4-34. According to the DEIR's emissions estimates, implementation of these mitigation measures would reduce the PM10 emissions to less than significant, but mitigated CO, VOC and NOx emissions would still considerably exceed the SCAQMD's CEQA significance thresholds.[38] DEIR, p. 5-7. Consequently, the DEIR finds significant individual and cumulative unavoidable adverse impacts on air quality from construction of the Project. DEIR, pp. 1-9 and 1-19.

2-210

1. The DEIR's Construction Mitigation Measures Are Inadequate

A lead agency may not conclude that an impact is significant and unavoidable without first imposing all feasible mitigation measures available to reduce the significant impact. CEQA Guidelines Secs. 15126.4, 15091. Review of the DEIR's mitigation measures shows that the DEIR does not require all feasible mitigation to reduce the significant impacts from construction of the Project on air quality, as required by CEQA. A number of additional and/or more stringent mitigation measures exist, have been required for other Projects as CEQA mitigation, and should be required for Project construction to further reduce the significant CO, VOC, and NOx emissions.

2-211

a. Tier 1 California Emission Standards For Construction Equipment With A Rating Of 100 hp Or More Are Not Stringent Enough

The DEIR requires that "[a]ll construction equipment diesel engines that have a rating of 100 hp or more shall meet, at a minimum, Tier 1 California Emission Standards for Off-Road Compression-Ignition Engines as specified in the California Code of Regulations, Title 13, Section 2423(b)(1) unless such engine is not available for a particular item of equipment." DEIR, AQ-2, p. 4-23. This mitigation measure is not stringent enough and its ambiguous wording renders it unenforceable.

2-212

2-213

Second, requiring just Tier 1 California off-road diesel emission standards is not stringent enough. Tier 1 standards for new off-road diesel engines for new engines were phased in from 1996 to 2000. The more stringent Tier 2 standards took effect for new equipment from 2001 through 2006. Tier 2-compliant construction equipment is available in the construction fleet[39] and has been required elsewhere to mitigate significant impacts from construction. The DEIR for the Los Angeles Police Headquarters Facility Plan ("PHFP"), for example, requires that "[a]ll heavy construction equipment engines [] use cooled exhaust gas recirculation or [] be Tier II compliant, as feasible." PHFP DEIR[40], p. 1-5. Thus, the DEIR should be revised to require at least a certain percentage of Tier 2-compliant equipment for construction of the Project to reduce the significant construction emissions, particularly NOx emissions. For example, the DEIR could require that the construction equipment achieve a project-wide fleet average of 20% nitrogen oxide reduction and 45% particulate reduction compared to the most recent CARB fleet average at time of construction.

2-214

b. Requiring Catalyzed Diesel Particulate Filters On Non-Tier 1 Engines Is Not Adequate Mitigation

In the event a Tier 1 engine is not available for any off-road engine larger than 100 hp, the DEIR requires that the engine be equipped with a catalyzed diesel particulate filter ("catalyzed DPF") "unless the use of such devices is not practical for such engine types." The DEIR considers the use of such a device "not practical" if (a) there is no available soot filter that has been certified by either CARB or the U.S. EPA for the engine in question, or (b) if the construction equipment is intended to be on-site for ten days or less. This mitigation measure is both ineffective and inadequate.

2-215

2-216

Second, classifying catalyzed DPFs that have not been CARB or EPA verified[41] as "non-practical" unduly restricts the use of such devices and renders this mitigation measure meaningless. Certification is a very expensive, complex, and time-consuming process. Many vendors have simply opted not to pursue it or are currently in the process of certifying their equipment. The absence of certification should not per se eliminate a control from consideration.

2-217

Further, this requirement essentially assures that no DPFs will be used. At present, the only diesel particulate filter verified by CARB for off-road equipment is Lubrizol's Engine Control Systems Unikat Combifilter.[42] This filter is: (a) not catalyzed and (b) cannot be used on engines operated on alternative diesel fuels such as PuriNOx, whose use is required by the DEIR's mitigation measure AQ-1. CARB 12/04[43]. The only DPF verified by the U.S. EPA for off-road applications is manufactured by Caterpillar. This technology is only approved for non-EGR (exhaust gas recirculation) equipped, 4-cycle, turbo-charged 1996 through 2005 engines with 174 to 302 hp and can only be operated on fuels with a sulfur content of no more than 30 ppm. U.S. EPA 06/05[44]. PuriNOx, required by the DEIR's mitigation measure AQ-1, contains 75% No. 2 diesel fuel, *i.e.* so-called low sulfur fuel with a maximum sulfur content of 500 ppm, which is prohibited for use with the Caterpillar DPF. In sum, there are no catalyzed DPFs available that are verified by either CARB or U.S. EPA. Thus, this mitigation measure is meaningless as written.

2-218

However, diesel particulate filters are highly effective in removing particulate matter[45]--whether they are verified by CARB and U.S. EPA or not --

2-218 (cont.)

nd should therefore be required for all construction equipment in addition to other control technologies. In the past 20 years, over 20,000 DPFs have been installed on off-road equipment. For example, the PHFP DEIR requires the use of DPFs for all heavy construction equipment in addition to cooled exhaust gas recirculation, Tier-2 compliance or NOx catalysts. PHFP DEIR, p. 1-5.

2-219

2. Additional Feasible Construction Mitigation Measures Exist and Should Be Required for the Project

Additional mitigation measures beyond those required by the DEIR exist. For example, diesel oxidation catalysts ("DOCs"), selective catalytic reduction ("SCR"), lean NOx catalysts ("LNC"), and exhaust gas recirculation ("EGR") have been successfully retrofitted on off-road vehicles and these technologies offer opportunities to greatly reduce PM10, CO, VOC, and NOx emissions. In addition, many projects have demonstrated the feasibility of installing verified on-road technologies on construction equipment. These technologies have been required as mitigation measures for other projects and should be required for this Project to reduce its significant CO, VOC, and NOx emissions from construction.

2-220

a. Diesel Oxidation Catalysts

Diesel oxidation catalysts installed on engines burning 500 ppm or less sulfur fuel have achieved total particulate matter reductions of 20% to 50%, VOC reductions of 60% to 90% (including those hydrocarbon species considered toxic), and significant reductions of CO[46], smoke, and odor. MECA 03/06[47], p. 2. Diesel oxidation catalysts can be used in conjunction with EGR to simultaneously reduce diesel particulate and NOx emissions. MECA 04/06, p. 28.

2-221

2-222

b. Selective Catalytic Reduction

Selective catalytic reduction, using urea as a reducing agent, can reduce NOx emissions from 75% to 90% while simultaneously reducing VOC emissions by up to 80% and PM emissions by 20% to 30%. SCR systems can be used in conjunction with DPFs and DOCs and have been successfully demonstrated on off-road vehicles. MECA 04/06[48], pp. 2-3; MECA 03/06, p. 17.

For example, the City of Houston Diesel Field Demonstration Project has demonstrated an 84% reduction of NOx emissions by using a DPF/SCR combination on a 1992 MY Cummins Gradall G3WD (5.9L 190 hp). As a result of this field demonstration program, the City of Houston retrofitted 33 rubber tire excavators and a dump truck with SCR systems. MECA 03/06, p. 12.

2-223

c. Lean NOx Catalysts

Lean NOx catalyst technology can achieve a 10% to 40% reduction in NOx emissions. LNC technology does not require any core engine modifications and can be used to retrofit older engines. This retrofit technology can be combined with DPFs or DOCs to provide both NOx and PM10 reductions. An LNC added to an exhaust system using a DPF can reduce NOx emissions by 10% to 25%. MECA 03/06, p. 14.

Lean NOx catalyst technology has been demonstrated and commercialized for a variety of off-road retrofit applications, including heavy-duty earthmoving equipment. MECA 03/06, p. 19.

2-224

2-224 (cont.)

Engine retrofits with low pressure EGR in conjunction with a DPF can achieve NOx reductions of over 40% and PM reductions of more than 90% and have been successfully demonstrated on off-road equipment. MECA 04/06, p. 14.

2-225

e. Other Measures

Other mitigation measures that are feasible and have been required elsewhere include:

- Use alternative fueled equipment, *e.g.*, propane, where available;
- Limit engine idling to three minutes for delivery trucks and dump trucks;
- Suspend construction activities during Stage II smog alerts;
- Purchase offsets;
- Employ a construction site manager to verify that engines are properly maintained, and keep a maintenance log.

2-226

2-227

2-227 (cont.)

unsuitable, the owner shall install and use an oxidation catalyst. [] The initial Suitability Report shall contain, at a minimum, the following:

- A list of all fuel burning, construction related equipment used,
- A determination of the suitability of each piece of equipment to primarily work appropriately with an oxidizing soot filter,
- A determination of the suitability of each piece of equipment to secondarily work appropriately with an oxidation catalyst,
- If a piece of equipment is determined to be suitable for an oxidizing soot filter,
- If a piece of equipment is determined to be unsuitable for an oxidizing soot filter, an explanation by the independent California Licensed Mechanical Engineer as to the cause of this determination,
- If a piece of equipment is determined to be unsuitable for an oxidizing soot filter, but suitable for an oxidation catalyst,
- If a piece of equipment is determined to be unsuitable for both an oxidizing soot filter and an oxidizing catalyst, an explanation by the independent California Licensed Mechanical Engineer as to the cause of this determination.
- Following the installation of either the oxidizing soot filter or oxidizing catalyst as prescribed in the Initial Suitability Report, a California Licensed Mechanical Engineer will issue an Installation Report that either confirms that the installed device is functioning properly or that installation was not possible and the cause.

The mitigation program further specifies the conditions for subsequent determination of unsuitability of such devices, and requires that the project owner submit to the construction project manager and CARB for approval the initial and subsequent suitability reports stamped by an independent licensed professional within a certain timeframe. Three Mountain Power[50], pp. 141-142. Similar construction mitigation has been required for many other CEC projects.

2-228

The DEIR should include similar language for all its mitigation measures to ensure that mitigation measures are successfully implemented.

---

[50] California Energy Commission, Three Mountain Power Plant Project, Application for Certification, Docket No. 99-AFC-2, Presiding Member's Proposed Decision, P 800-01-012, April 2001; http://www.energy.ca.gov/sitingcases/threemountain/documents/3_MOUNTAIN_PPMD.PDF, last accessed May 25, 2006.

2-229 **B. Operational Mitigation Is Required**

The DEIR concluded that operation of the project will not cause significant adverse air quality impacts. Thus, no operational mitigation was required. DEIR, p. 4-37. However, as discussed above, the project will significantly increase emissions of NOx, SO_2, PM10, and VOCs, thus requiring mitigation. Further, the air permitting file indicates that best available control technology ("BACT") will be required for some of the sources modified by the project. The DEIR did not disclose the BACT technologies, require the use of these technologies, or evaluate the environmental impacts associated with these control themselves.

2-230 1. <u>Coke Drum Venting</u>

The emissions in Table 4.1-7 of the DEIR indicate that the project requires Best Available Control Technology for coke drum depressurization for PM10 and VOCs. The DEIR is silent on BACT controls for this process. 3/17/06 Mueller, p. 5. The air permitting file indicates that the applicant argues that controls to reduce PM10 and VOCs from coker blowdown are not justified because one permit engineer is not aware of any appropriate control technologies, no one else controls vent gases, and the SCAQMD is proposing a rulemaking that will cover the stream.[51] A handwritten note dated 4/5/06 indicates that the "BACT issue" for coke drum venting is being worked on. Thus, evidentially, the DEIR was published without resolving this issue.

2-321 First, Chevron argues that the vent emissions are 99% steam and filter type controls do not work in a moist environment. Elsewhere in the record, in response to a SCAQMD question about whether a baghouse would work in a high humidity environment in the coke handling facility, the same Chevron employee states "[t]he facility has planned for high humidity and does not expect it to adversely impact baghouse operation. The facility has chosen an artificial fiber, similar to Gortex, that does well in a humid environment and won't eventually rot as a natural fiber such as cotton can."[52]

2-232 There are several options that are widely used in other industries to control PM emissions in humid environments. These include a wet electrostatic

---

[51] E-mail from Charlie Aarni, Regulatory Agency Liaison Health, Environment and Safety, Chevron, to Bob Sanford, SCAQMD, Re: Preliminary response to additional information request, March 15, 2006.

[52] E-mail from Charlie Aarni, Chevron, to Bob Sanford, SCAQMD, Re: Preliminary response to additional information request, March 14, 2006.

2-232 (cont.)

precipitator, condensing the steam and recovering it as blowdown, venting to a closed relief system (such as the LSFO relief system, which recovers vapors and returns them to the amine treating plants for sulfur removal), gravel bed filters, and wet scrubbers. The DEIR should be revised to identify and evaluate BACT level controls for coke drum venting and their indirect impacts.

2-233

2. Coker Relief System

The Coker relief system does not have a vapor recovery system. All of the pressure relief devices are vented directly to the Coker flare. 1/16/06 Aarni #2, p. 10. The increase in VOC emissions from coker depressurization triggers BACT. The DEIR should require that Chevron install a vapor recovery system to satisfy BACT.

2-234

3. Controls For Fired Sources

As discussed above in Comments I.A and I.B, the project would require increased firing of existing heaters and boilers. These increases must be mitigated and the secondary impacts of such mitigation disclosed in the DEIR.

2-235

The mitigation of increased CO and VOC emissions would require the installation of oxidation catalysts. These catalysts could potentially increase PM10 emissions from oxidation of SO_2 to SO_3, thus requiring emission offsets.

2-236

The NOx emissions from many of these units are already controlled using selective catalytic reduction ("SCR"). If not controlled, an SCR would be required. An SCR system injects ammonia into the gas stream. Some of this ammonia slips through the catalyst and is emitted to the atmosphere. The increased firing of heaters and boilers would require the use of increased amounts of ammonia. This would result in two potential impacts that were not evaluated in the DEIR.

2-237

First, ammonia is a PM10 precursor, which is regulated. The increase in PM10 emissions from increased ammonia slip should be mitigated by purchasing PM10 offsets or by using a post-SCR catalyst to remove the ammonia.

2-238

Second, the increase in ammonia demand would increase the amount of ammonia transported to, unloaded, and handled at the refinery. This would increase the risk of accidents during ammonia transport, unloading, and storage. These impacts are normally significant.

2-239 III. HYDROGEN SULFIDE IMPACTS ARE SIGNIFICANT

A. Odor

The DEIR evaluated the nuisance odor impacts of the project and concluded that they were not significant because the maximum modeled 1-hour average off-site H_2S concentration of 2.76 µg/m^3 (0.0020 ppm) is less than the H_2S odor threshold of 0.0081 ppm. DEIR, p. 4-31. The DEIR underestimated nuisance odor impacts for three reasons.

2-240 First, it used a relatively high odor threshold, 11 µg/m^3 (0.0081 ppm). The California Air Resources Board ("CARB") investigated the ability of H_2S to cause annoyance to the general population. CARB 1985,[53] p. 2. This study concluded that "an unpleasant odor is at or above the threshold of annoyance for half the people, when its concentration reaches 5 times the average threshold of detection." Recent work using reliable test methods indicates that the detectable threshold for H_2S ranges from 0.4 µg/m^3 (in studies in the Netherlands using a dynamic flow method) to 0.7 µg/m^3 (in studies in Japan using a static test method in an odor-free test room).[54] Thus, the concentration of H_2S that would annoy half the people would range from 2 µg/m^3 to 3.5 µg/m^3.

This is consistent with conclusions reached by the World Health Organization ("WHO"), which "considered that a level of 0.008 mg/m^3 (0.005 ppm) averaged over 30 min should not produce odour nuisance in most situations." [55] Extrapolating this to a 1-hour averaging time, it is equivalent to 3.5 µg/m^3 for a 1-hour exposure. These values are consistent with the annoyance range of 2 to 3.5 µg/m^3 estimated using CARB guidance. Thus, the threshold that the DEIR used to evaluate nuisance and annoyance is too high. The maximum 1-hour modeled H_2S concentration (2.76 µg/m^3) exceeds the lower end of the range of the level that would annoy at least half of the exposed parties. This is a significant impact that was not disclosed in the DEIR.

2-241 Second, the DEIR appears to evaluate odor impacts using only the increase in H_2S concentrations. Individuals experience the total concentration,

---

[53] John E. Amoore, The Perception of Hydrogen Sulfide Odor in Relation to Setting an Ambient Standard, Prepared for California Air Resources Board, ARB Contract A4-046-33, April 10, 1985.

[54] Y. Hoshika and others, International Comparison of Odor Threshold Values of Several Odorants in Japan and in The Netherlands, Environmental Research, v. 61, 1993, pp. 78-83.

[55] World Health Organization, Hydrogen Sulfide, Environmental Health Criteria No. 19, 1981, p. 13; National Research Council, Hydrogen Sulfide, University Park Press, Baltimore, 1979; T. Lindvall, On Sensory Evaluation of Odors Air Pollutant Intensities, Nord. Hyg. Tidskr., Supplement v. 2, 1970, pp. 1-181.

2-241 (cont.)

consisting of the increment due to the project plus the background, not just the increment. Thus, total H_2S concentrations should be evaluated to determine if H_2S odors would cause significant nuisance and annoyance impacts. If the H_2S increments reported in the DEIR were added to the ambient background, they likely would exceed even the DEIR's high significance threshold.

2-242

Third, the DEIR's analysis is based only on the increase in fugitive H_2S emissions from proposed modifications at the No. 6 H_2S Plant. DEIR, p. 4-31. Hydrogen sulfide is also emitted during coke drum depressurization, but the DEIR did not disclose or attempt to quantify these emissions.

2-243

Thus, the increase in ambient concentrations of H_2S during project operation is high enough to cause annoyance. This is a significant impact that was not disclosed in the DEIR. It is also a violation of Health & Safety Code Section 41700. Therefore, H_2S emissions from project operation must be mitigated.

2-244

IV. THE PROJECT WOULD RESULT IN SIGNIFICANT AIR QUALITY IMPACTS

A. Ozone Impacts Are Significant

Ozone is a regional pollutant that is formed from NOx and VOC emissions, downwind from their release. The DEIR admits that the project would increase NOx and VOCs, ozone precursors. DEIR, Table 4.1-7, p. 4-20. As discussed above, increased use of existing equipment to support the project would further increase VOC as well as NOx emissions, although we were unable to quantify many of these increases because the DEIR did not disclose them. The South Coast Air Basin currently violates both state and federal ozone standards. Thus, the project would contribute to an existing significant impact.

2-245

An understanding of the nature of ozone pollution will help to understand why an impact analysis is so vitally important to understanding the impacts of the project. Ozone, the principal element of smog, is a secondary pollutant produced when two precursor air pollutants — volatile VOCs and NOx — react in sunlight. *American Petroleum Institute v. Costle*, 665 F.2d 1176, 1181 (D.C. Cir. 1981). VOCs and NOx are emitted by a variety of sources, including cars, trucks, industrial facilities, petroleum-based solvents, and diesel engines.

The human health and associated societal costs from ozone pollution are extreme. In proposing a new rulemaking limiting emissions of NOx and

2-245 (cont.)

particulate matter from certain diesel engines, EPA summarized the effects of ozone on public health:

> A large body of evidence shows that ozone can cause harmful respiratory effects, including chest pain, coughing and shortness of breath, which affect people with compromised respiratory systems most severely. When inhaled, ozone can cause acute respiratory problems; aggravate asthma; cause significant temporary decreases in lung function of 15 to over 20 percent in some healthy adults; cause inflammation of lung tissue, produce changes in lung tissue and structure; may increase hospital admissions and emergency room visits; and impair the body's immune system defenses, making people more susceptible to respiratory illnesses. (66 Fed. Reg. 5002, 5012 (Jan. 18, 2001).)

Moreover, ozone is not an equal opportunity pollutant, striking hardest the most vulnerable segments of our population: children, the elderly, and people with respiratory ailments. *Id.* Children are at greater risk because their lung capacity is still developing, because they spend significantly more time outdoors than adults—especially in the summertime when ozone levels are the highest, and because they are generally engaged in relatively intense physical activity that causes them to breathe more ozone pollution. *Id.*

2-246

Ozone has severe impacts on millions of Americans with asthma. While it is as yet unclear whether smog actually causes asthma, there is no doubt that it exacerbates the condition. See 66 Fed. Reg. 5002, 5012 (Jan. 18, 2001) where EPA points to "strong and convincing evidence that exposure to ozone is associated with exacerbation of asthma-related symptoms." Moreover, as EPA observes, the impacts of ozone on "asthmatics are of special concern particularly in light of the growing asthma problem in the United States and the increased rates of asthma-related mortality and hospitalizations, especially in children in general and black children in particular." 62 Fed. Reg. at 38864. In fact:

> [A]sthma is one of the most common and costly diseases in the United States. . . . Today, more than 5 percent of the US population has asthma [and] [o]n average *15 people died every day* from asthma in 1995. . .. In 1998, the cost of asthma to the U.S. economy was estimated to be $11.3 billion, with hospitalizations accounting for the largest single portion of the costs. (66 Fed. Reg. at 5012.)

2-247

The health and societal costs of asthma are wreaking havoc here in California. There are currently 2.2 million Californians suffering from asthma. In 1997 alone, nearly 56,413 residents, including 16,705 children, required

2-247 (cont.)

hospitalization because their asthma attacks were so severe. Shockingly, asthma is now the leading cause of hospital admissions of young children in California.. Combined with very real human suffering is the huge financial drain of asthma hospitalizations on the state's health care system. The most recent data indicate that the statewide financial cost of these hospitalizations was nearly $350,000,000, with nearly a third of the bill paid by the State Medi-Cal program.[56]

2-248

The project will cause or contribute to exceedances of ozone ambient air quality standards in the South Coast Air Basin. The DEIR only reported exceedances of ozone standards for the station nearest the project site, Southwest Central Los Angeles, which violated standards on 3 days over the period 2001 to 2005. DEIR, Table 3.1-3. However, other stations exceeded the ozone standards much more frequently. For example, in 2002, the South Coast Air Basin exceeded the national and state 1-hour ozone standards on 32 and 81 days, respectively. The DEIR's ozone data summary is misleading because ozone is a regional pollutant and impacts are experienced downwind, at distance from the release point. In this case, ozone impacts from the project's emissions would be experienced inland, distant from the coastal environment where Chevron and the chosen monitoring station are located. Thus, emissions from the project will aggravate these exceedances, contributing to a significant impact.

2-249

In short, in light of the regional nature of the ozone problem, the failure of the Los Angeles area to meet ozone standards and the public health threat presented by ozone pollution, ozone is precisely the type of pollutant that must be analyzed for both its Project-specific and cumulative impacts. Thus, the SCAQMD must fully analyze, disclose to the public, and consider mitigation measures to address this important public health problem.

[56] California Department of Health Services, California County Asthma Hospitalization Chart Book, August 1, 2000.