Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109
(415) 771-6000

Permit Evaluation
and
Statement of Basis
for
RENEWAL of

MAJOR FACILITY REVIEW PERMIT

for

Shell Martinez Refinery, Shell Oil Products US
Facility #A0011

Facility Address:
3485 Pacheco Blvd.
Martinez, CA 94553

Mailing Address:
P O Box 711
Martinez, CA 94553

Application Engineer: Krishnaswamy R. Bhagavan
Site Engineer: Sanjeev Kamboj

Application: 18239

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Title V Statement of Basis

A. Background

This facility is subject to the Operating Permit requirements of Title V of the federal Clean Air Act, Part 70 of Title 40 of the Code of Federal Regulations (CFR), and BAAQMD Regulation 2, Rule 6, Major Facility Review because it is a major facility as defined by BAAQMD Regulation 2-6-212. It is a major facility because it has the "potential to emit" (as defined by BAAQMD Regulation 2-6-218) more than 100 tons per year of a regulated air pollutant.

Major Facility Operating permits (Title V permits) must meet specifications contained in 40 CFR Part 70 as contained in BAAQMD Regulation 2, Rule 6. The permits must contain all "applicable requirements" (as defined in BAAQMD Regulation 2-6-202), monitoring requirements, recordkeeping requirements, and reporting requirements. The permit holders must submit reports of all monitoring at least every six months and compliance certifications at least every year.

In the Bay Area, state and District requirements are also applicable requirements and are included in the permit. These requirements can be federally enforceable or non-federally enforceable. All applicable requirements are contained in Sections I through VI of the permit.

Each facility in the Bay Area is assigned a facility identifier that consists of a letter and a 4-digit number. This identifier is also considered to be the identifier for the permit. The identifier for this facility is A0011.

This facility received its initial Title V permit under Application 16467 on December 1, 2003. The initial permit was administratively amended on May 27, 2004 and July 28, 2004. The permit was reopened under Application's 9293 and 12430 and was re-issued on December 16, 2004 and May 17, 2007, respectively. The version of the permit reopened under Application 12430 included Authorities to Construct issued under applications 3930, 4106, 4192, 4688, 4695, 6745, 9504, 10053, 11157, 12473, 12732, 13078, 13086, 13410, and 14224. In addition to the above, the permit also included the final action taken on the following Title V applications: 9699, 11158, 12731, and 13085. The permit re-issued on May 17, 2007 was amended the following year to incorporate changes stemming from a minor revision to the permit under Application 15599. The amended permit was later re-issued on April 4, 2008. Section X of the permit, Revision History, has a list of these revisions in chronological order.

Authorities to Construct and/or Permits to Operate that were issued to Shell following the issuance of the April 4, 2008 permit are summarized in the table below. Table 1 below identifies those portions of the proposed renewal permit Application 18239 that have been impacted as result of the District's actions.

Table 1		
Application #	**Application Summary**	**Summary of changes**
14497	**OPCEN Hydrocarbon Flare re-route project:** The District authorized Shell to re-route	The project did not impact and/or warrant any changes to the proposed renewal permit.

Table 1		
Application #	**Application Summary**	**Summary of changes**
	routine (non-significant vent gas relief/flaring event) vent gas flows, which otherwise would have been flared at S-1772 "OPCEN Hydrocarbon Flare", to two existing Flare Gas Recovery Compressors at S-4201 "DC Clean Fuels Flare" to be recovered as Refinery Fuel Gas (RFG).	
15482	**Water Seals for Junction Boxes:** As part of their overall compliance strategy with Regulation 8, Rule 8 "Wastewater Collection and Separation Systems", the District authorized Shell to install low-pressure water seals (seals) on the atmospheric vents at S-2010 "LOG Wastewater Junction Boxes", which are located throughout the refinery. Shell has already implemented and continues to implement a number of pollution prevention measures aimed at minimizing/eliminating sources of hydrocarbon that tie into the refinery's sewer system. Installation of the seals at S-2010 would serve as a backup control measure in the event the pollution prevention measures at the source are not completely effective.	Table IV-CJ in the initial permit used to reference Sections 303 and 308 of Regulation 8, Rule 8 as the applicable requirements for S-2010. Because seals were installed on the atmospheric vents at S-2010, it is no longer an uncontrolled wastewater collection system component. Therefore, Sections 312, 505, and 603 which pertain to controlled wastewater collection system components have been added along with Sections 303 and 308 in Table IV-CJ in the proposed renewal permit. **Table II A:** Changed the source description for S-2010 from "LOG Wastewater Junction Boxes" to "LOG Wastewater Junction Boxes (Equipped with low-pressure water seals on select atmospheric vents)". **Table IV-CJ:** Added Sections 8-8-312, 505, and 603 for S-2010. **Table VII-DA:** Created a new table for S-2010 relating to recordkeeping requirements and inspection procedures to demonstrate compliance with 8-8-312.
15774	**Asphalt Tank Replacement:** The District authorized Shell to replace S-22 - an aging and out-of-service	**Table II A:** 1. Deleted S-22. 2. Added S-6068

Table 1		
Application #	**Application Summary**	**Summary of changes**
	asphalt tank with S-6068 a new 55,100 bbl heated vertical fixed roof tank.	**Table II B:** 1. Added S-6068 to sources abated by A-57. 2. Added a separate row under A-57 for part 5 of permit condition 23605. **Table IV:** 1. Deleted references to S-22 in Table IV-Ha. 2. Added a new Table IV-DY for S-6068. **Section VI:** 1. Deleted references to S-22 from part 1 of permit condition 18618 and added S-6068 where applicable. 2. Added new permit condition 23605 for S-6068. **Table VII:** 1. Deleted references to S-22 in Table VII-G. **2.** Added a new Table VII-DB for S-6068.
16726	**ALKY Reactor Replacement:** The District authorized Shell to replace one of the four reactors at S-1430 “CP Alkylation Plant (ALKY)” that had reached the end of its useful life.	The project did not impact and/or warrant any changes to the proposed renewal permit.
17633	**Ultra Low NOx Burners (ULNBs) Retrofit:** The District authorized Shell to replace burners at S-1486 and S-1763 with ULNBs to enhance their compliance with Regulation 9 “Inorganic Gaseous Pollutants”, Rule 10 “Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators and Process Heaters in Petroleum Refineries”.	The project did not impact and/or warrant any changes to the proposed renewal permit.

Table 1		
Application #	**Application Summary**	**Summary of changes**
18034	**SRU#3 CATOX Replacement:** The District authorized Shell to replace a Catalytic Oxidizer that used to abate tail gas emissions at S-1765 "Sulfur Recovery Unit #3" with a new Thermal Oxidizer.	**Table II B:** 1. Deleted A-1518. 2. Added A-2023 **Table IV:** Replaced parts 1 through 6 of the old permit condition 19748 with parts 1 through 21 in Table IV-AR. **Section VI:** Replaced parts 1 through 6 of the old permit condition 19748 with parts 1 through 21. **Table VII:** Replaced applicable monitoring requirements in parts 1 through 6 of the old permit condition 19748 with those in parts 1 through 21 in Table VII-AI.
18062	**NHT/SRHT Modification:** The District authorized Shell to modify S-1424 "DH Naphtha Straightrun Hydrotreater (NHT)" that would increase the NHT's throughput from 28,500 BPD to 31,500 BPD.	**Table IV:** Added parts 1 and 2 of permit condition 24162 to Table IV-AL. **Section VI:** 1. Deleted a row containing the Title V throughput limit for S-1424 from part 1 of permit condition 18618. 2. Added new permit condition 24162. **Table VII:** Added applicable monitoring requirements of permit condition 24162 to Table VII-AE.
19373	**Administrative Amendment to permit condition 18618:** To ensure there is no ambiguity in determining whether Shell's CO boilers	**Table IV:** Added parts 1 and 2 of permit condition 18618 to Table IV-BK.

<table>
<tr><th colspan="3">Table 1</th></tr>
<tr><th>Application #</th><th>Application Summary</th><th>Summary of changes</th></tr>
<tr><td></td><td>(COBs) comply with their daily firing rate limits outlined in part 1 of permit condition 18618, the existing firing rate limit for the COBs (S-1507, S-1509, & S-1512) was amended to express the limit in terms of both LHV and HHV of the fuels combusted in them. For example, the daily firing rate limit for each of Shell's three COBs is expressed as 5,568 MMBTU/day (LHV) and 6,125 MMBTU/day (HHV) in the proposed renewal permit. Because permit condition 18618 is non-federally enforceable, the proposed changes qualified as an administrative amendment per Regulation 2-6-201.</td><td><u>Section VI:</u>
1. Changed the reference to Regulation 2-1-234.4 in the preamble to part 1 to Regulation 2-1-234.3.
2. Expressed the firing rate limit for the COBs in terms of both the LHV and HHV of the fuels combusted in them.

<u>Table VII:</u>
Added a new row under Table VII-BA citing the daily & annual throughput limits (~maximum firing rate) for the COBs expressed in terms of the LHV and HHV of the fuels combusted in them.</td></tr>
<tr><td>19465</td><td><u>Consent Decree:</u>
Shell's Consent Decree (CD) requires the company to complete a program to reduce overall NOx emissions from heaters and boilers that are part of the CD. To obtain credit for projects, which result in NOx reductions, Shell is required by the CD to apply for and receive enforceable permit limits from the local permitting authority.

In light of the above, the District issued Shell enforceable limits in the form of permit conditions for S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, and S-1499 because the above sources were retrofitted with ultra low NOx burners (ULNB) under Applications # 5258 (for S-1490 through S-1493) in May 2002, #14651 (for S-1494) in February 1995, and #13078 (for S-1495 through S-1499) in July 2005 to enhance compliance with Regulation 9</td><td><u>Table IV:</u>
As part of the proposed renewal and because applicable requirements in Tables IV-BA and BC almost mirror each other with a few exceptions, the above tables were merged into Table IV-BA.
1. Added parts 1 through 3 of permit condition 22119 to Table IV-AZb (for S-1760).
2. Added parts 1 through 3 of permit condition 24263 to Table IV-BA. (for S-1490, S-1491, S-1492, S-1493, S-1495, S-1496, S-1497, S-1498, S-1499, & S-1762)
3. Added parts 1 through 3 of permit condition 24263 to Table IV-BD. (for S-1494)</td></tr>
</table>

<table>
<tr><th colspan="3">Table 1</th></tr>
<tr><th>Application #</th><th>Application Summary</th><th>Summary of changes</th></tr>
<tr><td></td><td>“Inorganic Gaseous Pollutants”, Rule 10 “Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators and Process Heaters in Petroleum Refineries”.

In addition, the District also administratively amended permit conditions 17532 and 22119 governing S-1514 and S-1760, respectively.</td><td>4. Added part 4 of permit condition 17532 to Table IV-BL. (for S-1514)

<u>Section VI:</u>
1. Amended part 3 of and added part 4 to permit condition 17532. (for S-1514).
2. Amended part 2 of and added part 3 to permit condition 22119. (for S-1760).
3. Added parts 1 through 3 of permit condition 24263. (for S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, and S-1499).

<u>Table VII:</u>
1. Added applicable monitoring requirements of permit condition 22119 to Table VII-AQb (for S-1760).
2. Added applicable monitoring requirements of permit condition 24263 to Table VII-AR. (for S-1491, S-1492, S-1493, S-1495, S-1496, S-1497, & S-1498)
3. Added applicable monitoring requirements of permit condition 24263 to Table VII-AT. (for S-1490 & S-1499)
4. Added applicable monitoring requirements of permit condition 24263 to Table VII-AU.</td></tr>
</table>

Table 1		
Application #	**Application Summary**	**Summary of changes**
		(for S-1494) 5. Added applicable monitoring requirements of permit condition 17532 to Table VII-BB. (for S-1514)
20070	**<u>Gasoline Dispensing Facility # 7114 (for S-1598):</u>** On March 26, 2009, the District authorized Shell to replace the Phase II vapor recovery equipment on their gasoline service station (S-1598) with an EVR certified Phase II system.	**<u>Table IV-BO:</u>** 1. The effective date of Regulation 8, Rule 7 was changed from March 24, 2003 to November 6, 2002. 2. Regulation 8-7-311 was deleted. 3. Added part 1 of permit condition 7878. 4. Deleted parts 1 through 2 of permit condition 14098. **<u>Section VI:</u>** 1. Added part 1 of permit condition 7878. 2. Deleted permit condition 14098. 3. Amended permit condition 21593. 4. Added permit condition 24298. **<u>Table VII-BD:</u>** 1. Added applicable monitoring requirements of permit conditions 7878 and 24298. 2. Deleted applicable monitoring requirements pertaining to permit condition 14098.
20868	**<u>ALKY Reactor Replacement:</u>** The District authorized Shell to replace two of the four reactors at S-1430 “CP Alkylation Plant (ALKY)” that had	The project did not impact and/or warrant any changes to the proposed renewal permit.

Table 1		
Application #	**Application Summary**	**Summary of changes**
	reached the end of its useful life.	

This application (# 18239) is for the second renewal of the Title V permit. The standard sections of the permit have been upgraded to include new standard language used in all Title V permits. Also, various other corrections have been made to the permit. This statement of basis will include all proposed changes to the permit in ~~strikeout~~/underline format.

B. Facility Description

The Shell Martinez Refinery (Shell) consists of a petroleum refinery and chemical manufacturing complex. The crude unit at the refinery is permitted to process approximately 178,800 barrels of crude oil per day into many finished products, including liquefied petroleum gas, automotive gasoline, jet fuel, diesel, industrial fuel oils, asphalt and petroleum coke. The chemical plant manufactures several different specialty chemicals.

Shell has been in operation since 1915. The light oil processing (LOP) units were added in the mid 1970's, and the Flexicoker and associated units were added in the mid 1980's. Several new "clean fuels" units were added in 1995, including the Delayed Coker unit.

Finished products from the refinery include Liquefied Petroleum gas (LPG), which is sold as propane and used for home heating, cooking, recreational vehicles, etc. Automotive gasoline and diesel are marketed throughout California and Nevada and used to power cars, trucks, busses, boats and farm equipment. Heavier fuel oils are used for heating, in industrial steam boilers and utilities. Asphalt is used as a road mix material throughout the western United States and Canada.

Through a variety of chemical reactions and physical changes, Shell manufactures finished petroleum products from crude oil. Oil Refining includes four basic processes, described below:

SEPARATION	Liquid hydrocarbons are separated into common boiling point fractions by distillation. The distillation process makes a "rough cut" of the crude oil, producing gases, light, medium and heavy boiling-range materials, and residuals. These cuts, or intermediate streams are then further processed by more sophisticated means.
CONVERSION	Cracking - This process breaks or cracks large hydrocarbon molecules into smaller ones. This is done by thermal or catalytic cracking. Reforming - This process uses high temperatures and catalysts to rearrange the chemical structure of a particular oil stream to improve its quality.

	Combining - This process chemically combines two or more hydrocarbon streams to produce a higher-grade product. Liquefied petroleum gas streams are combined in this manner to produce gasoline.
PURIFICATION	This process converts contaminants into an easily removable or acceptable form.
BLENDING	This process mixes combinations of hydrocarbon liquids to produce a final product.

A more detailed description of petroleum refinery processes and the resulting air emissions may be found in Chapter 5 "Petroleum Industry" of EPA's publication AP-42, Compilation of Air Pollutant Emission Factors. This document may be found at:

http://www.epa.gov/ttn/chief/ap42/ch05/index.html

The principal sources of air emissions from refineries are:

- Combustion units (furnaces, boilers, and cogeneration facilities)
- FCC (Fluidized Catalytic Cracking) units
- Storage tanks
- Fugitive emissions from pipe fittings, pumps, and compressors
- Sulfur plants
- Wastewater treatment facilities

Combustion unit emissions are generally controlled through the use of burner technology, steam injection, or selective catalytic reduction. Emissions from the FCCU are controlled through the use of improved catalyst regeneration, CO boilers, electrostatic precipitators, hydrotreating the feed, and use of catalysts to remove impurities. Storage tank emissions are controlled through the use of add-on controls and or fitting-loss controls. Fugitive emissions have been controlled through the use of frequent inspections and maintenance checks. Sulfur plants are equipped with tail gas units to reduce emissions. Wastewater treatment facilities are controlled by covering units, gasketing covers, and add-on controls, such as carbon canisters.

The District recently determined Equilon Enterprises LLC to be a support facility of the refinery. As a result, Equilon Enterprises LLC, which is a bulk storage and loading terminal located adjacent to the refinery, submitted an application to obtain an initial Title V permit from the District on February 17, 2010. Equilon Enterprises LLC is the smaller of the two facilities and operates under a different facility identifier number, B1956.

Although Equilon Enterprises LLC and the refinery are considered to be the same facility, Equilon Enterprises LLC will receive a separate Title V permit. Equilon has a different responsible official and the facility has asked for a separate permit. The definition of permit in the federal Title V regulations at 40 CFR 70.1, below, allows agencies to issue more than one permit to a facility and the District has issued more than one Title V permit to several facilities.

> "Part 70 permit or permit (unless the context suggests otherwise) means any permit or *group of permits* covering a part 70 source that is issued, renewed, amended, or revised pursuant to this part."

Therefore, the refinery permit and the Equilon permit can be proposed and issued separately.

The District has determined that sources at the refinery will not be subject to additional applicable requirements due to the refinery's association with Equilon Enterprises LLC.

BAAQMD Regulation 2-6-412.2 requires a description of the emissions changes in the public notice. There have been no significant changes in emissions at this facility.

C. Permit Content

The legal and factual basis for the permit follows. The permit sections are described in the order presented in the permit.

I. Standard Conditions

This section contains administrative requirements and conditions that apply to all facilities. If the Title IV (Acid Rain) requirements for certain fossil-fuel fired electrical generating facilities or the accidental release (40 CFR § 68) programs apply, the section will contain a standard condition pertaining to these programs. Many of these conditions derive from 40 CFR § 70.6, Permit Content, which dictates certain standard conditions that must be placed in the permit. The language that the District has developed for many of these requirements has been adopted into the BAAQMD Manual of Procedures, Volume II, Part 3, Section 4, and therefore must appear in the permit.

The standard conditions also contain references to BAAQMD Regulation 1 and Regulation 2. These are the District's General Provisions and Permitting rules.

<u>Changes to permit</u>

- The adoption and amendment dates of the rules in Standard Condition I.A have been updated.
- Reference to Regulation 3 as basis was deleted from Standard Condition I.E & I.F as this regulation applies to Fees only and has no concern with Records requirements.
- Section I.J.2 has been modified to clarify that the capacity limits shown in Table II-A are enforceable limits.

II. Equipment

This section of the permit lists all permitted or significant sources. Each source is identified by an S and a number (e.g., S24).

Permitted sources are those sources that require a BAAQMD operating permit pursuant to BAAQMD Rule 2-1-302.

Significant sources are those sources that have a potential to emit of more than 2 tons per year of a “regulated air pollutant”, as defined in BAAQMD Rule 2-6-222, or 400 pounds per year of a “hazardous air pollutant” ,as defined in BAAQMD Rule 2-6-210.

All abatement (control) devices that control permitted or significant sources are listed. Each abatement device whose primary function is to reduce emissions is identified by an A and a number (e.g., A-24). If a source is also an abatement device, such as when an engine controls VOC emissions, it will be listed in the abatement device table but will have an “S” number. An abatement device may also be a source (such as a thermal oxidizer that burns fuel) of secondary emissions. If the primary function of a device is to control emissions, it is considered an abatement (or “A”) device. If the primary function of a device is a non-control function, the device is considered to be a source (or “S”).

The equipment section is considered to be part of the facility description. It contains information that is necessary for applicability determinations, such as fuel types, contents or sizes of tanks, etc. This information is part of the factual basis of the permit.

Each of the permitted sources has previously been issued a permit to operate pursuant to the requirements of BAAQMD Regulation 2, Permits. These permits are issued in accordance with state law and the District’s regulations. The capacities in the permitted sources table are the maximum allowable capacities for each source, pursuant to Standard Condition I.J and Regulation 2-1-403.

Changes to Table II A “Permitted Sources”:

- Deleted S-22, S-1005, S-5140, and S-6058.
- Added S-6068, which was permitted under Application 15774 to replace S-22.
- As previously discussed under Table 1 in the “Background” section, the source description for S-2010 was amended under Application 15482.

Changes to Table II B “Abatement Devices”:

- On December 5, 2007 Regulation 6 “Particulate Matter and Visible Emissions”, was renumbered as Regulation 6, Rule 1, and renamed as “Particulate Matter, General Requirements”. In light of the above all references to sections, which cited Regulation 6 have been changed to Regulation 6-1. As an example, consider A-1. The applicable requirement for A-1 was changed from Regulation 6-301 to Regulation 6-1-301.
- As previously discussed under Table 1 in the “Background” section, S-6068 permitted under Application 15774 replaced S-22. The amendments to Table II B reflect the fact that S-6068 is abated by A-57, and its operation is governed by permit condition 23605.
- A-771 was permitted under Application 7771 to abate S1769 on July 8, 2003. A-771 was never included in the initial Title V permit (Application 16467) and/or in the subsequent revisions to the initial permit under Applications 9293, 12430, and 15599. This oversight on the part of the District is addressed in this permitting action, and the amendments also

reflect the fact that A-771's operation is governed by permit condition 20755.

- Deleted reference to S-1426 from the row entry corresponding to S-1470, because S-1470 abates only S-4338, and S-1426 is abated by S-1471.

- As previously discussed under Table 1 in the "Background" section, A-2023 permitted under Application 18034 replaced A-1518. The amendments to Table II B reflect the fact that A-1518 is no longer in service, and that the S-1765 is abated by A-2023.

- Amendments to the "Operating Parameters" and "Limit or Efficiency" columns corresponding to A-1805, A-2017, and A-2020 are discussed in detail under the "NESHAP FF" discussion.

- Amended the description for A-4005 to clarify it is a coke barn and not a coke corral.

- A20070 and A20080 don't exist and were deleted.

III. Generally Applicable Requirements

This section of the permit lists requirements that generally apply to all sources at a facility including insignificant sources and portable equipment that may not require a District permit. If a generally applicable requirement applies specifically to a source that is permitted or significant, the standard will also appear in Section IV and the monitoring for that requirement will appear in Sections IV and VII of the permit. Parts of this section apply to all facilities (e.g., particulate, architectural coating, odorous substance, and sandblasting standards). In addition, standards that apply to insignificant or unpermitted sources at a facility (e.g., refrigeration units that use more than 50 pounds of an ozone-depleting compound) are placed in this section.

Unpermitted sources are exempt from normal District permits pursuant to an exemption in BAAQMD Regulation 2, Rule 1. They may, however, be specifically described in a Title V permit if they are considered "significant sources" as defined in BAAQMD Rule 2-6-239.

<u>Changes to permit</u>

- Updated rule adoption dates.

- Added BAAQMD Regulation 2, Rules 2, 4, 5, 6, & 9; Regulation 3; Regulation 8, Rule 10; and Regulation 9, Rule 1.

- Added SIP Regulation 2-1-429; Regulation 2, Rules 2, 4, & 6; Regulation 3; Regulation 6; Regulation 8, Rules 2, 10, & 40; and Regulation 9, Rule 1.

- Added Sections 41750 & 44300 of the California Health and Safety Code; and revised the description for 40 CFR Part 61, Subpart M.

- Shell does not use hexavalent chromium in its cooling towers. Therefore, Regulation 11, Rule 10 was deleted.

IV. Source-Specific Applicable Requirements

This section of the permit lists the applicable requirements that apply to permitted or significant sources. These applicable requirements are contained in tables that pertain to one or more sources that have the same requirements. The order of the requirements is:

- District Rules
- SIP Rules (if any) are listed following the corresponding District rules. SIP rules are District rules that have been approved by EPA for inclusion in the California State Implementation Plan. SIP rules are "federally enforceable" and a "Y" (yes) indication will appear in the "Federally Enforceable" column. If the SIP rule is the current District rule, separate citation of the SIP rule is not necessary and the "Federally Enforceable" column will have a "Y" for "yes". If the SIP rule is not the current District rule, the SIP rule or the necessary portion of the SIP rule is cited separately after the District rule. The SIP portion will be federally enforceable; the non-SIP version will not be federally enforceable, unless EPA has approved it through another program.
- Other District requirements, such as the Manual of Procedures, as appropriate.
- Federal requirements (other than SIP provisions)
- BAAQMD permit conditions. The text of BAAQMD permit conditions is found in Section VI of the permit.
- Federal permit conditions. The text of Federal permit conditions, if any, is found in Section VI of the permit.

Section IV of the permit contains citations to all of the applicable requirements. The text of the requirements is found in the regulations, which are readily available on the District or EPA websites, or in the permit conditions, which are found in Section VI of the permit. All monitoring requirements are cited in Section IV. Section VII is a cross-reference between the limits and monitoring requirements. A discussion of monitoring is included in Section C.VII of this permit evaluation/statement of basis.

<u>Changes to the proposed renewal permit:</u>

Changes to the proposed renewal permit stem from any one and/or all of the following:

- Changes to the federal enforceability status and/or the applicability of BAAQMD regulations for a source or group of sources.
- Changes in applicable federal (non-BAAQMD regulations) requirements for a source or group of sources.
- Changes to existing permit conditions and/or incorporation of new permit conditions based on comments received from Shell.
- Changes resulting from the incorporation of applications, for which the District issued an AC and/or a PO, that were previously excluded from a permit that was public noticed and issued to Shell on April 4, 2008.

<u>Changes to the renewal permit stemming from BAAQMD regulations:</u>

The discussion that follows pertains only to those BAAQMD regulations whose State Implementation Plan (SIP) status has changed since Shell was issued its initial permit on December 1, 2003. Simply stated, either certain sections in <u>or</u> all sections of a given regulation are not federally enforceable. For regulations where certain sections of the regulation are not federally enforceable (~not SIP approved) a table summarizes the affected section(s). Likewise, regulations that were previously deemed non-federally enforceable in whole and/or in part (certain sections) which are now federally enforceable are also discussed. Also, the SIP related sections have been deleted i.e. old rule date, affected sections, etc.

BAAQMD Regulation 6 "Particulate Matter",
Rule 1 "General Requirements":

The purpose of this rule is to limit the quantity of particulate matter in the atmosphere through the establishment of limitations on emission rates, concentration, visible emissions and opacity.

Regulation 6, Particulate Matter and Visible Emissions, was renumbered as Regulation 6, Rule 1, and renamed as Particulate Matter, General Requirements on December 5, 2007. The equivalent rule in the State Implementation Plan (SIP) is Regulation 6, Particulate Matter and Visible Emissions, which was published in the Federal Register on September 4, 1998. The rule in its current form (Regulation 6, Rule 1) is not federally enforceable, although its requirements exactly mirror those contained in the SIP approved version of the rule (Regulation 6). In light of the above, Tables IV-Ha, Hb, AG, AP, AQ, AS, AW, AXa, AXb, AXc, AZ, AZb, BA, BD, BG, BK, BL, BP, BU, BW, BX, BZ, CA, CB, CO, CQ, CS, CU, CV, CW, CX, CY, DE, DNa, and DX and Tables VII-G, AA, AG, AH, AJ, AN, AO, AOa, AOb, AQ, AQb, AR, AT, AU, AX, BA, BB, BE, BG, BI, BJ, BL, BM, BN, BX, BZ, CB, CE, CG, CH, CI, CTa, CZ, and DB were amended to include the non-SIP approved version of the rule.

BAAQMD Regulation 8 "Organic Compounds",
Rule 2 "Miscellaneous Operations":

The purpose of this rule is to reduce emissions of precursor organic compounds from miscellaneous operations.

The effective date of the rule was changed in Table IV-AL from 6/15/94 to 7/20/05. All sections of the BAAQMD rule with the exception of 8-2-117 and 201, which are not contained/referenced in the permit, are federally enforceable.

Table 1 below summarizes the non-federally enforceable sections of the rule.

Table 1		
BAAQMD Regulation	**Effective Date of the Rule**	**Non-Federally Enforceable Sections of the Rule (Sections either not contained in or deleted from SIP approved version of the rule)**
Regulation 8 "Organic Compounds", Rule 2 "Miscellaneous Operations"	July 20, 2005	General: 8-2-117 Definitions: 8-2-201

BAAQMD Regulation 8 "Organic Compounds",
Rule 4 "General Solvent and Surface Coating Operations":

The purpose of this rule is to limit emissions of volatile organic compounds from the use of solvents and surface coatings in operations such as model making, printed circuit board manufacturing and assembly, electrical and electronic component manufacturing, surface coating of test panels, training facilities where the application of coating is for training purposes, stencil coatings, low usage coating activities exempt from other Regulation 8 rules, coatings specifically exempt from other Regulation 8 rules or solvent usage not specified by other Regulation 8 rules.

All sections of this rule are federally enforceable. Therefore, the SIP version of the rule dated 12/20/95 was deleted from Table IV-CB, and all sections of the District's version of the rule were deemed federally enforceable in Tables IV-CB and VII-BN.

Certain sections of the rule, which were previously deemed non-federally enforceable in the above tables, were changed to reflect them as being federally enforceable in light of the SIP approved version of the District's rule, which has been effective since October 16, 2002.

BAAQMD Regulation 8 "Organic Compounds",
Rule 5 "Storage of Organic Liquids":

The purpose of this rule is to limit emissions of organic compounds from storage tanks.

The effective dates of the rules (SIP approved and non-SIP approved versions) were updated for tanks in Tables IV-A, Ca, Ea, Ec, I, Ja, Jb, Jc, M, R, U, Y, AC, AEa, AEb, AEc, AH, AK, DG, DJ, and DW. In addition to the above, the effective dates of the rules in Tables IV-AXa (for flares A-101 & A-102 that serve as backup abatement devices for VRU's A-25 & A-56, respectively), AXb (for flare A-103 that serves as backup abatement device for VRU A-26), and DV (for the Facility) were also updated. Specifically, the SIP approved version of the rule was published in the Federal Register on June 5, 2003 and the non-SIP approved version of the rule has been effective since October 18, 2006.

Table 2 below summarizes the non-federally enforceable sections of the rule.

Table 2		
BAAQMD Regulation	**Effective Date of the Rule**	**Non-Federally Enforceable Sections of the Rule (Sections either not contained in or deleted from SIP approved version of the rule)**
Regulation 8 "Organic Compounds", Rule 5 "Storage of Organic Liquids"	**October 18, 2006**	General: 8-5-111, 8-5-111.1, 8-5-111.2, 8-5-111.5, 8-5-111.6, 8-5-112, 8-5-112.1, 8-5-112.1.1, 8-5-112.2, 8-5-112.4, 8-5-112.5, 8-5-112.6, 8-5-112.6.1, 8-5-112.6.2, 8-5-112.6.3,

Table 2		
BAAQMD Regulation	**Effective Date of the Rule**	**Non-Federally Enforceable Sections of the Rule (Sections either not contained in or deleted from SIP approved version of the rule)**
		8-5-112.6.4, 8-5-116, 8-5-117, 8-5-118, 8-5-119, 8-5-119.1, 8-5-119.2, and 8-5-119.3. Definitions: 8-5-201, 8-5-202, 8-5-206, 8-5-209, 8-5-210 8-5-222, 8-5-223, 8-5-224, 8-5-225, and 8-5-226. Standards: 8-5-301, 8-5-302, 8-5-303, 8-5-303.1 8-5-303.2, 8-5-304, 8-5-304.4, 8-5-304.5 8-5-304.6, 8-5-304.6.1, 8-5-304.6.2, 8-5-305, 8-5-305.3, 8-5-305.5, 8-5-305.6, 8-5-306, 8-5-306.1, 8-5-306.2, 8-5-307, 8-5-307.1, 8-5-307.2, 8-5-307.3, 8-5-320.2, 8-5-320.3, 8-5-320.5.2, 8-5-321.1, 8-5-321.3, 8-5-321.4, 8-5-322, 8-5-322.1, 8-5-328, 8-5-328.1, 8-5-328.2, 8-5-328.3, 8-5-331, 8-5-331.1, 8-5-331.2, 8-5-331.3, 8-5-332, 8-5-332.1, and 8-5-332.2. Administrative Requirements: 8-5-401.1, 8-5-401.2, 8-5-402.2, 8-5-402.3, 8-5-403, 8-5-403.1, 8-5-403.2, 8-5-404, 8-5-405, 8-5-411, 8-5-411.1, 8-5-411.2, 8-5-411.3, and 8-5-412. Monitoring and Records: 8-5-501.1, 8-5-501.2, 8-5-501.3, 8-5-501.4, 8-5-502, 8-5-502.1, 8-5-502.2, 8-5-502.2.1, 8-5-502.2.2, and 8-5-503. Manual of Procedures: 8-5-601, 8-5-602, 8-5-603, 8-5-604, 8-5-605 “Pressure Vacuum Valve Gas Tight Determination”, 8-5-605 “Measurement of Leak Concentrations and Residual Concentrations”, 8-5-605.1, 8-5-605.2, 8-5-606, 8-5-606.1, 8-5-606.2, and 8-5-606.3.

The facility has four types of tanks storing organic liquids:

- Fixed roof tanks:
  Regulation 8, Rule 5 applicable requirements for these tanks are summarized under Tables IV-I, M, AEa, AEb, AEc, AH, DG, and DJ. Consistent with information summarized in Table 2 above, the federal enforceability of the affected sections was updated in the above tables to reflect their SIP status.

  Tanks listed under Tables IV-I, AH, and DJ have a storage capacity of less than 19,803 gallons and the true vapor pressure of the tank contents is greater than 0.5 psia and less than/equal to 1.5 psia. Tanks listed under Table IV-DJ are pressure tanks with nitrogen blanketing. As a result and in addition to other Regulation 8, Rule 5 applicable requirements, tanks listed under Table IV-DJ must also comply with the requirements of sections 8-5-307.2 and 307.3.

  In contrast, the storage capacity of tanks listed under Tables IV-M, AEa, AEb, AEc, and DG is greater than/equal to 39,626 gallons. Emissions from tanks listed in Tables IV-M, AEa, AEb, AEc, DG, and DJ are abated, whereas emissions from tanks listed under Tables IV-I and AH are unabated. As a result sections 8-5-118 and 306.1 are not cited as applicable requirements in Tables IV-I and AH.

- Tanks without explicit tank attributes:

  Regulation 8, Rule 5 applicable requirements for these tanks are summarized under Tables IV-A, Ca, Ea, and Ec. Though these tanks are equipped with fixed roofs, the tanks listed under the above tables differ in the BAAQMD and Federal applicable requirements they are subject to from those that are explicitly listed as fixed roof tanks in Tables IV-I, M, AEa, AEb, AEc, AH, DG, and DJ - hence the distinction and separate placement of these tanks in Tables IV-A, Ca, Ea, and Ec.

  The true vapor pressure of the tank contents stored in tanks listed under Tables IV-A, and Ca is less than or equal to 0.5 psia. Therefore, the subject tanks qualify for the exemption in section 8-5-117 and cite the above section in the afore referenced tables. In contrast, emissions from tanks listed in the Tables IV-Ea and Ec are abated. Therefore, sections 8-5-118 and 306.1 are cited as applicable requirements in the above tables.

- External Floating Roof (EFR) Tanks:
  Regulation 8, Rule 5 applicable requirements for these tanks are summarized in Tables IV-Ja, Jb, Jc, U, Y, and AC. The above tables contain the “Enhanced Monitoring Program” requirements, which are tailored for EFR tanks listed under them. As a result and in addition to other Regulation 8, Rule 5 applicable requirements, the above tables also cite the non-federally enforceable sections in 8-5-119, 119.1, 119.2, 119.3, 411, 411.1, 411.2, and 411.3 that pertain to the “Enhanced Monitoring Program”. Consistent with information summarized in Table 2 above, all sections of the BAAQMD rule with the exception of 8-5-111.3, 112.3, 401, and 501 applicable to EFR tanks were deemed non-federally enforceable.

- Internal Floating Roof (IFR) Tanks:
  Regulation 8, Rule 5 applicable requirements for these tanks are summarized in Tables IV-R and AK. Consistent with information summarized in Table 2 above, all sections of

the BAAQMD rule with the exception of 8-5-111.3, 112.3, 402, 402.1, and 501 applicable to IFR tanks were deemed non-federally enforceable.

- Related Information/Other Changes:
  In light of the exemption listed under section 8-5-118, none of the tanks whose emissions are abated cite 8-5-306.2 as an applicable requirement. It is assumed that equipment leaks from sources (abatement equipment, etc.) downstream of the tank would be covered by inspections required under Regulation 8, Rule 18.

  Section 8-5-328 has been amended significantly since it was last approved as part of the SIP in 2003. The above section used to be made up of subsections 328.1 (1.1 & 1.2) and 328.2. The current non-SIP approved version of the rule, which became effective in October 2006, is made up of subsections 328.1, 328.2, and 328.3. The requirements contained in the afore-referenced sections of the new rule also differ from those contained in their SIP approved predecessor. In light of the above, references to the SIP version of Section 8-5-328.1 were deleted from Tables VII-Dc, H, I, J, L, R, T, W, X, Y, AD, CO and CT; references to SIP version of Section 8-5-328.2 were changed to 8-5-328.1 in Tables VII-I, P, Y, and AOa; and the SIP version of Section 8-5-328.1.1 was deleted from Table VII-P.

  The SIP approved version of the rule did not contain any subsections in Section 8-5-306, whereas the non-SIP approved version of the rule is made up of two subsections (306.1 and 306.2). As a result, references to SIP version of Section 8-5-306 were changed to 8-5-306.1 in Tables VII-Y and AOa. Section 8-5-405 that used to exist in the SIP approved version of the rule was deleted from the non-SIP version of the rule in October 2006, and Section 8-5-331 that did not exist when the rule was adopted as part of the SIP was added to the non-SIP version of the rule. The above changes, where applicable, can be found in Tables VII-Da, Dc, H, I, J, L, P, R, T, W, X, Y, AD, AO, AOa, CO, CT, and DC.

  References to SIP version of Sections 8-5-401.2 and 405 were replaced with non-SIP version Section 8-5-401.1 in Tables VII-H, I, J, R, T, and W. It should be noted that the revised tables noted above contain both Sections 8-5-401.1 and 401.2 in them. The SIP approved version of the rule did not contain any subsections in Section 8-5-502, whereas the non-SIP approved version of the rule is made up of two subsections (502.1 and 502.2). As a result, references to Section 8-5-502 were changed to 8-5-502.2 in Tables VII-H, I, J, L, P, R, T, W, X, Y, AD, AOa, CL, CO, and CT. In addition, a reference to Section 8-5-501 was changed to 8-5-502.1, and 8-5-404 was deleted from Table VII-Y.

  The SIP approved version of the rule contained two subsections in Section 8-5-603 (603.1 and 603.2), whereas the non-SIP approved version of the rule does not contain any subsections. As a result and where applicable, references to Sections 8-5-603.1 and 8-5-603.2 were changed to 8-5-603 in Tables VII-B, Da, Dc, H, I, J, L, P, R, T, W, X, Y, AD, AOa, CL, CO, and CT. It should be noted that Regulation 8, Rule 5 applicable requirements were included as part of Tables VII-AO (for A-101 and A-102) and AOa (for A-103) because the above flares, which serve as backup abatement devices for VRU's, abate emissions from storage tanks when VRU's A-25 (backup A-101), A-26 (backup A-103), and A-56 (backup A-102) are either taken out of service for routine maintenance and/or due to an unexpected upset. Flares A-101 through A-103 are not used as control devices when degassing tanks, nor can the flares be source tested. Therefore, Regulations 8-5-328, 328.1, 502, and 502.1 don't apply to them and were deleted from Tables IV-AXa and AXb.

BAAQMD Regulation 8 "Organic Compounds",
Rule 6 "Organic Liquid Bulk Terminals and Bulk Plants":

The purpose of this rule is to limit emissions of volatile organic compounds from transfer operations at non-gasoline organic liquid bulk terminals and bulk plants.

All sections of this rule, which was adopted on February 2, 1994, are federally enforceable. The LPG loading rack (S-4338) abated by the LOG LPG Flare (S-1470) is subject to Regulation 8, Rule 6. However, S-4338 is exempt from the above rule per Section 8-6-117. In light of the above, Section 8-6-117 was added to Table IV-DD (for S-4338).

BAAQMD Regulation 8 "Organic Compounds",
Rule 8 "Wastewater Collection and Separation Systems":

The purpose of this rule is to limit the emissions of organic compounds from wastewater collection and separation systems that handle liquid organic compounds from industrial processes.

The effective dates of the rules (SIP approved and non-SIP approved versions) were updated in/added to Tables IV-AT, AV, CG, CJ, CH, and DM. Specifically, the SIP approved version of the rule was published in the Federal Register on August 29, 1994 and the non-SIP approved version of the rule has been effective since September 15, 2004.

Table 3 below summarizes the non-federally enforceable sections of the rule.

Table 3		
BAAQMD Regulation	**Effective Date of the Rule**	**Non-Federally Enforceable Sections of the Rule (Sections either not contained in/deleted from SIP approved version of the rule)**
Regulation 8 "Organic Compounds", Rule 8 "Wastewater Collection and Separation Systems"	September 15, 2004	General: 8-8-101, 8-8-112, 8-8-113, 8-8-115, and 8-8-116. Definitions: 8-8-201, 8-8-204, 8-8-210, 8-8-216, 8-8-217, 8-8-219, 8-8-220, 8-8-221, 8-8-222, 8-8-223, 8-8-224, 8-8-225, 8-8-226, 8-8-227, 8-8-228, 8-8-229, 8-8-230, 8-8-231, and 8-8-232. Standards:

Table 3		
BAAQMD Regulation	**Effective Date of the Rule**	**Non-Federally Enforceable Sections of the Rule (Sections either not contained in/deleted from SIP approved version of the rule)**
		8-8-301.2.3, 8-8-302.2.3, 8-8-302.3, 8-8-302.6 8-8-304, 8-8-305.2, 8-8-306.2, 8-8-307.2, 8-8-312, 8-8-313, 8-8-313.1, 8-8-313.2, and 8-8-314. Administrative Requirements: 8-8-402, 8-8-402.1, 8-8-402.2, 8-8-402.3, 8-8-402.4, 8-8-402.5, 8-8-403, 8-8-403.1, 8-8-403.2, 8-8-403.3, 8-8-403.4, and 8-8-404. Monitoring and Records: 8-8-501, 8-8-502, 8-8-505, 8-8-505.1, 8-8-505.2, 8-8-505.3, and 8-8-505.4. Manual of Procedures: 8-8-601, 8-8-602, and 8-8-603.

All sections of the BAAQMD rule with the exception of 8-8-501 are federally enforceable. Regulation 8-8-302.4 under "Citation of limit" in Table VII-AK was replaced by the more recent & stringent vapor tight standard in Regulation 8-8-302.6. Amendments to Tables VII-BSa and BSb reflect the fact that Section 8-8-307.1 is federally enforceable. .

Section 8-8-200 was significantly revised since it was last approved as part of the SIP in 1994. The above section consisting of definitions was made up of 18 subsections (201 through 218). The current non-SIP approved version of the rule, which became effective in September 2004, contains 32 subsections (201 through 232). One new subsection 8-8-230 includes "process drains" under the definition of "Wastewater Separator System". Therefore, the permit shield for "process drains" under Table IX A-9 is no longer valid and was deleted. The process drains are subject to and are expected to comply with Regulation 8, Rule 8 (Section 8-8-313 and others). Please refer to note #4 under Table IV-EB.

BAAQMD Regulation 8 "Organic Compounds",
Rule 15 "Emulsified and Liquid Asphalts":

The purpose of this rule is to limit the emissions of volatile organic compounds caused by the use of Emulsified and Liquid asphalt in paving materials and paving and maintenance operations.

All sections of this September 16, 1987 rule are federally enforceable, and Section 8-15-501 was amended on June 1, 1994. The above change is reflected in Table IV-DV.

BAAQMD Regulation 8 "Organic Compounds",
Rule 16 "Solvent Cleaning Operations":

The purpose of this rule is to limit emissions from solvent cleaning operations.

All sections of this rule are federally enforceable. Therefore, the SIP version of the rule dated 12/9/94 was deleted from Tables IV-CD and DV. Certain sections of the rule, which were previously deemed non-federally enforceable were changed in the above tables to reflect them as being federally enforceable in light of the SIP approved version of the District's rule which has been effective since October 16, 2002. In light of the above, the old SIP rule requirements in Tables VII-BP and CY were deleted, and the federal enforceability of Sections 8-16-118, 303.4.1, and 303.5 was updated to reflect that they are SIP approved.

BAAQMD Regulation 8 "Organic Compounds",
Rule 18 "Equipment Leaks":

The purpose of this rule is to limit emissions of organic compounds and methane from leaking equipment at petroleum refineries, chemical plants, bulk plants and bulk terminals including, but not limited to: valves, connectors, pumps, compressors, pressure relief devices, diaphragms, hatches, sight-glasses, fittings, sampling ports, meters, pipes, and vessels.

The effective dates of the rules (SIP approved and non-SIP approved versions) were updated in/added to Tables IV-AL, AOa, AP, and EC. Specifically, the SIP approved version of the rule was published in the Federal Register on June 5, 2003 and the non-SIP approved version of the rule has been effective since September 15, 2004.

Table 4 below summarizes the non-federally enforceable sections of the rule.

Table 4		
BAAQMD Regulation	**Effective Date of the Rule**	**Non-Federally Enforceable Sections of the Rule (Sections either not contained in/deleted from SIP approved version of the rule)**
Regulation 8 "Organic Compounds", Rule 18 "Equipment Leaks"	September 15, 2004	General: 8-18-101 and 8-18-110 Definitions: 8-18-203, 8-18-204, 8-18-208, 8-18-219, and 8-18-225. Standards: 8-18-302, 8-18-302.1, 8-18-302.2, 8-18-302.3, 8-18-303, 8-18-303.1, 8-18-303.2, 8-18-303.3, 8-18-303.3, 8-18-304, 8-18-304.1, 8-18-304.2, 8-18-304.3, 8-18-306, 8-18-306.1, 8-18-306.2, 8-18-306.3, and 8-18-306.4. Administrative Requirements:

Table 4		
BAAQMD Regulation	**Effective Date of the Rule**	**Non-Federally Enforceable Sections of the Rule (Sections either not contained in/deleted from SIP approved version of the rule)**
		8-18-401.9 and 8-18-401.10. <u>Monitoring and Records:</u> 8-18-502.4, 8-18-503, 8-18-503.1, and 8-18-503.2. <u>Manual of Procedures:</u> 8-18-603 and 8-18-604

Several sections of the rule pertaining to the standards, such as but not limited to 8-18-302, 303, 304, and 306 have been significantly revised in the District's non-SIP version. Likewise, sections pertaining to inspection, records, and reports have also been significantly revised. The federal enforceability of the affected sections has been updated in Tables IV-AL and AP and Tables VII-AE and AG to reflect their SIP status.

BAAQMD Regulation 8 "Organic Compounds",
Rule 19 "Surface Preparation and Coating of Miscellaneous Metal Parts and Products":

The purpose of this rule is to limit the emission of volatile organic compounds from the surface preparation and coating of miscellaneous metal parts and products.

All sections of this rule are federally enforceable. Therefore, the SIP version of the rule dated 12/20/95 was deleted from Table IV-CB. Certain sections of the rule, which were previously deemed non-federally enforceable were changed in the above table to reflect them as being federally enforceable in light of the SIP approved version of the District's rule which has been effective since October 16, 2002. No changes were made to Table VII-BN.

BAAQMD Regulation 8 "Organic Compounds",
Rule 28 "Episodic Releases from Pressure Relief Devices at Petroleum Refineries and Chemical Plants":

The purpose of this Rule is to prevent the episodic emissions of organic compounds from pressure relief devices on equipment handling gaseous organic compounds at petroleum refineries, and to collect information on episodic organic and inorganic compound emissions from pressure relief devices at petroleum refineries and chemical plants.

The effective dates of the rules (SIP approved and non-SIP approved versions) were updated in/added to Tables IV-AL, AOa, and AP. Specifically, the SIP approved version of the rule was published in the Federal Register on May 24, 2004 and the non-SIP approved version of the rule has been effective since December 21, 2005.

Table 5 below summarizes the non-federally enforceable sections of the rule.

Table 5		
BAAQMD Regulation	**Effective Date of the Rule**	**Non-Federally Enforceable Sections of the Rule (Sections either not contained in/deleted from SIP approved version of the rule)**
Regulation 8 “Organic Compounds”, Rule 28 “Episodic Releases from Pressure Relief Devices at Petroleum Refineries and Chemical Plants”	December 21, 2005	General: 8-28-101, 8-28-111, 8-28-113, 8-28-114, and 8-28-115. Definitions: 8-28-201, 8-28-207, 8-28-209, 8-28-210, 8-28-211, 8-28-212, 8-28-213, 8-28-214, 8-28-215, and 8-28-216. Standards: 8-28-302, 8-28-303, 8-28-303.1, 8-28-303.2, and 8-28-304.1. Administrative Requirements: 8-28-401, 8-28-401.2, 8-28-401.3, 8-28-401.6, 8-28-401.9, 8-28-402, 8-28-402.1, 8-28-402.2, 8-28-403, 8-28-404, 8-28-405, 8-28-405.1, 8-28-405.2, 8-28-405.3, 8-28-405.4, 8-28-406, 8-28-406.1, 8-28-406.2, 8-28-406.3, 8-28-406.4, 8-28-406.5, 8-28-406.6, and 8-28-407. Monitoring and Records: 8-28-502, 8-28-502.1, 8-28-502.2, 8-28-502.3, 8-28-502.4, 8-28-503, 8-28-503.1, 8-28-503.2, and 8-28-503.3. Manual of Procedures: 8-28-602

Several sections of the rule pertaining to the standards, such as but not limited to 8-28-302, 303, and 304 have been significantly revised in the District’s non-SIP version. Likewise, sections pertaining to reporting, inspection, identification, process safety requirements, monitoring system demonstration report, and process unit identification report have also been significantly revised. Sections 8-28-502 and 503 that were not part of the SIP approved rule have been added to the District’s non-SIP version of the rule. The federal enforceability of the affected sections has been updated in/added to Tables IV-AL, AOa, and AP and Tables VII-AE, AFa, and AG to reflect their SIP status.

BAAQMD Regulation 8 "Organic Compounds",
Rule 31 "Surface Preparation and Coating of Plastic Parts and Products":

The purpose of this rule is to limit the emission of volatile organic compounds from the surface preparation and coating of plastic parts and products, including polyester resin (fiberglass) products.

All sections of this rule are federally enforceable. Therefore, the SIP version of the rule dated 12/20/95 was deleted from Table IV-CB. Certain sections of the rule, which were previously deemed non-federally enforceable were changed in the above table to reflect them as being federally enforceable in light of the SIP approved version of the District's rule which has been effective since October 16, 2002. No changes were made to Table VII-BN.

BAAQMD Regulation 8 "Organic Compounds",
Rule 40 "Aeration of Contaminated Soil and Removal of Underground Storage Tanks":

All sections of this rule, with the exception of Section 8-40-118, are federally enforceable. Section 8-40-118 was amended on June 15, 2005 and differs from its SIP counterpart in that Table 2-5-1 in District Regulation 2, Rule 5 is referenced instead of now obsolete Table 2-1-316 in District Regulation 2, Rule 1. The above change is reflected in Table IV-DV. The remaining sections in the non-SIP approved version of the rule, which has been effective since June 15, 2005 mirror their SIP approved counterparts which were published in the Federal Register on April 19, 2001. No changes were made to Table VII-CY.

Table 6 below summarizes the non-federally enforceable section of the rule.

Table 6		
BAAQMD Regulation	**Effective Date of the Rule**	**Non-Federally Enforceable Sections of the Rule (Sections either not contained in/deleted from SIP approved version of the rule)**
Regulation 8 "Organic Compounds", Rule 40 "Aeration of Contaminated Soil and Removal of Underground Storage Tanks"	June 15, 2005	General: 8-40-118

BAAQMD Regulation 9 "Inorganic Gaseous Pollutants",
Rule 8 "Nitrogen Oxides and Carbon Monoxide From Stationary Internal Combustion Engines":

The purpose of this rule is to limit emissions of nitrogen oxides and carbon monoxide from stationary internal combustion engines with an output rated by the manufacturer at more than 50 brake horsepower. BAAQMD rule sections 9-8-330, 502.1, and 530 cited in Table IV-DNa, which have been effective since June 25, 2007, are not federally enforceable. Neither are any of the above sections part of the SIP approved version of the rule that was published in the Federal Register on December 15, 1997. Therefore, in the absence of SIP approved counterparts for the above sections only the non-federally enforceable sections of the rule are cited in the above table.

Sources S-6051 through S-6060 (excluding S-6058) are “in-use” diesel engines that are solely used as a standby source of motive power for emergency standby generators that they are part of. These sources were exempt from District until May 17, 2000, when BAAQMD Regulation 2, Rule 1, General Requirements, was amended to require permits for all stationary engines over 50 hp. The requirement for permits is not federally enforceable because SIP Regulation 2, Rule 1 still has an exemption for standby engines.

Shell applied for District permits for these sources on March 29, 2002 under Application 4688. The District permits were issued on April 18, 2002.

BAAQMD Regulation 9, Rule 8, as adopted on January 20, 1993, did not apply to engines under 250-hp, liquid-fueled engines, or emergency standby engines. On August 1, 2001, the rule was amended to include hours of operation limits for emergency standby engines. On July 25, 2007, the rule was amended to include limits for non-emergency liquid fueled engines and engines under 250-hp. These new limits will be effective on January 1, 2012. Since the engines at Shell are emergency standby engines, they will only be subject to the following sections of the rule: 9-8-330, 9-8-502.1, and 9-8-530, which essentially restrict the hours of operation for standby engines. These provisions are not federally enforceable because the SIP rule is the 1993 rule.

On November 8, 2004, the California Air Resources Board (CARB or ARB) adopted an Air Toxics Control Measure (ATCM) for stationary diesel engines, which was effective on January 1, 2005. The measure restricted the hours of operation for older standby engines and required controls and/or lower emission rates for prime and new standby engines. Since the ATCM is a state standard, it is not federally enforceable.

The CARB’s ATCM applicable requirements for S-6051 through S-6060 (excluding S-6058) have been incorporated into the proposed renewal permit. In addition, applicable requirements contained in Regulation 6, Rule 1, Regulation 9, Rules 1 and 8 were also incorporated into Tables IV-DNa and VII-CTa. The engines, which were previously governed by permit condition 19097, will henceforth be subject to BAAQMD Standard Condition #22820.

It should also be noted that S-5140 and S-6058 were incorrectly described in Table II A “Permitted Sources” as a diesel engines. The above engines were gasoline engines used in emergency standby service that no longer operate at Shell. As a result, all references to the above engines have been deleted in the proposed renewal permit.

Following is a discussion of the requirements of the ATCM.
Section 93115.5 requires the use of CARB diesel or several alternatives. The owner/operator will comply by burning CARB diesel.

The operating requirements and emissions standards are contained in Section 93115.6.

The engines are not subject to Section 93115.6(a) because they are not new as defined by the ATCM.

The engines are not subject to Section 93115.6(b)(1) of the ATCM because the BAAQMD permit does not allow operation in anticipation of a rotating outage.

The engines are not subject to Section 93115.6(b)(2) of the ATCM because the engines are not located within 1000 feet of a school.

Section 93115.6(b)(3)(A) allows the owner/operator to choose 20 hours of operation for maintenance and testing, to show that the engine has particulate emissions below 0.15 g/bhp, or to control the particulate emissions of the engine by 85%. The owner/operator has chosen to operate the engines for less than 20 hours/yr for maintenance and testing. An unlimited number of hours is allowed during emergencies.

Section 93115.6(b)(3)(A)(2), which allows more hours for maintenance and testing in certain cases is not cited because the owner/operator will comply by not operating the engines for more than 20 hr/yr for maintenance and testing.

The engines are not subject to Section 93115.6(b)(3)(B) because the owner/operator is not using an emission control strategy that is not verified through CARB's Verification Procedure.

The engines are not subject to Section 93115.6(b)(3)(C) because the District has not established more stringent standards for these engines.

The engines are not subject to Section 93115.6(c) because the engines are not being used in a demand response program.

The requirements of 93115.7 are not cited because these requirements are for prime engines.

The requirements of 93115.8 are not cited because these requirements are for agricultural engines.

The requirements of 93115.9 are not cited because these requirements are for new engines under 50-hp.

The notification requirements of Section 93115.10(a) are not cited because the requirements have already been met.

The requirements of Section 93115.10(b) have not been cited because they apply only to sellers of engines.

The requirements of Section 93115.10(c)(1) have not been cited because they apply only to new engines as defined by the ATCM.

The requirements of Section 93115.10(c)(2) have not been cited because the reporting requirements have already been met.

The notification requirements of Section 93115.10(d) are not cited because the engines are not exempt from requirements pursuant to Sections 93115.3 or 93115.8(a)(2).

The engines are subject to the requirement in Section 93115.10(e)(1) to have a non-resettable hour meter.

Section 93115.10(e)(2) is not cited because the engines do not have diesel particulate filters.

Section 93115.10(e)(3) is not cited because the District has not required additional monitoring.

Section 93115.10(f) is not cited because the engines are exempted by the ATCM.

The requirement for monthly recordkeeping in Section 93115.10(g) applies to the engines.

The requirement in Section 93115.10(h) applies only to the San Diego Gas and Electric Company.

The requirement in Section 93115.10(i) applies only to engines that are used to fulfill the requirements of an Interruptible Service Contract as defined by the ATCM.

Section 93115.11 is not cited because the owner/operator has 4 or more engines.

Section 93115.12 is cited because the owner/operator has 4 or more engines. The compliance schedule in 93115.12(a) applies to the engines because the owner/operator has chosen to comply by reducing the hours of operation to 20 hr/yr.

Section 93115.12(b) is not cited because the owner/operator has chosen to comply with Section 93115.12(a).

Section 93115.13 is not cited because the owner/operator will comply by reducing the hours of operation, not by testing or installing diesel particulate filters.

Section 93115.14 is not cited because the owner/operator is not required to test the engines.

Section 93115.15, Severability, is cited because invalidation of one part of the ATCM does not invalidate the remaining parts.

Monitoring for opacity for diesel standby reciprocating engines, such as S-6051 through S-6060 (excluding S-6058), is not required in accordance with Section I.O.1 in CAPCOA/ARB/EPA Region IX Periodic Monitoring committee recommendations in the June 24, 1999 document entitled: “Periodic Monitoring Recommendations For Generally Applicable Requirements in SIP.” The reason is that sources in California burn low-sulfur, low-aromatic fuels. When the recommendations were written, California diesel contained 0.05% sulfur. Now the fuels contain 0.0015% sulfur, so particulate should be even lower.

In addition, in the Bay Area, the standard for opacity for emergency standby engines is Ringelmann 2, which is roughly equivalent to 40% opacity. It is unlikely that even an old engine would exceed 40% opacity.

Moreover, these engines operate infrequently.

For the three reasons above, no monitoring for opacity is required for these engines.

Monitoring for filterable particulate (FP) for diesel standby reciprocating engines is not required in accordance with Section II.A.1 in CAPCOA/ARB/EPA Region IX Periodic Monitoring committee recommendations in the June 24, 1999 document entitled: "CAPCOA/CARB/EPA Region IX Recommended Periodic Monitoring for Generally Applicable Grain Loading Standards in the SIP: Combustion Sources." This determination applies to engines that are operated for maintenance and testing for less than 200 hours/yr. These engines are operated for maintenance and testing for less than 20 hours/yr, so no monitoring for FP is justified.

The generally applicable FP limit in the Bay Area is 0.15 grains/dscf. It is highly unlikely that any engine could exceed this standard, especially taking the fuel's low sulfur and aromatic content into account

No monitoring is required for the 0.5% standard for S by weight in BAAQMD Regulation 9, Rule 1, because the only diesel fuel available in California has a sulfur content of 0.0015% by weight.

The CARB ATCM and BAAQMD permit condition have a limit of 20 hours/yr for maintenance and testing. The engines must have non-resettable meters for the hours of operation and the owner/operator must is required to keep monthly records. This is appropriate monitoring for the operational limit.

BAAQMD Regulation 9 "Inorganic Gaseous Pollutants",
Rule 9 "Nitrogen Oxides From Stationary Gas Turbines":

The purpose of this rule is to limit emissions of nitrogen oxides from stationary gas turbines.

The effective dates of the rules (SIP approved and non-SIP approved versions) were updated in Table IV-CV. Specifically, the SIP approved version of the rule was published in the Federal Register on December 15, 1997 and the non-SIP approved version of the rule has been effective since December 6, 2006.

Table 7 below summarizes the non-federally enforceable sections of the rule.

Table 7		
BAAQMD Regulation	**Effective Date of the Rule**	**Non-Federally Enforceable Sections of the Rule (Sections either not contained in/deleted from SIP approved version of the rule)**
Regulation 9 “Inorganic Gaseous Pollutants”, Rule 9 “Nitrogen Oxides From Stationary Gas Turbines”	**December 6, 2006**	General: 9-9-110, 9-9-111.3, 9-9-112, 9-9-113, 9-9-114, 9-9-115, 9-9-116, and 9-9-120. Definitions: 9-9-201, 9-9-202, 9-9-203, 9-9-204, 9-9-205, 9-9-206, 9-9-207, 9-9-208, 9-9-209, 9-9-210, 9-9-211, 9-9-212, 9-9-213, 9-9-214, 9-9-215, 9-9-216, 9-9-217, 9-9-218, 9-9-219, 9-9-220, and 9-9-221. Standards: 9-9-301, 9-9-301.1, 9-9-301.1.1, 9-9-301.1.2, 9-9-301.1.3, 9-9-301.2, 9-9-301.3, 9-9-301.4, 9-9-302, 9-9-302.1, 9-9-302.2, 9-9-303, 9-9-304, and 9-9-305. Administrative Requirements: 9-9-401, 9-9-402, 9-9-402.1, 9-9-402.2, 9-9-403, 9-9-404, 9-9-404.1, 9-9-404.2, 9-9-404.3, 9-9-404.4, 9-9-405, and 9-9-406. Monitoring and Records: 9-9-501, 9-9-502, 9-9-503, and 9-9-504. Manual of Procedures: 9-9-601, 9-9-603, 9-9-604, and 9-9-605.

Most sections in the District’s non-SIP approved version of the rule have been significantly revised from their SIP approved counterparts. The federal enforceability of the affected sections was updated in Table’s IV-CV and VII-CG pertaining to Gas Turbines (S-4190 and S-4192) to reflect their SIP status.

Natural gas is exclusively combusted at the gas turbines and the capacity of each turbine is limited to 13,152 MMBTU/day (~548 MMBTU/hr) by permit condition 18618. Effective January 1, 2010 and in accordance with Section 9-9-301.2, NOx emissions (corrected to 15% O2, dry basis) for each of Shell’s two gas turbines (S-4190 and S-4192) is limited to 5 ppmv or 0.15 lbs/MWhr averaged over a 1-hour period. The above NOx emission limit replaced the 9 ppmv (corrected to 15% O2, dry basis) limit in Regulation 9-9-301.1.3. Therefore, Regulation’s 9-9-

301.1.3 and 9-9-401 were deleted from Table IV-CV, and the new NOx limit was also incorporated into Table VII-CG.

Applicable requirements of the rule that were previously contained in Table IV-CW for the Supplemental Steam Generators (S-4191 and S-4193), which are downstream of Gas Turbines, were deleted because the duct burners at the Supplemental Steam Generators are not subject to Regulation 9, Rule 9. The above rationale has been consistently applied to duct burners at Supplemental Steam Generators located downstream of combined cycle gas turbines at power plants in the District's jurisdiction. It is likely that the District erred in including the applicable requirements of the above rule for S-4191 & S-4193 when issuing Shell their initial permit.

Deleting Regulation 9, Rule 9 applicable requirements does not absolve the Supplemental Steam Generators at Shell from complying with the above rule. This is so because each cogeneration unit (cogen) consists of a Gas Turbine and a Supplemental Steam Generator. There are two such cogen pairs at Shell i.e. S-4190 & S-4191, and S-4192 & S-4193. Combined NOx emissions from each cogen pair exhaust through a dedicated stack that is equipped with NOx, SO2, and O2 CEMs, and the NOx emissions from each cogen pair is limited to 5 ppmv, dry, corrected to 15% oxygen, averaged over 3 hours by part 24.c of permit condition 12271. Therefore, though not explicitly subject to the requirements in Regulation 9, Rule 9, Shell would still have to demonstrate ongoing compliance with the most stringent emission limitations and requirements for the Gas Turbines in the above rule for the combined emissions emanating from each cogen pair per Regulation 1-107 which states the follows:

"1-107 Combination of Emissions: Where air contaminants from two or more sources are combined prior to emission and there are no adequate and reliable means to establish the nature, extent and quantity of emission from each source, District Regulations shall be applied to the combined emission as if it originated in a single source. Such emissions shall be subject to the most stringent limitations and requirements of District Regulations applicable to any of the sources whose air contaminants are so combined."

In other words, the combined NOx emissions from each cogen pair per Regulation 1-107 cannot exceed 5 ppmv in any rolling 1-hour and/or 3-hour averaging period.

BAAQMD Regulation 9 "Inorganic Gaseous Pollutants", Rule 10 "Nitrogen Oxides and Carbon Monoxide From Boilers, Steam Generators and Process Heaters in Petroleum Refineries":

This rule limits the emissions of nitrogen oxides and carbon monoxide from boilers, steam generators, and process heaters in petroleum refineries.

The effective dates of the rules (SIP approved and non-SIP approved versions) is reflected in Tables IV-AZ, AZb, BA, BD, BG, BK, BL, BZ, CS, and CU. Specifically, the SIP approved version of the rule was published in the Federal Register on March 29, 2001 and the non-SIP approved version of the rule has been effective since July 17, 2002.

Table 8 below summarizes the non-federally enforceable sections of the rule.

Table 8		
BAAQMD Regulation	**Effective Date of the Rule**	**Non-Federally Enforceable Sections of the Rule (Sections either not contained in/deleted from SIP approved version of the rule)**
Regulation 9 "Inorganic Gaseous Pollutants", Rule 10 "Nitrogen Oxides and Carbon Monoxide From Boilers, Steam Generators and Process Heaters in Petroleum Refineries"	July 17, 2002	<u>General:</u> 9-10-111 and 9-10-112. <u>Standards:</u> 9-10-301, 9-10-301.1, 9-10-301.2, 9-10-301.3, 9-10-303, 9-10-304, 9-10-304.1, 9-10-304.2, 9-10-305, and 9-10-306.3 (missing from SIP posted on EPA Region 9 website). <u>Administrative Requirements:</u> 9-10-401, 9-10-401.1, 9-10-401.1.1, 9-10-401.1.2, 9-10-401.1.3, 9-10-401.1.4, 9-10-401.1.5, 9-10-401.2, 9-10-402.1.2, and 9-10-403. <u>Monitoring and Records:</u> 9-10-501, 9-10-501.1, 9-10-501.2, 9-10-502, 9-10-502.1, 9-10-504, 9-10-504.1, 9-10-504.1.1, 9-10-504.1.2, 9-10-504.1.3, 9-10-504.1.3, 9-10-504.1.4, 9-10-504.1.5, 9-10-504.1.6, 9-10-504.1.7, 9-10-504.2, 9-10-505, 9-10-505.1, 9-10-505.2, 9-10-505.2.1, and 9-10-505.2.2. <u>Manual of Procedures:</u> 9-10-601 and 9-10-602.

Most sections in the District's non-SIP approved version of the rule have been significantly revised from their SIP approved counterparts. The federal enforceability of the affected sections has been updated in Tables IV-AZ, AZb, BA, BD, BG, BK, BL, BZ, CS, & CU and Tables VII-AQ, AQb, AR, AT, AU, AX, BA, BB, BL, CB & CE to reflect their SIP status.

The record keeping requirements prescribed under Section 9-10-504.2 are for "small units" subject to Section 9-10-306.2. Section 9-10-217 defines a "small unit" as any refinery boiler, steam generator, or process heater with a rated heat input less than 10 million BTU/hour but greater than or equal to 1 million BTU/hour that has the capability of firing any fuel other than natural gas or liquefied petroleum gas. None of the sources contained in Tables IV-AZ, AZb, BA, BD, BG, BK, BL, BZ, CS, & CU meet the above definition. Therefore, references to Section 9-

10-504.2 and in Tables VII-AQ, AQb, AR, AT, AU, AX, BA, BB, BL, CB & CE were deleted and replaced with Section 9-10-504.1.

Sources contained in the above tables, with the exception of Table IV-BK and VII-BA, are governed by permit condition 18265 for refinery-wide compliance with Regulation 9, Rule 10. The "Future Effective Date" of "January 1, 2005" in the last column of Tables IV-AZ, AZb, BA, BD, BG, BL, BZ, CS, & CU corresponding to parts 1, 3, 4, 5, 6, 7, 8, 9, 10, and 11 was deleted because the date has passed and is no longer valid. Likewise, the "Future Effective Date" of September 1, 2004 corresponding to part 2 of permit condition 18265 in the above tables has passed and is no longer valid. Parts 17, 18, 19, and 21 of permit condition 18265 were deleted from the above tables because a "sunset date" of "Until January 1, 2005" referenced in the above parts of the permit condition has passed and is no longer valid.

Sources S-1480, S-1481, S-1483, S-1506, and S-4021 are not equipped with NOx CEMs. Because S-1480, S-1481, S-1483, & S-1506 are rated at less than 25 MMBTU/hr, compliance with the NOx emission factors outlined for the above sources in part 5.A of permit condition 18265 is verified via annual source tests. In contrast, S-4021 is operated within the confines of a NOx Box to demonstrate compliance with the non-federal NOx limit of 0.033 lbs/MMBTU in Section 9-10-301. In light of the above, only certain parts of permit condition 18265 apply to a given source depending on whether it is or is not equipped with NOx CEMs. Specifically, parts 1 through 7, 9, 10, 12 through 15, and 20 of permit condition 18265 pertain to sources complying with emission factors/ranges established in the NOx Box.Please refer to Tables IV-AZ & CS and Tables VII-AQ & CB. In contrast, sources equipped with NOx CEMs are subject to parts 1, 2, 8, 10, 11, 13 through 15, and 20. Please refer to Tables IV- AZb, BA, BD, BG, BL, & CU and Tables VII-AQb, AR, AT, AU, AX, BB, & CE. In addition to being subject to the afore-referenced parts for sources equipped with NOx CEMs, source S-1800 is also subject to part 16. Please refer to Table IV-BZ and VII-BL.

Applicable requirements for the three CO Boilers (S-1507, S-1509, and S-1512) are contained in Table IV-BK, and the Applicable Limits & Compliance Monitoring Requirements are in Table VII-BA. Though the CO Boilers (COBs) are subject to Regulation 9, Rule 10, they differ from non-COB units subject to the above rule in that they are not subject to either the 0.033 lbs/MMBTU (non-federal) and/or the 0.20 lbs/MMBTU (federal) refinery-wide NOx emission rate in Sections 9-10-301 and 303. Instead, the COBs are subject to the NOx and CO limits outlined in 9-10-303.1, 304 and 305. Therefore, the COBs are not subject to permit condition 18265, which is intended to ensure refinery-wide compliance with the non-federal NOx limit for non-COB sources subject to Regulation 9, Rule 10.

BAAQMD Regulation 11 "Hazardous Pollutants",
Rule 10 "Hexavalent Chromium Emissions from Cooling Towers":

The purpose of this rule is to reduce emissions of hexavalent chromium from cooling water towers (CWTs) by eliminating chromium based circulating water treatment programs.

Shell does not use hexavalent chromium in its CWTs: S-1457, S-1778, and S-4210. Therefore, a reference to Regulation 11, Rule 10 in Table III "Generally Applicable Requirements" was deleted. Applicable Requirements for Shell's CWTs are contained in Table's IV-AS & CY and the Applicable Limits & Compliance Monitoring Requirements are contained in Table VII-AJ.

BAAQMD Regulation 12 "Miscellaneous Standards of Performance", Rule 11 "Flare Monitoring at Petroleum Refineries"and Rule 12 "Flares at Petroleum Refineries":

The purpose of Rule 11 is to require monitoring and recording of emission data for flares at petroleum refineries. Rule 12 is geared toward reducing the emissions from flares at petroleum refineries by minimizing the frequency and magnitude of flaring. Though Shell's five process flares (S-1471, S-1472, S-1771, S-1772, and S-4201) are subject to the above rules, the flexigas flare (S-1771) is exempt from the total hydrocarbon and methane composition monitoring and reporting requirements per Section 12-11-114 in Regulation 12, Rule 11, which states the following:

"Limited Exemption, Total Hydrocarbon and Methane Composition Monitoring and Reporting: The provisions of Sections 12-11-401.2, 401.3, 401.5, 502.2 and 502.3 that require monitoring and reporting of total hydrocarbon and methane composition shall not apply to a flare that exclusively burns flexicoker gas with or without supplemental natural gas, provided that the owner or operator demonstrates by weekly sampling and analysis, verified by the APCO, that the methane content and the non-methane content of the vent gas flared are less than 2 percent and 1 percent by volume, respectively."

The flexigas flare qualifies for the above exemption because the composition of flexigas generated at the Flexicoker (S-1759), excess quantities of which are flared at S-1771, is less than 2% methane and less than 1% non-methane. Therefore, references to Section 12-11-502.3 in Tables IV-BW and VII-BI pertaining to S-1771 were deleted. In contrast, Table's IV-AXc & VII-AOb (for S-1471 & S-1472), IV-BX & VII-BJ (for S-1772), IV-CX & VII-CI (for S-4201) contain Section 12-11-502.3 as an applicable requirement.

Changes to the renewal permit stemming from Federal regulations:

The following paragraphs discuss sections of certain federal regulations that were either not applicable to sources at Shell when they were issued their initial permit on December 1, 2003, or are currently applicable to sources at the refinery. In light of the above, sections of federal regulations that are no longer applicable have been deleted from either Table IV "Source-Specific Applicable Requirements" and/or from Table VII "Applicable Limits & Compliance Monitoring Requirements" for either a source or for a group of sources. Likewise, sections of federal regulations that previously either did not apply and/or were not included in the initial permit as applicable requirements have now been included in both Tables IV and VII for either an affected source or for a group of sources.

40 CFR Part 60 "Standards of Performance for New Stationary Sources", Subpart A "General Provisions" (NSPS A) 40 CFR 60.11 "Compliance with Standards and Maintenance Requirements":

Emissions from the Fluid Catalytic Cracking Unit (S-1426) at Shell are abated by three CO boilers (S-1507, S-1509, and S-1512), which are downstream of it. Each CO boiler stack is equipped with a dedicated opacity CEM. Because S-1426 is subject to the opacity and non-opacity related standards in NSPS J (which is discussed later in this document), sections 60.11(a) through (g) were added as applicable requirements under Table IV-AP in the proposed renewal permit.

40 CFR 60, Subpart Db (NSPS Db)

"Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units": NSPS Db applies to each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 MMBtu/hr).

NSPS Db was amended on June 13, 2007. The amendment did not impact any of the applicable requirements for the above rule cited in Table IV-CW for the duct burners at the Supplemental Steam Generators (S-4191 and S-4193). As a result, the old rule date of March 13, 2000 was replaced with the June 13, 2007 amendment date in the above table.

40 CFR 60, Subpart J (NSPS J) "Standards of Performance for Petroleum Refineries":

Provisions of NSPS J apply to the following three source categories at petroleum refineries:

- Fluid catalytic cracking unit regenerators or fuel gas combustion devices (excluding flares), which were constructed, reconstructed or modified after June 11, 1973 and on/before May 14, 2007.
- Fuel gas combustion devices (flares), which were constructed, reconstructed or modified after June 11, 1973 and on/before June 24, 2008.
- Claus sulfur recovery plants, which were constructed, reconstructed or modified after October 4, 1976 and on/before May 14, 2007.

Three CO boilers S-1507, S-1509, and S-1512 (~waste heat boilers) abate emissions from Shell's fluid catalytic cracking unit regenerator (S-1426). Therefore, S-1426 is subject to, among other requirements, sections 60.102(a)(1), (a)(2), and (b) for PM, and section 60.103 for CO, respectively. Because the unit is not equipped with an add-on control device to abate SO2 emissions it is only subject to sections 60.104(b)(2) and (c) for sulfur oxides. Please refer to Table IV-AP.

Section 60.104(a)(1) limits emissions of sulfur oxides from any fuel gas combustion device (including flares) by limiting the H2S content in the gases burnt in them to not exceed 0.10 gr/dscf (162 ppmv on a 3-hour rolling average). Aside from the reactions that occur in the reactor and regeneration sections of the fluid catalytic cracking unit, no fuel is burnt at the unit. Instead fuel is burnt at the heaters (for S-1510 and S-1511) serving the unit. Therefore, section 60.104(a)(1) is not cited under Table IV-AP and is instead cited under Table IV-BA for the FCCU's heaters. In addition to the above, the above section is also cited as an applicable requirement in Tables IV-AW, AXa, AXb, AXc, AZ, AZb, BD, BG, BK, BL, BW, BX, BZ, CF, CS, CU, CV, CW, and CX.

Shell operates four Claus sulfur recovery plants (S-1431, S-1432, S-1765, and S-4180). Each of the above plants consists of an oxidation control system followed by incineration. Therefore, section 60.104(a)(2)(i) limits the sulfur dioxide emissions at each of the four Claus sulfur recovery plants to not exceed 250 ppmv (dry basis) at zero percent excess air. The above section is cited as an applicable requirement in Table IV-AQ.

References to sections 60.105 and 105(e)(3) that were incorrectly cited under NSPS A in Table IV-BG were deleted. In addition, redundant references to sections 60.105(a)(4), 106, and 106(e) under NSPS J in the above table were also deleted.

Following is a discussion on sources at Shell that will demonstrate compliance with NSPS J standards/requirements via EPA approved Alternative Monitoring Plans (AMPs):

- Sources S-4002, S-4003, and S-4141 will comply with the 162 ppmv H2S limit in 40 CFR 60.104(a)(1) using an AMP that was approved by the EPA on December 4, 2002. Please refer to Tables IV-BD & VII-AU (for S-4141), Tables IV-BG & VII-AX (for S-4002 & S-4003), and permit condition 24336.
- Shell will comply with the H2S limit in 40 CFR 60.104(a)(1) for PSA gas burnt at S-4161 using an AMP that was approved by the EPA on September 27, 1995. Please refer to Tables IV-CU, VII-CE, and permit condition 24339.
- The Catalytic Cracking Unit (S-1426) at Shell is not equipped with an add-on control device to abate SO2 emissions. Therefore, it is subject to the SOx limit calculated as SO2 of 20 lbs/ton coke burn-off in 40 CFR 60.104(b)(2). Shell will demonstrate compliance with the above SOx limit for S-1426 using an AMP that was approved by the EPA section on August 23, 2004. Please refer to Tables IV-AP, VII-AG, and permit condition 24335.
- 40 CFR 60.104(a)(2)(i) limits the sulfur dioxide emissions at S-4180 to not exceed 250 ppmv (dry basis) at zero percent excess air. To demonstrate compliance with the NSPS J SO2 limit, section 60.105(a)(5) requires the use of a SO2 and O2 CEMs. The span values for the SO2 and O2 CEMs are required by section 60.105(a)(5)(i) to be 500 ppm SO2 and 25 percent O2, respectively. Shell will comply with the requirement in the above section using an AMP that was approved by EPA on August 27, 2003 that would allow the SO2 CEMs to be spanned at 250 ppm and 2,500 ppm. Please refer to Tables IV-DF, VII-AH, and permit condition 24338.

In light of the above discussion, the alternative monitoring requirements in 40 CFR 60.13(i) is cited under Tables IV- AP, BD, BG, CU, and DF. In addition, Tables IV-AW (for S-1470), BX (for S-1772), CF (for S-2001, S-2002, S-2003, & S-2004), and CS (for S-4021) also reference 40

CFR 60.13(i). Shell's AMP to demonstrate compliance with the 162 ppmv H2S limit in 40 CFR 60.104(a)(1) for S-1470 is pending EPA approval. Please refer to permit condition 24337. Parts 12 through 14 of permit condition 4288 contain the AMP requirements to demonstrate compliance with the 162 ppmv H2S limit in 40 CFR 60.104(a)(1) for S-2001, S-2002, S-2003, & S-2004.

NSPS A and J applicable requirements relating to Shell's five process flares (S-1471, S-1472, S-1771, S-1772, and S-4201) are contained in Tables IV-AXc (for S-1471 & S-1472), BW (for S-1771), BX (for S-1772), and CX (for S-4201). The above tables were amended to make the applicable requirements pertaining to the five process flares consistent in the proposed renewal permit.

Sources S-1480, S-1481, and S-1506 do not use AMPs to comply with NSPS A and/or J. Therefore, Tables IV-AZa and VII-AQa were deleted. Applicable requirements in the above rules for the above sources are correctly referenced in Tables IV-AZ and VII-AQ.

Flares A-101 & A-102 (in Table IV-AXa), A-103 (in Table IV-AXb), S-1471 & S-1472 (in Table IV-AXc), S-1771 (in Table IV-BW), S-1772 (in Table IV-BX), and S-4201 (in Table IV-CX) were incorrectly shielded from section 60.104(a)(1) in Table's IXA-12 & 13. Because the 162 ppm limit in NSPS J applies to all flares, the above permit shield tables were deleted in the proposed renewal permit.

40 CFR 60, Subpart Kb
(NSPS Kb)
"Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984":

NSPS Kb applies to each storage vessel with a capacity greater than or equal to 75 m^3 (~19,803 gallons) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984.

Sections 60.110b(a) and (b) in NSPS Kb which were amended on October 15, 2003 state the following:

"(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa."

Per information contained in Table II-A "Permitted Sources", the storage capacity of tanks S-4307 and S-4309 are 6,200 gallons and 17,000 gallons, respectively, and the true vapor pressure of their tank contents are less than 3.5 kPa (~0.5 psia). Prior to the 60.110b(b) exemption, the tanks were previously subject to NSPS Kb in the initial permit, , because they were constructed as part of Shell's Clean Fuels Project on/after July 23, 1984. In light of the above exemption and because there are no substantive differences in the applicable requirements contained in Tables IV-Ca (for S-4307) and Cb (for S-4309), applicable requirements contained in the above tables were consolidated into Table IV-Ca (for S-4307 & S-4309), and Table IV-Cb was deleted from the proposed renewal permit. Because NSPS Kb is no longer applicable to S-4307 and S-4309, references to the above rule and the reporting requirements in sections 60.116b(a) and (b) were deleted from Table IV-Ca in the proposed renewal permit. . The storage tank provisions in 40 CFR 63.646 of MACT CC only applies to Group 1 tanks (vapor pressure > 3.5 kPa). Therefore, S-4307 and S-4309, which are Group 2 tanks (< 3.5 kPa) under MACT CC, are only subject to the reporting recordkeeping requirements in 40 CFR 63.655(i)(1)(iv) and 63.655(i)(5) of the above rule.

Back in 1995 during their Clean Fuels Project, Shell had proposed to modify S-13. The proposed modifications would have subjected S-13 to NSPS Kb. However, the scope of the project to make the required modifications was canceled and the changes that would have triggered the NSPS Kb applicability were never made. As a result, the NSPS Kb applicable requirements contained in the initial permit for S-13 are no longer applicable. Therefore, S-13 was deleted from Tables IV-AEc and VII-X in the proposed renewal permit. Because S-13 meets the NSPS Ka requirements and is also equipped with vapor recovery, the applicable requirements for S-13 are contained in Tables IV-Ec and VII-Dc of the proposed renewal permit instead.

Permit condition 7215 under Table's IV-AEb (for S-1805) & AEc (for S-4334) does not pertain to either of the above tanks. Instead, the above permit condition governs the operation of spent acid tanks S-1114 and S-1115 (in Table IV-AEa). In light of the above, parts 1 through 3 of permit condition 7215 were deleted from Table's IV-AEb & AEc in the proposed renewal permit.

40 CFR 60, Subpart GG
(NSPS GG)
"Standards of Performance for Stationary Gas Turbines":

The provisions of NSPS GG are applicable to all stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBTU/hr), based on the lower heating value of the fuel fired, which were constructed, modified, or reconstructed after October 3, 1977.

NSPS GG was amended on February 24, 2006. Therefore, the old rule date of January 27, 1982 was replaced with the February 24, 2006 amendment date in Table IV-CV. The applicable NOx standards in section 60.332, for the two gas turbines at Shell that use steam injection for NOx control, were not incorporated into the above table for the following reasons:

As previously discussed under "BAAQMD Regulation 9, Rule 9", natural gas is exclusively combusted at the gas turbines (S-4190 and S-4192) and the capacity of each turbine is limited to 13,152 MMBTU/day (~548 MMBTU/hr) by permit condition 18618. The gas turbines use steam injection for NOx control. Since the combined emissions from each cogen pair S-4190 & S-4191 and S-4192 & S-4193 exhaust through a dedicated stack that is equipped with NOx , SO2, and O2 CEMs, the above sources are subject to the most stringent emission NOx limit in the above rules. Specifically, the duct burners at the Supplemental Steam Generators (S-4191 and S-4193), which are downstream of gas turbines, are not subject to NSPS GG. Instead, the duct burners are subject to NSPS Db. In a letter to the company dated September 30, 1997 and instead of individually demonstrating compliance with the NOx standards in NSPS GG (for the gas turbines) and NSPS Db (for the duct burners at the supplemental steam generators), the District allowed Shell to collectively demonstrate compliance of each cogen pair with the more stringent NOx standard of 0.20 lb/MMBTU in NSPS Db.

The following emission calculations are intended to demonstrate that excluding the section 60.332 NOx standards in NSPS GG from Table IV-CV will not impact the ability of the turbines and/or the cogens from complying with the above rule:

Section 60.332(a)(1) in 40 CFR 60, Subpart GG prescribes the following equation to compute the permissible NOx emissions levels from combined cycle gas turbines, such as sources S-4190 and S-4192:

$$STD = 0.0075\frac{(14.4)}{Y} + F$$

Where:

STD = allowable ISO corrected (if required as given in § 60.335(b)(1)) NOx emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NOx emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

As an example, consider S-4190. The maximum heat input rate for S-4190 is 548 MMBTU/hr and each cogen pair is capable of generating 49 MW. Please refer to Table IX A-15. Since the steam produced by the supplemental steam generators is more valuable to the refinery than the electricity they can generate, it is assumed the turbines generate all the electricity. In light of the above and in order to determine “Y”, the combined maximum heat input rate of the turbine in “MMBTU/hr” is converted to “kJ/watt-hr” as follows:

= (548 MMBTU/hr) x (10E6 BTU/MMBTU) x (1054.2 J/BTU) x (kJ/1000J) x (1/49 MW) x (1 MW/10E6 watts)
= 11.79 kJ/watt-hr

Since S-4190 exclusively combusts natural gas, it is assumed that the percent weight of fuel-bound nitrogen in natural gas is < 0.015%. Per guidance in paragraph (a)(4) of Section 60.332, the value of “F” is equal to zero when the percent weight of fuel-bound nitrogen is < 0.015%.

Substituting the values of “Y” and “F” in the above equation,
STD = 0.0092% by volume; 92 ppmv @ 15% O2, dry basis; 326 ppmv @ 0% oxygen, dry basis

The following calculation is intended to convert the NSPS Db NOx mass emission rate standard of 0.20 lb/MMBTU in 60.44b(a) to a concentration value in order to compare it with the NSPS GG NOx concentration derived in the preceding paragraph. The duct burners at the supplemental steam generators (S-4191 and S-4193) burn refinery make gas and the dry flue gas factor for the above fuel i.e. it is the ratio of the volume of the dry flue gas to the heating value of the fuel that

is used to produce the flue gas, is assumed to be 8,650 dscf/MMBTU (as opposed to 8,710 dscf/MMBTU for natural gas).
= (0.20 lb NOx/MMBTU x 379.4 scf NOx/lb-mole NOx)/(8,650 scf flue gas/MMBTU x 46 lb NOx/lb-mole NOx)
= 191 ppmv @ 0% oxygen, dry basis.

It can be seen from the above calculations that the cogens are subject to a more stringent NOx concentration limit in NSPS Db (191 ppmv) in comparison to NSPS GG (326 ppmv).

Because the fuel combusted in the gas turbines meets the definition of natural gas in section 60.331(u), Shell elected to not monitor the total sulfur content of the fuel per section 60.334(h)(3). To recap, the cogens comply with the NOx and PM/opacity standards in NSPS Db, and the SO2 standards in NSPS GG.

40 CFR 60, Subpart QQQ (NSPS QQQ)
"Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems"

Shell operates two effluent treatment plants (ETPs). The following table summarizes sources and abatement devices that are part of primary and secondary wastewater treatment units at Shell:

Treatment system	ETP #	Source #	Abatement device #			References in proposed renewal permit
			Water scrubber	Carbon Adsorber	None	
Primary	1	1469	1401	1402		Table IV-AT, Permit condition 5077, Table VII-AK
			1469	1473		
			1470	1474		
			1471	1475		
			1472	1476		
			20090	20120		
		2007	2007	2008		Table IV-CH, Table VII-BSb
			2017	2020		
		2008	2009	2012		
			2017	2020		
	2	5115 & 5116		5115 & 5116		Table IV-CG, Permit condition 11313, Table VII-BSa
	1 & 2	12490 & 12491			X	Table IV-AC, Permit condition 8502, Table VII-W, Table IX B-3
Secondary	1	1063[1] 1067			X	Table IV-Y, Permit condition 7618, Table VII-T, Table IX B-1

[1] S-1063 is a recovered oil tank.

Treatment system	ETP #	Source #	Abatement device #			References in proposed renewal permit
			Water scrubber	Carbon Adsorber	None	
	1 & 2	1467, 5117, 5118, 5119,	[redacted]		X	Table IV-DZ Table VII-DE
	2	1468 & 1466	[redacted]		X	Table IV-EA Table VII-DF
	1 & 2	2014	[redacted]		X	

It can be seen from the above table that the sources that make up the primary wastewater treatment units are S-1469, S-2007, & S-2008 (at ETP 1), S-5115 & S-5116 (at ETP 2), and S-12490 & S-12491 (common to both ETPs 1 & 2). Wastewater treatment units that make up the secondary system are S-1067 & S-1467 (at ETP 1), S-5117, S-5118, & S-5119 (at ETP 2), and S-2014 (common to both ETPs 1 & 2). Because wastewater to the LOG Wastewater Ponds #6 (S-1468) and #8 (S-1466) at ETP 2 can be routed to them from either upstream or downstream of the DNFs (S-5115 and S-5116), the ponds could be part of either the primary or the secondary treatment system. If the ponds are used upstream of the DNFs, it is during a storm water diversion. Therefore, per Regulation 8-8-114, the ponds are exempt from the requirements of Sections 8-8-301, 302, and 307. As is the case with S-2014, ponds #6 (S-1468) and #8 (S-1466) normally store water at the end of the wastewater treatment process. Therefore, per Regulation 8-8-113, the ponds (S-1466, S-1468, and S-2014) are exempt from the requirements of Sections 8-8-301, 302, 306, and 308.

Applicable requirements for the primary wastewater treatment units can be found in Table IV-AT (for S-1469), Table IV-CH (for S-2007 & S-2008), Table IV-CG (for S-5115 & S-5116), and Table IV-AC (for S-12490 & S-12491). Likewise, Table IV-Y (for S-1067), Table IV-DZ (for S-1467, S-5117, S-5118, and S-5119), and Table IV-EA (for S-1466, S-1468, & S-2014) contain the applicable requirements for the secondary wastewater treatment units.

Though the applicability of NSPS QQQ is not explicitly cited in any of the above tables, the applicability of the above rule as it relates to fugitive sources is discussed under Table's IV-EB and EC. Also, the applicable requirements in the above rule pertaining to individual drain systems at affected units cited in the above tables is summarized under Table IV-DQ.

<u>Slop Oil Tanks:</u>
Fixed roof tanks S-4319, S-4350, & S-4356, and external floating roof tanks S-12490 & S-12491 are the process wastewater/slop oil tanks at Shell. Applicable requirements for the above tanks are summarized under Tables IV-DG (for the fixed roof tanks) and IV-AC (for the external floating roof tanks).

40 CFR Section 60.692-3(d) under 40 CFR Section 60.692-3 "Standards: Oil-water separators" in NSPS QQQ states:

> "Storage vessels, including slop oil tanks and other auxiliary tanks that are subject to the standards in §§60.112, 60.112a, and 60.112b and associated requirements, 40 CFR part 60, subparts K, Ka, or Kb are not subject to the requirements of this section."

In light of the above and because S-4319, S-4350, S-4356, S-12490, & S-12491 are subject to NSPS Subpart Kb, the process wastewater/slop oil tanks at Shell are not subject to the requirements of Section 60.692-3. Given that there is no other applicable requirements for slop oil tanks in NSPS QQQ it is reasonable to assume that the above rule does not apply to them. Source S-1063, which was built in 1962 and has not been modified since, is not subject to NSPS QQQ because the tank requirements in the above rule only applies to tanks used as oil water separators which were either built, modified or reconstructed after May 1987.

40 CFR 61, Subpart FF
(NESHAP FF)
"National Emission Standard for Benzene Waste Operations":

The provisions of this subpart apply to owners and operators of petroleum refineries that treat, store, or dispose of benzene-containing hazardous wastes. NESHAP FF requires that when the total annual benzene quantity from the facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), the facility must manage and treat both aqueous and non-aqueous waste streams in accordance with the requirements of Section 61.342(c). As an alternative to complying with the requirements of Section 61.342(c), NESHAP FF allows facilities to manage and treat the facility waste pursuant to the requirements in Section 61.342(e), which Shell elected. Under Section 61.342(e), Shell must manage and treat the non-aqueous and aqueous waste per the requirements in Sections 61.342(e)(1) and 61.342(e)(2), respectively.

There are no non-aqueous benzene waste streams at the facility at the present time. However, Section 61.342(e)(1) is included as an applicable requirement in Table IV-DV in the event the facility commences to manage and treat non-aqueous benzene waste streams after the permit is renewed.

To comply with the requirements in Section 61.342(e)(2), Shell uses the "6BQ" compliance option to manage aqueous waste streams (or wastes that become aqueous during management). Aqueous streams with higher benzene content are managed in controlled systems, whereas those with lower benzene content are managed in "uncontrolled" systems in such a way that ensures that their total benzene emissions are below 6 Mg/yr. In accordance with Section 61.355(k)(1), aqueous wastes at ETP-1 (sewers, oil water separators, DNFs) that are not managed in controlled waste management units are counted toward the 6 Mg/yr limit at the point of generation. This means that any benzene that enters ETP-1 is counted toward the 6 Mg/yr limit at the point the waste is generated. For example, if a benzene-containing waste is sent to an ETP-1 sewer during a maintenance activity (e.g. pump maintenance), the benzene in the benzene-containing waste is counted toward the 6 Mg/yr limit.

In contrast, Shell operates ETP-2 (hard piping, tanks, and DNFs) as a controlled system. Accordingly, any benzene-containing waste sent to ETP-2 is not included toward the 6 Mg/yr limit, and all equipment associated with ETP-2 is operated in compliance with the appropriate control standards outlined in Sections 61.343 through 61.348. Therefore, the DNFs (S-5115 & S-5116) at ETP-2 are controlled and the storage tanks comply with the standards for “Tanks” outlined in Section 61.343. Section 61.343 requires, among other things, that the facility conduct annual instrument inspections and quarterly visual inspections at ETP-2 tanks, and that the vapors from ETP-2 tanks be routed to a closed vent system and control device that complies with the requirements in Section 61.349.

In order to comply with the control device requirements in Section 61.349, a facility can choose either an enclosed combustion device (vapor incinerator, boiler, or process heater), a vapor recovery system (carbon adsorption system, or condenser), a flare, or a control device that meets the requirements outlined in 61.349(a)(2)(iv). Section 61.349(h) requires the owner/operator of the above control devices to monitor them in accordance with Section 61.354(c). However, Section 61.354(c)(7), which addresses carbon adsorption systems, only addresses such systems that regenerate the carbon bed directly in the control device (carbon canisters). Because the carbon adsorption systems (A-5115 & A-5116), which abate the DNFs at ETP-2 don’t regenerate the carbon bed directly on site in the control device (carbon canisters), the facility must monitor either the concentration level of the organic compounds or the concentration level of benzene in exhaust vent stream from the carbon adsorption system for breakthrough in accordance with the requirements in Section 61.354(d).

As previously discussed, the facility manages ETP-1 as an uncontrolled system. Therefore, the standards for “Tanks” outlined in Section 61.343 are not applicable to the tanks at ETP-1. Further, ETP-1 is not subject to the control device requirements in Section 61.349. NESHAP FF does not explicitly state nor does it require the facility to either install a control device and/or monitor the control device for carbon breakthrough. Therefore, the monitoring requirements in Section 61.354(d) are not applicable to the carbon adsorption vessels (A-2008 & A-2012) abating the DNF’s (S-2007 & S-2008) at ETP-1.

In light of the above, some changes were made to the “Operating Parameters” and “Limit or Efficiency” columns in Table II B corresponding to A-1805, A-2017, and A-2020. Specifically, in addition to receiving DNF float solids from “uncontrolled” DNF units (S-2007 & S-2008) at ETP-1, S-1805 also receives DNF float solids from “controlled” DNF units (S-5115 & S-5116) at ETP-2. Emissions from S-1805 are abated by A-1805. The initial permit had no column entry under “Operating Parameters” for A-1805. Rather than leave it blank, “None” has been entered under the column instead. In contrast, DNF units (S-2007 & S-2008) at ETP-1 are 6BQ related because they are “uncontrolled”. As a result, A-2017 and A-2020 that are downstream of S-2007 and S-2008 are also “uncontrolled”. The initial permit did not contain any entries under

"Operating Parameters" (for A-2017 and A-2020) and "Limit or Efficiency" (for A-2017). Rather than leave it blank, "None" has been entered under the columns instead.

40 CFR 63, Subpart CC
(MACT CC)
"National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries":

MACT CC was amended on June 30, 2010. Therefore, the old rule date of August 8, 1995 was replaced with the June 30, 2010 amendment date and/or was added to Tables Tables IV-A, Ca, Ha, I, Ja, Jb, Jc, M, Y, AC, AK, CG, CZ, DG, DR, DS, DT, DU, DV, DY, and EA.

Reporting and recordkeeping requirements for storage vessels in the pre-June 30, 2010 version of the rule used to be cited under 40 CFR 63.654(i). As it currently exists, 40 CFR 63.654 in the amended rule pertains to heat exchange systems and only goes up to 63.654(g)(4)(ii). The reporting and recordkeeping requirements were renumbered to 40 CFR 63.655 in the amended rule, and the pertinent requirements for storage vessels are cited under 40 CFR 63.655(i). In light of the above and where applicable, references to 63.654 was replaced with 63.655 in Tables IV-Ja & Jc (for Group 1 storage vessels) and IV-A, Ca, Ha, I, Jb, & DY (for Group 2 storage vessels). With the exception of tanks listed under Table IV-Jc and because the Group 1 and 2 storage vessels listed in Tables IV-A, Ca, Ha, I, Ja, Jb, & DY were constructed prior to June 11, 1973 (NSPS K applicability date), and have not been modified since (per the NSPS definition of modification), no additional NSPS rules are cited under the above tables.

For example, consider S-4307 and S-4309, which were previously discussed under NSPS Kb. The above tanks (~storage vessels) qualify as Group 2 storage vessels under MACT CC. This is so because the above tanks do not meet the definition of a Group 1 storage vessel under section 63.641 which states:
"*Group 1 storage vessel* means a storage vessel at an existing source that has a design capacity greater than or equal to 177 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 10.4 kilopascals and stored-liquid annual average true vapor pressure greater than or equal to 8.3 kilopascals and annual average HAP liquid concentration greater than 4 percent by weight total organic HAP"

Because neither S-4307 nor S-4309 is a Group 1 storage vessel, the storage vessel provisions for Group 1 tanks outlined in section 63.646 is not included in Table IV-Ca (S-4307 & S-4309) of the proposed renewal permit. Instead, only the Group 2 tank reporting and recordkeeping requirements listed under 63.655(i)(1)(iv) and 63.655(i)(5) are cited in Table IV-Ca.

The June 30, 2010 amendments also resulted in changes to Tables IV- M, Y, AC, AK, CG, CZ, DG, DR, DS, DT, DU, DV, DY, & EA, Tables VII - L, T, W, X, Y, AD, BSa, CO, CW, CX, & CY, and Tables IX B-1, 2 & 3.

40 CFR 63, Subpart EEE
(MACT EEE)

"National Emission Standards for Hazardous Air Pollutants from Hazardous Waste Combustors":

The provisions of MACT EEE apply to hazardous waste combustors that are defined in section 63.1201 as follows:
"Hazardous waste combustor means a hazardous waste incinerator, hazardous waste burning cement kiln, hazardous waste burning lightweight aggregate kiln, hazardous waste liquid fuel boiler, hazardous waste solid fuel boiler, or hazardous waste hydrochloric acid production furnace."

A hazardous waste liquid fuel boiler is defined in the above section as follows:
"*Hazardous waste liquid fuel boiler* means a boiler defined under §260.10 of this chapter that does not burn solid fuels and that burns hazardous waste at any time. Liquid fuel boiler includes boilers that only burn gaseous fuel."

Shell's CO boilers (S-1507, S1509, and S-1512) meet the definition of a hazardous waste liquid fuel boiler because they are capable of burning liquid hazardous waste in concert with gaseous fuels in them. Because MACT EEE was revised following the District's issuance of the initial Title V permit on December 1, 2003, the CO boilers, which were previously shielded from the above rule by the permit shield in Table IXA-16, are now subject to the above rule in the proposed renewal permit. Therefore, the permit shield in Table IXA-16 was deleted and the applicable MACT EEE rule requirements were incorporated into Tables IV-BK and VII-BA. A performance test to demonstrate compliance with MACT EEE was conducted by Shell at the CO boilers on April 5 through 9, 2010.

40 CFR 63, Subpart UUU
(MACT UUU)

"National Emission Standards For Hazardous Air Pollutants For Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, And Sulfur Recovery Units":

MACT UUU applies to a process vent or group of process vents on Catalytic Cracking Units (such as S-1426), Catalytic Reforming Units (such as S-1425), and Sulfur Recovery Units (such as S-1431, S-1432, S-1765, and S-4180). Bypass lines on vent systems located at the above units that are capable of diverting vent streams away from the control device(s) abating them are also subject to MACT UUU. Sources S-1425, S-1426, S-1431, S-1432, S-1765, and S-4180 are existing affected sources as defined under Section 63.1562(e). Because the CCU and the SRU's at Shell are subject to the emission standards & applicable requirements in NSPS J, the initial compliance demonstration requirements outlined in MACT UUU for the above sources don't apply, and were therefore, deleted from Tables IV-AP (for CCU) and IV-AQa (for SRU's 1 through 4). For reasons stated above, the permit shield in Table IX A-1a (for SRU 3 & 4) was also deleted. Because the initial performance test for the CRU (S-1425) was conducted by Shell on January 4, 2005, the initial compliance demonstration requirements outlined in MACT UUU were deleted from Table IV-AOa.

Following is an overview of MACT UUU's requirements as it pertains to sources at Shell:

- Process vents at Catalytic Cracking Units:
  Emission limits for metal HAP emissions and organic HAP emissions are outlined in sections 63.1564(a)(1) and 63.1565(a)(1), respectively. The rule allows sources such as S-1426, which are already subject to sections 60.102 and 60.103 in NSPS J, to demonstrate compliance with the MACT UUU emission limits by meeting the NSPS J emission limits for PM and CO. Please refer to Table IV-AP.
- Process vents at Catalytic Reforming Units:
  Emission limits for organic HAP emissions and inorganic HAP emissions are outlined in sections 63.1566 and 63.1567, respectively. Organic HAP emissions from the CRU are routed to a fuel gas system. Therefore, per section 63.1562(f)(5) the CRU is not subject to the applicable requirements in section 63.1566. Likewise, the inorganic HAP emissions limit can be complied with by choosing from one of two options under 63.1567. Shell demonstrates compliance with the inorganic HAP emissions limit via 63.1567(a)(1)(i). There are no CEMs at the CRU. Therefore, sections 63.1575(e) and 1576(b) are not cited under Table IV-AOa. An erroneous reference to "Sulfur" corresponding to Section 63.1567(a)(1) in Table IV-AOa of the initial permit was deleted.
- Process vents at Sulfur Recovery Units:
  The rule allows sources such as S-1431, S-1432, S-1765, and S-4180, which are already subject to section 60.104 in NSPS J, to demonstrate compliance with the MACT UUU HAP emission limit in section 63.1568 by meeting the NSPS J emission limit for sulfur oxides. Please refer to Tables IV-AQ, and AQa.
- Bypass lines serving Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units:
  Section 60.1569 outlines the requirements for HAP emissions from bypass lines.
  The CO boiler bypass line is located downstream of the CCU (S-1426) and upstream of the three CO boilers (S-1507, S-1509, and S-1512). Its purpose is to provide an outlet, if necessary, for the CCU regenerator flue gases to prevent the downstream CO boilers from over-pressuring. The bypass stack is equipped with a butterfly valve, which is normally set at 50% open. In accordance with permit condition 12911, which requires the presence of a water seal in the bypass stack (downstream of the butterfly valve), a flow controller is set to provide a continuous flow of water to the water seal with the excess water flowing to the sewer. Consistent with section 63.1569(a)(1)(i) and Option 1 in Table 36, an automated level controller on the water seal ensures that unabated CCU regenerator flue gases are not released from the bypass stack into the atmosphere. In light of the above, sections 63.1569(a), (a)(1)(i), (a)(3), and (c) are included as applicable requirements in Table IV-AP for the CCU.

  Because there are no bypass lines at the CRU, section 60.1569 is not cited as an applicable requirement. Please refer to Tables IV-AOa.

  Shell opted to seal the bypass lines at SRU #1 (S-1431), #2 (S-1432), #3 (S-1765), and #4 (S-4180). Therefore, sections 63.1569(a), (a)(1)(iii), (a)(3), and (c) are included as applicable requirements in Table IV-AQa (for S-1431,S-1432S-1765, & S-4180. Rather than separately list applicable requirements for SRU's 1 through 4 in Tables IV-AQa and AQb, the above tables were merged into Tables IV-AQa. Because applicable requirements for the bypass lines, were previously excluded from the initial permit, the above requirement is cited under the merged Table IV-AQa in the proposed renewal permit.

- General Requirements:
  Section 63.1570(a) through (g), with the exception of (e) which is "Reserved", outline the general requirements for sources subject to MACT UUU. Because 63.1570(b) pertains to opacity and visible emissions it is only cited under Table IV-AP (for S-1426). Please refer to Tables IV-AOa, AP, AQ, and AQa.

Changes to and consolidation of tables in Section IV not discussed above:

Table I.D./Section I.D.	Summary of changes
Table IV-B	Permit condition 18618 contains the Title V throughput limits for various sources at Shell. Table IV-B in the initial permit had listed all sources subject to throughput limits in permit condition 18618. Rather than list all of the sources under one table in the proposed renewal permit, the above permit condition is referenced under a source/group of sources in its own source-specific applicable requirements table, with the exception of S-1235 and S-1236, which have no other applicable requirements. In light of the above, parts 1 and 2 of permit condition 18618 were added as applicable requirements in the following tables of the proposed renewal permit: Tables IV-A, Ea, Ec, Ha, I, Ja, Jb, Jc, M, U, AEc, AK, AL, AOa, AP, CD, CO, and DY. Parts 1 and 2 of permit condition 18618 were added to existing applicable requirements of the above permit condition in the following tables of the proposed renewal permit: Tables IV-AQ, BK, CV, and CW.
Table IV-D	In 1995 during its Clean Fuels Project, Shell had proposed to modify S-13. The proposed modifications would have subjected S-13 to NSPS Kb. However, the scope of the project to make the required modifications was canceled and the changes that would have triggered the NSPS Kb applicability were never made. As a result, the NSPS Kb applicable requirements contained in Table IV-AEc of the initial permit for S-13 are not applicable. Therefore, S-13 was deleted from Tables IV-AEc and VII-X in the proposed renewal permit, and the applicable requirements for S-13 are contained in Tables IV-Ec and VII-Dc. All references to S-13 in permit condition 12271 that was intended to govern sources that were either constructed/modified as part of the Clean Fuels Project were deleted. In light of the above, Table IV-D

Table I.D./Section I.D.	Summary of changes
	that had contained applicable requirements pertinent to part 45 of permit condition 12271 for S-13 in the initial permit was deleted.
Table IV-Eb	Rather than separately list permit conditions for tanks in various tables in the permit, the pertinent permit condition in Table IV-Eb (PC[2] 20398 for S-534 & S-1141), was consolidated along with other applicable requirements in Table IV-Ea. In light of the above, Table IV-Eb was deleted.
Table IV-F	Rather than separately list permit conditions for tanks in various tables in the permit, the pertinent permit condition in Table IV-F (PC 7618 for S-14, S-20, S-483, S-484, S-530, S-532, S-1139, S-1140, S-1141, S-1751, S-1752, S-1753, S-1754, and S-1757), was consolidated along with other applicable requirements in Table IV-Ea, Ec, and M. In light of the above, Table IV-F was deleted.
Table IV-G	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table IV-G (Parts 1, 2.a, 2.b.i, 2.b.ii, 3, and 4 of PC 18646 for S-19 and S-1139) was consolidated along with other applicable requirements in Table IV-Ea. In light of the above, Table IV-G was deleted.
Table IV-Ha	The subject tanks under this table were previously described in the initial permit as being used for asphalt storage. In light of the above, the reference to "asphalt storage" has been deleted from the source description for the tanks.
Table IV-Kb	Rather than separately list permit conditions for tanks in various tables in the permit, the pertinent permit condition in Table IV-Kb (PC 7618 for S-1076), was consolidated along with other applicable requirements in Table IV-Jb. In light of the above, Table IV-Kb was deleted.
Table IV-N	Rather than separately list permit conditions for EFR tanks in various tables in the permit, the pertinent permit condition in Table IV-N (PC 11951 for S-540), was consolidated along with other EFR applicable requirements in Table IV-Ja. In light of the above, Table IV-N was deleted.
Table IV-O	Rather than separately list permit conditions for EFR tanks in various tables in the permit, the pertinent permit condition in Table IV-O (PC 11850 for S-544), was consolidated along with other EFR applicable requirements in Table IV-Ja. In light of the above, Table IV-O was deleted.
Table IV-P	Rather than separately list permit conditions for EFR tanks in various tables in the permit, the pertinent permit condition in Table IV-P (PC 12174 for S-545), was consolidated along

[2] PC – permit condition

Table I.D./Section I.D.	Summary of changes
	with other EFR applicable requirements in Table IV-Ja. In light of the above, Table IV-P was deleted.
Table IV-Q	Rather than separately list permit conditions for tanks in various tables in the permit, the pertinent permit condition in Table IV-Q (PC 6111 for S-549), was consolidated along with other applicable requirements in Table IV-A. In light of the above, Table IV-Q was deleted.
Table IV-W	Rather than separately list permit conditions for EFR and IFR tanks in various tables in the permit, the pertinent permit condition in Table IV-W (PC 17648 for S-1006, S-2013, S-2445, S-2446, and S-4322), was consolidated along with other EFR and IFR applicable requirements in Tables IV-R and U. In light of the above, Table IV-W was deleted.
Table IV-AA	Rather than separately list permit conditions for tanks in various tables in the permit, the pertinent permit condition in Table IV-AA (PC 18153 for S-1070), was consolidated along with other applicable requirements in Tables IV-Ea. In light of the above, Table IV-AA was deleted.
Table IV-AB	Rather than separately list permit conditions for EFR tanks in various tables in the permit, the pertinent permit condition in Table IV-AB (PC 7382 for S-1072), was consolidated along with other EFR applicable requirements in Table IV-Ja. In light of the above, Table IV-AB was deleted.
Table IV-AI	Rather than separately list permit conditions for FR tanks in various tables in the permit, the pertinent permit condition in Table IV-AI (PC 12190 for S-1117), was consolidated along with other FR applicable requirements in Table IV-AH. In light of the above, Table IV-AI was deleted.
Table IV-AJ	Rather than separately list permit conditions for EFR tanks in various tables in the permit, the pertinent permit condition in Table IV-AJ (PC 12271 for S-1129, S-1130, S-1131, and S-4310), was consolidated along with other EFR applicable requirements in Table IV-Ja, Jb, and U. In light of the above, Table IV-AJ was deleted.
Table IV-AL	The initial permit contained applicable requirements for various sources including the CRU (S-1425) in Table IV-AL. S-1425 was deleted from Table IV-AL in the proposed renewal permit. Instead, the proposed renewal permit now contains applicable requirements for S-1425 pertaining to Regulations 8, Rules 9, 10, 18, and 28, along with other applicable requirements in Table IV-AOa. Also, applicable requirements from a non-SIP approved version of Regulation 8, Rule 28 (dated March 18, 1998) was deleted from Table IV-AOa, and was replaced with applicable requirements contained in the December 21, 2005 version of the above rule.

Table I.D./Section I.D.	Summary of changes
Table IV-AN	Rather than separately list permit conditions for sources listed under Tables IV-AL & AP in various tables in the permit, the pertinent permit condition in Table IV-AN (PC 18643 for S-1426, S-1429, S-1430, S-1449, S-1764, S-4080, and S-4140), was consolidated along with existing applicable requirements in Tables IV-AL and AP. In light of the above, Table IV-AN was deleted.
Table IV-ANb	Rather than separately list permit conditions for sources listed under Table IV-AL in various tables in the permit, the pertinent permit condition in Table IV-ANb (PC 18643 for S-1417 and S-4050), was consolidated along with existing applicable requirements in Table IV-AL. In light of the above, Table IV-ANb was deleted.
Table IV-AO	Rather than separately list permit conditions for the CU (S-1420) in Table IV-AL in various tables in the permit, the pertinent permit condition in Table IV-AO (PC 7618 for S-1420), was consolidated along with existing applicable requirements in Table IV-AL. In light of the above, Table IV-AO was deleted.
Table IV-AP (Changes resulting from AMP permit condition for S-1426)	On August 23, 2004, EPA approved Shell's AMP to use of information recorded by the SO2 CEM at each of the three CO boiler stacks in concert with the appropriate mass balance calculations in lieu of daily manual testing, using Method 8 (40 CFR Part 60, Appendix A), to determine compliance with the sulfur oxides (SOx) limit calculated as SO2 of 20 lbs/ton coke burn-off in 40 CFR 60.104(b)(2). In light of the above, parts 1 through 5 of permit condition 24335 were incorporated into Table IV-AP (for S-1426).
Table IV-AT	Rather than separately list applicable requirements for Shell's three OWS (S-1465, S-1469, and S-1779) in Table's IV-AU, AV, and BY, the applicable requirements were consolidated into Table IV-AT. In light of the above, Table's IV-AU, AV, and BY were deleted.
Table IV-BB	With the exception of part E.2 of permit condition 7618 listed in Table IV-BB, Table IV-BA contains applicable requirements of the above permit condition in Table IV-BA. Part E.2 pertains to S-1486, S-1487, S-1488, S-1495, S-1496, S-1497, and S-1508. Rather than separately list permit conditions in various tables in the permit, part E.2 of permit condition 7618 in Table IV-BB, was consolidated along with existing applicable requirements in Table IV-BA for the above sources. As a result, Table IV-BB was deleted.
Table IV-BC	Because applicable requirements in Tables IV-BA and BC almost mirror each other with a few exceptions, the above

Table I.D./Section I.D.	Summary of changes
	tables were merged into Table IV-BA, and Table IV-BC was deleted.
Tables IV-BD and BG (Changes resulting from AMP permit condition for S-4002, S-4003, & S-4141)	In lieu of installing a CEMS at the CR-2 oxidizer combined vent to demonstrate compliance with the NSPS J H2S limit in section 60.104(a)(1), EPA approved Shell's AMP on December 4, 2002 that would allow them to test and review the CR-2 caustic strength once per day. In light of the above, parts 1 and 2 of permit condition 24336 were incorporated into Tables IV-BD (for S-4141) and BG (for S-4002 & S-4003).
Table IV-BE	Rather than separately list the applicable requirements of permit condition 7618 for S-1494, S-1502, S-1503, S-1505, S-1515, and S-1761 in Table IV-BE, the applicable requirements of the above permit condition plus part E.2 (for S-4031 & S-4141) were consolidated along with existing applicable requirements in Table IV-BD. In light of the above, Table IV-BE was deleted.
Table IV-BF	Rather than separately list permit conditions for S-1494 in various tables in the permit, the pertinent permit condition in Table IV-BF (PC 7618 part E.2), was consolidated along with existing applicable requirements in Table IV-BD. In light of the above, Table IV-BF was deleted.
Table IV-BH	Rather than separately list the applicable requirements of permit condition 7618 for S-1500, S-1504, and S-1763 in Table IV-BH, the applicable requirements of the above permit condition were consolidated along with existing applicable requirements in Table IV-BG. In light of the above, Table IV-BH was deleted. The emissions from S-1500, S-1504, and S-1763 are capped under the REFEMs emissions cap (permit condition 7618) while the emission limits in the above permit condition don't apply to S-4002 and S-4003. S-4002 & S-4003 were permitted under a separate permitting action and their emissions are capped under the CFP emissions cap (permit condition 12271).
Table IV-BI	Rather than separately list the applicable requirements of permit condition 7618 (part E.2) for S-1504 and S-1763 in Table IV-BI, the applicable requirements of the above permit condition were consolidated along with existing applicable requirements in Table IV-BG. In light of the above, Table IV-BI was deleted.
Table IV-BJ	Rather than separately list permit conditions for S-1505, S-1515, and S-1761 in various tables in the permit, the pertinent permit condition in Table IV-BJ (PC 7618, part E.2), was consolidated along with existing applicable requirements in Table IV-BD. In light of the above, Table IV-BJ was deleted.

Table I.D./Section I.D.	Summary of changes
Table IV-BM	Rather than separately list permit conditions for S-1523 in various tables in the permit, the pertinent permit condition in Table IV-BM (PC 4101, part 1), was consolidated along with existing applicable requirements in Table IV-Hb. In light of the above, Table IV-BM was deleted.
Table IV-BQ	Rather than separately list permit conditions for S-1759 in various tables in the permit, the pertinent permit condition in Table IV-BQ (PC 7618), was consolidated along with existing applicable requirements in Table IV-AL. In light of the above, Table IV-BQ was deleted.
Table IV-BR	Rather than separately list the applicable requirement of permit condition 7618 (part E.2) in Table IV-BR for S-1760, part E.2 was added to other parts of the above permit condition in Table IV-AZb. Therefore, Table IV-BR was deleted.
Table IV-BS	Rather than separately list the applicable requirement of permit condition 7618 (part E.2) in Table IV-BS for S-1762, part E.2 was added to other parts of the above permit condition in Table IV-BA. Therefore, Table IV-BS was deleted.
Table IV-BU	In July 2003, the District issued Shell a Permit to Operate (PO) for A-771 under Application 7771. Neither A-771 and/or the permit condition (#20755) that were part of the PO were included in the initial permit. In light of the above, parts 1 and 2 of permit condition 20755 were added to Table IV-BU (for S-1769) in the proposed renewal permit.
Table IV-BW	A redundant reference to permit condition 7618 not containing parts E.2.b and E.2.c was deleted from Table IV-BW (for S-1771).
Table IV-CC	Rather than separately list permit conditions for FR tanks in various tables in the permit, the pertinent permit condition in Tables IV-CC (PC 4298 for S-1805), was consolidated along with other FR applicable requirements in Table IV-AEb. In light of the above, Table IV-CC was deleted.
Table IV-CL	Rather than separately list permit conditions for EFR tanks in various tables in the permit, the pertinent permit condition in Table IV-CL (PC 6503 for S-2013), was consolidated along with other EFR applicable requirements in Table IV-U. In light of the above, Table IV-CL was deleted.
Table IV-CN	Rather than separately list permit conditions for IFR tanks in various tables in the permit, the pertinent permit condition in Table IV-CN (PC 6707 for S-2445 and S-2446), was consolidated along with other IFR applicable requirements in Table IV-R. In light of the above, Tables IV-CN was deleted.
Table IV-CP	Rather than separately list applicable requirements for S-4002

Table I.D./Section I.D.	Summary of changes
	and S-4003 in various tables in the permit, the pertinent requirements in 60 CFR Subpart A and permit conditions (#'s 7618, 12271, and 16688) in Table IV-CP were consolidated along with other applicable requirements in Table IV-BG. In light of the above, Table IV-CP was deleted.
Table IV-CQ	Changed the reference to "corral" in parts 79 and 80 of permit condition 12271 to "barn".
Table IV-CR	Rather than separately list permit conditions for S-4001, S-4020, S-4050, S-4080, S-4140, and S-4160 in various tables in the permit, the pertinent permit condition in Table IV-CR (PC 12271), was consolidated along with existing applicable requirements in Table IV-AL. In light of the above, Table IV-CR was deleted.
Table IV-CSa	Rather than separately list the alternative monitoring provision of Section 60.13(i) for S-4021 in a separate table, i.e. Table IV-CSa, the above section is cited along with other existing applicable requirements in Table IV-CS. In light of the above, Table IV-CSa was deleted.
Table IV-CT	Rather than separately list applicable requirements for S-4031 and S-4141 in various tables in the permit, the pertinent permit conditions (#'s 7618, 12271, and 16688) in Table IV-CT were consolidated along with other applicable requirements in Table IV-BD. In light of the above, Table IV-CT was deleted.
Table IV-CTa	Rather than separately list the alternative monitoring provision of Section 60.13(i) for S-4141 in a separate table i.e. Table IV-CTa, the above section is cited along with other existing applicable requirements in Table IV-BD. In light of the above, Table IV-CTa was deleted.
Tables IV-CU (Changes resulting from AMP permit condition for S-4161)	In lieu of installing a CEMS to demonstrate compliance with the NSPS J H2S limit in section 60.104(a)(1) for PSA gas burnt at S-4161, the District in concert with EPA approved Shell's AMP on September 27, 1995 that would employ Dräger tube sampling instead. In light of the above, parts 1 and 2 of permit condition 24339 were incorporated into Table IV-CU (for S-4161).
Table IV-DAb	Rather than separately list permit conditions for S-4311, S-4329, S-4330, and S-4349 in various tables in the permit, the pertinent permit condition in Table IV-DAb (PC 12271), was consolidated along with existing applicable requirements in Table IV-DAa. In light of the above, Table IV-DAb was deleted.
Table IV-DF (Changes resulting from AMP permit condition for S-4180)	Section 60.104(a)(2)(i) limits the sulfur dioxide emissions at S-4180 to not exceed 250 ppmv (dry basis) at zero percent excess air. To demonstrate compliance with the NSPS J SO2

Table I.D./Section I.D.	Summary of changes
	limit, section 60.105(a)(5) requires the use of a SO2 and O2 CEMs. The span values for the SO2 and O2 CEMs are required by section 60.105(a)(5)(i) to be 500 ppm SO2 and 25 percent O2, respectively. On August 27, 2003 EPA approved Shell's AMP that would allow the SO2 CEMs to be spanned at 250 ppm and 2,500 ppm. In light of the above, part 1 of permit condition 24338 was incorporated into Table IV-DF (for S-4180).
Table IV-DI	Rather than separately list permit conditions for FR tanks in various tables in the permit, the pertinent permit condition in Table IV-DI (PC 12271 for S-4334), was consolidated along with other FR applicable requirements in Table IV-AEc. In light of the above, Table IV-DI was deleted.
Table IV-DK	The initial permit used to cite applicable requirements pertaining to part 1 of PC 11504 under Table IV-DK for S-5112, S-5113, and S-5114. Rather than separately list applicable requirements for the vessels in various tables in the permit, Tables IV-DJ and DK were merged into one table i.e. Table IV-DJ.
Table IV-DN	Rather than separately list permit conditions for EFR tanks in various tables in the permit, the pertinent permit condition in Table IV-DN (PC 8502 for S-12490 and S-12491), was consolidated along with other EFR applicable requirements in Table IV-AC. In light of the above, Table IV-DN was deleted.
Table IV-DNb	Rather than separately list permit conditions for EFR tanks in various tables in the permit, the pertinent permit condition in Table IV-DNb (PC 20042 for S-17095), was consolidated along with other EFR applicable requirements in Table IV-U. In light of the above, Table IV-DNb was deleted.
Table IV-DQ	Amended the table to include certain sections of NSPS QQQ pertaining to individual drain systems.
IV-AOa and VII-AFa (for S-1425), IV-AP and VII-AG (for S-1426), IV-AQa and VII-AHa (for S-1431,S-1432, S-1765, and S-4180)), IV-DV (for Facility)	Future effective dates pertaining to MACT General Provisions and Subpart UUU that have passed were deleted from the tables.
IV-AXa (for A-101 & A-102), IV-AXb (for A-103) IV-CX (for S-4201)	The future effective dates in part 19 of permit condition 18618 pertaining to the non-process flares (A-101 through A-103) of December 1, 2004, and of January 1, 2005 for the process flare (S-4201) have passed and were therefore deleted from the tables. The non-process flare S-1470 is not subject to permit condition 18618.

Table I.D./Section I.D.	Summary of changes
IV-AXc and VII-AOb (for S-1471), IV-BW and VII-BI (for S-1771), IV-BX and VII-BJ (for S-1772), IV-CX and VII-CI (for S-4201)	Where applicable, the future effective date of January 1, 2005 in parts 12 through 17 of permit condition 18618 pertaining to the process flares has passed and was therefore deleted from the tables. Also, where applicable the future effective date of January 1, 2005 in part 18, which pertains to the flexigas flare (S-1771), has passed and was therefore deleted from Table IV-BW. Lastly, where applicable future effective dates pertaining to Regulation 12, Rule 11 that have passed were deleted from the tables. A reference to part 18 relating to S-1771 and a redundant reference to part 19 were deleted from Table IV-CX (for S-4201).
<u>Sources without NOx CEMS:</u> IV-AZ and VII-AQ (for S-1480, S-1481, S-1483, and S-1506) IV-CS and VII-CB (for S-4021) <u>Sources with NOx CEMS:</u> IV-AZb and VII-AQb (for S-1760) IV-BA and VII-AR (for S-1486, S-1487, S-1488, S-1491, S-1492, S-1493, S-1495, S-1496, S-1497, S-1498, S-1508, S-1510, S-1511) IV-BA and VII-AT (for S-1490, S-1499, S-1762) IV-BD and VII-AU (for S-1494, S-1502, S-1503, S-1505, S-1515, S-1761, S-4031, S-4141) IV-BG and VII-AX (for S-1500, S-1504, S-1763, S-4002, S-4003) IV-BL and VII-BB (for S-1514) IV-BZ and VII-BL (for S-1800) IV-CU and VII-CE (for S-4161)	Sources S-1480, S-1481, S-1483, S-1506, and S-4021 are not equipped with NOx CEMs and are operated within the confines of a NOx Box to demonstrate compliance with the non-federal NOx limit of 0.033 lbs/MMBTU in Section 9-10-301. As a result, only certain parts of permit condition 18265 apply to a given source depending on whether it is <u>or</u> is not equipped with NOx CEMs. Parts 1 through 7, 9, 10, 12 through 15, and 20 pertain to sources complying with ranges established in the NOx Box. Please refer to Tables IV-AZ & CS and Tables VII-AQ & CB. In contrast, sources equipped with NOx CEMs are subject to parts 1, 2, 8, 10, 11, 13 through 15, and 20. Please refer to Tables IV- AZb, BA, BC, BD, BG, BL, & CU and Tables VII-AQb, AR, AT, AU, AX, BB, & CE. In addition to being subject to the afore-referenced parts for sources equipped with NOx CEMs, source S-1800 is also subject to part 16. Please refer to Table IV-BZ and VII-BL. The “Future Effective Date” of “January 1, 2005” in the last column of the above tables corresponding to parts 1, 3, 4, 5, 6, 7, 8, 9, 10, and 11 was deleted because the date has passed and is no longer valid. Likewise, the “Future Effective Date” of September 1, 2004 corresponding to part 2 of permit condition 18265 in the above tables has passed and is no longer valid. Parts 17, 18, 19, and 21 of permit condition 18265 were deleted from the above tables because a “sunset date” of “Until January 1, 2005” referenced in the above parts of the permit condition has passed and is no longer valid. Deleted the “Future Effective Date” of January 1, 2004 pertaining to Regulation 9-10-301 from Table VII-BB (for S-1514).

Table I.D./Section I.D.	Summary of changes
Table IV-AF (for S-1114 and S-1115)	Applicable requirements for permit condition 7215 (parts 1 through 3) contained in Table IV-AF are redundant, since the above requirements are contained in Table IV-AEa. Therefore, Table IV-AF was deleted.
Table IV-DB	Rather than separately list permit conditions for IFR tanks in various tables in the permit, the pertinent permit condition in Table IV-DB (PC 12271 for S-4322), was consolidated along with other IFR applicable requirements in Table IV-R. In light of the above, Tables IV-DB was deleted.
Table IV-DL (for S-5115 and S-5116)	Rather than separately list the applicable requirements for permit condition 11313 (parts 1 through 8) in Table IV-DL, parts 1 through 8 were added to the existing applicable requirements for S-5115 and S-5116 in Table IV-CG. Going forward, the proposed renewal permit will contain all the applicable requirements pertaining to permit condition 11313 for S-5115 and S-5116 in Table IV-CG. Therefore, Table IV-DL was deleted.
Table IV-AR (for S-1765)	Applicable requirements for SRU#3 (S-1765) are contained in Tables IV-AQ, AQa, and AR. Therefore, the note that used to state "See Table IV – AQ for additional requirements" in the initial permit has been changed to "See Table IV – AQ and AQa for additional requirements" in the proposed renewal permit.
Table IV-DF (for S-4180)	Applicable requirements for SRU#4 (S-4180) are contained in Tables IV-AQ, AQa, and DF. Therefore, the note that used to state "See Table IV – AQ for additional requirements" in Table IV-DF in the initial permit has been changed to "See Table IV – AQ and AQa for additional requirements" in the proposed renewal permit.
IV-DV (for Facility)	Added Subparts A, C, P, Y, and MM of 40 CFR Part 98 "Mandatory Greenhouse Gas Reporting". With regards to 112(j), standards that were promulgated after the refinery permits were first issued in 2003 were deleted. Specifically, under Section 63.52(e)(1) the RICE standard, the turbine standard, the organic liquid distribution standard, and the site remediation standard were deleted, because these standards were promulgated. Please refer to the discussion on 40 CFR 63, Subparts ZZZZ and GGGGG under the "Complex Applicability Determinations" discussion.
Tables IV-DZ and EA	Added new tables summarizing the applicable requirements for bio-treaters and bio-clarifiers (S-1467, S-5117 through S-5119) at ETP1 and ETP2, and for the equalization ponds (S-1466, S-1468, and S-2014) associated with the above ETPs.

Table I.D./Section I.D.	Summary of changes
Tables IV-EB and EC	Added new tables summarizing the applicable requirements for fugitive sources.

Complex Applicability Determinations:

Applicability of 6-1-311 to ESP Exhaust Abating Emissions from FCCUs and CO Boilers:

In connection with "Revision 2" to the Title V permits for the Bay Area refineries in April of 2005, an issue arose regarding whether District Regulation 6-1-311 was applicable to the exhaust from the Electrostatic Precipitators (ESPs) that remove particulate matter from the CO gas that is exhausted from refinery FCCUs and then burned in CO boilers. This issue involves three Bay Area refineries that have FCCUs that exhaust their CO gas to CO boilers: Tesoro, Valero and Shell.

The ESPs involved are at the end of an emissions train that starts with the FCCUs, which produce CO gas containing a high level of particulate matter. The CO gas is then sent to the CO boilers, where it is burned (along with refinery fuel gas) to further reduce the CO to CO2. The resulting heat is used to generate steam for use in refinery operations. This process recovers energy from the CO gas, and it also acts as abatement for the CO in the exhaust stream as well as (to a lesser extent) abating some of the particulate in the exhaust stream. The resulting emissions are then sent from the CO boiler to the ESP, which abates the remaining particulate matter to levels that are compliant with applicable regulatory emissions standards. Finally, after treatment in the ESP the exhaust is emitted to the atmosphere from a stack downstream from the ESP.

In Shell's case, the emissions train relating to the FCCU, CO boilers, and ESP's is as follows: FCCU (S-1426) → CO Boilers (S-1507, S1509, & S-1512) → ESP's (A-12, A-13, & A-14) → Emission Points (P-26, P-27, & P-28) → atmosphere.

During the Revision 2 process, EPA commented that the District needed to consider imposing monitoring for compliance with Regulation 6-1-310 and 6-1-311 in the emission stream from the ESPs. In response, the Air District imposed monitoring requirements for compliance with Regulation 6-1-310. This monitoring requires the refineries to use opacity meters on the stack to monitor the functioning of the ESPs, and then to conduct source tests if opacity readings above 30% indicate that the ESPs may not be working properly. With respect to Regulation 6-1-311, the Air District reasoned that the ESPs were abating emissions from the CO boilers, and boilers are heat transfer operations which are exempt from Regulation 6-1-311. Accordingly, the District reasoned, 6-1-311 was not an applicable requirement at this emissions point (at the ESP exhaust point) and did not require any monitoring. The District published this explanation in the Statement of Basis for the Revision 2 permit for Tesoro. (*See* Tesoro "Revision 2" Permit Evaluation and Statement of Basis, April 2005, at p. 17.) The District was silent on the issue of Regulation 6-1-311 applicability in the Statements of Basis for Shell and Valero, but the Revision 2 permits for those refineries implemented ESP monitoring requirements only for Regulation 6-1-310, and did not include any requirements related to Regulation 6-1-311.

The District has reviewed this interpretation of whether the emissions from these ESPs are subject to Regulation 6-1-311 in connection with the current permit renewal. The District has concluded that the Revision 2 interpretation was incorrect and that 6-1-311 is applicable to this emissions stream, for several reasons.

First, in Revision 2 the District reasoned that the ESPs are abatement devices for the exhaust from the CO boilers. But this interpretation does not fully address the function of the ESPs, which are required primarily to abate the particulate matter in the emissions stream from the FCCUs. The ultimate source of the particulate matter in the exhaust stream that the ESPs abate is the FCCUs, not the CO boilers. The CO boilers burn the CO exhaust gas and do have some (albeit relatively minor) effect in abating the particulate matter in the exhaust stream. But primarily, the process of the generation of the particulate matter and its subsequent abatement occurs at the FCCUs, which generate the PM, and the ESPs, which abate it. This is clear from the situation at refineries with FCCUs that do not use downstream CO boilers. In this configuration, the FCCUs exhaust directly to the ESP to abate the particulate matter before emissions to the atmosphere, and there has never been any question that Regulation 6-1-311 applies at the ESP exhaust in this situation. Inserting a CO boiler between the FCCU and the ESP in order to recover some of the energy content in the CO gas that would otherwise be wasted should not be construed to alter the applicability of Regulation 6-1-311. It still applies to the ESPs, whose fundamental purpose is to abate the particulate matter generated in the FCCU exhaust gas. The District has therefore concluded, based on further review and analysis that its discussion in the Revision 2 Statement of Basis was in error.

Second, CO boilers themselves are not exempt in this specific situation. Although a steam boiler would normally, standing alone, be exempt from Regulation 6-1-311 as a heat transfer operation, when it is used in the manner described here, Regulation 6-1-311 still applies. When a CO boiler is used to burn CO gas from an FCCU, it serves a dual purpose partly as an abatement device and partly as an emissions source. It serves as an abatement device because it reduces the CO in the FCCU exhaust gas (as well as, to a lesser extent, abating some particulate matter). When emissions are measured at the exhaust from an abatement device, they are subject to whatever emissions limits apply to the source that they abate. Here, looking at the CO boilers as abatement devices for the FCCUs, they would be subject to the standards applicable to the FCCUs, including Regulation 6-1-311.

Alternatively, the CO boilers also function not just as abatement devices but as emissions sources in their own right, as they burn fuel (CO exhaust gas mixed with refinery fuel gas) to generate steam for use in the refinery. But even considering a CO boiler as a source in its own right, the emissions from the downstream ESP would still be subject to Regulation 6-1-311 because at that point, the emissions stream is a combination of emissions from two sources, the FCCU and the CO boiler (to the extent the CO boiler is seen as a separate source). When exhaust streams from multiple emissions sources are combined prior to emission to the atmosphere, the emissions stream is subject to the most stringent requirement applicable to either source. (*See* District Regulation 1-107.) With regard to particulate matter, the Regulation 6-1-311 limit is the most stringent, and so it applies at the combined emissions point of the FCCU and CO boiler, downstream of the ESP.

This principle is an important one from the perspective of protecting air quality, because the opposite rule would allow a refinery to exempt its FCCU emissions from the more stringent particulate matter limits simply by inserting a CO boiler between the FCCU and ESP. This result could allow the refinery to emit greater amounts of particulate matter than otherwise would be allowed, for example if it allowed the abatement efficiency of the ESP to degrade. Conversely, applying Regulation 6-1-311 to this emissions stream will not add any appreciable compliance costs or burdens to the refinery, as compliance is achieved by implementing the ESP and ensuring that it is functioning properly, which is already required.

Third, longstanding District practice prior to Revision 2 was to treat Regulation 6-1-311 as applicable to the exhaust from the ESPs on CO boilers in situations like this. Both the District and the refineries themselves have long tested for compliance with the 40 lb/hr particulate emissions limit at this emissions point. When exceedances of the 40 lb/hr limit have been observed, the District has issued Notices of Violation and the refineries have agreed to settle the District's penalty claims based on them. The position the District took in the Revision 2 permits was a sharp departure from this prior practice. For the reasons described above the District now believes that the Revision 2 position was not well considered and was in error. The District is therefore withdrawing the statements it made in connection with the Revision 2 permits and is including Regulation 6-1-311 as an applicable requirement for the exhaust from the ESPs downstream from the CO boilers and FCCUs.

The District is therefore adding Regulation 6-1-311 to the appropriate FCCU and CO Boiler tables in Sections IV and VII of the proposed renewal permit. Please refer to Tables IV-AP & VII-AG (for the FCCU "S-1426") and Tables IV-BK & VII-BA (for the CO boilers "S-1507, S-1509, & S-1512"). Though not explicitly stated under part 9 of permit condition 18618, Shell is required by the above permit condition to annually test the outlet grain loading rate (in gr/dscf) and hourly particulate matter emission rate (in lbs/hr) for compliance with Regulations 6-1-310 and 6-1-311 at the three discrete emission points (~exhaust stacks) "P-26, P-27, & P-28" downstream of each of the three ESP's "A-12, A-13, & A-14" abating each of three CO boilers. In light of the above discussion the allowable particulate emissions rate at each individual stack downstream of each CO boiler/ESP emissions train is 13.33 lbs/hr/stack i.e. maximum allowable particulate emissions rate of 40 lbs/hr (assuming a process weight rate of 28.66 TPH) divided by the three exhaust stacks, when all three CO boilers are operating.

<u>Applicability of Regulation 8-2-114 exemption to cooling water towers:</u>

Organic compound emissions emanating from Cooling Water Towers (CWT) are exempt from the requirements of Regulation 8, Rule 2 "Organic Compounds - Miscellaneous Operations" per Regulation 8-2-114 if the operator of a CWT employs best modern practices. Best Modern Practice (BMP) is defined in the State Implementation Plan (SIP) as one that minimizes emissions through the employment of modern maintenance and operating practices used by superior operators of like equipment and which may be reasonably applied under the circumstances.

Shell employs the following maintenance practices to ensure organic compound emissions from CWTs are minimized:

- All heat exchangers upstream of the CWTs are closely examined during turnaround, and are back flushed.
- The steel contained in the heat exchangers undergoes re-passivation.
- The tubes within the heat exchangers that show evidence of corrosion or pitting are sealed.

The net effect of the above maintenance practices is intended to minimize and/or eliminate leaks and to ensure the timely detection and repair of significant leaks.

Shell employs the following operating/monitoring practices to ensure emissions from CWTs are minimized:

- Frequent visual observations (several times on a daily basis) of the cooling water by refinery operators to detect any changes in the appearance of the water that could indicate hydrocarbon contamination.
- Regular refinery operator presence on the CWT decks, which would allow the operators to detect any unexpected odors from the water.
- Measurement of the residual chlorine by refinery operators at the CWTs one or two times per shift for the following reasons:
  Hydrocarbons are reducers, which tend to combine with the oxidizing chlorine atoms. In the presence of hydrocarbons, the residual chlorine would drop significantly. In addition to being detected via measurement, a reduction in chlorine (a biocide) could foster microbial growth, which could be visually observed by the refinery operators.
- Use of hand-held monitors, such as PIDs or FIDs, to detect the presence of hydrocarbons in the air, in the event that refinery operators suspect a leak.
- Measurement of the Oxidation Reduction Potential (ORP) by refinery operators using a hand-held monitor if a leak is suspected. A change in the reducer side of the measurement would indicate the presence of hydrocarbons.
- Use of an on-line Total Hydrocarbon Analyzer that continuously determines the hydrocarbon vapor concentration from the cooling water.

It can be seen from the above discussion that Shell uses best modern practices to monitor cooling tower water for indications of heat exchanger leaks. Therefore, CWTs S-1457, S-1778, & S-4210 whose applicable requirements are contained in Table's IV-AS (for S-1457 & S-1778) and IV-CY (for S-4210) are exempt from Regulation 8, Rule 2. Shell will have to maintain the necessary records to demonstrate their CWTs meet the requirements of the Regulation 8-2-114 exemption.

Applicability of the flare design requirements in
NSPS 40 CFR 60.18 and NESHAP 40 CFR 63.11:

The District has reviewed the applicability of the flare design requirements contained in 60.18 and 63.11 to ensure that the above sections are cited as an applicable requirement for flares in the renewed permit when it is used to control regulated emissions.

A. Applicable. For some of the Bay Area refineries, 60.18 and/or 63.11 applied to selected flares. This applicability is based on vapor discharges from many emission points being "regulated" when the standards require control. These emission points include the following:

Pressure Relief Device Leakage (NSPS Subpart GGG and GGGa, VV and VVa)
Oil-Water Separators (NSPS Subpart QQQ, NESHAP Subpart FF)

Fixed Roof Tanks (NSPS Subpart Kb)
Fixed Roof Tanks, with HAPs (MACT Subpart CC, MACT Subpart G)
Marine Terminal, with HAPs (MACT Subpart CC, MACT Subpart Y)
Bulk Plant, with HAPs (MACT Subpart CC, MACT Subpart R)

Depending on the applicable subpart, control options include routing the emissions to one or more of the following:

Vapor Recovery System (e.g. condensers and adsorbers)
Fuel Gas System
Process System
Enclosed Combustion Device (e.g. vapor incinerator, boiler or heater)
Vapor Balancing System
Flare

Except for a flare, all of these options have requirements to demonstrate compliance with the control standard. For flares, it is recognized that, in most instances, compliance demonstration is not practical. Thus for flares, the demonstration is satisfied by adhering to one or more of the design requirements detailed in 40 CFR 60.18 or 40 CFR 63.11, which were included in the permit. As previously discussed in the preamble, the above requirements were inconsistently applied to flares operating at all Bay Area refineries.

B. Not Applicable. For other Bay Area refineries, 60.18 and/or 63.11 were not applicable. This is based on the fact that most of the time, the regulated gases of the Bay Area refineries are controlled by a vapor recovery system that directs the regulated gas to a process or a fuel gas system. Sometimes these regulated gases are not controlled by the vapor recovery system. This would be in situations where the capacity of the vapor recovery compressors is exceeded. In this case, the gas cannot be recovered and is sent to one or more refinery flares. However, because this exceedance of the vapor recovery compressor capacity is most likely to occur (or even *only* occurs) during a startup, shutdown or malfunction (SSM) event, it is argued that the SSM exemption(s) mean 60.18 and/or 63.11 do not apply. During a SSM event where the capacity of the vapor recovery compressors is exceeded, the regulated gas from any emission point is commingled with the gas generated by the SSM unit or equipment. The refinery flare or flares (depending on the volume of the total waste gas) would then control the combined waste gas (which contains both the regulated gas and the SSM gas). As previously discussed in the preamble, it is not clear whether the above requirements were consistently deemed to be inapplicable to flares operating at all Bay Area refineries.

C. Discussion. The primary issue here is how is a regulatory authority supposed to treat commingled regulated gas and exempt gas. There is little doubt that the SSM gas generated at the unit or equipment experiencing the startup, shutdown or malfunction is not required to meet the applicable emission standards (pursuant to NSPS 40 CFR 60.8(c)). However, it is uncertain if this ‘exemption’ is intended to cover all refinery gases regardless of origin. If the exemption is only applicable to the gases generated at the unit or equipment experiencing the startup, shutdown or malfunction, then the commingled gas (SSM gas + non-SSM gas) is still subject to the control requirements of the applicable regulation.

A review of the available EPA Applicability Determinations did not find one specific to this issue of commingled exempt and regulated gas. However, one determination (Control Number PS39, 12/11/1992) regarding the Subpart VV standards that are applicable to a fuel gas system (as a closed vent system) stated the following:

> *It is the responsibility of the owner/operator to distinguish regulated emissions when they are combined with other unregulated process gases and demonstrate compliance with the recovery standards, or meet the standard applied to the combined stream.*

This appears to address directly the issue of commingled gas. The regulated gas needs to be considered separate from the exempt gas. In other words, when exempt gas from a SSM event is commingled with regulated gas, the commingled gas (SSM gas + non-SSM gas) does not automatically become an exempt gas.

If this interpretation is correct, any regulated gas needs to meet the applicable standard(s), including when it is commingled with SSM gas. When the commingled gas is directed to a flare and the flare is used to meet the standards of the regulated gas, the flare would be required to meet the requirements of 40 CFR 60.18 and/or 40 CFR 63.11. Simply stated, adhering to one or more of the design requirements detailed in 40 CFR 60.18 or 40 CFR 63.11, would ensure compliance with the control standard for flares.

In all, there are 9 flares (5-process flares and 4-non-process flares) at Shell. Of the five process flares (S-1471, S-1472, S-1771, S-1772, and S-4201), S-1472 (the main LOP flare) is shutdown. The four non-process flares are S-1470, A-101, A-102, and A-103. Flares A-101 through A-103 are air-assisted flares; S-1470, S-1471, and S-1772 are steam-assisted flares; S-1771 is a non-assisted flare; and S-4201 is partly steam-assisted and partly un-assisted flare.

Flares at Shell subject to the requirements in 60.18 are A-101, A-102, S-1471, and S-1772. Please refer to Tables IV-AXa & VII-AO (for A-101 & A-102), IV-AXd & VII-AOb (for S-1471), and IV-BX & VII-BJ (for S-1772) in the renewed permit. The rationale behind subjecting the above flares to the requirements in 60.18 is discussed below.

<u>60.18 applicability to A-101 & A-102 via NSPS Kb:</u>
40 CFR 60.112b(a)(3)(ii) is referenced as an applicable requirement in Tables IV-AEc (for S-4334 abated by A-101), and IV-DG (for S-4319, S-4350, and S-4356 abated by A-102). The afore-referenced NSPS Kb section requires control devices such as A-101 and A-102 to meet the specifications for flares in 60.18. As a result, A101 & A102 are subject to 60.18 (~60.18 flares).

<u>60.18 applicability to S-1471 & S-1772 via NSPS GGG and NSPS VV:</u>
The S-1424 (NHT) and S-1430 (ALKY) are upstream of S-1471. As a result, emissions emanating from fugitive components at the NHT and ALKY are subject to the requirements in NSPS GGG. The LOP flare (S-1471) is a 60.18 flare because 40 CFR 60.592(a) in NSPS GGG subjects equipment under the rule to the provisions in 40 CFR 60.482-1 to 10 of NSPS VV. Control devices such as S-1471 that are subject to 40 CFR 60.482-10 are required by 40 CFR 60.482-10(d) to comply with the requirements for flares in 60.18. As a result, S-1471 is a 60.18 flare.

Under Application 14497 (OPCEN HC flare re-route project) Shell had committed to subject S-1772 to the NSPS GGG requirements. Specifically, process units in the OPCEN area of the refinery were not subject to NSPS GGG prior to the submission of the above permit application because none of the OPCEN units were constructed or modified after January 4, 1983. However, Shell voluntarily agreed to make the process units in OPCEN area subject to NSPS GGG by 12/31/06 as part of a Consent Decree agreement with the EPA. As a result, the OPCEN units were required to comply with the standards outlined in 40 CFR 60.592. As previously discussed in the preceding paragraph, 40 CFR 60.592(a) subjects equipment under the rule to the provisions in 40 CFR 60.482-1 to 10 of NSPS VV. Control devices such as S-1772 that control emissions from equipment upstream of them that are subject to 40 CFR 60.482-10 are required by 40 CFR 60.482-10(d) to comply with the requirements for flares in 60.18. As a result, S-1772 is a 60.18 flare.

Please note that Tables IV-DP & VII-CU (for equipment and components subject to NSPS GGG) and IV-DS & VII-CW (for equipment in organic HAP service that are subject to the equipment leak standards in MACT CC) contain references to NSPS VV only because NSPS GGG references NSPS VV. The EPA's intent was to subject a facility (Shell in this case) to either NSPS GGG or NSPS VV and not both of the above rules. In other words, EPA intended NSPS GGG requirements to apply to refinery process units, and chemicals plants were expected to comply with the requirements in NSPS VV. The only exception to the above being refineries producing MTBE would be subject to NSPS VV. Because Shell and the remaining Bay Area refineries stopped producing MTBE years ago, it is safe to state that none of the local refineries (including Shell) are directly subject to NSPS VV.

Applicability of 40 CFR 63, Subpart R, National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations):

Sources affected by NESHAPS Subpart R, Section 63.420 are either bulk gasoline terminals or pipeline breakout stations. "Bulk gasoline terminal" means any gasoline facility that receives gasoline by pipeline, ship or barge. "Pipeline breakout station" means a facility along a pipeline containing storage vessels used to relieve surges or receive and store gasoline from the pipeline for reinjection and continued transportation by pipeline or to other facilities. As previously discussed under the "Facility Description" section, the District recently determined Equilon Enterprises LLC (Equilon) to be a support facility of the refinery. Subpart R applies to Equilon. Therefore, the applicable requirements contained in the above rule will be incorporated into Equilon's initial permit under a separate permitting action.

Applicability of 40 CFR 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines:

Shell operates two stationary combustion turbines (S-4190 & S-4192), which were installed before January 14, 2003. Therefore, S-4190 & S-4192 are considered to be existing turbines per Section 63.6090(a)(i). Because Section 63.6090(b)(4) exempts existing turbines from the standard, S-4190 & S-4192 are also exempt from 40 CFR 63, Subpart A, General Requirements, and the notification requirements in the above rule.

Applicability of 40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines:

Shell operates nine stationary reciprocating internal combustion engines (S-6051 through S-6057, S-6059, & S-6060) that are solely used as a standby source of motive power for emergency standby generators that they are part of. RICE's S-6051, S-6052, S-6054, S-6059, & S-6060 are each rated at/below 500 hp and were constructed/reconstructed before June 12, 2006. Likewise, S-6053, S-6055, S-6056, and S-6057 are each rated more than 500 hp and were constructed/reconstructed before December 19, 2002. Therefore, the above sources are considered existing stationary RICE's as defined per Section 63.6590(a)(1). Because Section 63.6590(b)(3) exempts existing stationary RICE's from the standard, S-6051 through S-6057, S-6059, & S-6060 are also exempt from 40 CFR 63, Subpart A, General Requirements, and from the notification requirements in the above rule.

Applicability of 40 CFR 63, Subpart GGGGG, National Emission Standards for Hazardous Air Pollutants: Site Remediation:

The site remediation activities at the facility are exempt from 40 CFR 63, Subpart GGGGG, because section 63.7881(b)(3) exempts activities that are performed under a Resource Conservation and Recovery Act (RCRA) corrective action conducted at a treatment, storage and disposal facility (TSDF) that is required by a permit issued under a State program authorized by the EPA under RCRA section 3006. The facility is subject to a RCRA corrective action that is required by its permit issued by the Regional Water Quality Control Board.

Applicability of 40 CFR 64, Compliance Assurance Monitoring (CAM):

The Compliance Assurance Monitoring (CAM) regulation in 40 CFR 64 was developed to provide assurance that facilities comply with applicable emissions limitations by adequately monitoring control devices. The CAM rule was effective on November 21, 1997. Facilities such as Shell are not affected by CAM requirements until they submit an application to renew their Title V permit. As part of this renewal application, Shell's applicability analysis for CAM is summarized in Appendix D.

CAM applies to a source of criteria pollutant or hazardous air pollutant (HAP) emissions if all the following requirements are met:

- The source is located at a major source for which a Title V permit is required; and
- The source is subject to a federally enforceable emission limitation or standard for a criteria pollutant or HAP; and
- The source uses a control device to comply with the federally enforceable emission limitation or standard; and
- The source has potential pre-control emissions of the regulated pollutant that are equal to or greater than the major source threshold for the pollutant (in BAAQMD, the major source thresholds are 100 tons per year for each criteria pollutant, 10 tons per year for a single HAP, and 25 tons per year for two or more HAPs); and
- The source is not otherwise exempt from CAM.

A source potentially subject to CAM may be exempt from the rule per the exemptions specified in 40 CFR 64.2(b)(1) – Exempt Emission Limitations or Standards. Exemptions in 40 CFR 64.2(b)(1) that could reasonably apply to sources at Shell are:

- 40 CFR 62(b)(1)(i) – Emission limitations or standards proposed by the Administrator after November 15, 1990, pursuant to section 111 or 112 of the ACT; or
- 40 CFR 62(b)(1)(vi) – Emission limitations or standards for which a Title V Permit specifies a continuous compliance determination method (a method, specified by the

applicable standard or an applicable permit condition, which: (1) is used to determine compliance on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and (2) Provides data either in units of the standard or correlated directly with the compliance limit).

Based on Shell's analysis, none of the sources at the refinery are subject to CAM requirements.

District permit applications not included in this proposed permit

This facility sends a large number of permit applications to the District every year. Review of the following permit applications was not completed in time to include the results in this Title V permits. The Title V permit will be revised periodically to incorporate these applications as permit revisions following the procedures in Regulation 2, Rule 6, Major Facility Review.

Application #	Project Description
19872	FCCU Revamp Project
21359	ETP #3 (Biotreater and Bio-clarifier)

V. Schedule of Compliance

A schedule of compliance is required in all Title V permits pursuant to BAAQMD Regulation 2-6-409.10 which provides that a major facility review permit shall contain the following information and provisions:

"409.10 A schedule of compliance containing the following elements:

10.1 A statement that the facility shall continue to comply with all applicable requirements with which it is currently in compliance;

10.2 A statement that the facility shall meet all applicable requirements on a timely basis as requirements become effective during the permit term; and

10.3 If the facility is out of compliance with an applicable requirement at the time of issuance, revision, or reopening, the schedule of compliance shall contain a plan by which the facility will achieve compliance. The plan shall contain deadlines for each item in the plan. The schedule of compliance shall also contain a requirement for submission of progress reports by the facility at least every six months. The progress reports shall contain the dates by which each item in the plan was achieved and an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted."

Since the District has not determined that the facility is out of compliance with an applicable requirement, the schedule of compliance for this permit contains only sections 2-6-409.10.1 and 2-6-409.10.2.

The BAAQMD Compliance and Enforcement Division has conducted a review of compliance over the past year and has no records of compliance problems at this facility during the past year. The compliance report is contained in Appendix A of this permit evaluation and statement of basis.

VI. Permit Conditions

During the Title V permit development, the District has reviewed the existing permit conditions, deleted the obsolete conditions, and, as appropriate, revised the conditions for clarity and enforceability. Each permit condition is identified with a unique numerical identifier, up to five digits.

When necessary to meet Title V requirements, additional monitoring, recordkeeping, or reporting requirements have been added to the permit.

All changes to existing permit conditions are clearly shown in “strike-out/underline” format in the proposed permit. When the permit is issued, all “strike-out” language will be deleted and all “underline” language will be retained, subject to consideration of comments received.

The existing permit conditions are derived from previously issued District Authorities to Construct (A/C) or Permits to Operate (P/O). Permit conditions may also be imposed or revised as part of the annual review of the facility by the District pursuant to California Health and Safety Code (H&SC) § 42301(e), through a variance pursuant to H&SC § 42350 et seq., an order of abatement pursuant to H&SC § 42450 et seq., or as an administrative revision initiated by District staff. After issuance of the Title V permit, permit conditions will be revised using the procedures in Regulation 2, Rule 6, Major Facility Review.

The District has reviewed and, where appropriate, revised or added new annual and daily throughput limits on sources so as to help ensure compliance with District rules addressing preconstruction review. The applicability of preconstruction review depends on whether there is a “modified source” as defined in District Rule 2-1-234. Whether there is a modified source depends in part on whether there has been an “increase” in “emission level.”   2-1-234 defines what will be considered an emissions level increase, and takes a somewhat different approach depending on whether a source has previously permitted by the District.

Sources that were modified or constructed since the District began issuing new source review permits will have permits that contain throughput limits, and these limits are reflected in the Title V permit. These limits have previously undergone District review, and are considered to be the legally binding “emission level” for purposes of 2-234.1 and 2-1-234.2. By contrast, for older sources that have never been through preconstruction review (commonly referred to as “grandfathered” sources), an “increase” in “emission level” is addressed in 2-1-234.3. A grandfathered source is not subject to preconstruction review unless its emission level increases above the highest of either: 1) the design capacity of the source, 3) the capacity listed in a permit to operate, or 3) highest capacity demonstrated prior to March 2000. However, if the throughput capacity of a grandfathered source is limited by upstream or downstream equipment (i.e., is "bottlenecked"), then the relaxing of that limitation ("debottlenecking") is considered a modification.

The District has written throughput limits into the Title V permit for grandfathered sources. As discussed above, these limits are written for the purpose of determining whether an increase in emission levels has occurred. The purpose of these limits is to facilitate implementation of preconstruction review program. If these limits are exceeded, the facility would be expected to report the exceedence, and the District would treat the reported exceedence as presumptively establishing the occurrence of a modification. The facility would then be expected to apply for a preconstruction permit addressing the modification and the District would consider whether an enforcement action was appropriate.

It is important to note the presumptive nature of throughput limits for grandfathered sources that are created in the Title V permit. These limits are generally based upon the District's review of information provided by the facility regarding the design capacity or highest documented capacity of the grandfathered source. To verify whether these limits reflect the true design, documented, or "bottlenecked" capacity (pursuant to 2-10234.1) of each source is beyond the resource abilities of the District in this Title V process. Moreover, the District cannot be completely confident that the facility has had time or resources necessary to provide the most accurate information available in this regard. Creating throughput limits in the Title V permit for grandfathered sources is not required by either Part 70 or the District's Major Facility Review rules. Despite the lack of such a requirement, and despite the resource and information challenges presented in the Title V process, the District believes that writing presumptive limits for grandfathered sources into the Title V permit will provide a measure of predictability regarding the future applicability of the preconstruction review program, and that this increased predictability is universally beneficial.

It follows from the presumptive nature of these throughput limits for grandfathered sources that exceedence of these limits is not per se a violation of the permit. *Failure to report an exceedence would be a permit violation.* In this sense, the throughput limits function as monitoring levels, and are imposed pursuant to the District's authority to required monitoring that provide a reasonable assurance of compliance. If an exceedence occurs, the facility would have an opportunity to demonstrate that the throughput limit in fact did not reflect the appropriate limit for purposes of 2-1-234.3. If the facility can demonstrate this, no enforcement action would follow, and the permit would be revised at the next opportunity. It also follows that compliance with these limits is not a "safe harbor" for the facility. If evidence clearly shows that a grandfathered source has undergone a "modification" as defined in 2-1-234.3, the District would consider that a preconstruction review-triggering event, notwithstanding compliance with the throughput limit in the Title V permit. In other words, the protection afforded the facility by complying with the throughput limit in the Title V permit is only as strong as the information on which it was based. There is no Title V "permit shield" associated with throughput limits for grandfathered sources, as they are being proposed. A shield may be provided if the District determines with certainty that a particular limit is appropriate for purposes of 2-1-234.3.

Conditions that are obsolete or that have no regulatory basis have been deleted from the permit.

Conditions have also been deleted due to the following:

- Redundancy in recordkeeping requirements.
- Redundancy in other conditions, regulations and rules.
- The condition has been superseded by other regulations and rules.
- The equipment has been taken out of service or is exempt.
- The event has already occurred (i.e. initial or start-up source tests).

The regulatory basis is listed following each condition. The regulatory basis may be a rule or regulation. The District is also using the following terms for regulatory basis:

- BACT: This term is used for a condition imposed by the Air Pollution Control Officer (APCO) to ensure compliance with the Best Available Control Technology in Regulation 2-2-301.
- Cumulative Increase: This term is used for a condition imposed by the APCO that limits a source's operation to the operation described in the permit application pursuant to BAAQMD Regulation 2-1-403.
- Offsets: This term is used for a condition imposed by the APCO to ensure compliance with the use of offsets for the permitting of a source or with the banking of emissions from a source pursuant to Regulation 2, Rules 2 and 4.
- PSD: This term is used for a condition imposed by the APCO to ensure compliance with a Prevention of Significant Deterioration permit issued pursuant to Regulation 2, Rule 2.
- TRMP: This term is used for a condition imposed by the APCO to ensure compliance with limits that arise from the District's Toxic Risk Management Policy.

Changes to the proposed renewal permit stemming from changes to existing permit conditions and/or from incorporating new permit conditions:

BAAQMD Permit condition 4288:

Section 60.104(a)(1) in NSPS J limits emissions of sulfur oxides from any fuel gas combustion device (including flares) by limiting the H2S content in the gases burnt in them to not exceed 0.10 gr/dscf (162 ppmv on a 3-hour rolling average). In light of the above, the H2S concentration limit outlined in part 12.c. was changed from 163 ppmvd to 162 ppmvd.

BAAQMD Permit condition 5077:

Shell's three OWS (S-1465, S-1469, and S-1779) comply with the standards in Regulation 8, Rule 8 via Sections 302.4 & 302.6, and not 302.1. Therefore, the references to Regulation 8-8-302.1 in parts 3, 6, & 9 were deleted.

BAAQMD Permit condition 7382:

S-1005 was demolished and is not an active source. Therefore, the reference to S-1005 in permit condition 7382 was deleted.

BAAQMD Permit conditions 7618 & 12271:

Sources at Shell operate under two separate emission bubbles called the "REFEMS" and "Clean Fuels Permit" bubbles. Emissions from sources operating under the "REFEMS" and "Clean Fuels Project" bubbles are governed by permit conditions 7618 and 12271, respectively. Under Application 6904, the District adjusted the NOx emissions for sources operating under the above emission bubbles to reflect the NOx emission reductions required by Regulation 9, Rule 10 and issued Shell a Permit to Operate on January 2003. Specifically, the "Facility Baseline Profile – NOx Emissions (lbs/day)" under Table II in permit condition 7618 was reduced by 7,121 lbs/day, and the combined NOx emissions of 6,770 lbs/day from the three CO Boilers (S1507, 1509, and 1512) under part 85 of permit condition 12271 was reduced by 1,318 lbs/day to 5,452 lbs/day. However, neither of the above NOx reductions was reflected in either of the above permit conditions in the initial permit. In light of the above, each row entry under the column entitled "Pounds per day" in Table II of permit condition 7618 was reduced by 7,121 lbs/day. As an example, the row entry of "18,448.6 lbs/day" corresponding to the column entry under "No. of days" for "28 to 29" was reduced to "11,327.60 lbs/day". Likewise, the combined NOx emissions limit for the CO boilers in part 85 was reduced from 6,770 lbs/day to 5,452 lbs/day, and the NOx emissions from a CO boiler with a non-functioning NOx CEM was reduced from 2,257 lbs/day/CO boiler to 1,817 lb/day/CO boiler in part 86 of permit condition 12271. Assuming urea injection is not occurring at the normal rate for a given CO boiler, no changes were warranted to the uncontrolled NOx emission rate of 3,286 lbs/day/CO boiler in part 86 of permit condition 12271 because the above rate was derived using a pre-adjustment value of 1,799.20 tons/yr cited in part 85 of the above condition which was not affected by changes that were part of Application 6904. i.e. [(1799.2 TPY) x (2000 lb/ton) / (365 day/yr)] / [3 CO boilers]. The ammonia limit cited for S-4161 in Table VII-CE was changed from 20 ppmv dry at 15% O2 to 20 ppmv dry at 3% O2.

BAAQMD Permit condition's 7878, 14098, 21593, and 24298:

Changes to the above permit conditions were previously discussed under Application 20070 in Table 1 in the “Background” section of this document.

BAAQMD Permit condition 12271:

Section 60.104(a)(1) in NSPS J limits emissions of sulfur oxides from any fuel gas combustion device (including flares) by limiting the H2S content in the gases burnt in them to not exceed 0.10 gr/dscf (162 ppmv on a 3-hour rolling average). In light of the above, the H2S concentration limit outlined in part 15.b. was changed from 163 ppm to 162 ppm. Changed the reference to “corral” in parts 79 and 80 to “barn”.

BAAQMD permit condition 12911:

Background:

Under normal operating conditions, flue gases from Shell’s Fluid Catalytic Cracking Unit (S-1426) are routed to and are abated by CO boilers (S-1507, S-1509, & S-1512) and the ESPs (A-12, A-13, & A-14). Between October through December 2001, Shell experienced problems with its FCCU and had to bypass the CO boilers & ESPs. As a result, the unabated FCCU emissions were vented directly to the atmosphere via S-1426’s dump stack. Shell was issued numerous violation notices by the District’s Compliance & Enforcement staff and was cited to be in violation of Regulation’s 6-1-301, 305, 310, & 311, and 8-2-301. On December 11, 2001, District staff authored an internal policy memo to address emissions emanating from dump stacks/blowdowns. Based on information contained in the District’s database, it appears permit condition 12911 was originally authored during the above timeframe and has not been amended since its inception. On two recent but separate occasions Shell vented unabated FCCU emissions directly to the atmosphere via the dump stack on April 5, 2010 and July 11, 2010. In light of the above, the District finds amendments to permit condition 12911 as necessary and warranted.

Rationale:

As it currently exists, part 4 of permit condition 12911 requires that Shell maintain a water seal upstream of the dump stack, conduct a visible emission inspection when a breakthrough of the water seal occurs and initiate corrective action to restore the water seal following a breakthrough of the water seal. Part 5 of permit condition 12911 requires that a continuous level monitor be installed on the water seal compartment of the dump stack, and that Shell maintain records pertaining to the water level in the water seal compartment and also record visible emissions detected when a breakthrough of the water seal occurs.

Permit condition 12911 in Shell’s permit does not automatically assume that a violation of the Ringelmann No. 1 opacity standard has occurred when ever there is a breakthrough of the water seal (albeit the fact that the dump stack is not equipped with a COMS). There is also no assurance as to whether the unabated emissions comply with emission limits/standards in Regulation’s 6-1-302[3], 305, 310, & 311, 8-2-301, and 9-1-310.1. The problem is further compounded because the FCCU is also subject to emission standards in federal rules such as 40 CFR 60, Subpart J (NSPS J) and 40 CFR 63, Subpart UUU (MACT UUU).

Proposed changes:

[3] Regulation 6-1-302: The continuous level monitor/recorder at the water seal is installed in lieu of an opacity CEM. Therefore, it is implied that a water seal breakthrough constitutes a Regulation 6-1-302 violation.

In light of the above discussion, permit condition 12911 is amended in the proposed renewal permit as follows:

Condition # 12911
For S1426, CP Catalytic Cracking Unit (CCU):

1. The Additive Catalyst Storage and Injection System associated with the CP Catalytic Cracking Unit (CCU) (S1426) shall be abated by the Catalyst Additive Storage and Injection System for CCU (A1427) Baghouse (A1427). . [basis: BACT]

2. A visible emission that is darker than No. 0.5 on the Ringelmann Chart, or of such opacity as to obscure an observer's view to an equivalent or greater degree, shall not be emitted from the Baghouse (which is integral to the Catalyst Storage and Injection System) for a period or periods aggregating more than three minutes in any hour. [basis: BACT]

3. The exhaust from S1426 shall be vented to S1507, S1509, and/or S1512, unless allowed per Condition 18407. [basis: Regulation 2-6-409.2]

4. The water seal of the CCU (S-1426) dump stack shall be maintained such that a water seal exists. If a breakthrough of the water seal at the CCU (S-1426) dump stack is detected, the District may assume the opacity of unabated emissions vented via the dump stack (hereinafter bypass event) has exceeded the Ringelmann No. 1 standard (20% opacity) in Regulation 6-1-302, except where it can be confirmed that the dump stack was not used or an opacity excess did not occur. When a breakthrough of the water seal occurs, CARB certified personnel may be employed/contracted by the owner/operator to conduct a visible emission evaluation to confirm that the bypass event did not result in an opacity excess, and the owner/operator shall initiate corrective action to restore the water seal. The BAAQMD shall be notified within 24 hours if breakthrough of the water seal is detected, and a report summarizing the root cause of the problem shall be submitted to the Director of the District's Compliance & Enforcement Division within 60 days of the notification date. For each bypass event, the Causal Analysis report shall quantify emissions of particulate matter, precursor organic compounds, carbon monoxide, and sulfur dioxide. In addition, the Causal Analysis report shall evaluate compliance with Regulations 6-1-305, 6-1-310, 6-1-311, 8-2-301, 9-1-310, and the emission limits/standards outlined in 40 CFR 60, Subpart J and 40 CFR 63, Subpart UUU. [basis: Regulations 1-441, 2-1-403, 6-1-~~301~~302]

5. A continuous level monitor shall be installed on the water seal compartment of the CCU (S-1426) dump stack, including continuous data historization for the parametric level monitor, and maintain the instrument in good operating condition at all times.[basis Regulation 1-523]. Water level records shall be maintained for a period of at least 5 years from the date of entry and shall be made available to the APCO upon request. ~~Any occurrence of visible emissions detected during water seal breakthrough shall also be recorded. [basis: Regulation 6-1-301]~~

BAAQMD Permit condition 16688:

The enforceable limits (in MMBTU/day) for S-1480, S-1481, and S-1506 in part 1 of permit condition 16688 was lowered from 600 MMBTU/day/source to 599MMBTU/day/source. The reason for making the above change is discussed in detail under permit condition 18265.

BAAQMD Permit condition's 17532, 22119, and 24263:

Changes to the above permit conditions were previously discussed under Application 19465 in Table 1 in the "Background" section of this document.

BAAQMD Permit condition 18265:

Obsolete Effective Dates:

Sources contained in Tables IV-AZ, AZb, BA, , BD, BG, BL, BZ, CS, & CU are governed by permit condition 18265 for refinery-wide compliance with Regulation 9, Rule 10. The "Future Effective Date" of "January 1, 2005" in the last column of the above tables corresponding to parts 1, 3, 4, 5, 6, 7, 8, 9, 10, and 11 was deleted because the date has passed and is no longer valid. Likewise, the "Future Effective Date" of September 1, 2004 corresponding to part 2 of permit condition 18265 in the above tables has passed and is no longer valid. Parts 17, 18, 19, and 21 of permit condition 18265 were deleted from the above tables because a "sunset date" of "Until January 1, 2005" referenced in the above parts of the permit condition has passed and is no longer valid.

Sources with and without NOx CEMS:

Sources S-1480, S-1481, S-1483, S-1506, and S-4021 are not equipped with NOx CEMs. Instead, the above sources are operated within the confines of a NOx Box to demonstrate compliance with the non-federal NOx limit of 0.033 lbs/MMBTU in Section 9-10-301. As a result, only certain parts of permit condition 18265 apply to a given source depending on whether it is <u>or</u> is not equipped with NOx CEMs. Specifically, parts 1 through 7, 9, 10, 12 through 15, and 20 pertain to sources complying with ranges established in the NOx Box. Please refer to Tables IV-AZ & CS and Tables VII-AQ & CB. In contrast, sources equipped with NOx CEMs are subject to parts 1, 2, 8, 10, 11, 13 through 15, and 20. Please refer to Tables IV- AZb, BA, BD, BG, BL, & CU and Tables VII-AQb, AR, AT, AU, AX, BB, & CE. In addition to being subject to the afore-referenced parts for sources equipped with NOx CEMs, source S-1800 is also subject to part 16. Please refer to Table IV-BZ and VII-BL.

Typographical errors of "MMBH" in parts 3.A and 3.B were corrected to "MMBTU/hr". Also, the units used to the express the NOx emission factor was changed from "lb/Mmbtu" to "lb/MMBTU".

The following discussion is intended to help explain the changes made to permit 16688 in light of part 5.A. and the requirements in Regulation 9, Rule 10.

Part 5.A.:

As previously discussed under the Regulation 9, Rule 10 discussion, sources contained in Tables IV-AZ, AZb, BA, BD, BG, BL, BZ, CS, & CU are governed by permit condition 18265 for refinery-wide compliance with the above rule. Part 3 of permit condition 18265 categorizes sources not equipped with NOx CEMS in the above tables based on their size (~maximum firing rate). In lieu of a NOx CEMS, sources with maximum firing rates greater than or equal to 25 MMBTU/hr are required to comply with an "equivalent" verification system (~NOx Box). For a given source and in order to demonstrate its emissions were considered over its full-range of operations, the NOx Box is established using source test results and the following four conditions as its corners:

1. Low fire/low O2
2. Low fire/high O2
3. High fire/low O2
4. High fire/high O2

The boundaries of the NOx Box are established by connecting the four corners with straight lines. As a result, for a given source the emission rate or factor for all operations within the confines of the NOx Box is either the highest measured rate or factor from any source test, or a higher emission rate or factor proposed by the facility.

Sources (also referred to as "medium" units) that operate within the confines of a NOx Box to demonstrate compliance with the non-federal NOx limit of 0.033 lbs/MMBTU in Section 9-10-301 are required, among other things, to perform District-approved NOx, CO, and O2 source tests on a semi-annual basis. In contrast, sources with maximum firing rates less than 25 MMBTU/hr (also referred to as "small" units), are not required to demonstrate compliance with Section 9-10-301 via a NOx Box. Instead, "small" units are required to perform a District-approved NOx, CO, and O2 source test on an annual basis to demonstrate compliance with the above section.

In light of the above discussion, sources contained in Tables IV-AZ (S-1480, S-1481, S-1483, & S-1506), and IV-CS (S-4021) are not equipped with NOx CEMs. The maximum firing rates outlined in permit condition 16688 for sources S-1480, S-1481, and S-1506 are 25 MMBTU/hr/source, and the maximum firing rates for S-1483 and S-4021 are 20 MMBTU/hr and 49 MMBTU/hr, respectively. Since the inception of permit condition 18265 and rather than establish a NOx Box for sources S-1480, S-1481, and S-1506, Shell has complied with part 5.A. of permit condition 18265 by performing a District-approved NOx, CO, and O2 source test on an annual basis. Going forward and to make the permit conditions in the proposed renewal permit less ambiguous, the enforceable limit (in MMBTU/day) for S-1480, S-1481, and S-1506 in permit condition 16688 was changed from 600 MMBTU/day/source to 599 MMBTU/day/source. Doing so would make the annual source tests conducted by Shell at sources S-1480, S-1481, and S-1506 consistent with not having to establish a NOx Box for the above sources.

It should be noted that though the emission factors (in lb/MMBTU) cited in part 5.A. of permit condition 18265 of 0.20 (for S-1480 and S-1506), and 0.16 (for S-1481 and S-1483), are above the NOx limit of 0.033 lbs/MMBTU, this limit is a facility-wide limit and can be met by over-control on other heaters. If Shell exceeds the 0.033 lb/ MMBTU for the facility, Shell uses Interchangeable Emission Reduction Credits (IERCs) generated from NOx reductions at its three CO boilers (S-1507, S-1509, and S-1512) to offset the difference in emissions via an Alternative Compliance Plan. Though its emission factor of 0.029 lb/MMBTU in part 5.A. of permit condition 18265 is below the 0.033 lbs/MMBTU NOx limit, S-4201 is required to operate within the confines of its NOx Box, to ensure continued compliance with the above limit in the absence of a NOx CEMS.

Minor editorial changes were made to part 5.B. to make it less confusing and also highlight the fact that the three scenarios (low firing rates, startup or shutdown periods, and periods of curtailed operation) outlined in it are mutually exclusive.

Part 5.B.:

Part 5.B. of permit condition 18265 in the initial permit stated the following:
"Part 5A. does not apply to low firing rate conditions (i.e., firing rate less than or equal to 20% of the unit's rated capacity), during startup or shutdown periods or periods of curtailed operation (ex. during heater idling, refractory dryout, etc.) lasting 5 days or less. During these conditions the means for determining compliance with the refinery wide limit shall be accomplished using the method described in 9-10-301.2 (i.e. units out of service & 30-day averaging data)."

Part 5.B. was reworded as follows in the proposed renewal permit to make it less confusing:
"Part 5A. does not apply to low firing rate conditions (i.e., firing rate less than or equal to 20% of the unit's rated capacity), or during startup or shutdown periods, or during periods of curtailed operation (ex. during heater idling, refractory dryout, etc.) lasting 5 days or less. During these conditions the means for determining compliance with the refinery wide limit shall be accomplished using the method described in 9-10-301.2 (i.e. units out of service & 30-day averaging data)."

The time period to submit source test results to the Manager of the District's Source Test Section was extended from 45-days to 60-days in parts 6 and 7 of the permit condition. Rather than startup sources, that operate either infrequently, and/or for very short periods of time, and/or on an unplanned basis, with the sole intent to perform a source test, part 7.A.3 was amended to clarify that such sources don't have to be source tested. The amendment also sheds light on the problems a facility would face in trying to schedule a source test on a very short notice.

Consistent with the intent of Regulation 1-107, which was previously discussed under Regulation 9, Rule 9, and to help identify the sources that exhaust into the atmosphere from a common point part 11 was amended as discussed below.

Part 11:

Part 11 of permit condition 18265 in the initial permit stated the following:

"Effective January 1, 2005, the owner/operator shall operate a continuous emission monitor (CEM) to measure the NOx and O2 concentrations from the following sources that are subject to this Alternative Compliance Plan. In the case where two or more sources exhaust through a common stack, a single NOx and O2 CEM may be used to measure the combined concentrations from all sources that exhaust through the stack.

S1486, S1487, S1488, S1490, S1491, S1492, S1493, S1494, S1495, S1496, S1497, S1498, S1499, S1500, S1502, S1503, S1504, S1505, S1508, S1510, S1511, S1514, S1515, S1760, S1761, S1762, S1763, S1800, S4002, S4003, S4031, S4141, and S4161."

In light of Regulation 1-107, part 11 was reworded as follows in the proposed renewal permit:

"Effective January 1, 2005, the owner/operator shall operate a continuous emission monitor (CEM) to measure the NOx and O2 concentrations from the following sources that are subject to this Alternative Compliance Plan. In the case where two or more sources exhaust through a common stack (Chimney # 1, Chimney #2, S-4002 & S-4003[4], and S-4031 & S-4141[5]), a single

[4] The DCU heaters (S-4002 and S-4003) exhaust through a single exhaust stack.
[5] The HGHT heaters (S-4031 and S-4141) exhaust through a single exhaust stack.

NOx and O2 CEM may be used to measure the combined concentrations from all sources that exhaust through the stack.

Sources exhausting through Chimney #1: S1486, S1487, S1488, S1490, S1491, S1492, S1493, S1494, S1495, S1496, S1497, S1498, and S1499.~~,~~

Sources exhausting through Chimney #2: S1500, S1502, S1503, S1504, S1505, and S1515.

Sources with dedicated exhaust stacks: S1508, S1510, S1511, S1514, S1760, S1761, S1762, S1763, S1800, and S4161."

BAAQMD Permit condition 18618:

The reference to Regulation 2-1-234.4 in the preamble to part 1 of the permit condition was changed to Regulation 2-1-234.3.

The District authorized Shell to replace S-22 with S-6068 under Application 15774, and sources S-1409 and S-1415 were taken out of service in August 2004. Therefore, references to the above sources were deleted from part 1 of the permit condition. Because S-1424 was modified under Application 18062, the throughput limit for the above source was deleted from part 1 of the permit condition, and is instead cited in permit condition 24162. In order to alleviate any confusion for the District's Compliance and Enforcement staff when determining compliance of the three CO boilers (S-1507, S-1509, and S-1512) with their daily and annual firing rate limits in part 1 of the permit condition, the proposed renewal permit lists the above limits in terms of the Lower Heating Value (LHV) and the Higher Heating Value (HHV) of the fuels combusted in the CO boilers. The reference to Regulation 6-330 in part 8 of permit condition was changed to 6-1-330.

Parts 12 through 19 of the permit condition pertain to flares and flaring and were intended to contain the applicable monitoring requirements of Regulation 12, Rule 11 for Shell's process flares (S-1471, S-1472, S-1771, S-1772, and S-4201). The volumes of vent gas that can be flared in the process flares are limited by part 12. Part 13 is a recordkeeping requirement to demonstrate compliance with the flaring limits in part 12, part 14 defines a flaring event, part 15 outlines the procedures to be followed after a flaring event, part 16 outlines visual inspection options, part 17 contains the recordkeeping requirements for flaring events, VE checks, and etc., part 18 contains the weekly VE requirements for the FXG flare, and part 19 contains the types of gases that can be flared at S-4201 and the non-process flares (A-101 through A-103).

Parts 14 and 15 apply to flaring events for all process flares - including the FXG flare (S-1771). Source S-1771 does not "smoke" due to the steady fuel delivery system supplying flexigas to the flare, the composition of flexigas burned in the flare, and the stability of combustion occurring within the flare. Typically, flares that process vent gas streams with high carbon to hydrogen mole ratio (> 0.35) have a tendency to smoke and require better mixing (~steam). Because S-1771 is not a smoking flare, it is not subject to the monitoring requirements in parts 14 and 15. Instead, the monitoring requirements for S-1771 are contained in part 18 which in turn part 16 that allows the use of the visual inspection procedures in part 15.b.ii. as a compliance option. In light of the above discussion and in order to provide clarity, the following sentence was added to the beginning of part 14: "Conditions for monitoring smoking flares (except for those flares that exclusively burn flexicoker gas with or without supplemental natural gas)".

Per the above discussion, the reference to part 12 in parts 14 and 15 of the permit condition were replaced with the non-Flexigas process flares S-1471, S-1472, S-1772, and S-4201 to highlight the fact that S-1771 is not subject to the monitoring requirements in either part 14 and/or 15.

Part 19 of the permit condition in the initial permit restated NSPS J Sections 60.101(d) and (e), and therefore limited Shell's options to demonstrate compliance with the 162 ppmv H2S limit in the rule. Specifically, Section 60.104(a)(1) limits emissions of sulfur oxides from any fuel gas combustion device (including flares) by limiting the H2S content in the gases burnt in them to not exceed 0.10 gr/dscf (162 ppmv on a 3-hour rolling average). As it currently exists, no gases other than fuel gas and process upset gas can be burnt at S-4201, A-101, A-102, and A-103. In order to demonstrate compliance with Section 60.104(a)(1), NSPS J requires Shell to continually monitor the H2S content of gases burnt in the above flares either using a H2S CEMS, or an EPA approved Alternative Monitoring Plan (AMP). In lieu of installing H2S CEMS, Shell is considering submitting AMPs to the EPA for vent gases burnt at S-4201, A-101, A-102, and A-103. Rather than restate the requirements in Sections 60.101(d) and (e) and limit Shell's compliance options under NSPS J, part 19 was amended as shown below:

19. Effective January 1, 2005, the owner/operator shall operate S4201, A101, A102, and A103 Flares to comply with H2S fuel gas limit in 60.104(a)(1) and the monitoring requirements in 60.105 at all times, except when burning fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions, or process upset gases as defined in 60.101(e). ~~to burn only process upset gases as defined by 60.101(e) or fuel gas as defined by 60.101(d) that is released to it as a result of relief valve leakage or other emergency malfunctions.~~ (basis: 60.104(a)(1); Regulation 2-1-403)

With the exception of S-4201, non-process flares A-101, A-102, and A-103 are not subject to monitoring requirements similar to those found for the process flares previously discussed because the non-process flares are not subject to the requirements in Regulation 12, Rule 11, and also because the vent gas streams processed by the above flares have low carbon to hydrogen ratio (~non-smoking flares). Nevertheless, Sections 6-1-301 and 310 are cited as applicable requirements in Tables IV-AXa & VII-AO (for A-101 and A-102) and Tables IV-AXb & VII-AOa (for A-103). For reasons stated above, Table IXA-2 also shields A-101, A-102, and A-103 from Regulation 12, Rule 11.

BAAQMD Permit condition 19097:

This permit condition was deleted from the proposed renewal permit per the Regulation 9, Rule 8 discussion relating to the diesel engines at Shell. Specifically, the operation of S-6051 through S-6060 used to be governed by permit condition 19097. Going forward and in light of the CARB's ATCM, the operation of the above sources, with the exception of S-6058, will be governed by permit condition 22820.

BAAQMD Permit condition 19748:

Changes to the above permit condition were previously discussed under Application 18034 in Table 1 in the "Background" section of this document.

BAAQMD Permit condition 20755:

In July 2003, the District issued Shell a Permit to Operate (PO) for A-771 under Application 7771. Neither A-771 and/or the permit condition (#20755) that were part of the PO were included in the initial permit. In light of the above, A-771 was added to Table II-B; parts 1 and 2 of permit condition 20755 were added to Table IV-BU (for S-1769); permit condition 20755 was added to Section VI; and Table VII-BG (for S-1769). References to sections in Regulation 6, Rule 1 in permit condition 20755, where applicable, were deemed non-federally enforceable in Tables IV-BU and VII-BG.

BAAQMD Permit condition 21671:

References to sections in Regulation 6, Rule 1 in permit condition 21671, where applicable, were deemed non-federally enforceable in Tables IV-DX and VII-CZ (for S-6061). The initial permit listed permit condition 21671 out of sequence i.e. before 20762 instead of after it, in Section VI. This error has been corrected in the proposed renewal permit. A new row was added to Table VII-CZ to include part 2 (coke throughput limit) as a "Citation of Limit" which uses part 3 (daily throughput records) to ensure compliance.

BAAQMD Permit condition 21896:

The time period to submit source test results to the Manager of the District's Source Test Section was extended from 45-days to 60-days in part 1 of the permit condition.

BAAQMD Permit condition 22165:

Following is an excerpt of item #13 "Electro-Static Precipitator Particulate Monitoring" at Chevron, Shell, Tesoro, Valero in Attachment 2 "List of Applicability and Monitoring Determinations" from EPA's October 8, 2004 letter to the District in response to their review of the proposed permits that were submitted to them on August 25, 2004:

"The District has committed to working with EPA to analyze the relevant technical data and develop permit conditions that require Shell, Tesoro, and Valero to monitor ESP operating parameters. We anticipate that the District will select appropriate monitoring parameter(s) and specific range(s) and revise the permits accordingly.

Four of the refineries operate electro-static precipitators (ESPs) to control emissions from fluidized catalytic cracking units (FCCU), carbon monoxide boilers (burning FCCU gas), cokers, and at Valero other units as well (Table II-A of permitted sources in the proposed Conoco permit does not list any ESP). These emissions can amount to thousands of tons per year, if they are not controlled. Bay Area SIP rules 6-310 and 6-311 limit the concentration and mass of the particulate emissions from the ESP in each case, but lack monitoring. Therefore the permits must be revised to include periodic monitoring under

70.6(a)(3)(B).

The District has added annual testing to permits that previously lacking PM testing for the FCCU emissions. Annual testing at the ESP outlet, however, is inadequate because there is no way to determine whether the control device is operating at a level that meets the applicable requirements during the rest of the year.

The District has also added opacity monitoring for the opacity limit that is also contained in Rule 6 where the opacity monitoring was lacking in the permit, and in some cases appears to cite it as a monitoring requirement for the particulate limits (for instance, see Tesoro Table VII-V). While we agree that monitoring for the opacity limit is appropriate, no connection has been established in the rule or in the permit between compliance with the opacity limit in the SIP and the particulate limits.

The Chevron permit (see Table VII.C.2.1) requires four source tests per year and parameter monitoring for the applicable New Source Review limit. The District should either demonstrate that it has already conducted a review that shows that the NSR monitoring in the Chevron permit is adequate periodic monitoring for the SIP, or conduct a similar monitoring review for the Chevron permit.

Also, we recommend correcting the monitoring listed in Shell permit Table VII-AG for 63.1654(a)(1)(i), which appears to indicate that meeting the NSPS opacity limit of 30% will satisfy the monitoring requirements for the lb PM/lb coke burn-off emission rates. While opacity could be selected as a monitoring approach for the PM limit, it is incorrect to assume that compliance with the NSPS Subpart J 60.102(a)(2) opacity limit for these units assures compliance with the separate PM limit under 63.1654(a)(1)(i)."

Following is an excerpt from Shell's Revision 2 SOB in response to item #13:
"The District determined that the monitoring required for compliance with MACT UUU is an appropriate means of providing a reasonable assurance of compliance with Regulation 6. The District has added Permit Condition # 22165 to Table IV-BK, which contains the applicable requirements for sources S1507 – UTIL CO Boiler 1, S1509 - UTIL CO Boiler 2, and S1512 - UTIL CO Boiler 3. Permit Condition # 22165 requires the owner/operator to conduct an initial compliance demonstration that will establish a correlation between chosen parameters (voltage/current or opacity) and particulate emissions. The facilities are already required to continuously measure opacity at these stacks. The permit will be reviewed after the compliance demonstration to incorporate the results into federally enforceable permit conditions."

Because Shell conducted the initial demonstration study to develop a correlation between opacity and particulate matter emissions, and also established an opacity range that would assure compliance with the Regulation 6-1-310.3 particulate matter limit, parts 2 and 3 of permit condition 22165 were deleted from the proposed renewal permit. Continuous opacity readings gathered via the COMS at A-12, A-13, and A-14 would assure compliance with the 30% opacity limit prescribed in 40 CFR 63, Subpart UUU. The opacity readings in turn would serve as a surrogate to ensure compliance with Regulation 6-1-310.3. In light of the above, the requirement to perform a source test in part 4 was deleted since it would not yield any meaningful information, nor would it help correct a violation that has already occured. Because the refinery routinely reports all exceedances to the District, part 5 was found to be redundant and was therefore, deleted. Though Shell's correlation study concludes that an opacity measured by the COMS at/above 70% would correlate to a grain loading limit higher than 0.15 gr/dscf, the addition of part 6 conservatively assumes an opacity reading greater than 30% is an exceedance of the Regulation 6-1-310.3 limit. The above action is consistent with permit conditions found in other Bay Area refinery permits that have COMS on their CO boiler stacks. Please refer to the chart in Appendix C that was constructed using data obtained from the initial demonstration study.

BAAQMD Permit condition 22820:

Changes to the above permit condition were previously discussed under Regulation 9, Rule 8.

BAAQMD Permit condition 23605:

Changes to the above permit condition were previously discussed under Application 15774 in Table 1 in the "Background" section of this document.

BAAQMD Permit condition 24162:

Changes to the above permit conditions were previously discussed under Application 18062 in Table 1 in the "Background" section of this document.

Permit conditions resulting from
Alternative Monitoring Plans (AMPs) approved by EPA:

NSPS J AMP permit condition for CCU:

Background:

The Fluid Catalytic Cracking Unit (S-1426) at Shell is not equipped with an add-on control device to abate SO2 emissions. As a result, it is subject to sections 60.104(b)(2) and (c) for sulfur oxides. Demonstrating compliance with the NSPS J sulfur oxides limit would require Shell to follow the monitoring requirements outlined in section 60.105(c), the test methods & procedures outlined in section 60.106(i), and the reporting & recordkeeping requirements in sections 60.107(b)(2), (c)(1)(ii), and (c)(5). Source S-1426 is abated by three CO boilers (S-1507, S-1509, and S-1512), which are downstream of it. Each CO boiler stack is equipped with a dedicated opacity, SO2, NOx, O2, and CO CEMs.

Shell had requested the EPA to approve an AMP that would permit the use of information recorded by the SO2 CEM at each of the three CO boiler stacks in concert with the appropriate mass balance calculations in lieu of daily manual testing, using Method 8 (40 CFR Part 60, Appendix A), to determine compliance with the sulfur oxides (SOx) limit calculated as SO2 of 20 lbs/ton coke burn-off in 40 CFR 60.104(b)(2).

Rationale:

Shell would certify the SO2 CEM at the three CO boiler stacks by Performance Specification 2 in Appendix B of 40 CFR Part 60, and the CEM would be quality assured through annual relative accuracy test audits (RATA). The alternative mass balance calculations to estimate SOx would include adjusting the CO boiler SO2 CEM concentration data with a correction factor of 1.072 for unmeasured sulfur trioxide (SO3). Fuels burnt in the CO boilers are generated either within and/or outside of the CCU. The CCU produces vast volumes of CO gas, associated with coke burn-off, in the catalyst regeneration step. The CO gas is burnt along with other non-CCU fuels such as refinery fuel gas, flexigas, and liquid hazardous waste in the CO boilers. The information recorded by the H2S CEMs, which are in place to demonstrate compliance with section 60.104(a)(1), for the refinery fuel gas and flexigas, would be converted from an H2S concentration into an equivalent SO2 value. The SO2 emissions contributed from the hazardous waste combustion is negligible. The SO2 emissions associated with the refinery fuel gas and flexigas would be subtracted from the total SOx concentration recorded by the SO2 CEMs at each of the three CO boiler stacks. The corrected SO_x emissions (excluding contributions from refinery fuel gas and flexigas), the CO boiler dry stack flow rate, and mass balance assumptions will be used to calculate the equivalent emission rate of sulfur oxides (calculated as SO2) for every ton of coke burn-off in the CCU's regenerator section to demonstrate compliance with 40 CFR 60.104(b)(2). In accordance with section 60.104(c), compliance with section 60.104(b)(2) would be determined daily on a 7-day rolling average basis using the calendar day averages of each measured parameter.

<u>Outcome:</u>
EPA approved Shell's AMP on August 23, 2004.

<u>Permit condition (#24335):</u>

1. In lieu of the daily testing using Method 8 (40 CFR Part 60, Appendix A) and for the purposes of demonstrating compliance with the sulfur oxides (SOx) limit (calculated as sulfur dioxide) of 20 lb/ton of coke burn-off in Section 60.104(b)(2), the owner/operator of the CCU (S-1426) shall be permitted to use information recorded by the sulfur dioxide (SO2) CEMS at each of the three CO boiler stacks located at S-1507, S-1509, and S-1512 in concert with the appropriate mass balance calculations. The owner/operator shall use a factor of 1.072 to correct the SO2 CEMS concentration for unmeasured sulfur trioxide (SO_3). (Basis: Alternative Monitoring Plan, 40 CFR 60.13(i))

2. The owner/operator shall certify the SO_2 CEMs at each of the three CO boiler stacks located at S-1507, S-1509, and S-1512 by Performance Specification 2 of Appendix B of 40 CFR Part 60, and the CEMs will be quality assured through annual relative accuracy test audits (RATA).
(Basis: Alternative Monitoring Plan, 40 CFR 60.13(i))

3. The owner/operator shall measure oxygen (O_2), carbon monoxide (CO) and carbon dioxide (CO_2) in the CCU regenerator off-gas with O_2, CO and CO_2 CEMS in place of using Methods 1,2,3 and 4 in 40 CFR Part 60, Appendix A. The CEMS data shall be used to determine the flue gas flow rate and moisture content by nitrogen balance around the CCU regenerator and fuel combustion stoichiometry. (Basis: Alternative Monitoring Plan, 40 CFR 60.13(i))

4. The owner/operator shall certify the O_2, CO and CO_2 CEMs by the appropriate performance specifications in Appendix B of 40 CFR Part 60 and quality assured through annual RATA. (Basis: Alternative Monitoring Plan, 40 CFR 60.13(i))

5. Credits for the portion of SO2 derived from auxiliary fuels, such as refinery fuel gas and flexigas, burned in the CO boilers would be determined through hydrogen sulfide (H2S)

CEMS that are in place to demonstrate compliance with the NSPS J H2S limit. The H2S measured by the CEMS would be converted into equivalent SO2 value and would be subtracted from the total SOx. The owner/operator shall use the corrected SO_x emission rates for auxiliary fuel credits, the CO boiler dry stack flow rate, and approved mass balance assumptions in order to calculate the equivalent SO_x/Mg coke burn-off. The rolling 7-day average SO_x emission rate from S-1426 would be based on using the calendar day averages of each measured parameter. (Basis: Alternative Monitoring Plan, 40 CFR 60.13(i))

Changes to permit:
Applicable requirements pertaining to S-1426 contained in parts 1 through 5 of permit condition 24335 were incorporated into Tables IV-AP and VII-AG.

NSPS J AMP permit condition for S-4002, S-4003, and S-4141:

Background:
The C3/C4 treaters upstream of Caustic Regenerator #2 (CR-2) have H2S removal capacity via amine contacting followed by caustic treating. Spent caustic from the caustic treatment step at the C3/C4 treaters is sent to CR-2, which consists of an oxidation tower and two stages of separation. The amine treating in combination with caustic treating allows very little opportunity for H2S to enter CR-2 via the spent caustic. Any remnants of H2S following amine treatment would readily react with caustic in the caustic treatment step to form sodium sulfide. The sodium sulfide in the spent caustic sent to CR-2 would react with oxygen in the oxidizer column to create sodium thiosulfate and sodium hydroxide. The above two components would stay in the aqueous phase and H2S would not be recreated.

The mixing of air in the oxidation column at CR-2 regenerates the spent caustic and produces a vent gas, which is routed to S-4002 (F-13425-A) and S-4003 (F-13425-B) in the Heavy Cracked Gasoline Hydrotreater Unit (S-4140), and S-4141 (F-14011) in the Delayed Coking Unit (S-4001) as fuel gas via the CR-2 oxidizer combined vent. Sources S-4002, S-4003, and S-4141 are fuel gas combustion devices (heaters) that are subject to the H2S limit in section 60.104(a)(1) of NSPS J. One of the requirements of the above section is to ensure that any fuel gas burnt in any fuel gas combustion device (including flares) does not contain H2S in excess of 0.10 gr/dscf (162 ppmv on a 3-hour rolling average).

Rather than install a CEMS at the CR-2 oxidizer combined vent to demonstrate compliance with the NSPS J H2S limit in section 60.104(a)(1) Shell requested the EPA to approve an AMP that would allow them to test and review the CR-2 caustic strength once per day.

Rationale:
Shell identified a minimum CR-2 caustic strength of 2 % by wt. sodium hydroxide in the aqueous phase as a representative process parameter that can function as an indication of a stable and low H2S concentration for the vent gas stream that is routed as fuel gas to heaters S-4002, S-4003, and S-4141. The vent gas is expected to have 0 ppmv H2S, since H2S readily reacts with caustic to form sodium sulfide as long as free sodium hydroxide is available. The minimum CR-2 caustic strength of 2% by wt. sodium hydroxide will indicate that free sodium hydroxide is available to react with any remnants of H2S in the stream. In other words, a caustic strength of 2% by wt.

sodium hydroxide is an indication of compliance with the NSPS J limit, and a H2S concentration higher than the NSPS J limit would reduce the alkalinity of the regenerated caustic and would result in readings below 2% by wt. of sodium hydroxide.

Outcome:
EPA approved Shell's AMP on December 4, 2002.

Permit condition (#24336):

1. For the purposes of demonstrating compliance with Section 60.104(a)(1), the owner/operator shall test the caustic strength of the regenerated caustic at the Caustic Regenerator #2 (CR-2) once per day to ensure a minimum caustic strength of 2 weight percent of sodium hydroxide. If the measured value of the caustic is less than 2 percent by weight of sodium hydroxide the owner/operator shall conduct Dräger-Tube ® sampling at unit pressure control valve "49 PV-137A" and initiate corrective action.
   (Basis: Alternative Monitoring Plan, 40 CFR 60.13(i))

2. The owner/operator shall maintain the following records for a period of up to 5 years from the last date of entry on site and shall make them available to District representatives for review upon request:
   a. Daily test results of the caustic strength of the regenerated caustic at CR-2.
   b. The time and date of when Dräger-Tube ® sampling was warranted; the Dräger-Tube ® sampling test results; the time and date of when the corrective actions were taken; and a report summarizing the root cause of the problem.
   (Basis: Regulation 2-6-501)

Changes to permit:
Applicable requirements contained in parts 1 and 2 of permit condition 24336 were incorporated into Tables IV-BD (for S-4141) and BG (for S-4002 and S-4003), and the applicable monitoring requirements were incorporated into Tables VII-AU and AX.

NSPS J AMP permit condition for S-1470:

Background:
The LOG LPG Flare (S-1470) is subject to the H2S limit in section 60.104(a)(1). The above section requires any fuel gas burnt in any fuel gas combustion device to not contain H2S in excess of 0.10 gr/dscf (162 ppmv on a 3-hour rolling average). The section exempts a flare from the above requirement if it combusts process upset gases or fuel gas that is released to it as a result of relief valve leakage or other emergency malfunctions. In accordance with part 74 of permit condition # 12271 vapors displaced from the LPG loading operations at the LOG Pentane Loading Facility (S-4338) are controlled by S-1470. Prior to being loaded into railcars, the LPG vapors are mixed with natural gas. The final products transferred into the railcars at S-4338 fall into one of the following three categories:

- Category #1: LPG products with sulfur specifications that are inherently low in sulfur (≤ 30 ppmv) and are therefore exempt from monitoring such streams for compliance with section 60.104(a)(1) per section 60.105(a)(4)(iv). Examples of products that fall into this category are: isobutene, normal butane, and natural gasoline/pentane.

- Category #2: LPG products with sulfur specifications not specifically exempt per section 60.105(a)(4)(iv) but are inherently are low in sulfur are potentially exempt from monitoring such streams for compliance with section 60.104(a)(1) if the owner/operator applies for an exemption from monitoring with the Administrator per the guidelines set forth in section 60.105(b). The owner/operator is shielded from the monitoring requirements until such time that the Administrator acts on the exemption request. Examples of products that fall into this category are: propane, butane/butylenes mix, and butane.

- Category #3: LPG products without sulfur specifications that are not specifically exempt per section 60.105(a)(4)(iv), and for which an owner/operator has not applied for an exemption from monitoring with the Administrator per the guidelines set forth in section 60.105(b).

Rationale:
Almost all of the LPG products loaded at S-4338 fall into either Categories 1 or 2. Rather than continually sample/install a SO_2/H_2S CEM at the LPG supply/transfer lines to demonstrate compliance with section 60.104(a)(1) when the LPG flare is processing vapors displaced during the loading operations at S-4338 when loading LPG products that fall under Category #3, Shell has proposed the following:

- A single sample would be taken from a fuel gas stream with the highest sulfur specification once a day just upstream of V-395, the LPG blowdown drum, using a Gastec #4LL H2S tube. No additional sampling would be warranted, if the single sample taken for a fuel gas stream with the highest sulfur specification demonstrates compliance with the H2S limit.

Outcome:
Shell's AMP is pending EPA approval.

Permit condition (#24337):

1. Contingent on EPA's approval of their Alternative Monitoring Plan (AMP) and for the purposes of demonstrating compliance with Section 60.104(a)(1) for fuel gas streams that do not meet the inherently low sulfur exemption per 40 CFR 60.105(a)(4)(iv) or have not applied for an exemption per 40 CFR 60.105(b), the owner/operator shall take a single sample from a fuel gas stream with the highest sulfur specification once a day just upstream of V-395, the LPG blowdown drum, using a Gastec #4LL H2S tube. No additional sampling would be warranted, for products with low sulfur specifications, if the single sample taken for a fuel gas stream with the highest sulfur specification demonstrates compliance with the H2S limit.
(Basis: Alternative Monitoring Plan, 40 CFR 60.13(i))

2. For samples taken to demonstrate compliance with Section 60.104(a)(1) in accordance with part 1 of this permit condition, a detector tube result greater than 162 ppmv shall

warrant the owner/operator to lower the LPG loading rate in order to minimize volatilization of H2S, or the owner/operator shall cease the LPG loading operation.

(Basis: Alternative Monitoring Plan, 40 CFR 60.13(i))

3. Following EPA's approval of their AMP application, the owner/operator shall submit a permit application to the District per permit revision procedures outlined in Regulation 2 "Permits", Rule 6 "Major Facility Review" to revise Table IV "Source-Specific Applicable Requirements" and Table VII "Applicable Limits and Compliance Monitoring Requirements" in the Major Facility Review permit. (Basis: Regulation 2-1-403)

4. Following EPA's rejection of their AMP application, the owner/operator shall submit a permit application to the District to administratively amend the Major Facility Review permit at which time all parts of this permit condition will be deleted from Section VI "Permit Conditions" per permit revision procedures outlined in Regulation 2 "Permits", Rule 6 "Major Facility Review".
(Basis: Regulation 2-1-403)

Changes to permit:
Applicable requirements pertaining to S-1470 contained in parts 1 through 4 of permit condition 24337 were incorporated into Section VI.

NSPS J AMP permit condition for SRU #4:

Background:
Sources, such as SRU #4 (S-4180), that were reviewed under Shell's Clean Fuels Project permit application #8407 in 1992 are governed by permit condition # 12271. Part 66 of the above permit condition limits the concentration of total reduced sulfur (H2S, COS, and CS2) in the facility's Claus Offgas Treatment (SCOT) unit exhaust, prior to the SCOT Thermal Oxidizer for Sulfur Plant 4 (A-4181), to not exceed 100 ppm, dry, at 0% oxygen, averaged over 8 hours.

Section 60.104(a)(2)(i) limits the sulfur dioxide emissions at S-4180 to not exceed 250 ppmv (dry basis) at zero percent excess air. To demonstrate compliance with the NSPS J SO2 limit, section 60.105(a)(5) requires the use of a SO2 and O2 CEMs. The span values for the SO2 and O2 CEMs are required by section 60.105(a)(5)(i) to be 500 ppm SO2 and 25 percent O2, respectively. Shell had requested the EPA to approve an AMP that would allow the SO2 CEMs to be spanned at 250 ppm and 2,500 ppm.

Rationale:
At the expected operating range of less than 100 ppm, a 0 to 250 ppm analyzer has a greater resolution than that afforded by a 0-500 ppm analyzer. Further once the reading exceeds 250 ppm, the analyzer would automatically switch to the 0- 2,500 ppm mode, which then would provide readings up to 2,500 ppm.

Outcome:
EPA approved Shell's AMP on August 27, 2003.

Permit condition (#24338):

1. For the purposes of demonstrating compliance with the NSPS J SO2 limit of 250 ppmv (dry basis) at zero percent excess in Section 60.104(a)(2)(i), the owner/operator shall be permitted to install a SO2 CEM analyzer at SRU #4 (S-4180) that shall be spanned at 250 ppm and 2,500 ppm. (Basis: Alternative Monitoring Plan, 40 CFR 60.13(i))

Changes to permit:

Applicable requirements pertaining to S-4180 contained in part 1 of permit condition 24338 was incorporated into Tables IV-DF and VII-AH.

NSPS J AMP permit condition for S-4161:

Background:

Steam methane reformer (S-4161) located at Hydrogen Plant #3 is the only reformer at Shell's three hydrogen plants that is capable of burning Pressure Swing Absorption (PSA) gas. Part 18 of permit condition # 12271 requires, among other things, that the H2S content of any combination of fuels burnt in Shell's Clean Fuels Project sources be at/below 50 ppm averaged over 24-hours. In addition to using PSA gas as fuel, S-4161 also burns refinery make gas and flexigas. Source S-4161 is a fuel gas combustion device that is subject to the H2S limit in section 60.104(a)(1). One of the requirements of the above section is to ensure that any fuel gas burnt in any fuel gas combustion device (including flares) does not contain H2S in excess of 0.10 gr/dscf (162 ppmv on a 3-hour rolling average). Since no other sources at the refinery use PSA gas as fuel and rather than continually sample/install a H2S CEM to monitor the concentration of H2S in the PSA gas, Shell has proposed to employ using Dräger tube sampling instead. Per Section 60.105(a)(4)(iv)(C) in the newly amended NSPS J, fuel gas streams such as PSA that are produced in process units such as S-4161 that are intolerant to sulfur contamination qualify as fuel gas streams inherently low in sulfur content. Therefore, such fuel gas streams are exempt from Sections 60.105(a)(3) and (a)(4).

Rationale:

Feed to the hydrogen plant passes through the Hydrogenation Reactor Vessel (V-104), two Desulfurizer Vessels (V-105A and B), the reformer (S-4161), the High Temperature Shift (HTS) catalyst and the Low Temperature Shift (LTS) catalyst. If untreated, sulfur compounds in the feed stream to the hydrogen plant would poison the Low Temperature Shift (LTS) catalyst. Therefore, it is important that sulfur in the feed be removed via the zinc oxide sulfur removal beds at V-105A & B. A failure of the desulfurizer beds would have to be corrected immediately. Else, sulfur would break through to the LTS and subsequently to the PSA gas, which is generated during the hydrogen purification step. In order to demonstrate compliance with the H2S limit in section 60.104(a)(1) and/or part 18 of permit condition # 12271, Shell has proposed to monitor the outlet of V-104 and the zinc oxide sulfur removal beds at V-105 A & B once a week using Dräger tubes. The Dräger tubes would be capable of measuring H2S concentrations anywhere between 0.5 to 15 ppmv. An H2S concentration at the outlet of the lead Desulfurizer Vessel (V-105A) greater than 90% of the inlet concentration would require the catalyst in the bed to be replaced. In the event V-105A is taken out of service, the lag Desulfurizer Vessel (V-105B) would abate the H2S.

Outcome:
The District in concert with EPA approved Shell's AMP on September 27, 1995.

Permit condition (#24339):
1. For the purposes of demonstrating compliance with the 3-hour H2S concentration limit of 162 ppmv in Section 60.104(a)(1) of NSPS J, the owner/operator of S-4161 shall monitor the outlet of Hydrogenation Reactor Vessel (V-104), and the zinc oxide sulfur removal beds at Desulfurizer Vessels (V-105 A & B) once a week using Dräger tubes which are capable of measuring H2S concentrations anywhere between 0.5 to 15 ppmv. In the event the concentration of H2S monitored at the outlet of the lead Desulfurizer Vessel is greater than 90% of the inlet concentration, the owner/operator shall take the vessel out of service and replace the catalyst in its bed. During such times that V-105A is out of service, the owner/operator shall ensure that H2S emissions are abated by the lag Desulfurizer Vessel which shall serve as the lead vessel until such time the zinc oxide sulfur removal beds in V-105A are replaced.
(Basis: Alternative Monitoring Plan, 40 CFR 60.13(i))

2. The owner/operator shall maintain the following records for a period of up to 5 years from the last date of entry on site and shall make them available to District representatives for review upon request:
a. Weekly Dräger tubes monitoring results taken at the outlet of V-104, V-105 A & B.
b. The time and date when the catalyst in V-105A was replaced; the Dräger-Tube ® sampling test results that triggered V-105A to be taken out of service; the time and date of when the corrective actions were taken; and a report summarizing the root cause of the problem.
(Basis: Regulation 2-6-501)

Changes to permit:
Applicable requirements pertaining to S-4161 contained in parts 1 and 2 of permit condition 24339 were incorporated into Tables IV-CU and VII-CE.

VII. Applicable Limits and Compliance Monitoring Requirements

This section of the permit is a summary of numerical limits and related monitoring requirements for each source. The summary includes a citation for each monitoring requirement, frequency of monitoring, and type of monitoring. The applicable requirements for monitoring are completely contained in Sections IV, Source-Specific Applicable Requirements, and VI, Permit Conditions, of the permit.

The District has reviewed all monitoring and has determined the existing monitoring is adequate with the following exceptions.

The tables below contain only the limits for which there is no monitoring or inadequate monitoring in the applicable requirements. The District has examined the monitoring for other limits and has determined that monitoring is adequate to provide a reasonable assurance of compliance. Calculations for potential to emit will be provided in the discussion when no monitoring is proposed due to the size of a source.

Monitoring decisions are typically the result of a balancing of several different factors including: 1) the likelihood of a violation given the characteristics of normal operation, 2) degree of variability in the operation and in the control device, if there is one, 3) the potential severity of impact of an undetected violation, 4) the technical feasibility and probative value of indicator monitoring, 5) the economic feasibility of indicator monitoring, and 6) whether there is some other factor, such as a different regulatory restriction applicable to the same operation, that also provides some assurance of compliance with the limit in question.

These factors are the same as those historically applied by the District in developing monitoring for applicable requirements**.** It follows that, although Title V calls for a re-examination of all monitoring**,** there is a presumption that these factors have been appropriately balanced and incorporated in the District's prior rule development and/or permit issuance. It is possible that, where a rule or permit requirement has historically had no monitoring associated with it, no monitoring may still be appropriate in the Title V permit if, for instance, there is little likelihood of a violation**.** Compliance behavior and associated costs of compliance are determined in part by the frequency and nature of associated monitoring requirements. As a result, the District will generally revise the nature or frequency of monitoring requirements only when it can support a conclusion that existing monitoring is inadequate**.**

Table I.D.	Summary of changes
Table VII-A	Permit condition 18618 contains the Title V throughput limits for various sources at Shell. Table VII-A in the initial permit used to list all sources subject to throughput limits in permit condition 18618. Rather than list all of the sources under one table in the proposed renewal permit, the above permit condition is referenced under a source/group of sources in their own individual applicable limits and compliance monitoring requirements table, with the exception of S-3, S-4, S-257, S-548, S-967, S-1235, and S-1236, which have no other applicable requirements. In light of the above and where applicable, parts 1 and 2 of permit condition 18618 were added as applicable requirements in the following tables of the proposed renewal permit: Tables VII-Da, Dc, G, H, I, J, L, O, R, X, AD, AE, AH, AK, BA, BP, BX, CG, CH, and DB.
Table VII-C	Back in 1995 during their Clean Fuels Project, Shell had proposed to modify S-13. The proposed modifications would have subjected S-13 to NSPS Kb. However, the scope of the project to make the required modifications was canceled and the changes that would have triggered the NSPS Kb applicability were never made. As a result, the NSPS Kb applicable requirements contained in Table IV-AEc of the initial permit for S-13 are not applicable. Therefore, S-13

Table I.D.	Summary of changes
	was deleted from Tables IV-AEc and VII-X in the proposed renewal permit, and the applicable requirements for S-13 are contained in Tables IV-Ec and VII-Dc of the proposed renewal permit. All references to S-13 in permit condition 12271 that was intended to govern sources that were either constructed/modified as part of the Clean Fuels Project were deleted. In light of the above, Table VII-C that used to contain applicable monitoring requirements pertinent to part 45 of permit condition 12271 for S-13 in the initial permit was deleted.
Table VII-Db	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-Db (Parts 1 and 2 of PC 20398 for S-534 & S-1141) was consolidated along with other applicable requirements in Table VII-Da. In light of the above, Table VII-Db was deleted.
Table VII-E	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-E (Part D.1.a of PC 7618 for S-14, S-20, S-483, S-484, S-530, S-532, S-1139, S-1140, S-1141, S-1751, S-1752, S-1753, S-1754, S-1757, and S-1758) was consolidated along with other applicable requirements in Tables VII-Da, Dc, and L. In light of the above, Table VII-E was deleted.
Table VII-F	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-F (Parts 1, 2.a, 2.b.i, 2.b.ii of PC 18646 for S-19 and S-1139) was consolidated along with other applicable requirements in Table VII-Da. In light of the above, Table VII-F was deleted.
Table VII-K	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-K (Part D.2 of PC 7618 for S-1076) was consolidated along with other applicable requirements in Table VII-I. In light of the above, Table VII-K was deleted.
Table VII-M	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-M (Part 1 of PC 11951 for S-540) was consolidated along with other applicable requirements in Table VII-H. In light of the above, Table VII-M was deleted.
Table VII-N	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-N (Part 1 of PC 11850 for S-544) was consolidated along with other applicable requirements in Table VII-H. In light of the above, Table VII-N was deleted.
Table VII-U	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-U

Table I.D.	Summary of changes
	(Parts 1 & 2 of PC 18153 for S-1070) was consolidated along with other applicable requirements in Table VII-Da. In light of the above, Table VII-U was deleted.
Table VII-V	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-V (Parts 4 & 5 of PC 7382 for S-1072) was consolidated along with other applicable requirements in Table VII-H. In light of the above, Table VII-V was deleted.
Table VII-Z	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-Z (Part 2 of PC 7215 for S-1114 & S-1115) was consolidated along with other applicable requirements in Table VII-X. In light of the above, Table VII-Z was deleted.
Table VII-AC	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-AC (Parts A and 51 of PC 12271 for S-1129, S-1130, S-1131, and S-4310) was consolidated along with other applicable requirements in Tables VII-H, I, and R. In light of the above, Table VII-AC was deleted.
Table VII-AF	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-AF (Part C.a. of PC 7618 for S-1420) was consolidated along with other applicable requirements in Table VII-AE. In light of the above, Table VII-AF was deleted.
Table VII-AG (Changes resulting from AMP permit condition for S-1426)	On August 23, 2004, EPA approved Shell's AMP to use of information recorded by the SO2 CEM at each of the three CO boiler stacks in concert with the appropriate mass balance calculations in lieu of daily manual testing, using Method 8 (40 CFR Part 60, Appendix A), to determine compliance with the sulfur oxides (SOx) limit calculated as SO2 of 20 lbs/ton coke burn-off in 40 CFR 60.104(b)(2). In light of the above, the applicable monitoring requirements of permit condition 24335 were incorporated into Table VII-AG (for S-1426).
Table VII-AFa	The initial permit contained applicable requirements for various sources including the CRU (S-1425) in Table VII-AE. S-1425 was deleted from Table VII-AE in the proposed renewal permit. Instead, the proposed renewal permit now contains applicable requirements pertaining to Regulations 8, Rules 10, 18, and 28, along with other requirements in Tables VII-AFa.
Table VII-AH (Changes resulting from AMP permit condition for S-4180)	Section 60.104(a)(2)(i) limits the sulfur dioxide emissions at S-4180 to not exceed 250 ppmv (dry basis) at zero percent excess air. To demonstrate compliance with the NSPS J SO2 limit, section 60.105(a)(5) requires the use of a SO2 and O2 CEMs. The span values for the SO2 and O2 CEMs are

Table I.D.	Summary of changes
	required by section 60.105(a)(5)(i) to be 500 ppm SO2 and 25 percent O2, respectively. On August 27, 2003 EPA approved Shell's AMP that would allow the SO2 CEMs to be spanned at 250 ppm and 2,500 ppm. In light of the above, the applicable monitoring requirement of permit condition 24338 was incorporated into Table VII-AH (for S-4180).
Table VII-AHa	Rather than separately list monitoring requirements for Shell's four SRU's (S-1431, S-1432, S-1765, and S-4180) in Table's VII-AHa and AHb, the monitoring requirements were consolidated into Table VII-AHa and Table VII-AHb was deleted.
Table VII-AK	Rather than separately list monitoring requirements for Shell's three OWS (S-1465, S-1469, and S-1779) in Table's VII-AL, AM, and BK, the monitoring requirements were consolidated into Table VII-AK. In light of the above, Table's VII-AL, AM, and BK were deleted. References to Regulation 8-8-302.4 in the table were replaced by the more recent & stringent vapor tight standard in Regulation 8-8-302.6. An erroneous reference to part 12 of PC 5077, which does not exist was deleted.
Tables VII-AN, AQ, AQb, AR, AT, AU, AX, BA, BB, BI, BL, BR, CB, CE, CG, and CH	Section 60.104(a)(1) in NSPS J limits emissions of sulfur oxides from any fuel gas combustion device (including flares) by limiting the H2S content in the gases burnt in them to not exceed 0.10 gr/dscf (162 ppmv on a 3-hour rolling average). In light of the above, the H2S concentration limit referenced in the affected tables was changed from 163 ppm to 162 ppm.
Table VII-AOb	Parts 14, 16, and 17 were added to part 15 under the "Monitoring Requirement Citation" for BAAQMD Regulations 6-1-301 and 310 in Table VII-AOb (for S-1471 and S-1472). In addition, a new row entry entitled "Vent Gas Limit" citing parts 12 (as the Citation of Limit) and 13 (as the Monitoring Requirement Citation) was added to Table VII-AOb.
Table VII-AOc	Rather than separately list applicable requirements in various tables in the permit, the pertinent requirements in Table VII-AOc (60.18(c)(2) for S-1471) was consolidated along with other applicable requirements in Table VII-AOb. In light of the above, Table VII-AOc was deleted.
Table VII-AS	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-AS (Part E.2 of PC 7618 for S-1486, S- 1487, S-1488, S-1495,

Table I.D.	Summary of changes
	S-1496, S-1497, and S-1508) was consolidated along with other applicable requirements in Table VII-AR. In light of the above, Table VII-AS was deleted.
Tables VII-AU and AX (Changes resulting from AMP permit condition for S-4002, S-4003, & S-4141)	In lieu of installing a CEMS at the CR-2 oxidizer combined vent to demonstrate compliance with the NSPS J H2S limit in section 60.104(a)(1), EPA approved Shell's AMP on December 4, 2002 that would allow them to test and review the CR-2 caustic strength once per day. In light of the above, the applicable monitoring requirements of permit condition 24336 were incorporated into Tables VII-AU (for S-4141) and AX (for S-4002 & S-4003).
Table VII-AV	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-AV (Parts A & C.d of PC 7618 for S-1494, S-1502, S-1503, S-1505, S-1515, and S-1761) was consolidated along with other applicable requirements in Table VII-AU. In light of the above, Table VII-AV was deleted.
Table VII-AW	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-AW (Part E.2 of PC 7618 for S-1494, S-1505, S-1515, and S-1761) was consolidated along with other applicable requirements in Table VII-AU. In light of the above, Table VII-AW was deleted.
Table VII-AY	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-AY (Parts A, C.d, C.e, & E.1 of PC 7618 for S-1500, S-1504, and S-1763) was consolidated along with other applicable requirements in Table VII-AX. In light of the above, Table VII-AY was deleted.
Table VII-AZ	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-AZ (Part E.2 of PC 7618 for S-1504, and S-1763) was consolidated along with other applicable requirements in Table VII-AX. In light of the above, Table VII-AZ was deleted.
Table VII-BA	The daily and annual firing rate limits for the three CO boilers (S-1507, S-1509, and S-1512) are expressed in the proposed renewal permit in terms of the Lower Heating Value (LHV) and the Higher Heating Value (HHV) of the fuels combusted in them.
Table VII-BF	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-BF (Part C.b of PC 7618 for S-1759) was consolidated along with other applicable requirements in Table VII-AE. In light of the above, Table VII-BF was deleted.

Table I.D.	Summary of changes
Table VII-BG	In July 2003, the District issued Shell a Permit to Operate (PO) for A-771 under Application 7771. Neither A-771 and/or the permit condition (#20755) that were part of the PO were included in the initial permit. In light of the above, parts 1 and 2 of permit condition 20755 were added to Table VII-BG (for S-1769) in the proposed renewal permit.
Table VII-BI	Parts16 and 17 were added to part 18 under the "Monitoring Requirement Citation" for BAAQMD Regulations 6-1-301 and 310 in Table VII-BI (for S-1771).
Table VII-BJ	Parts 14, 16, and 17 were added to part 15 under the "Monitoring Requirement Citation" for BAAQMD Regulations 6-1-301 and 310 in Table VII-BJ (for S-1772).
Table VII-BO	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-BO (Part 1 of PC 4298 for S-1805) was consolidated along with other applicable requirements in Table VII-Y. In light of the above, Table VII-BO was deleted.
Table VII-BV	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-BV (Part 1 of PC 6503 for S-2013) was consolidated along with other applicable requirements in Table VII-R. In light of the above, Table VII-BV was deleted.
Table VII-BW	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-BW (Parts 1, 2.a, 2.b.i, 2.b.ii of PC 6707 for S-2445 & S-2446) was consolidated along with other applicable requirements in Table VII-P. In light of the above, Table VII-BW was deleted.
Table VII-BY	Rather than separately list applicable requirements in various tables in the permit, the pertinent requirements in Table VII-BY (60.104(a)(1), Part E.2 of PC 7618, Parts A, 15, 18.a, 35, 36, and 37 of PC 12271 for S-4002 & S-4003) was consolidated along with other applicable requirements in Table VII-AX. In light of the above, Table VII-BY was deleted.
Table VII-BZ	Changed the reference to "corral" to "barn".
Table VII-CA	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-CA (Parts A, N, and 11 of PC 12271 for S-4001, S-4020, S-4050, S-4080, S-4140, and S-4160) was consolidated along with other applicable requirements in Table VII-AE. In light of the above, Table VII-CA was deleted.
Table VII-CD	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-CD (Part E.2 of PC 7618, Parts A, 15, 18, 35, 36, and 37 of PC

Table I.D.	Summary of changes
	12271 for S-4031 and S-4141) was consolidated along with other applicable requirements in Table VII-AU. In light of the above, Table VII-CD was deleted.
Table VII-CDa	Rather than separately list applicable requirements in various tables in the permit, the pertinent requirements in Table VII-CDa (60.104(a)(1) for S-4141) was consolidated along with other applicable requirements in Table VII-AU. In light of the above, Table VII-CDa was deleted.
Table VII-CE (Changes resulting from AMP permit condition for S-4161)	In lieu of installing a CEMS to demonstrate compliance with the NSPS J H2S limit in section 60.104(a)(1) for PSA gas burnt at S-4161, the District in concert with EPA approved Shell's AMP on September 27, 1995 that would employ Dräger tube sampling instead. In light of the above, the applicable monitoring requirements of permit condition 24339 were incorporated into Table VII-CE (for S-4161).
Table VII-CJ	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-CJ (Parts A and 55 of PC 12271 for S-4210) was consolidated along with other applicable requirements in Table VII-AJ. In light of the above, Table VII-CJ was deleted.
Table VII-CM	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-CM (Parts N and 51 of PC 12271 for S-4311, S-4329, and S-4330) was consolidated along with other applicable requirements in Table VII-CL. In light of the above, Table VII-CM was deleted.
Table VII-CQ	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-CQ (Parts A and 51 of PC 12271 for S-4322) was consolidated along with other applicable requirements in Table VII-P. In light of the above, Table VII-CQ was deleted.
Table VII-CR	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-CR (Parts A, 45, and 51 of PC 12271 for S-4334) was consolidated along with other applicable requirements in Table VII-X. In light of the above, Table VII-CR was deleted.
Table VII-CTb	Rather than separately list permit conditions in various tables in the permit, the pertinent permit condition in Table VII-CTb (Part 1 of PC 20042 for S-17095) was consolidated along with other applicable requirements in Table VII-R. In light of the above, Table VII-CTb was deleted.
Table VII-DA	Added a new table for LOG Wastewater Junction Boxes S-2010 whose applicable requirements are listed in Table IV-CJ.

Table I.D.	Summary of changes
Table VII-DB	Added a new table for asphalt tank S-6068 whose applicable requirements are listed in Table IV-DY.
Table VII-DC	Added a new table for fixed roof tank S-568 whose applicable requirements are listed along with S-63, S-355, and S-432 in Table IV-I.
Table VII-DD	Added a new table for individual drain systems subject to NSPS QQQ whose applicable requirements are listed in Table IV-DQ.
Table VII-DE	Added a new table for bio-treaters and bio-clarifiers at ETP 1 and 2 whose applicable requirements are listed along in Table IV-DZ.
Table VII-DF	Added a new table for wastewater equalization ponds whose applicable requirements are listed in Table IV-EA.

Following is a summary of emission limits and monitoring not previously discussed.

<u>NOX Sources</u>

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
Combustion sources cited under Table's IV-AZ, AZb, BA, BC, BD, BG, BL, BZ, CS, & CU	BAAQMD 9-10-303	0.20 lbs/MMBTU	None. Combustion sources cited under Table's IV-AZ, AZb, BA, BC, BD, BG, BL, BZ, CS, & CU comply with more restrictive limits in the rule by either operating within the confines of a NOx box, or having their emissions monitored via CEMs. Please refer to Table's VII-AQ, AQb, AR, AT, AU, AX, BB, BL, CB, and CE.

NOX Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
CO boilers cited under Table IV-BK	BAAQMD 9-10-304	150 ppm, dry at 3% oxygen, based on an operating-day average	Continuous. Exhaust stacks located downstream of each of the three CO boiler/ESP pollutant trains are equipped with NOx CEMs.

NOx Discussion:
Sources S-1480, S-1481, S-1483, S-1506, and S-4021 are not equipped with NOx CEMs. Because S-1480, S-1481, S-1483, & S-1506 are rated at less than 25 MMBTU/hr, compliance with the NOx emission factors outlined for the above sources in part 5.A of permit condition 18265 is verified via annual source tests. In contrast, S-4021 is operated within the confines of a NOx Box to demonstrate compliance with the non-federal NOx limit of 0.033 lbs/MMBTU in Section 9-10-301. In light of the above, only certain parts of permit condition 18265 apply to a given source depending on whether it is or is not equipped with NOx CEMs. Specifically, parts 1 through 7, 9, 10, 12 through 15, and 20 of permit condition 18265 pertain to sources complying with emission factors/ranges established in the NOx Box. Please refer to Tables IV-AZ & CS and Tables VII-AQ & CB. Sources equipped with NOx CEMs are subject to parts 1, 2, 8, 10, 11, 13 through 15, and 20. Please refer to Tables IV- AZb, BA, BC, BD, BG, BL, & CU and Tables VII-AQb, AR, AT, AU, AX, BB, & CE. In addition to being subject to the afore-referenced parts for sources equipped with NOx CEMs, source S-1800 is also subject to part 16. Please refer to Table IV-BZ and VII-BL.

CO Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
Applicable to existing boilers, steam generators, and process heaters.	BAAQMD 9-10-303	400 ppmv, dry at 3% oxygen, based on an operating-day average	Continuous, Semi-annual source test, annual source test

CO Discussion:
Combustion units abated by SCR/SNCR and/or that are rated at greater than 200 MMBTU/hr and/or that are rated between 25 to 200 MMBTU/hr (equipped with NOx and O2 CEMs) are required to perform a semi-annual source tests to demonstrate that the concentration of CO measured is 400 ppmv or less, dry at 3% oxygen, based on an operating-day average. Likewise, sources operating under a NOx box (for example S-4021) are also required to demonstrate compliance with the above limit on a semi-annual basis. The requirement to install a CO CEM under the above scenarios is warranted if two or more tests performed at a given source within a 5-year period indicates CO concentrations above 200 ppmv, dry at 3% oxygen, based on an

operating-day average. For example, the CO boilers (S-1507, S-1509, and S-1512) demonstrate compliance with Regulation 9-10-303 via CO CEMs. Sources rated at less than 25 MMBTU/hr that (for example S-1480, S-1481, S-1483, & S-1506) are required to perform an annual source test to demonstrate compliance with the CO limit.

SO_2 Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
All combustion sources	BAAQMD 9-1-301	Ground level concentrations of SO2 shall not exceed: 0.5 ppm for 3 consecutive minutes AND 0.25 ppm averaged over 60 consecutive minutes AND 0.05 ppm averaged over 24 hours	None
All combustion sources	BAAQMD 9-1-302	300 ppm (dry)	None
Combustion sources permitted to combust liquid fuels cited under Table IV-DNa	BAAQMD 9-1-304	Sulfur content of fuel < 0.5% by weight	None

SO_2 Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
SRU #1: S-1431 Sulfur pit at SRU#1: S-1578 SRU #2: S-1432 Sulfur pit at SRU#2: S-1579 SRU #1, #2, and pits collectively abated by A-1501 & A-1517 SRU #3: S-1765 Sulfur pit at SRU#3: S-1766 SRU #3 abated by A-2023 SRU #4: S-4180 Sulfur pit at SRU#3: S-4347 SRU #4, and pits at SRU #3 and #4 collectively abated by A-4181	BAAQMD 9-1-313.2	Operation of a sulfur removal and recovery system that removes and recovers: 95% of H2S from refinery fuel gas, 95% of H2S and ammonia from process water streams (sulfur recovery is required when a facility removes 16.5 ton/day or more of elemental sulfur)	None

SO2 Discussion:

BAAQMD Regulation's 9-1-301 & 9-1-302

Facilities such as Shell are subject to the SO_2 emission limitations in District Regulation 9, Rule 1 (ground-level concentration and emission point concentration). In order to demonstrate compliance with the ground level SO_2 concentration requirements of Regulation 9-1-301 i.e. less than or equal to 0.5 ppm continuously for 3 consecutive minutes or 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours, Shell maintains and operates Ground Level Monitors (GLMs) .

Most sources at Shell are either subject to the limitations in Sections 9-1-304 through 9-1-312, and/or are subject to limits that are more stringent than 300 ppm (dry) limit in Regulation 9-1-302.

BAAQMD Regulation 9-1-304

Per CAPCOA/ARB/EPA Agreement, certification by the fuel supplier for each fuel delivery of diesel delivered to the nine stationary reciprocating internal combustion engines (S-6051 through S-6057, S-6059, & S-6060) would assure compliance with Section 304. Specifically, the fuel supplier would certify each purchase lot, and the certification records would be cross-referenced to a given purchase lot number. Because diesel sold in California has sulfur content at/below 0.05 %, by weight it is reasonable to state that the vendor fuel oil certification would suffice.

It should be noted that though sources cited under Tables IV-BA, BG, and BL cite Regulation 9-1-304 none of the heaters cited under the above tables combust liquid fuels. It is unclear whether the above limit applies to liquid wastes combusted in the CO boilers cited under Table IV-BK. Assuming the limit applied, the CO boilers would demonstrate compliance with Regulation 9-1-304 via SO2 CEMS located at exhaust stacks downstream of the ESPs A-12, A-13, & A-14 abating them.

<u>BAAQMD Regulation 9-1-313.2</u>

The District deleted permit conditions contained in the local refinery permits related to monitoring for compliance with 9-1-313.2 in a previous permitting action. Regulation 9-1-313 allows three options for compliance, but is complied with at all Bay Area refineries through section 313.2, which requires operation of a sulfur removal and recovery system that achieves 95% reduction of H2S from refinery fuel gas. Permit conditions warranting monitoring for compliance with Regulation 9-1-313.2 were established in the 2003 issuance of these permits to periodically verify that a 95% reduction was being achieved. Though details varied amongst the five refineries, all permits required some form of compliance demonstration, generally involving inlet-outlet source testing. The refineries consistently objected to these conditions, noting that source testing for H2S reduction is, on the one hand, costly and a significant safety risk, and on the other, unlikely to yield data useful to determining compliance. Having reconsidered the issue, the District deleted the permit conditions.

The monitoring in all five refinery permits was established pursuant to Regulation 2-6-409.2, which provides that, where the applicable requirement does not contain periodic monitoring or testing, “the permit shall contain periodic monitoring sufficient to yield reliable data from the relevant time periods that is representative of the source’s compliance with the permit.” This provision was established in Regulation 2, Rule 6 to satisfy EPA’s program approval criteria found in 40 CFR 70.6(a)(1)(iii), commonly known as the periodic monitoring requirement. The District has consistently applied a balancing test to determinations of periodic monitoring, considering, among other things, the likelihood of a violation during normal operation, variability in the operation and in the control device, the technical feasibility and probative value of the monitoring under consideration, and cost. Applying these factors to Regulation 9-1-313.2, the District now believes that compliance with the above section is sufficiently assured without the addition of Title V monitoring.

A periodic monitoring determination should take as its starting point the intent of the underlying requirement. While some District regulations impose a reduction efficiency with the intent that it be measured on an ongoing basis, other regulations use reduction efficiency to describe the requisite design of equipment to be installed. The latter are sometimes referred to as design standards.

Regarding Regulation 9-1-313.2, both the rule language and contemporaneous explanations of the rule suggest that the 95% reduction requirement was intended as a design standard. Furthermore, the target of 95% was aimed at ensuring that no significant fuel gas stream went untreated, rather than acting as a performance standard for treatment systems. Regulation 9-1-313 prohibits operation of a refinery of a certain size unless one of three conditions is met, one of which (§ 313.2) is that "*there is a* sulfur removal and recovery system that removes and recovers, on a refinery wide basis, 95% of H2S from refinery fuel gas" (emphasis added). This phrasing places primacy on the presence of a system capable of achieving a reduction, rather than achievement of the reduction. Moreover, another of the three possible methods of compliance with Section 313 (§ 313.3) allows (prior to a certain date) compliance merely by way of an enforceable commitment to construct such a system. This third compliance option reinforces the inference that the primary intent of Section 313 was to require operation of a sulfur recovery and removal system.

Regulation 9-1-313 was adopted in 1990, at a time when all but one Bay Area gasoline-producing refinery were already operating Sulfur Recovery Units (SRU's). The remaining gasoline-producing refinery, Pacific Refining (which has since closed), was instead using a caustic scrubbing system, and had a history of causing odor problems in the community due, in part, to high H2S levels in fuel gas. The 1990 District staff reports evidence that the primary purpose of the rule was to require installation of an SRU at this facility. This also happens to be the purpose of the Section 313.3 compliance option. The staff reports do not evidence a concern with ensuring a certain level of performance at facilities with existing SRU's. Nor do the staff reports characterize Section 303 as being in any way intended to fulfill a requirement of the federal Clean Air Act. The 1990 staff reports indicate that Bay Area refineries with SRU's were known at the time to be reducing sulfur content in fuel gas to well below applicable regulatory standards.

In 1995 the District revised Regulation 9-1-313.2 to add a requirement that a refinery removing more than 16.5 tons of elemental sulfur per day must install a sulfur recovery plant or sulfuric acid plant. The content of the accompanying staff report suggests that, once again, this rulemaking was directed at one facility, Pacific Refining. The caustic scrubbing system in use at Pacific Refining had not resolved the odor problem at the refinery. The rule revision was intended to require Pacific Refining to install a sulfur plant. Of relevance for the purposes of this discussion is the fact that the staff report includes a statement that while a caustic scrubbing system can be expected to achieve a 95% H2S reduction, reduction at an SRU typically exceeds 99%.

The language of Regulation 9-1-313.2 and District staff reports are consistent with the view that the intent of the rule was to require Bay Area refineries to install and operate an SRU. Though there is an expressed assumption that reduction of better than 99% can be achieved by an SRU, there is no mention in the rule or in the staff reports of how a 95% reduction could be verified on an ongoing basis. This is consistent with the characterization of section 313.2 as a design standard that is satisfied by installation and operation of an adequately designed system.

The discussion that follows explains why periodic monitoring would not be appropriate even if the 95% reduction requirement of section 313.2 is characterized as a performance standard.

Although the following discussion can stand alone as a justification for not imposing additional monitoring, it can also be viewed as overlapping with discerning the original intent of the rule. The technical considerations weighing against establishing monitoring through Title V are synonymous with the policy reasons for why monitoring was not included in the rule as adopted in 1990, and why that rule is most accurately viewed as a design standard.

The District believes that monitoring to verify a 95% reduction is not appropriate. The monitoring would be costly and burdensome. To attempt measurement of inlet and outlet concentrations would require that samples be taken from multiple points simultaneously. The refineries have asserted this is not possible. The District acknowledges that doing so is at the least costly, complicated, and, to the District's knowledge, unprecedented. The task is made more difficult due to the risks of exposure to H2S during sampling, particularly at inlet concentrations. Safety precautions would require 2-3 personnel at each sample point, and additional precautions during sample transport and handling. Because the standard is expressed as a refinery-wide standard, samples would need to be taken simultaneously at each fuel gas treatment system in order to determine compliance.

A monitoring regime may be burdensome and yet still justifiable if, among other things, results are accurate and probative regarding compliance with the standard. This is not the case regarding the 95% reduction goal of section 313.2. The accuracy of inlet-outlet source testing would be hampered by the limits of available methods for analyzing H2S samples at these levels of dilution.   Moreover, many of the other sulfur species present interfere with measurement of H2S, and as a result routine fluctuation in sulfide species will tend to confound calculations comparing inlet and outlet H2S concentrations. There is no recognized method for quantifying and taking this into account.

Moreover, the District believes the margin of compliance with the 95% reduction goal is likely very large. Of course, due to the considerations discussed above, this cannot be verified with significant accuracy. However, each refinery has regulatory and operational reasons for employing an SRU to maintain H2S concentrations at very low levels. NSPS Subpart J, for instance, requires that fuel gas contain no more than 230 ppm H2S. Concentrations at the Bay Area refineries are typically far below this level in all gas combusted as fuel. While the actual percentage of reduction would depend on the inlet concentrations, the low concentrations found post-SRU fuel gas yields a safe assumption that reductions well in excess of 95% are occurring.

In summary, Regulation 9-1-313 was adopted primarily to force installation of an SRU at a single refinery that no longer operates. Though not stated in the staff reports, the expression of a 95% reduction goal was likely inserted in the rule to ensure that any SRU installed would address fuel gas comprehensively, not merely in part. H2S reduction efficiency for an entire fuel gas system can be estimated but cannot be accurately measured. The District believes there is a high degree of certainty that when all fuel gas is processed in an SRU, an H2S reduction efficiency well above 95% will be achieved. However, monitoring for this result would entail high costs and safety risks for measurements insufficiently exact to be relied on as a measurement of compliance. Such monitoring is therefore not justified for a District regulation that has no historical and no direct functional relationship to a federal Clean Air Act requirement.

PM Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
Gaseous fuel-fired sources	BAAQMD Regulation 6-1-301	Ringelmann 1.0 for no more than 3 minutes in any hour	N/A
Flares S-1471, S-1472, S-1771, S-1772, and S-4201			Video monitoring per Regulation 12-11-507; parts 14, 15, 17 of permit condition 18618 Also, refer to Table's VII-AOb, BI, BJ, and CI.
Stationary diesel engines cited under Table IV-DNa	BAAQMD Regulation 6-1-303.1	Ringelmann 2 for no more than 3 minutes in any hour	None
Process Heaters S1480, S1481, S1483, S1486, S1487, S1488, S1491, S1492, S1493, S1495, S1496, S1497, S1498, S1500, S1504, S1506, S1508, S1510, S1511, S1760, S1763, S1490, S1499, S1494, S1502, S1503, S1504, S1505, S1515, S1761, S1762, S1800, S4002, S4003, S4021, S4031, S4141, S4161, S4191, and S4193	BAAQMD 6-1-304	During tube cleaning, Ringelmann No. 2 for 3 min/hr and 6 min/one billion BTU in 24 hours	Part 6 of permit condition 18618
All sources with particulate emissions	BAAQMD 6-1-305	No nuisance particulate fallout	None.
Stationary diesel engines cited under Table IV-DNa	BAAQMD Regulation 6-1-310	0.15 gr/dscf at 6% O2	None
Process Heaters S1486, S1487, S1488, S1491, S1492, S1493, S1495, S1496, S1497, S1498, S1500, S1504, S1508, S1510, S1511, S1763, S4002, and S4003	BAAQMD Regulation 6-1-310.3	0.15 gr/dscf at 6% O2	Part 3 of permit condition 18618
S1650, S1767, S1768, and S1769			Part 5 of permit condition 18618

PM Discussion:

Visible Emissions

BAAQMD Regulation 6-301 limits visible emissions to no darker than 1.0 on the Ringelmann Chart (except for periods or aggregate periods less than 3 minutes in any hour). Visible emissions are normally not associated with combustion of gaseous fuels, such as natural gas. , Therefore, no additional monitoring is required to assure compliance with this limit for sources that exclusively burn gaseous fuels, per the EPA's June 24, 1999 agreement with CAPCOA and ARB titled "Summary of Periodic Monitoring Recommendations for Generally Applicable Requirements in SIP",.

BAAQMD Regulation 6-1-303.1

The operation of the nine diesel engines, summarized under Table IV-DNa, for reliability and testing purposes is limited by permit condition 22820 to not exceed 20 hours/year/engine. Because S-6051 through S-6057, S-6059, & S-6060 are solely used on an intermittent basis as a standby source of motive power for emergency standby generators that they are part of, visible emissions from the engines are not monitored.

BAAQMD Regulation 6-1-304

Tube cleaning is periodically performed on furnaces that burn liquid fuels, to remove soot build up from the outside of furnace tubes. If improperly performed, these cleaning operations can result in visible emissions. Hourly visible observations of the stack for a given combustion source during tube cleaning would ensure any improper tube cleaning methods used are detected and corrected. Compliance with part 6 of permit condition 18618 would assure that Ringelmann No. 2 standard is not exceeded.

BAAQMD Regulation 6-1-305

Regulation 6-1-305 only applies if visible particles fall on real property other than that of the person responsible for the emission. As a result, this regulation is not violated unless the source is a nuisance. No monitoring is necessary since a violation can only occur if, among other things, the particles emitted cause annoyance to persons outside the refinery.

Particulate Weight Limitation

BAAQMD Regulation 6-310 limits filterable particulate (FP) emissions from any source to 0.15 grains per dry standard cubic foot (gr/dscf) of exhaust volume. Section 310.3 limits filterable particulate emissions from "heat transfer operations" to 0.15 gr/dscf @ 6% O_2. These are the "grain loading" standards.

As previously discussed under "BAAQMD Regulation 6-1-303.1", the nine diesel engines at Shell are intermittently allowed to operate in non-emergency mode for 20 hours/year/engine. Per CAPCOA/ARB/EPA Agreement, adequate monitoring for combustion of liquid fuels is a visible emissions inspection after every 1 million gallons diesel combusted, to be counted cumulatively over a 5-year period. As a result and for the interim, it is unlikely that any additional monitoring is required/warranted.

Unlike the diesel engines discussed above, S1486, S1487, S1488, S1491, S1492, S1493, S1495, S1496, S1497, S1498, S1500, S1504, S1508, S1510, S1511, S1650, S1763, S1767, S1768, S1769, S4002, and S4003 are also capable of burning liquid fuels in addition to diesel. If a visible emissions inspection, as required by parts 3 & 5 of permit condition 18618, documents opacity, a method 9 evaluation is to be completed within 3 working days, or during the next scheduled operating period if the unit ceases firing on diesel fuel within the 3 working day time frame. Parts 3 and 5 of permit condition 18618 contain requirements to monitor visible emissions after every 1 million gallon of fuel is combusted. The above monitoring frequency, it appears, was selected by balancing the likelihood of coming across significant opacity related non-compliance issues versus the expense of requiring more frequent monitoring. The cost to monitor sources that use liquid fuels either infrequently or in negligible quantities was not justifiable. As a result, the cost of conducting method 9 evaluations was determined to not be a prudent use of resources. This was especially true if previous visible emissions inspections concluded that a source either had not emitted/does not have the potential to emit smoke when burning liquid fuels.

POC Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
Oil Water Separators S-1465, S-1469, and S-1779	Parts 1, 4, and 7 of permit condition 5077	Design rated capacity S-1465 ≤ 3,400 GPM S-1469 ≤ 6,000 GPM S-1779 ≤ 3,000 GPM	Records Part 2 of permit condition 18618
Non-Retail GDF S-1598	SIP Regulation 8-7-301.2	95% recovery of gasoline vapors	None
	BAAQMD Regulation 8-7-301.10	98% or highest vapor recovery rate specified by CARB	
	BAAQMD Regulation 8-7-313.1	Fugitives ≤ 0.42 lb/1000 gallon	
	BAAQMD Regulation 8-7-313.2	Spillage ≤ 0.42 lb/1000 gallon	
	BAAQMD Regulation 8-7-313.3	Liquid Retain + Spitting ≤ 0.42 lb/1000 gallon	

POC Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
	Part 1 of permit condition 7878	600,000 gal/yr gasoline throughput	Records Part 2 of permit condition 18618
Exempt storage tanks cited under Table's IV-A, Ca, & DW	BAAQMD Regulation 8-5-117	TVP ≤ 0.5 psia	Permit condition 20762
Gas turbine/HRSG pairs S-4190/S-4191 & S-4192/S-4193	Part 25.b. of permit condition 12271	0.013 lb/MMBTU	Annual source test per part 114 of permit condition 12271

POC Discussion:
S-1598:
According to CARB, uncontrolled emissions due to tank filling, vehicle fueling, and minor spillage are approximately 21.2 pounds of VOC per 1000 gallons of gasoline dispensed. In light of the above guidance, the uncontrolled emissions from S-1598 assuming an annual throughput of 600,000 gallons is 12,270 lbs/yr. The controlled emissions are estimated by multiplying the uncontrolled emissions calculated above by the percent reduction (≥ 98%)achieved by a CARB compliant Phase II system required by Regulation 8-7-301.10. Therefore, the controlled emissions from S-1598 are 0.1272 TPY. Because emissions from S-1598 are low, no additional monitoring is required to demonstrate compliance with Regulation 8-7-301.2, 301.10, 313.1, 313.2, and 313.3.

Discussion of Other Pollutants:

Sulfuric Acid Mist (SAM)

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
Sulfur Recovery Units S-1431, S-1432, S-1765, & S-4180	BAAQMD Regulation 6-1-330 SIP Regulation 6-330	Concentration of SO3 or H2S04, or both, expressed as 100% H2S04, exceeding 183 mg per dscm (0.08 gr/dscf) of exhaust gas volume	Source test each SRU annually Part 8 of permit condition 18618
Sulfur Recovery Unit S-1765	Part 13 of permit condition 19748	SAM ≤ 7.47 TPY	Annually source test A-2023's stack Part 14 of permit condition 19748

Ammonia

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
CO boilers S-1507, S-1509, & S-1512	Part 2 of permit condition 17533	Ammonia exhaust outlet concentration ≤ 50 ppmv, at 3% O2, averaged over 3 hours	Annual source test Part 8 of permit condition 17533
Furnaces with SCR S-4002, S-4003, S-4031, & S-4141	Part 37 of permit condition 12271	Ammonia slip ≤ 20 ppm of ammonia, dry, corrected to 3% oxygen	Annual source test Part 111 of permit condition 12271
SMR at HP-3 S-4161	Part 31 of permit condition 12271		Annual source test Part 112 of permit condition 12271
Gas turbine/HRSG pairs S-4190/S-4191 & S-4192/S-4193	Part 26 of permit condition 12271		Annual source test Part 113 of permit condition 12271

VIII. Test Methods

This section of the permit lists test methods that are associated with standards in District or other rules. It is included only for reference. In most cases, the test methods in the rules are source test methods that can be used to determine compliance but are not required on an ongoing basis. They are not “applicable requirements” as defined by Regulation 2-6-202.

If a rule or permit condition requires ongoing testing, the requirement will also appear in Section IV of the permit.

<u>Changes to permit:</u>

- Added test methods pertaining to BAAQMD and SIP (where applicable) Regulations: 6-1-311; 8-2-301; 8-3-302 & 304; 8-4-302 & 302.3; 8-5-301, 303.2, 306, 307, 320, 321, 322, 328.1.2, 601, & 602; 8-8-301, 301.3, 302, 302.3, 303, 304, 305.2, 306.2, 307.2, 602, & 603; 8-18; 8-45-305, 603, & 604; 9-1-304, 313, & 604; and 9-10-301, 303, & 305.

- Added test methods pertaining to 40 CFR 60 Subparts A, Db, J, Kb, GG, VV, QQQ; 40 CFR 61 Subpart FF; and 40 CFR 63 Subparts A, CC, & VV

- Added CARB test methods pertaining to S-1598.

IX. Permit Shield:

The District rules allow two types of permit shields. The permit shield types are defined as follows: (1) A provision in a major facility review permit explaining that specific federally enforceable regulations and standards do not apply to a source or group of sources, or (2) A provision in a major facility review permit explaining that specific federally enforceable applicable requirements for monitoring, recordkeeping and/or reporting are subsumed because other applicable requirements for monitoring, recordkeeping, and reporting in the permit will assure compliance with all emission limits.

The second type of permit shield is allowed by EPA's "White Paper 2 for Improved Implementation of the Part 70 Operating Permits Program." The District uses the second type of permit shield for all streamlining of monitoring, recordkeeping, and reporting requirements in Title V permits. The District's program does not allow other types of streamlining in Title V permits.

This facility has the first and second types of permit shield.

<u>Changes to permit:</u>

- <u>Table IXA-1a:</u>
  Sources S-1765, and S-4180 are existing affected sources as defined under Section 63.1562(e). Because the above sources are subject to the emission standards & applicable requirements in NSPS J for SRU's , the initial compliance demonstration requirements outlined in MACT UUU for the above sources don't apply, and were therefore, deleted from Table IV-AQa (for SRU's 1 through 4). Therefore, the permit shield was deleted.

- <u>Table IXA-2:</u>
  Amended the explanation to clarify the applicability of the permit shield for the LPG flare (S-1470).

- <u>Table IXA-4:</u>
  Amended the explanation to clarify the applicability of the permit shield.

- <u>Table IXA-6:</u>
  Deleted the table because Regulation 8, Rule 46 was deleted on December 7, 2005.

- <u>Table IXA-7:</u>
  Amended the explanation to clarify the applicability of the permit shield.

- <u>Table IXA-8:</u>
  Clarified that the permit shield applies to sources listed under Tables IV-DZ and EA.

- Table IXA-9:
  The current non-SIP approved version of Regulation 8, Rule 8, which became effective in September 2004, contains 32 subsections (201 through 232). One new subsection 8-8-230 includes “process drains” under the definition of “Wastewater Separator System”. Therefore, the permit shield for “process drains” under Table IX A-9 is no longer valid and has been deleted. The process drains are subject to and are expected to comply with Regulation 8, Rule 8 (Section 8-8-313 and others).

- Table IXA-11:
  Amended the explanation to clarify the applicability of the permit shield.

- Table’s IXA-12 & 13 (non-Regulation 12-11 related):
  All flares, including the flexigas flare, are subject to section 60.104(a)(1). Therefore, the tables were deleted.

- Table IXA-14:
  Amended the explanation to clarify the applicability of the permit shield.

- Table IX-A16:
  CO boilers (S-1507, S1509, and S-1512) meet the definition of a hazardous waste liquid fuel boiler because they are capable of burning liquid hazardous waste in concert with gaseous fuels in them. Since MACT EEE was revised after Shell was issued its initial Title V permit on December 1, 2003 the CO boilers, which were previously shielded from above rule by the permit shield in Table IXA-16 are subject to the above rule in the proposed renewal permit. In light of the above discussion, the applicable MACT EEE rule requirements were incorporated into Table IV-BK and the permit shield in Table IXA-16 was deleted.

- Table’s IXB-1, 2 & 3:
  Corrected the reference to the reporting and recordkeeping requirements in MACT CC from 63.654 to 63.655 in light of the June 30, 2010 amendments to the above rule.

X. Glossary

Changes to permit:

Added RICE – Reciprocating Internal Combustion Engine

XI. Appendix A - State Implementation Plan

This section has been deleted. The address for EPA's website is now found in Sections III and IV.

D. Alternate Operating Scenarios:

No alternate operating scenario has been requested for this facility.

E. Compliance Status:

Please refer to Appendix A to review the BAAQMD's Compliance Report for this facility.

F. Differences between the Application and the Proposed Permit:

This facility received its initial Title V permit under Application 16467 on December 1, 2003. The initial permit was administratively amended on May 27, 2004 and July 28, 2004. The permit was reopened under Application's 9293 and 12430 and was re-issued on December 16, 2004 and May 17, 2007, respectively. The version of the permit reopened under Application 12430 included Authorities to Construct issued under applications 3930, 4106, 4192, 4688, 4695, 6745, 9504, 10053, 11157, 12473, 12732, 13078, 13086, 13410, and 14224. In addition to the above, the permit also included the final action taken on the following Title V applications: 9699, 11158, 12731, and 13085. The permit re-issued on May 17, 2007 was amended the following year to incorporate changes stemming from a minor revision to the permit under Application 15599. The amended permit was later re-issued on April 4, 2008.

Following the issuance of the April 4, 2008 permit, the District issued Shell Authorities to Construct and/or Permits to Operate under applications 14497, 15482, 15774, 16726, 17633, 18034, 18062, 19373, 19465, 20070, and 20868. Changes stemming from the issuance of Authorities to Construct and/or Permits to Operate under the above applications resulted in the installation of the following new sources/abatement devices: S-6068 (which replaced S-22) and A-2023 (which replaced A-1518). The Authorities to Construct and/or Permits to Operate issued under the above applications also resulted in alterations/modifications to the following sources/abatement devices: S-1424, S-1430, S-1486, S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, S-1499, S-1507, S-1509, S-1512, S-1514, S-1598S-1760, S-1763, S-1765, S-1772, S-2010. Changes resulting from the above permitting actions are reflected in the proposed renewal permit (# 18239) and are discussed in this document.

Equilon Enterprises LLC was recently determined to be a support facility of the Shell refinery. As a result, Equilon Enterprises LLC, which is a bulk storage and loading terminal located adjacent to the Shell refinery, submitted an application to obtain an initial Title V permit from the District on February 17, 2010. Although Equilon Enterprises LLC and the Shell refinery are considered to be the same facility, a separate Title V permit will be issued to Equilon Enterprises LLC.

In addition to addressing the applicability of District and Federal rules to sources operating at this facility, this document also discusses complex applicability of the above rules relating to the:

- Applicability of 6-1-311 to ESP Exhaust Abating Emissions from FCCUs and CO Boilers
- Applicability of Regulation 8-2-114 exemption to cooling water towers
- Applicability of the flare design requirements in NSPS 40 CFR 60.18 and NESHAP 40 CFR 63.11
- Applicability of 40 CFR 63, Subpart R, National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) to Equilon Enterprises LLC

- Applicability of 40 CFR 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines
- Applicability of 40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
- Applicability of 40 CFR 63, Subpart GGGGG, National Emission Standards for Hazardous Air Pollutants: Site Remediation
- Applicability of 40 CFR 64, Compliance Assurance Monitoring (CAM)

APPENDIX A

BAAQMD COMPLIANCE REPORT

COMPLIANCE & ENFORCEMENT DIVISION

Inter-Office Memorandum

December 16, 2009

TO: BRIAN BATEMAN – DIRECTOR OF ENGINEERING

FROM: KELLY WEE – DIRECTOR OF ENFORCEMENT

SUBJECT: REVIEW OF COMPLIANCE RECORD OF:

SHELL OIL PRODUCTS, U.S. - SITE # A0011

Background

This review was initiated as part of the District evaluation of an application by Shell Oil Products, U. S. for a Title V Permit Renewal. It is standard practice of the Compliance and Enforcement Division to undertake a compliance review in advance of a renewal of a Title V Permit to Operate. The purpose of this review is to assure that any non-compliance problems identified during the prior five-year permit term have been adequately addressed by returning the facility to compliance, or, if non-compliance persists, that a schedule of compliance is properly incorporated into the Title V permit compliance schedule. In addition, the review checks for patterns of recurring violation that may be addressed by additional permit terms. Finally, the review is intended to recommend, if necessary, any additional permit conditions and limitations to improve compliance.

Compliance Review

Staff reviewed Shell Oil Products, U. S. Annual Compliance Certifications for December 1, 2003 to September 30, 2009 and found no ongoing non-compliance and no recurring pattern of violations, which have not already been corrected.

The District has conducted a compliance review of 83 Notices of Violation (NOVs) issued to Shell Oil Products from December 1, 2003 to September 30, 2009. While the petroleum refining facility received a number of violations over this 5.8-year period, for facilities as large, complex, and heavily-regulated as a petroleum refining facility within the Bay Area Air Quality Management District's jurisdiction, violations are likely to occur. It is important to note that all of the violations associated with the NOVs were in compliance at the time of this review. Furthermore, the District's analysis of the NOVs for the 5.8-year period indicated that there are no ongoing violations or pattern of recurring violations that would currently require a compliance schedule.

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Shell Oil Products US - SITE #A0011
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Understanding how the District handles the violations associated with the NOVs is important to understanding how the District evaluated the facility's compliance status. Whenever the District discovers a violation, it begins a two-step process. The first step is to end the violation and bring the alleged violator back into compliance. Once compliance is achieved, the second step is to proceed with penalty assessment. It is District policy to not proceed with penalty assessment until compliance has been achieved. If a facility has not achieved compliance in a timely fashion, the District proceeds with additional enforcement action. The vast majority of Notice of Violation penalties are resolved through settlement negotiations.

The results of the District's compliance review are shown in Table I. As stated above, the 95 violations associated with the 83 NOVs were in compliance at the time of this review. In 84% of the violations, compliance was achieved within 1 day of occurrence. In the remaining 16% of the violations, the violations achieved compliance shortly after discovery but did not represent ongoing violation that would require a compliance schedule in a Title V permit. There were several sources that had multiple violations. The violations did not indicate recurrent patterns of violation because investigations into the cause of the violations revealed unrelated causes.

Of the 83 NOVs issued, approximately 84% of the violations resulted from the facility self-reporting, pursuant to District Regulations and Title-V requirements. Based on this review and analysis of all the violations for the 5.8-year period, the District has concluded that no schedule of compliance or change in permit terms is necessary beyond what is already contained in the petroleum refining facility's Title V permit, as the record showed that the violations returned to compliance, were intermittent or did not evidence on-going non-compliance, there are no patterns of recurring violation, and the facility was in compliance at the time of this review.

The violation details associated with the 83 Notices of Violation (95 violations) are summarized below and detailed in Table 1.

Violation Category	TOTAL
Emissions Related	63
Administrative	32
Permit-to-Operate	0
TOTAL	**95**

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District Staff has conducted a compliance review of 11 Notice to Comply (NTC's) issued to Shell from December 1, 2003 though September 30, 2009. The District may use the NTC to achieve compliance by using enforcement action appropriate to the severity of the violation. In most cases, these violations involve procedural, administrative, or recordkeeping omissions that did not conceal a violation or were de minimis emissions. During this reporting period none of the NTC's resulted in the issuance of a Notice of Violation for failing to correct a minor NTC violation.

Staff also reviewed additional District compliance records for Shell Oil Products U. S. for December 1, 2003 to September 30, 2009. During this period the Shell refinery activities known to the District include:

The District received ninety-one (91) air pollution complaints alleging the Shell refinery as the source. Nineteen (19) of these complaints were confirmed.

The District received three hundred and fifty-two (352) notifications for Reportable Compliance Activity (RCA)[1]: eleven (11) breakdown requests, one hundred and twenty-five (125) indicated monitor excesses, five (5) pressure relief device releases, and two hundred and sixteen (216) in-operative monitor reports. Thirty-eight (38) of the RCAs resulted in NOVs.

The District entered into two (2) enforcement agreements with Shell Oil Products- U. S.

- The first enforcement agreement was associated with the compliance of violation A47754. The agreement stipulates that Shell modify the fuel combustion sources to bring sulfur emissions under the permit condition and to seek a modification to the permit for these same combustion sources.

- The second enforcement agreement was associated with the compliance schedule for violation A48930. Due to the magnitude of the initial emission. Compliance with the limit for the rolling average for carbon monoxide was achieved within 12 months.

The District processed one (1) docket for a variance and permit appeal, before the District's Hearing Board.

- Docket # 3450 was filed as an appeal to the various revisions of the Title-V Permit. These matters were continued and handled through resolution of issues with the permit.

[1] Reportable Compliance Activity (RCA), also known as "Episode" reporting, is the reporting of compliance activities involving a facility as outlined in District Regulations and State Law. Reporting covers breakdown requests, indicated monitor excesses, pressure relief device releases, inoperative monitor reports and flare monitoring.

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Conclusion

The Compliance and Enforcement Division has made a determination that for the review period Shell Oil Products U. S. was in intermittent compliance. There is no evidence of on-going non-compliance and no recurring pattern of violations with the exception of violations that are being addressed through a compliance and enforcement agreement, that would warrant consideration of a Title V permit compliance schedule or additional permit terms.

KJW;WK;JGG;PC

Bay Area Air Quality Management District
Review of Compliance Record

SHELL REFINERY
(A0011)

V#	S#	Occur	Issue	Reg	Violation Comments	Compliance Achieved	Basis for No Compliance Schedule
A13946A	1765	12/13/2003	2/9/2004	9-1-307	E-04A87 SO2 > 250 ppm clk hr.	12/13/2003	This violation was corrected the same day after operators cleared the hydrocarbon contaminated DEA and regained control of the unit and SO2 levels fell below 250 PPM over 1 hour.
A47753A	2001	1/14/2004	7/19/2005	2-6-307	No Tox records for leading events; P/C #4288(6)	1/14 & 6/26	This is an administrative violation for no continuous records of thermal oxidizer operation for regulated loading events that took place on 1/14/04 and 6/26/04. Shell now has oxidizer temperature on its computer trend data system.
A13948A	1765	2/1/2004	3/29/2004	9-1-307	E- 04B88 SO2 >250 ppm clk hr.	2/1/2004	This violation was corrected the same day after operators reestablished the proper ratio of hydrogen to natural gas at the SCOT section of the unit, and SO2 levels fell below 250 PPM over 1 hour.
A46277B	1114	3/2/2004	6/7/2004	10	Tk-1114 PRV leaking > 500 ppm, Reg 10-KB-60.112b(a)(3)(i)	3/3/2004	This violation was corrected within two days after Shell repaired the leaking PRV.
A46276B	1469 1779	3/2/2004	6/7/2004	2-6-307	Failure to report API Separator Leaks within 15 days per P/C 5077-3		This is an administrative violation for failure to report. Shell report a 10-day deviation on 4/7/04 for API -1469 (2/24/04 & API-1779 (3/2/04).
A46278A	4193	3/31/2004	6/17/2004	2-6-307	E-04C91 NOx > 5 ppm, Condition 12271 item 24c	3/31/2004	This violation was corrected the same day when operators re-established ammonia flow to the CoGen #2 abatement device.
A46294B	4160	4/2/2004	1/11/2005	8-10-401	Failure to submit initial report	4/2/2004	This was an administration violation for failing to submit an initial process vessel list on or by April 1, 2004. Air Product submitted the list on 12/14/04.
A13950A	1151	4/8/2004	4/9/2004	8-18-301	Open ended line >100 ppm on Tk-1151 (10,000 ppm leak water drain line.)	4/8/2004	This violation was corrected the same the same day after the water drain line was blinded and remonitored.
A46279A	4180	5/18/2004	6/21/2004	9-1-307	E-04D96 SO2 > 250 ppm clk hr	5/18/2004	This violation was corrected the same day after operators reestablished lean MDEA flow to the SCOT absorber, and SO2 levels fell below 250 PPM over 1 hour.
A46286A	4180	5/20/2004	8/27/2004	2-6-307	E-04E03 SO2 >100 ppm 24hr avg, Condition #12271 Part 68	5/21/2009	This violation was corrected within two days after operators cleared the analyzer and reestablished control.
A46283A	4180	5/21/2004	8/4/2004	9-1-307	E-04E02 SO2 > 250 ppm clk hr	5/21/2009	This violation was corrected the same day after operators cleared the analyzer and reestablished control
A46287C	1759	6/7/2004	9/21/2004	1-522.7	Late Reporting E-04E49.	6/7/2004	This was an administrative violation, related to the late reporting of a monitor excess. Though it was late, the indicated monitor excess was reported to the District.
A46287A	1759	6/7/2004	9/21/2004	9-1-307	E-04E49 SO2 > 250 ppm clk hr. (6/7/04) E-04E50 SO2 > 250 ppm clk hr. (6/9/04)	6/9/2004	This violation was corrected the on each day (6/7 & 6/9) after operators reestablished control of the Flexsorb unit. Intermittent upsets at the unit continued until 6/18/04.
A46280A	1149	6/8/2004	7/15/2004	8-5-307	Tk-1149 PRV leaking > 500 ppm	6/10/2004	This violation was corrected within three days when the valve was repaired by Shell.
A46281A	1150	6/8/2004	7/15/2004	8-5-307	Tk-1150 PRV leaking > 500 ppm	6/10/2004	This violation was corrected within three days when the valve was repaired by Shell.

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V#	S#	Occur	Issue	Reg	Violation Comments	Compliance Achieved	Basis for No Compliance Schedule
A46287B	1759	6/8/2004	9/21/2004	2-6-307	E-04E55 SO2 > 250 ppm clk hr	6/10/2004	This violation was corrected within three days after operators reestablished control of the Flexsorb unit on 6/10/04. Intermittent upsets at the unit continued until 6/18/04.
A46282A	1781	6/8/2004	7/15/2004	8-5-307	Tk-1341 PRV leaking > 500 ppm	6/10/2004	This violation was corrected within three days when the valve was repaired by Shell.
A46284A	1149	7/13/2004	8/4/2004	8-5-307	Tk-1149 PRV leaking > 500 ppm	7/15/2004	This violation was corrected within three days when the valve was repaired by Shell.
A46285A	1150	7/13/2004	8/4/2004	8-5-307	Tk-1150 PRV leaking > 500 ppm	7/15/2004	This violation was corrected within three days when the valve was repaired by Shell.
A46294C	4160	7/23/2004	1/11/2005	8-10-503	Failure to maintain records	7/23/2004	There was no voc monitoring records available of a vessel depressurization that occurred on 7/23/04. Lost records. (Air Products)
A46289A	4180	9/4/2004	11/19/2004	9-1-307	E-04G15 SO2 > 250 ppm clk hr	9/4/2004	This violation was corrected the same day when operators brought the foaming MDEA under control with the addition of antifoam agent, and SO2 levels fell below 250 PPM over 1 hour.
A46288A	4001	10/5/2004	11/16/2004	9-2-301	E-04G70 H2S > 60 ppb 3 mins, Mt. View GLM	10/5/2004	This violation was corrected the same day when the coke drum stopped venting. Coke drum venting takes about 15 minutes so the source of H2S stopped.
A46292A	4180	10/23/2004	12/17/2004	9-1-307	E-04H20 SO2 > 250 ppm clk hr	10/23/2004	This violation was corrected the same day after operators brought the Clause Unit under control and SO2 levels fell below 250 PPM over 1 hour. The upset was caused by operator error.
A46293A	1047	11/29/2004	1/6/2005	8-5-307	Tk-1047 PRV leaking > 500 ppm	11/30/2004	This violation was corrected within two days after the valve was repaired by Shell.
A46296A	1507	12/15/2004	2/24/2005	1-522.4	Late reporting of InOp 04J46	12/15/2004	This was an administrative violation, related to the late reporting of an inoperative monitor. Though it was late, the inoperative monitor was reported to the District.
A46297A	4180	12/20/2004	2/24/2005	1-522.4	Late reporting of InOp 04J64	12/20/2004	This was an administrative violation, related to the late reporting of an inoperative monitor. Though it was late, the inoperative monitor was reported to the District.
A46295A	4160	1/1/2005	1/11/2005	8-18-401.3	Failure to perform 2004 annual inspection of PRD's, (HP3 Air Products)	1/1/2005	This is an administrative violation Air Products, (HP3), did not inspect their inaccessible PRD's in 2004. They did in 2005.
A45700A	1759	1/16/2005	4/29/2005	10 40CFR60.104 (a)(1)	E-04K30 H2S > 160 ppm 3 hr avg.	1/16/2005	This violation was corrected the same day when operators controlled the foaming of the Flexsorb solution. Shell had a series of excesses caused by Flexsorb solution foaming in June of 2004. This was associated with the initial start up of the Flexsorb unit and did not persist after the start up period.
A45699A	4141	2/10/2005	4/29/2005	2-6-307	Source Test NH3 >20 ppm @ 3% O2; ref S.T. #OS-955 through 957	2/10/2005	This violation was corrected on the same day. This source test is a one-day snapshot of emissions, and only documents a violation for one day. A compliant source tests for ammonia slip was conducted on 3/17/05.

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V#	S#	Occur	Issue	Reg	Violation Comments	Compliance Achieved	Basis for No Compliance Schedule
A47754A	4002 4003	2/26/2005	7/21/2005	2-6-307	PC# 12271-18, rolling TRS > 70 ppm annual avg.	5/26/2005	This violation was corrected within 98 days when Shell stopped burning Flexigas in some of its combustion sources per Enforcement Agreement by May 2005. This reduced the TRS to comply with permit conditions.
A47751A	4021	3/11/2005	5/26/2005	2-6-307	Source Test CO > 50 ppm @ 3% O2; ref S.T. #OS-983	3/11/2005	This violation was corrected on the same day. This source test is a one-day snapshot of emissions, and only documents a violation for one day. A compliant source test for carbon monoxide was conducted on 3/16/05.
A47752A	4180	4/12/2005	6/29/2005	9-1-307	E-04M23 SO2 > 250 ppm clk hr	4/12/2005	This violation was corrected the same day when operators reduced foaming of the MDEA (Methyl Diethyl Ammine) solution at SRU #4.
A47756A	4180	5/15/2005	8/30/2005	9-1-307	E-04M84 SO2 >250 ppm clk hr	5/15/2005	This violation was corrected the same day when operators reduced foaming of the MDEA at SRU #4.
A47757A	4192	6/30/2005	9/8/2005	2-6-307	E-04N59 NOx > 5 ppm/3 hr avg; P/C #12271 (24c)	6/30/2005	This violation was corrected the same day when the load on the gas turbine was reduced and a steam injection valve was replaced.
A47758A	4003	7/11/2005	9/8/2005	2-6-307	E-04N76 NOx > 10 ppm 3 hr avg; P/C #12271 (35)	7/11/2005	This violation was corrected the same day when NOx decreased to below 10 ppm/3 hr. average limit. The ammonia injection was cooled using water mist.
A47759A	32102	7/12/2005	9/29/2005	8-18-402.1	26 Components Not ID'd per LDAR self audit	7/12/2005	This violation was corrected after review and the 26 components were tagged with a unique identification code and entered into the data base following the issuance of the external audit report.
A47755A	1754	8/25/2005	8/25/2005	8-5-306	Tk-1333 PRV leaking > 500 ppm	8/25/2008	This violation was corrected the same day when valve was replaced and rechecked by Shell.
A47761A	1772	9/1/2005	11/30/2005	10 40CFR60.104 (a)(1)	E-04P78 H2S > 160 ppm 3 hr avg	9/2/2005	This violation was corrected within two days after the H2S level dropped below the limit.
A47339A	1763	10/29/2005	4/27/2006	2-6-307	E-04Q80 H2S > 162 ppm 3 hr avg, combustion sources	10/29/2005	This violation was corrected the same day after operators re-established steam flow to DEA treater #1 and H2S-in-fuel-gas average concentrations fell below regulatory and permit condition limits.
A47339B	1763	10/29/2005	4/27/2006	10 CFR4060.104 (a)(1)	E-04Q80 H2S > 162 ppm 3 hr avg, combustion sources	10/29/2009	see above

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V#	S#	Occur	Issue	Reg	Violation Comments	Compliance Achieved	Basis for No Compliance Schedule
A47760A	1426	11/8/2005	11/10/2005	1-301	9 confirmed oil fallout complaints- refinery accident	11/8/2005	A Public Nuisance violation resulting from the release of a hot oil from a component within the Cat Cracker Unit (CCU) gas plant. A fallout of oil impacted the surrounding community, creating a public nuisance. The incident occurred and cleared on 11/8/05 as the hot oil release was contained and feed was taken out of the CCU.
A47338A	1431	12/1/2005	4/6/2006	9-1-307	E-04R42 SO2 > 250 ppm clk hr	12/2/2005	This violation was corrected within two days after operators brought the sulfur recovery system under control and SO2 concentrations fell below regulatory limits. The Reg 9 excess lasted for 9 hours from 1700 on 12/1/05 to 0200 on 12/2/05. NOV's A47336, A47337, A47338A and A47338B are all part of the same event. o
A47338B	1431	12/1/2005	4/6/2006	10 CFR4060.105 (a)(13)e(4)	E-04R42 SO2 > 250 ppm clk hr	12/2/2005	This violation was corrected within two days after operators brought the sulfur recovery system under control and SO2 concentrations fell below regulatory limits. This occurred at 0300 hrs on 12/2/05 per Technical Evaluation for the Regulation 10 violation. The Reg 10 excess lasted for 12 hours from 1500 on 12/1/05 to 0300 on 12/2/05. NOV's A47336, A47337, A47338A and A47338B are all part of the same event.
A47337A	1763	12/1/2005	4/6/2006	10 CFR4060.104 (a)(1)	E-04R43 H2S >163 ppm H2S in fuel gas	12/1/2005	This violation was corrected the same day after operators brought the sulfur recovery system under control and H2S levels fell below 163 PPM over 3 hours. A heavy rain event caused the upset.
A47336A	4002	12/1/2005	4/6/2006	2-6-307	E-04R45 H2S > 50 ppm/24 hr in clean fuels fuel gas	12/1/2005	This violation was corrected the same day after operators brought the sulfur recovery system under control and H2S levels fell below 50 PPM over 24 hours. A heavy rain event caused the upset.
A47341A	1431	1/19/2006	5/10/2006	9-1-307	E- 04S37 SO2 > 250 ppm clk hr	1/19/2006	This violation was corrected on the same day after operators skimmed the hydrocarbon out of the sour water stripper, and brought the sulfur recovery system under control with SO2 concentrations below regulatory limits.
A47342A	1765	2/3/2006	5/10/2006	9-1-307	E-04S61 SO2 > 250 ppm clk hr	2/3/2006	This violation was corrected on the same day after operators skimmed the hydrocarbon out of the DEA flash and skim drum. This action re-established proper oxygen levels in the SRU and the SO2 concentration fell below the regulatory limit.
A47343A	4180	3/23/2006	5/10/2006	9-1-307	E-04T45 SO2 > 250 ppm clk hr	3/23/2006	This violation was corrected the same day after operators re-established the proper level of DEA in the DEA flash and skim drum and the SO2 concentration fell below the regulatory limit.
A47345A	1765	4/9/2006	6/9/2006	9-1-307	E-04T81 SO2 > 250 ppm clk hr	4/9/2006	This violation was corrected the same day after operators regained proper operation in SWS #6 and the SO2 concentration fell below the regulatory limit.

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Bay Area Air Quality Management District
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SHELL REFINERY
(A0011)

V#	S#	Occur	Issue	Reg	Violation Comments	Compliance Achieved	Basis for No Compliance Schedule
A47344A	4201	5/15/2006	5/31/2006	12-11-502.2.3	No analysis of a required flare sample	5/15/2006	During analysis of the flare sample a mechanical or electronic problem with the GC resulted in no sample results. The procedure for analyzing flare samples was changed to take into account analyzer upsets. Samples will be held longer so that if the analysis fails there will be another chance to run it again.
A47348A	1772	6/5/2006	9/20/2006	10 40CFR60.104 (a)(1)	E-04V35 H2S >162 ppm 3 hr avg.	6/5/2006	This violation was corrected the same day after the Flexicoker was re-started and the Flexsorb Unit re-established H2S removal of Flexigas. The Flexicoker went into a sudden unplanned shutdown resulting from operator error during a test of the protective instrument system. This is an isolated incident.
A47346A	2001	6/7/2006	7/20/2006	2-6-307	Marine loading leak test not done before 20% loaded. Late reporting of deviation.	6/7/2006	There are 2 violations of Title V permit conditions. The first violation came into compliance at the time the emission survey was completed on 6/7/06. The second violation came into compliance when the deviation was reported. Leak check during Marine Loading event did not take place before 20% cargo loaded. Need better communication so leak check can take place earlier in loading event. This is an isolated incident.
A47347A	32102	7/5/2006	7/20/2006	8-18-402.1	Regulated components not ID'd, not in database per LDAR self audit.	7/5/2006	This violation was administrative for fugitive emission components not tagged and open-ended lines. Internal audit by Shell revealed components were not identified and open-ended lines with no cap or plug on the end. The components were identified and included in the fugitive component data base on the same day as discovery. Open-ended lines were fitted with a plug or cap as they were found.
A47349A	4180	9/15/2006	12/4/2006	9-1-307	E-04W76 SO2 > 250 ppm clk hr	9/15/2006	This violation was corrected the same day after operators re-established the proper gas flow in the MDEA absorber column. This situation was brought on by a sequence of actions associated with the planned shutdown of the Delayed Coker.
A48926A	32102	11/1/2006	3/21/2007	8-18-402.1	Internal LDAR audit 3rd and 4th quarter 2006 no ID'd components.	11/1/2006	This violation was administrative for fugitive emission components not tagged and open-ended lines. Internal audit by Shell revealed components were not identified and open-ended lines with no cap or plug on the end. The components were identified and included in the fugitive component data base on the same day as discovery. Open-ended lines were fitted with a plug or cap as they were found.
A47350A	1471	1/12/2007	3/8/2007	12-11-502.3	Flare sample no taken within 30 minutes of flaring.	1/12/2007	Shell failed to take a flare gas sample for the 1/12 event. The flaring event was short duration so there was only one sample required. They don't know what went wrong.

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A48928A	4002 4003	2/14/2007	3/27/2007	2-6-307	Source Test CO > 50 ppm @ 3% O2, Condition 12271 part 36- OS-1850	2/14/2007	This violation was corrected on the same day. This source test is a one-day snapshot of emissions, and only documents a violation for one day. Shell re-tested the same source on 2/16/07, and passed.
A48930A	1426	3/9/2007	4/26/2007	2-6-307	Excessive CO emissions at FCCU and CO Boilers- PC #7618 and 12911 and CFR sec. 63-1565	3/15/2008	A leak in the 650 pound steam header, and subsequent errors during the repair attempt along with mechanical failures forced the refinery to continue to operate the FCCU without abatement. As per the wording in the Shell incident report, simultaneous human error and two mechanical failures resulted in the shutdown of all 3 CO boilers while the FCCU remained on-line at minimum rates. The CO boilers shutdown beginning on 3/9/07 resulted in the only REFEMS condition violation since the permit was issued in 1984. The FCCU came into compliance with the Federal limit of 500 ppm carbon monoxide averaged over 1 hour at 1200 on 3/19/07. The refinery achieved compliance with Permit Condition #7618 on March 15, 2008 as per Enforcement Agreement.
A48930B	1426	3/9/2007	4/26/2007	Reg 10	40 CFR sec. 63-103 (FCCU operations)	3/15/2008	A leak in the 650 pound steam header, and subsequent errors during the repair attempt along with mechanical failures forced the refinery to continue to operate the FCCU without abatement. As per the wording in the Shell incident report, simultaneous human error and two mechanical failures resulted in the shutdown of all 3 CO boilers while the FCCU remained on-line at minimum rates. The CO boilers shutdown began on 3/9/07. The FCCU came into compliance with the Federal limit of 500 ppm carbon monoxide averaged over 1 hour at 1200 on 3/19/07.
A48931A	32102	4/24/2007	7/12/2007	8-18-402.1	Internal LDAR audit 1st quarter 2007- components not ID'd.	4/27/2007	This violation was administrative for fugitive emission components not tagged and open-ended lines. Internal audit by Shell revealed components that were not identified and open-ended lines with no cap or plug on the end. The components were identified and included in the fugitive component data base on the same day as discovery. Open-ended lines were fitted with a plug or cap as they were found.
A48933A	4031	5/9/2007	11/1/2007	2-6-307	E-05B42- bad calibration gas. Days of violaiton May 9, 10, 15-18, 21, 22, June 7, 8, 13-18	6/18/2007	This violation occurred for 16 days. This excess was the result of a mislabeled calibration gas. The normal operation of the HGHT furnace was not enough to reveal the periodic excess condition and only the calculated emissions following a source test revealed the inconsistency. When the inconsistency was revealed, prompt trouble shooting discovered source to be the mislabeled calibration gas. The days of excess end on 6/18/07 but the problem with the mislabeled calibration gas was not corrected until the source test calculations were completed sometime after 7/17/07.

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A48932A	1468	6/25/2007	9/12/2007	9-2-301	E-05A87, H2S > 30 ppb 1 hr. ACE GLM	9/12/2007	This violation was corrected the same day. An anaerobic condition along with the wrong size circulation pump in effluent treatment pond #6 was the source of H2S registered at the ACE Hardware GLM. The pond was fitted with a proper size circulation pump to fix the condition that generated the H2S.
A48934A	32102	7/30/2007	11/1/2007	8-18-402.1	Internal LDAR audit 2nd quarter 2007-components not ID'd.	7/30/2007	This violation was administrative for fugitive emission components not tagged. Internal audit by Shell revealed components that were not identified. The components were identified and included in the fugitive component data base on the same day as discovery.
A48934B	32102	7/30/2007	11/1/2007	10	40CFR-60 Sub GGG - open ended lines.	7/30/2007	This violation was administrative for fugitive emission components having open-end lines. Internal audit by Shell revealed components open-ended lines with no cap or plug on the end. Open-ended lines were fitted with a plug or cap as they were found.
A48935A	4190	8/7/2007	11/1/2007	2-6-307	E-05B48 NOx > 5 ppm 3 hr & > 9 ppm NOx 1 hr avg.	8/7/2007	This violation was corrected the same day when operators re-established adequate ammonia flow to the CoGen #1 abatement device and the exceedance cleared by 1600 on 8/7/07.
A48936A	1471	9/2/2007	11/1/2007	9-2-301	E-05B93 H2S > 60 ppb 3 min, ACE GLM	9/2/2007	This violation was corrected the same day after flaring stop. Flaring was caused by compressor maintenance. There was no plant upset. A large flow of sour gas overwhelmed the one compressor that was on-line at the LOP flare gas header and triggered a short flaring event. Enough H2S passed through the flare to register an H2S excess at the ACE GLM.
A49432A	1149	10/24/2007	10/24/2007	8-5-307	Tk-1149 PRV leaking > 500 ppm	10/25/2007	This violation was corrected within two days after the leaking pressure relief device on the tank was replaced.
A49433A	1150	10/24/2007	10/24/2007	8-18-301	Open-ended line leaking > 100 ppm (2,000 ppm)	10/24/2007	This violation was corrected the same day it was discovered. The leaking equipment was removed and the valve blinded off.
A48937A	32102	12/5/2007	2/5/2008	8-18-402.1	Internal LDAR audit 3rd quarter 2007-components not ID'd	12/5/2007	This violation was administrative for fugitive emission components not tagged and open ended lines. internal audit by Shell revealed components that were not identified and open-ended lines with no cap or plug on the end. The components were identified and included in the fugitive component data base on the same day as discovery. Open-ended lines were fitted with a plug or cap as they were found.
A48938A	4180	12/14/2007	3/6/2008	9-1-307	E-05D21 SO2 > 250 ppm clk hr	12/14/2007	This violation was corrected the same day after operators re-established the steam trace to the eductor line and the sulfur plug cleared from the system, (burned through).

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A48939A	1432	1/14/2008	3/6/2008	9-1-307	E-05D66 SO2 > 250 ppm clk hr	1/14/2008	This violation was corrected the same day after operators restored stripping steam to the MDEA regeneration tower and the built-up load of H2S in the MDEA was removed and passed through the oxidizer. An interruption in stripping steam flow to the MDEA regeneration tower triggered a SO2 excess.
A50327B	32102	2/4/2008	3/3/2009	10	40 CFR 60 SubGGG- open-ended lines	2/4/2009	This violation was administrative for fugitive emission components having open-end lines. Internal audit by Shell revealed open-ended lines with no cap or plug on the end. Open-ended lines were fitted with a plug or cap as they were found.
A48949A	32102	2/5/2008	4/15/2008	8-18-402.1	Internal LDAR audit 4th quarter 2007-components not ID'd	2/5/2008	This violation was administrative for fugitive emission components not tagged. Internal audit by Shell revealed components that were not identified. The components were identified and included in the fugitive component data base on the same day as discovery.
A48942B	32102	2/5/2008	4/15/2008	10	40CFR- 60 Sub GGG, open-ended lines	2/5/2008	This violation was administrative for fugitive emission components having open-end lines. Internal audit by Shell revealed open-ended lines with no cap or plug on the end. Open-ended lines were fitted with a plug or cap as they were found.
A48940A	1432	2/18/2008	4/8/2008	9-1-307	E-05E35 SO2 > 250 ppm clk hr	2/18/2008	This violation was corrected on the same day after operators closed the bypass butterfly valve and the elemental sulfur in the Scot plant passed through. A partially open Scot bypass valve triggered an SO2 excess.
A48941A	4180	2/18/2008	4/8/2008	9-1-307	E-05E36 SO2 > 250 ppm clk hr	2/18/2008	This violation came into compliance on the same day after operators discovered and unplugged the sample line going to the tail gas analyzer at SRU #4.
A48944A	610	4/4/2008	6/26/2008	8-5-306	Tk-610 component leaking >500 ppm for > 48 hours	4/8/2008	This violation was correct within 7 days. Shell discovered an explosion hatch assembly on tank 610 leaking in excess of 500 ppm. They replaced the leaking hatch assembly and confirmed that it was vapor tight but did so more than 48 hours after discovery. Shell staff confirmed that the new explosion hatch assembly was vapor tight at 0900 on 4/8/08.
A48943A	32102	5/1/2008	6/11/2008	8-18-402.1	Internal LDAR audit 1st quarter 2008-components not ID'd.	5/1/2008	This violation was administrative for fugitive emission components not tagged. Internal audit by Shell revealed components that were not identified. The components were identified and included in the fugitive component data base on the same day as discovery.
A48943B	32102	5/1/2008	6/11/2008	10	40 CFR 60 SubGGG- open-ended lines	5/1/2008	This violation was administrative for fugitive emission components having open-end lines. Internal audit by Shell revealed open-ended lines with no cap or plug on the end. Open-ended lines were fitted with a plug or cap as they were found.
A48946A	32102	8/19/2008	10/16/2008	8-18-402.1	Internal LDAR audit 2nd quarter 2008-components not ID'd	8/19/2008	This violation was administrative for fugitive emission components not tagged. Internal audit by Shell revealed components that were not identified. The components were identified and included in the fugitive component data base on the same day as discovery.

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A48946B	32102	8/19/2008	10/16/2008	10	40 CFR 60 SubGGG- open-ended lines	8/19/2008	This violation was administrative for fugitive emission components having open-end lines. Internal audit by Shell revealed open-ended lines with no cap or plug on the end. Open-ended lines were fitted with a plug or cap as they were found.
A48949A	4005	9/17/2008	12/4/2008	2-6-307	Title V condition #12271 part 79- coke barn bag house	10/7/2008	This violation was corrected within 17 days. The coke handling facility was in operation from 9/17/08 to 10/7/08 without operating the abatement device as required by permit condition. The coke pile was wet throughout the breakdown period. This violation is more administrative than emission based. Shell staff and contractors did not communicate regarding regulatory requirements.
A48947A	1149	10/23/2008	10/31/2008	8-5-307	Tk-1149 PRV leak >500 ppm, (4200 ppm)	10/24/2008	This violation was corrected within two days. District staff measured a butane leak >500 ppm at the PRV relief horn on 10/23/08. Shell repaired the relief horn and confirmed that it was vapor tight on 10/24/08.
A48948A	32102	10/29/2008	11/18/2008	8-18-402.1	Internal LDAR audit 3rd quarter 2008- components not ID'd	10/29/2008	This violation was administrative for fugitive emission components not tagged. Internal audit by Shell revealed components that were not identified. The components were identified and included in the fugitive component data base on the same day as discovery.
A48948B	32102	10/29/2008	11/18/2008	10	40 CFR 60 SubGGG- open-ended lines	10/29/2008	This violation was administrative for fugitive emission components having open-end lines. Internal audit by Shell revealed open-ended lines with no cap or plug on the end. Open-ended lines were fitted with a plug or cap as they were found.
A50326A	1134	2/3/2009	2/11/2009	8-18-301	Tk-1134 open-ended line > 500 ppm	2/3/2008	This violation was corrected the same day when District staff found 2 valves open at the base of a pressure vacuum valve located on top of a cone roof tank containing gasoline. Both valves were closed immediately upon discovery by District Staff.
A50327A	32102	2/4/2009	3/3/2009	8-18-402.1	Internal LDAR audit 4th quarter 2008- components not ID'd	2/4/2009	This violation was administrative for fugitive emission components not tagged. Internal audit by Shell revealed components that were not identified. The components were identified and included in the fugitive component data base on the same day as discovery.
A50661A	1598	4/1/2009	5/29/2009	8-7-302.1	Operating a gasoline dispensing facility w/o certified Phase II system		Administrative NOV. The Phase II deadline was extended.
A50328A	32102	4/29/2009	5/12/2009	8-18-402.1	Internal LDAR audit 1st quarter 2009- components not ID'd	4/29/2009	This violation was administrative for fugitive emission components not tagged. Internal audit by Shell revealed components that were not identified. The components were identified and included in the fugitive component data base on the same day as discovery.
A50328B	32102	4/29/2009	5/12/2009	10	40 CFR 60 SubGGG- open-ended lines	4/29/2009	This violation was administrative for fugitive emission components having open-end lines. Internal audit by Shell revealed components open-ended lines with no cap or plug on the end. Open-ended lines were fitted with a plug or cap as they were found.

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V#	S#	Occur	Issue	Reg	Violation Comments	Compliance Achieved	Basis for No Compliance Schedule
A50331A	1469	7/16/2009	7/23/2009	8-8-302	API separator > 500 ppm leak around hatch cover	7/16/2009	This violation was corrected the same day after District staff discovered a leaking hatch cover on the API oil/water separator.
A50334A	1509	7/23/2009	10/27/2009	6-1-302	E-05N38- Opacity >30% 3 min clk hr	7/23/2009	This violation was corrected the same day when electrostatic precipitator, (ESP), resumed operation once power to the ESP grid was restored. Excess at Carbon Monoxide Boiler #2, (COB)
A50332A	32102	8/10/2009	8/20/2009	8-18-402.1	Internal LDAR audit 2nd quarter 2009- components not ID'd	8/10/2009	This violation was administrative for fugitive emission components not tagged. Internal audit by Shell revealed components that were not identified. The components were identified and included in the fugitive component data base on the same day as discovery.
A50332B	32102	8/10/2009	8/20/2009	10	40 CFR 60 SubGGG- open-ended lines	8/10/2008	This violation was administrative for fugitive emission components having open-end lines. Internal audit by Shell revealed open-ended lines with no cap or plug on the end. Open-ended lines were fitted with a plug or cap as they were found.
A50335A	4031	9/7/2009	10/27/2009	2-6-307	E-05P02 NOx > 10 ppm 3 hr avg. PC #12271 part 35	9/7/2009	This violation was corrected on the same day when operators re-lit the furnace and stabilized feed to the Heavy Gas Hydrotreater and NOx concentration dropped below the regulatory limit.

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APPENDIX B
ENGINEERING EVALUATION REPORTS

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11
Application: 14497

Background
Shell Oil Products US – Martinez Refinery (Shell) has submitted this application to obtain a Permit to Operate (PO) to perform certain alterations at the following *existing* flare:

S-1772 OPCEN[6] Hydrocarbon Flare

Shell has proposed to route its routine (non-significant vent gas relief/flaring event) vent gas flows, which otherwise would have been flared at S-1772, to two existing Flare Gas Recovery Compressors (FGRCs) to be recovered as Refinery Fuel Gas (RFG), that serve the following *existing* flare:

S-4201 DC[7] Clean Fuels Flare

As it currently exists, S-1772 does not have a flare gas recovery system i.e. it is not equipped with FGRCs. As a result, vent gas contained in S-1772's flare header is not recovered and is routinely flared. Flaring information posted on the District's website for the time period between January 2005 to December 2005, indicated that S-1772 flared every day in year 2005. Specifically, 53.6 Million Standard Cubic Feet (MMSCF) of vent gas was routed to S-1772 during the above time period and resulted in 7.46 TPY, 29.68 TPY, and 0.27 TPY of Methane, Non-Methane Hydrocarbon, and Sulfur Dioxide emissions, respectively. Please refer to the attached Regulation 12, Rule 11 "Flare Monitoring at Petroleum Refineries" monthly reports that were compiled for the purposes of this evaluation based on information submitted by Shell to the District's Compliance & Enforcement Division (CED) that are posted at the following location on the District's website: http://www.baaqmd.gov/enf/flares/

When implemented, the vent gas recovered by the FGRCs at S-4201 will be sent to the vent gas treaters to remove hydrogen sulfide (H_2S), and then to the refinery fuel gas system. The refinery fuel gas system supplies the RFG which is combusted as fuel in various refinery heaters and boilers. . Combustion of the RFG in these heaters and boilers will result in lower SO_2 emissions, than had the untreated vent gas been combusted in the S-1772 OPCEN Hydrocarbon Flare. In similar fashion, combustion of the treated vent gas in well designed and operated burners, could lead to significantly lower CO emissions, than had the untreated vent gas been flared in S-1772.

At the present time, combustion units at Shell combust gases, such as RFG that are generated at the refinery, as well as natural gas purchased from outside vendors. The recovery of the routine vent gases by the FGRCs at S-4201 will result in an increased supply of RFG, and will therefore reduce the demand for natural gas.

Emissions Calculations
The project to route the routine vent gas flows from S-1772 to the FGRCs at S-4201 will involve the installation of a new water seal vessel, interconnecting piping, valving, and related instrumentation. The water seal vessel, which will be approximately 30 feet (from tangent to tangent) in height with an approximately 10 foot diameter, will be installed downstream of the existing liquid knockout pot (V-1074) that serves S-1772. The new piping and components, summarized in the Table 1 below, will connect the S-1772 flare header to the S-4201 flare header to enable routing of routine vent gas flows from S-1772 to the FGRCs at S-4201.

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[6] OPCEN – Operations Central
[7] DC – Delayed Coking

Table 1						
Type/service	**Number of components**[1]	**Emission factor (lb/hr/ component)**[2]	**POC, lb/hr**	**POC, lb/day**	**POC, lb/yr**	**POC, TPY**
Valves/Gas/Light Liquid	48	0.0000231	0.0011	0.0266	9.71	0.005
Flanges/All[3]	86	0.00017	0.0146	0.3509	128.07	0.0640
Totals	**134**		**0.0157**	**0.3775**	**137.78**	**0.069**

Note:
1) Component counts estimated by Shell.
2) Emission factor (~ leak rate) furnished in Application 1821, developed from Martinez Refinery 1999 inspection and monitoring data using CAPCOA revised EPA correlation equations.
3) Flange counts include connectors. Based on previous installations, a ratio of 1.78 flanges/valve was assumed.

Source S-1772 controls emissions resulting from process upsets, maintenance, startups and shutdowns, and routine operations at the following OPCEN sources that are upstream of it: S-1759, S-1764, S-1765, S-1774, and A-1751. In similar fashion, S-4201 controls emissions resulting from process upsets at the following DC sources that are upstream of it: S-4001, S-4020, S-4050, S-4080, S-4140, S-4160, S-4180, S-4190, S-4191, S-4192, S-4193, S-4211, S-4212, S-4310, S-4329, and S-4330. For safety reasons, the flare gas header systems at S-1772 and S-4201 must be isolated from one another when process units upstream of either of the flares experiences an upset that could lead to a significant flaring event. To address this problem, Shell has proposed to install an isolation valve between the two flare gas header systems that will prevent gas flow from S-4201 to S-1772 when S-4201 experiences a significant flaring event. When S-4201 is active, the isolation valve will close and flaring could occur at both S-4201 and S-1772. During such times, routine vent gas flows from S-1772 cannot be recovered when S-4201 is in operation and will be flared at S-1772. In similar fashion, the isolation valve will close when an upset at OPCEN units upstream of S-1772 leads to a significant flaring event at the flare. Since S-1772 is not equipped with FGRCs, Shell continuously monitors the H2S concentration vent gas sent to the flare via a continuous emission monitor. Per Regulation 12-11, both the OPCEN and DC flares have flare flow meters and sampling systems. Shell does not plan to deviate from this arrangement when the isolation valve is closed and S-1772 is active.

Please refer to the attached process flow diagram that details the existing and the proposed process modifications discussed in the preceding paragraphs.

Toxic Risk Screen Analysis
Shell maintains a database containing speciation information for various process streams at the refinery. This data is used for a variety of reports, such as the Toxic Release Inventory (TRI) reports among others. In order to ensure the air toxics release data is consistently reported, speciation data from Shell's database has been used in this evaluation to estimate the Toxic Air Contaminants (TACs) and non-TAC emissions from the new fugitive components. These emissions are summarized in Table 2 below.

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Table 2				
Chemical Name	**CAS Number**	**Maximum Concentration wt. %**	**TAC lbs/day**[8]	**TAC Emissions TPY**[9]
1,2,4-trimethylbenzene	95-63-6	0.0003%	1.14E-06	2.08E-07
1,3-butadiene	106-99-0	0.0003%	1.14E-06	2.08E-07
Benzene	71-43-2	0.0023%	8.74E-06	1.60E-06
Carbon monoxide	630-08-0	1.0000%	3.80E-03	6.94E-04
Cumene	98-82-8	0.0003%	1.14E-06	2.08E-07
Cyclohexane	110-82-7	0.0032%	1.22E-05	2.22E-06
Ethylbenzene	100-41-4	0.0003%	1.14E-06	2.08E-07
Ethylene	74-85-1	5.0000%	1.90E-02	3.47E-03
Hydrogen sulfide	7783-06-4	2.0000%	7.60E-03	1.39E-03
Propylene	115-07-1	4.0000%	1.52E-02	2.77E-03
Toluene	108-88-3	0.0019%	7.22E-06	1.32E-06
Xylene (mixed isomers)	1330-20-7	0.0002%	7.60E-07	1.39E-07

Table 3 compares the TAC emissions summarized in Table 2 above, to their corresponding TAC Trigger Levels in Table 2-5-1 of Regulation 2, Rule 5 if District Acute and Chronic Trigger Levels have been defined.

Table 3					
TAC	**CAS Number**	**TAC Emissions (lbs/yr)**	**Table 2-5-1 Acute Trigger Level (lb/hr)**	**Table 2-5-1 Chronic Level (lb/yr)**	**Do TAC emissions exceed Table 2-5-1 TAC Trigger Levels? (Yes, No, NA)**[10]
1,3-butadiene	106-99-0	4.16E-04	NA	1.1	No
Benzene	71-43-2	3.19E-03	2.9	6.4	No
Ethylbenzene	100-41-4	4.16E-04	NA	77,000	No
Hydrogen sulfide	7783-06-4	2.774	0.093	390	No
Propylene	115-07-1	5.548	NA	120,000	No
Toluene	108-88-3	2.64E-03	82	12,000	No
Xylene (-m)	1330-20-7	2.77E-04	49	27,000	No
Total		**8.325**			

[8] For example, the daily emissions of 1,2,4-trimethylbenzene can be estimated as follows:
= (0.0003%) x (0.38 – from Table 1) = 1.14E-06 lbs/day.

[9] For example, the annual emissions of 1,2,4-trimethylbenzene can be estimated as follows:
= (1.14E-06) x (365) / 2000 = 2.08 E-07 TPY

[10] To compare the hourly TAC emissions to the acute TAC trigger level divide the lbs/yr TAC estimated by 8,760 hrs/yr

It can be seen from Table 3 above, that a Toxic Health Risk Screening Analysis (HRSA) is not warranted.

Regulation 2-1-128.21 Exemption
Regulation 2-1-128.21 states the following:
2-1-128 Exemption, Miscellaneous Equipment: The following equipment is exempt from the requirements of Sections 2-1-301 and 302, provided that the source does not require permitting pursuant to Section 2-1-319.
128.21 Modification, replacement, or addition of fugitive components (e.g. valves, flanges, pumps, compressors, relief valves, process drains) at existing permitted process units at petroleum refineries, chemical plants, bulk terminals or bulk plants, provided that the cumulative emissions from all additional components installed at a given process unit during any consecutive twelve month period do not exceed 10 lb/day, and that the components meet applicable requirements of Regulation 8 rules.

It can be seen from the emission calculations presented in Table 1 above that the cumulative emissions from the 134 additional fugitive components that will be installed at process units (~ flares) that are part of this application are below 10 lb/day i.e. 0.38 lb/day. The fugitive components, summarized in Table 1 will meet the requirements of Regulation 8, Rule 18 “Equipment Leaks” and will be incorporated into Shell’s Leak Detection and Repair (LDAR) program. Therefore, it is safe to conclude that the addition of the fugitive components summarized in Table 1 above qualifies for the exemption under Regulation 2-1-128.21.

Regulation 2-1-316 through 2-1-319:

- Regulation 2-1-316:
  The Hazardous Air Pollutant (HAP) or TAC emissions from the additional fugitive components and the proposed alterations to S-1772 summarized in Table’s 2 and 3 above, will neither result in the emission of 2.5 TPY or more of a single HAP emissions, or 6.5 TPY or more of a combination of HAPs. Please refer to Table 3 above.
- Regulation 2-1-317:
  The operation of fugitive components summarized in Table 1 above, which are designed to minimize emissions are subject to the inspection and maintenance programs in Regulation 8, Rule 18. Therefore, for the purposes of the exemption it is unlikely they will cause any public nuisance.
- Regulation 2-1-318:
  None of the hazardous substances listed in Regulation 2-1-318.1 through 2-1-318.8 will be emitted from either the additional fugitive components summarized in Table 1 above.
- Regulation 2-1-319:
  It can be seen from Table 1 above that the annual emissions of POC – the regulated air pollutant of interest, from the additional fugitive components is below 5 TPY i.e. 0.069 TPY.

BACT
Per Regulation 2, Rule 2, Section 301, BACT is only triggered if emissions from a new source or an increase in emissions from a modified source has the potential to emit 10 lbs or more per highest day of POC (pollutant of interest in this application). As previously discussed under the “Regulation 2-1-128.21 Exemption” discussion above, the fugitive components summarized in Table 1 above are exempt from permitting per Regulation 2-1-128.21. Therefore, BACT is not triggered.

On an unrelated topic (for the purposes of BACT), Shell voluntarily embarked on this project to recover routine vent gas flows, which otherwise would have been flared at OPCEN flare (S-1772), by rerouting them to the FGRCs at the DC flare (S-4201). If any, the proposed project would reduce routine flaring emissions at S-1772 from existing levels. In addition, Shell clarified that during a significant flaring event at either S-1772 or S-4201, a minor amount of routine OPCEN vent gas that is not recovered by the FGRCs at S-4201 will initially flare at the DC flare until the isolation valve between the above flare headers closes. However, Shell has contended that this minimal flaring of un-recovered OPCEN vent gas which could cause some increased flaring at S-4201 will not compromise the company’s ability to comply with the monthly and annual emission limits outlined in Tables A.1 and A.2 in Part A under “General Permit Conditions” of permit condition 12271, governing the operation of the above flare.

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Cumulative Increase & Offsets

Shell is an existing facility. Since the additional fugitive components summarized in Table 1 above are exempt under Regulation 2-1-128.21, the OPCEN hydrocarbon reroute project will not result in a cumulative increase in criteria pollutant emissions. Therefore, offsets are also not warranted. Tables 4 and 5 summarize data relating to the cumulative increase in criteria pollutant emissions and offsets at Plant 11 for information purposes only.

Table 4
Cumulative Increase

Pollutant	Increase in plant emissions prior to April 5, 1991 [11] (TPY)	Increase in plant emissions since April 5, 1991 [12] (TPY)	Increase in plant emissions associated with this application (TPY)	Cumulative increase in emissions (Post 4/5/91 + Current application increase)[13] (TPY)
NOx	0	0	0	0
POC	25.86	0	0[14]	0
CO	0	298.00	0	298.00
PM	0.05	0	0	0
PM10	0.11	0	0	0
SO2	0	0[15]	0	0
NPOC	11.00	14.70	0	14.70

Table 5
Offsets

Pollutant	Permitted plant emissions (TPY) Pre-April 5, 1991[16] + Post-April 5, 1991	Actual plant emissions[17] (TPY)	*Increase in plant emissions associated with this application* (TPY)	Total emissions (Higher of Permitted/Actual Emissions + Emissions associated with this application)[18] (TPY)	Regulation 2-2-302 and 2-2-303 Offset Triggers (TPY)
NOx	0	1783.89	0	1783.89	> 35
POC	25.86	1743.83	0	1743.83	> 35
CO	298.00	708.90	0	708.90	NA
PM	0.05	0	0	0.05	NA
PM10	0.11	425.85	0	425.85	> 1
SO2	0	1605.80	0	1605.80	> 1
NPOC	25.70	0	0	25.70	NA

[11] In PSDP do the following to obtain emissions data at the plant prior to April 5, 1991: option 1 → option 2.
[12] In PSDP do the following steps to get data on the aggregate sum of all increases as defined in Reg. 2-2-212 after April 5, 1991: option 1 → type of pollutant (options 3 through 8).
[13] Per 2-2-212, the cumulative increase in emissions considers only the permitted emission increases Post-4/5/91. The Pre-4/5/91 permitted emission increases will be considered when determining whether Offsets are warranted.
[14] Since the increase in emissions associated with the additional fugitive components is exempt per Reg. 2-1-128.21, there is no cumulative increase in emissions.
[15] SO2 emissions listed as –4.310
[16] If permitted increases attributable to sources that were permitted prior to April 5, 1991 have been archived, exclude their emissions when considering whether Offsets are warranted.
[17] Db → q2 →p → all
[18] For the purposes of determining whether Offsets are warranted, add the higher of the permitted emissions (Pre-April 5, 1991 + Post-April 5, 1991) and the actual emissions to the increase in emissions resulting from the source that is part of the current application.

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It can be seen from Table 5 above that the actual emissions of NOx, POC, CO, PM10, and SO2 are above the permitted emissions for the above pollutants. This is so because most sources at refineries are grandfathered (Pre-1971 sources). In light of the above, and for the purposes of determining whether offsets are warranted, only those emission increases, which occurred after April 5, 1991 (0 TPY) are considered.

Statement Of Compliance

The fugitive components summarized in Table 1 above will be subject to Sections 301, 302, 304, 306, and 307 in Regulation 8, Rule 18 "Equipment Leaks". Sections 301, 302, and 304 require, among other things, that organic compound leaks, not exceed 100 ppm for general components, valves, and connections. Section 8-5-306 limits the percentages of non-repairable equipment allowed. Section 8-5-307 requires that leaking equipment not be used unless the leak discovered by the operator, is minimized within 24 hours and repaired within 7 days.

Regulation 11, Rule 7 "Hazardous Pollutants – Benzene" limits the emission of benzene from sources (such as pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, flanges and other product accumulator vessels, and control devices) intended to operate in benzene service. Regulation 11-7-207 defines "In Benzene service" to be any equipment which either contains or contacts a fluid (liquid or gas) that is at least 10 percent benzene by weight. The proposed project will not involve process streams, which will either contain or contact a fluid that is at least 10 percent benzene by weight. Therefore, Regulation 11, Rule 7 does not apply to the OPCEN hydrocarbon flare gas recovery project.

Regulation 12, Rule 11 "Flare Monitoring at Petroleum Refineries" requires monitoring and recording of emission data for flares at petroleum refineries. The District expects Shell to comply with the requirements of Regulation 12, Rule 11, which was adopted on June 4, 2003, when the OPCEN hydrocarbon flare gas recovery project is implemented. The District's CED posts monthly reports submitted by Shell to demonstrate compliance with the above rule at the following location on the District's website: http://www.baaqmd.gov/enf/flares/

On July 20, 2005, the District adopted Regulation 12, Rule 12 and amended the rule on April 5, 2006. The purpose of the above rule is to reduce emissions from flares at petroleum refineries by minimizing the frequency and magnitude of flaring. In order to comply with the above rule, Shell will be submitting a Flare Minimization Plan (FMP) to the District's CED per Regulation 12-12-402 on or before August 1, 2006. The FMP will address the four process flares at Shell. The OPCEN hydrocarbon flare gas recovery project, which is aimed toward eliminating routine flare emissions from S-1772, will be an integral part of Shell's FMP. Shell will monitor the water level and the pressure of the new water seal that will be installed as part of the OPCEN hydrocarbon flare gas recovery project in accordance with Regulation 12-12-501.

Flares S-1772 and S-4201 are subject to 40 CFR Part 60, Subpart J "New Source Performance Standard for Petroleum Refineries" (NSPS J). As it currently exists, process units in the OPCEN area are not subject to 40 CFR Part 60, Subpart GGG "Equipment Leaks of VOC in Petroleum Refineries" (NSPS GGG) because none of the OPCEN units were constructed or modified after January 4, 1983. However, Shell has voluntarily agreed to make the process units in OPCEN subject to NSPS Subpart GGG by 12/31/06 as part of the Consent Decree entered between Shell and the EPA. As a result, the OPCEN units will be required to comply with the standards outlined in §60.592. §60.592(a) of NSPS GGG references §§60.482-1 to 60.482-10 in 40 CFR Part 60 Subpart VV "Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry" (NSPS VV). §60.482-10(d) in NSPS VV requires that flares such as S-1772, which will become subject to the above subpart, comply with §60.18 in 40 CFR 60, Subpart A "General Provisions" (NSPS A). The District expects S-1772 to comply with the requirements outlined in §60.18 when the OPCEN hydrocarbon flare gas recovery project is implemented.

40 CFR §§ 60.100(b) and 60.104 (a)(1) in New Source Performance Standard for Petroleum Refineries, 40 CFR Part 60, Subpart J, (NSPS J) prohibit any affected fuel gas combustion device, including a flare, built or modified after June 11, 1973 from combusting any fuel gas that contains H_2S in excess of 230 mg/dscm (0.10 gr/dscf). To monitor for compliance with the above H_2S limit, 40 CFR §§ 60.105 (a)(3)-(4)

require the use of continuous monitors. The H_2S limit, does not apply during times when fuel gas is combusted in a flare because of process upset or as a result of relief valve leakage or other emergency malfunctions. The H_2S limit in NSPS J applies to S-1772, which is equipped with H_2S Continuous Emission Monitoring System (CEMS), because it is not equipped with FGRCs.

The fugitive components summarized in Table 1 above are potentially subject to the requirements of NSPS GGG, and NSPS VV. However, when 40 CFR Part 63, Subpart CC "National Emissions Standards for Hazardous Air Pollutants from Petroleum Refineries" (MACT CC) overlaps with other regulations such as NSPS GGG and NSPS VV, §63.640(p) allows equipment leaks that are also subject to the provisions of 40 CFR Parts 60 and 61 to comply only with the provisions specified in the MACT. Therefore, equipment leaks from the new fugitive components summarized in Table 1 above will only be subject to MACT CC, which is discussed below.

The Maximum Achievable Control Technology (MACT) standards in 40 CFR Part 63 applies to toxic air emissions emanating from specific source categories at facilities, which are major sources of HAPs. The MACT standards that potentially are applicable to the OPCEN Hydrocarbon flare gas recovery project are 40 CFR Part 63, Subpart A "General Requirements", and MACT CC.

MACT CC applies to various refinery operations including miscellaneous process vents storage vessels, wastewater streams and treatment operations, equipment leaks, gasoline loading racks, and marine vessel loading operations. Emission sources of relevance (in light of MACT CC) as it relates to the OPCEN hydrocarbon flare gas recovery project include wastewater streams and equipment leaks. The proposed project does not involve miscellaneous process vents, storage vessels, gasoline loading, wastewater treatment operations, or marine vessels for the following reasons.

Per MACT CC, a miscellaneous process vent means a gas stream containing greater than 20 parts per million by volume organic HAP that is continuously or periodically discharged during normal operation of a petroleum refining process unit meeting the criteria specified in §63.640(a). However, the definition of a miscellaneous process vent under §63.641 explicitly does not include gaseous streams routed to a fuel gas system. The very intent of the OPCEN hydrocarbon flare gas recovery project is to route routine vent gas flows, which otherwise would have been flared at S-1772, to two existing FGRCs at S-4201 to be recovered as RFG.

MACT CC defines storage vessels to mean a tank or other vessel that is used to store organic liquids that are in organic HAP service. The new water seal vessel that Shell plans to install will not be used to store organic liquids as intended in the above definition.

Equipment leaks are defined in MACT CC to mean emissions of organic HAP from a pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, or instrumentation system "in organic HAP service".
"In organic hazardous air pollutant service" is defined in MACT CC as follows:
"*means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP's as determined according to the provisions of § 63.180(d) of subpart H of this part and table 1 of this subpart. The provisions of § 63.180(d) of subpart H also specify how to determine that a piece of equipment is not in organic HAP service.*"

The following HAPs are listed in Table 1 of MACT CC:
benzene, biphenyl, 1,3-butadiene, carbon disulfide, carbonyl sulfide, cresol (m-, o-, p-, and mixed isomers), cumene, 1,2-dibromoethane, 1,2-dichloroethane, diethanolamine, ethylbenzene, ethylene glycol, hexane, methanol, methyl ethyl ketone, methyl isobutyl ketone, methyl tert butyl ether, naphthalene, phenol, toluene, 2,2,4-trimethylpentane, and xylene (m-, o-, p-, and mixed isomers).

It can be seen from Table 2 above that the OPCEN hydrocarbon flare gas recovery project will result in emissions of benzene, 1,3-butadiene, cumene, ethylbenzene, toluene, and xylene (mixed isomers). Therefore, the fugitive components summarized in Table 1 above must comply with MACT CC if they will be used in organic HAP service.

PSD is not applicable to this project because there is no cumulative increase in emissions at the plant, since the modifications/alterations to process units that are part of this application are exempt from Regulation 2-1-301 per Regulation 2-1-128.21.

The California Environmental Quality Act (CEQA):

Per Section 2-1-311 of the District Rules and Regulations, a permit application for a proposed new or modified source will be classified as ministerial and will accordingly be exempt from the CEQA requirement of Section 2-1-310 if the District's engineering evaluation and basis for approval of the permit application for the project is limited to the criteria set forth in Section 2-1-428 and to the procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook. The method for determining whether a given permit application will be classified as ministerial is set forth in Section 2-1-427.

Per Section 2-1-427, if the District determines that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook, the District's evaluation of the permit application is classified as ministerial and the engineering evaluation of the permit application by the District will be limited to the use of said specific procedures, fixed standards and objective measurements. For such projects, the District will merely apply the law to the facts as presented in the permit application, and the District's decision regarding whether to issue the permit will be based only on the criteria set forth in Section 2-1-428 and in the District's Permit Handbook and BACT/TBACT Workbook.

For this permit application, the District determined that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook Chapter 3.4 "Petroleum Refinery Fugitive Emissions" and the BACT/TBACT Workbook (Document #'s: 78.1; dated January 18, 2006; 135.1 dated June 30, 1995; and 136.1 dated January 18, 2006). Since the District classified this permit application as ministerial pursuant to Section 2-1-427, and as a result of its evaluation of the permit application, the District determined that all of the criteria for approval of ministerial permit applications pursuant to Section 2-1-428 were met, the issuance by the District of an Authority to Construct and Permit to Operate for the proposed project is a mandatory ministerial duty and is accordingly exempt from the CEQA requirement of Section 2-1-310.

In addition to the ministerial exemption determination above, the District has also determined that the CEQA categorical exemptions of Sections 2-1-312.7 and 2-1-312.11 of the District Rules and Regulations and the CEQA "Common Sense Exemption" apply.

CEQA Categorical Exemptions and CEQA "Common Sense Exemption":

Though the District concludes that the modifications/alterations that are part of this application are ministerial, it also concludes that, even if it were not ministerial, certain other exemptions from CEQA apply (see CEQA Guidelines § 15300.1). Section 2-1-312 of the District Rules and Regulations sets forth specific types of projects, which have been determined by the District to be categorically exempt from CEQA.

Per Section 2-1-312.11, permit applications for a new or modified source or sources or for process changes, which will satisfy the "No Net Emission Increase" provisions of District Regulation 2, Rule 2 and for which there is no possibility that the project may have any significant environmental effect in connection with any environmental media or resources other than air quality, are exempt from the CEQA review. The reason for this exemption should be apparent on its face: if a facility is given legal permission to emit more air pollutants from certain points while at the same time being disallowed permission for an equivalent amount of the same type of emissions from other points at the facility, then there is deemed to be no net effect on the air environment, and therefore no possibility of a significant effect under CEQA, provided no-air impacts are also examined and deemed to be of no possible significant consequence.

Also, per the CEQA Guidelines in Title 14, California Code of Regulations, Chapter 3, Article 5, Section 15061(b)(3), a project is exempt from CEQA if the activity is covered by the general rule that CEQA applies only to projects, which have the potential for causing a significant effect on the environment. This is commonly known as the "Common Sense Exemption". Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to CEQA. The "no net increase" exemption of 2-1-312.11 is essentially a specific, codified, instance of the Common Sense Exemption.

Installation of the fugitive components summarized in Table 1 above is exempt from Regulation 2-1-301 per Regulation 2-1-128.21. As a result, the 0.069 TPY (~ 137.78 lbs/yr) increase in POC emissions summarized in Table 1 above will not be counted toward the cumulative increase in emissions at Shell. Therefore, the District has determined that the project satisfies the "No Net Emission Increase" provisions of District Regulation 2, Rule 2. Shell has completed and submitted to the District CEQA Appendix H, Environmental Information Form, for the project.

The District has reviewed the CEQA Appendix H form. Shell only checked "Yes" for item 29 regarding "Use or disposal of potentially hazardous materials, such as toxic substances, flammables or explosives". All other items on the form were checked "No". Shell responded to item 29 as follows:
"The new piping will route the flare header gas to either the fuel gas system for recovery or to a flare. Flare header gas is a combustible material and contains traces of toxic substances. There are no explosives associated with the proposed project. Note that the new piping will reroute the same materials as the existing piping; no new hazardous materials will be stored or used at the refinery as a result of the proposed project."

In addition to responding to the above form, and in efforts to address specific CEQA related questions posed by the District in previous applications, Shell submitted the following additional supplemental information in order for the District to determine the project's possible significant effects.

1. *Please provide a completed Appendix H, Environmental Information Form, which contains sufficient information for the District to complete the CEQA Initial Study of the project. For responses in the above form that are either marked "Yes" and/or "NA", please fully explain the relevant issue(s) in detail.*

   Shell has followed the guidelines in the Appendix H, Environmental Information Form provided in the preceding pages of this Appendix D.

2. *Please describe any new equipment, including pumps and piping that will be installed for this project. Will any new piping be installed aboveground?*

   The project involves the installation of a new water seal vessel, interconnecting piping, valving, and instrumentation. The new piping will be installed aboveground and visually inspected. There will be no piping installed below ground.

3. *To determine potential impacts to groundwater and surface water quality, please respond to the following:*

   a. *Will this project result in an increase in the risk of a spill with potential for impacting surface water and groundwater? Please explain.*

      There is minimal potential for the OPCEN Flare Gas Recovery Project to increase the risk of a spill that would impact surface water or groundwater. The contents of the new water seal vessel will be primarily water. An oil skim of up to 2 inches in height may be present as well. The dimensions of the new water seal vessel will be approximately 30 feet in height (from tangent to tangent) and 10 feet in diameter. The normal liquid level will be about 10 feet, 8 inches from the tangent line.

      The filling system is designed to prevent overfilling. The new water seal vessel will be equipped with a high level alarm which will automatically shutdown pumps and stop fill pipe flow when the liquid level reaches 11 feet. The liquid in the new water seal vessel will be used as a water seal only and therefore water will be added infrequently and at low levels as the water in the vessel evaporates.

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b. *What spill prevention measures and monitoring are in place at Shell to limit the potential risk of a spill due to this project.*

The project does not involve the storage of any hazardus material, thus spill prevention is not required. However, the filling system is designed to prevent overfilling. The new water seal vessel will be equipped with a high level alarm which will automatically shutdown pumps and stop fill pipe flow when the liquid level reaches 11 feet. The liquid in the new water seal vessel will be used as a water seal only and therefore water will be added infrequently and at low levels as the water in the vessel evaporates.

Shell's program of operator training, prevention, mitigation, and response is based on prevention of environmental impacts, and will further reduce the risk of a spill. Shell has prepared and implemented a SWPPP and a SPCC to prevent water quality contamination. Storm drains are closed by default, and collected storm water is sent to the Martinez Refinery's effluent wastewater treatment plant.

c. *Will the water seal vessel be equipped with a high level alarm which will automatically shutdown pumps and stop filling line flow when a pre-determined vessel level is reached?*

Yes, the new water seal vessel will be equipped with a high level alarm which will automatically shutdown pumps and stop fill pipe flow when the liquid level reaches 12 feet.

d. *To address runoff at the site, does Shell have a Storm Water Pollution Prevention Plan and Spill Prevention Control and Countermeasures Plan? If so, please submit copies of the*

Shell has prepared the SWPPP and SPCC Plan, as required. The plans are available onsite for inspection during normal business hours in accordance with the applicable regulations.

e. *How frequently does Shell conduct groundwater monitoring and how often are the analytical results submitted to the Regional Water Quality Control Board? Please provide the latest results submitted to the water board.*

Shell performs quarterly groundwater monitoring as required by Waste Discharge Requirements (WDR) Order 95-234, issued by the SFBRWQCB. Results are submitted to the SFBRWQCB twice a year. The test records are available onsite for inspection during normal business hours in accordance with the applicable regulations.

Additionally, Shell is required to perform a capture zone analysis on the facility. The WDR order requires that an ongoing hydraulic groundwater capture program be installed, operated, and maintained. Groundwater extraction systems are installed at the perimeter of the facility and serve to capture the groundwater before it leaves the site.

f. *What is direction of the groundwater flow beneath the Shell refinery site?*

The new water seal vessel will be located in the Central Valley groundwater basin of the facility. Groundwater flows from South to North at a velocity of approximately four feet per year.

4. *To determine potential impacts due to diesel-fueled trucks associated with the project, please respond to the following:*

   a. *How and from where will water be delivered to the new water seal vessel?*

   Utility water will be delivered to the new water seal vessel through new piping and pumps.

   b. *Would the installation of the new water seal vessel result in an increase in existing diesel-fueled truck traffic to and from the truck loading racks?*

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No new truck traffic will occur as a result of the proposed project.

c. For construction, how many diesel-fueled trucks will be used for mobilization, construction, and demobilization of the project?

The mobilization, construction, and demobilization activities related to the OPCEN Flare Gas Recovery Project will require up to about three months. During this time, approximately five diesel-fueled truck deliveries of materials will occur. During construction, the following diesel-fueled equipment will be on site:

- One backhoe – up to six days
- One drilling rig – up to six days
- Two cranes – up to 30 days, combined
- Four concrete trucks – up to six days, combined

Demobilization, which consists of the removal of construction materials, will require approximately one diesel-fueled truck.

d. What is the likely route that the diesel-fueled trucks will take from the nearest freeway to the Shell gate?

The most likely route for delivery of construction materials to the OPCEN Flare Gas Recovery Project construction site will be via Highway 680 to Marina Vista Avenue. The diesel-fueled trucks will enter the refinery through Gate 75.

The District finds the above assertions and arguments to be credible. Thus, the District concludes that the permit application is exempt from CEQA because it is ministerial, it is categorically exempt from CEQA, and the project qualifies for the "Common Sense Exemption" of Subsection (b)(3) of the State CEQA Guidelines.

Based on the information contained in the Appendix H form submitted and Shell's responses to the supplemental questions regarding possible water impacts and the number of diesel-fueled truck trips associated with the project, the District does not expect either to be significant. Based on all of the information before the District and the District's review of the information submitted, the District has determined that there is no possibility that the project may have any significant environmental effect.

The District has considered whether the installation of the fugitive components/alterations to S-1772 that are part of this application are part of a larger project for CEQA purposes, and has concluded that it is not. Although other Shell refinery permitting applications have been acted on or are currently pending before the District, the construction and operation of S-1772 and S-4201 is not necessarily linked to any of these. Specifically, the recovery of routine vent gas flows from S-1772 to the FGRCs at S-4201 is not necessary in order for Shell to proceed with other permit applications, nor are any changes proposed in this application a foreseeable consequence of other permit applications. In reaching this conclusion, the District is relying in part on Shell's responses to the supplemental questions.

On a general level, the stated purpose of the OPCEN Hydrocarbon Flare gas recovery project does not imply any necessary relationship to other projects, in the sense of being prerequisite to other projects or a foreseeable consequence of them.

PERMIT CONDITIONS

No new permit conditions will be added to govern the operation of S-1772 and/or S-4201. However, the following discussion is limited to discussing permit conditions that currently govern the operation of the above flares.

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The DC flare (S-4201) was permitted under Application 8407 – Shell's Clean Fuels Project (CFP). Sources that are part of Shell's CFP are governed by permit condition 12271. The monthly and annual emission limits for CFP sources are outlined in Tables A.1 and A.2 under Part A, entitled "General Conditions". As previously discussed in the preceding sections of this evaluation, during a significant flaring event at either the OPCEN hydrocarbon flare (S-1772) or S-4201, a minor amount of routine OPCEN vent gas that is not recovered by the FGRCs at S-4201 will initially flare at the DC flare until the isolation valve between the above flare headers closes. Shell has clarified that this minimal flaring of un-recovered OPCEN vent gas which could cause some increased flaring at S-4201 will not limit the company's ability to comply with the monthly and annual emission limits outlined in Tables A.1 and A.2. It should be noted that SRU #4 (S-4180) though permitted under Shell's CFP is physically located in the OPCEN area as opposed to the DC area. Vent gas emissions from S-4180 are conveyed to the FGRCs at the DC flare by an existing flare header. Shell's proposal under this application is to recover routine vent gas flows, that otherwise would have been flared at the OPCEN hydrocarbon flare, by connecting to the existing flare header that serves SRU #4.

Part 12 of permit condition 18618 limits the quantity of vent gas flared in S-1772 and S-4201 to not exceed 510,000 lbs/hr and 2,000,000 lbs/hr, respectively. Shell has clarified that the OPCEN hydrocarbon flare gas recovery project will not compromise the company's ability to comply with the above limits.

RECOMMENDATION

Waive the AC, and issue Shell a PO to perform alterations at the following equipment:

S-1772 OPCEN Hydrocarbon Flare

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11
Application: 15482

Background

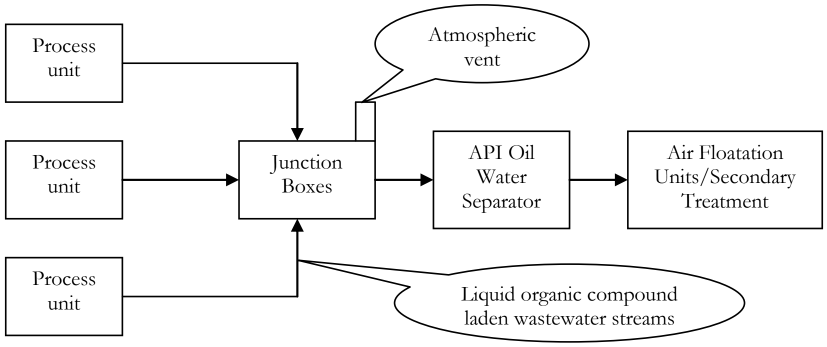
Shell Oil Products US – Martinez Refinery (Shell) has submitted this application to obtain a Permit to Operate (PO) to perform certain alterations at the following source:

S-2010 LOG Wastewater Junction Boxes
Equipped with low-pressure water seals on select atmospheric vents

As part of Shell's overall compliance strategy with Regulation 8, Rule 8 "Wastewater Collection and Separation Systems", the company has proposed to install low-pressure water seals (seals) on the atmospheric vents at S-2010, which are located throughout the refinery. Shell has already implemented and continues to implement a number of pollution prevention measures aimed at minimizing/eliminating sources of hydrocarbon that tie into the refinery's sewer system. Installation of the seals at S-2010 would serve as a backup control measure in the event the pollution prevention measures at the source are not completely effective.

The seal will serve as a simple water scrubber and will consist of a vent line block valve, a scrubber, an air purge connection, and a connection that would allow for future installation of an activated carbon adsorption drum if needed. In the event the seal proves ineffective, the activated carbon adsorption drum will be installed to comply with applicable limits in Regulation 8, Rule 8.

Following is a simplified process sketch of a refinery wastewater collection and separation system as it relates to this application:



It can be seen from the above discussion that the installation of the seals at S-2010 will not result in an increase in criteria pollutant emissions i.e. Precursor Organic Compounds (POC). Instead the seals will help contain (~passively abate) POC emissions. Therefore, the District's New Source Review requirements i.e. Air Toxics, BACT, Cumulative Increase, and Offsets are not triggered.

Statement Of Compliance
Source S-2010 is subject to and is expected to comply with Regulation 8, Rule 8 "Wastewater Collection and Separation Systems". Section 312 requires that all components be vapor tight. Some of the junction boxes already meet the requirement (perhaps due to the concentration of organic compounds in the wastewater). Shell will install the control devices on the junction boxes that cannot comply without control, such that all junction boxes will be "vapor-tight" by the April 30, 2007 deadline for compliance in Section 403.

The seals that will be installed on the atmospheric vents at S-2010 will meet the requirements contained in Section 232 of the above rule. Shell adopted the compliance schedule outlined in Section 403 to install controls (~ seals) on wastewater collection system components such as S-2010, which were uncontrolled as of January 1, 2005. Installation of any necessary controls (~ seals) on previously uncontrolled wastewater collection system components such as S-2010 ensures that the components will meet the "vapor tight" requirements in Section 204 of the above rule.

As it currently exists, Table IV-CJ in Shell's Title V Revision 2 permit contains Sections 303 and 308 of Regulation 8, Rule 8 as the applicable requirements for S-2010. When the District issues Shell a PO to perform the alterations at S-2010 under this application (Application 15482 - NSR portion), source S-2010 will no longer be an uncontrolled wastewater collection system component. In light of the above, Sections 312, 505, and 603 which pertain to controlled wastewater collection system components will be added to the above table in Shell's Title V Revision 2 permit under Application 15483 (Title V portion).

The installation of the seals at S-2010 will not result in an increase in POC emissions. Therefore, the alterations to S-2010 don't qualify as either a construction/reconstruction/modification of the above source as defined in New Source Performance Standard (NSPS) Subpart A "General Provisions (except flares)". Also, since source S-2010 was neither constructed/reconstructed/modified after May 4, 1987, the installation of the seals on the atmospheric vents at S-2010 is not subject to NSPS Subpart QQQ "Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems".

PSD is not applicable to this project because there is no cumulative increase in emissions at the plant, since the alterations to S-2010 will not result in an increase in POC emissions.

The California Environmental Quality Act (CEQA):
Per Section 2-1-311 of the District Rules and Regulations, a permit application for a proposed new or modified source will be classified as ministerial and will accordingly be exempt from the CEQA requirement of Section 2-1-310 if the District's engineering evaluation and basis for approval of the permit application for the project is limited to the criteria set forth in Section 2-1-428 and to the procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook. The method for determining whether a given permit application will be classified as ministerial is set forth in Section 2-1-427.

Per Section 2-1-427, if the District determines that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook, the District's evaluation of the permit application is classified as ministerial and the engineering evaluation of the permit application by the District will be limited to the use of said specific procedures, fixed standards and objective measurements. For such projects, the District will merely apply the law to the facts as presented in the permit application, and the District's decision regarding whether to issue the permit will be based only on the criteria set forth in Section 2-1-428 and in the District's Permit Handbook and BACT/TBACT Workbook.

For this permit application, the District determined that its evaluation of the permit application is **not** covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook. Therefore, the District cannot classify this permit application as ministerial pursuant to Section 2-1-427. As a result of its evaluation of the permit application, the District has determined that all of the criteria for approval of ministerial permit applications pursuant to Section 2-1-428 were **not** met. In light of the above, the issuance by the District of a Permit to Operate for the proposed alterations (~ project) does not qualify as a mandatory ministerial duty and is therefore **not** exempt from the CEQA requirement of Section 2-1-310.

CEQA Categorical Exemptions and CEQA "Common Sense Exemption":
Though the District concludes that the alterations to S-2010 are **not** ministerial, it also concludes that certain other exemptions from CEQA apply (see CEQA Guidelines § 15300.1). Section 2-1-312 of the District Rules and Regulations sets forth specific types of projects, which have been determined by the District to be categorically exempt from CEQA. Specifically, the alterations to S-2010 qualify under the CEQA categorical exemptions of Sections 2-1-312.2, 2-1-312.6, and 2-1-312.11 of the District Rules and Regulations and the CEQA "Common Sense Exemption".

Following is a textual description of the above referenced sections:
2-1-312 Other Categories of Exempt Projects: In addition to ministerial projects, the following categories of projects subject to permit review by the District will be exempt from the CEQA review, either because the category is exempted by the express terms of CEQA (subsections 2-1-312.1 through 312.9) or because the project has no potential for causing a significant adverse environmental impact (subsections 2-1- 312.10 and 312.11). Any permit applicant wishing to qualify under any of the specific exemptions set forth in this Section 2-1-312 must include in its permit application CEQA-related information in accordance with subsection 2-1-426.1. In addition, the CEQA-related information submitted by any permit applicant wishing to qualify under subsection 2-1-312.11 must demonstrate to the satisfaction of the APCO that the proposed project has no potential for resulting in a significant environmental effect in connection with any of the environmental media or resources listed in Section II of Appendix I of the State CEQA Guidelines.
312.2 Permit applications to install air pollution control or abatement equipment.
312.6 Permit applications relating exclusively to the repair, maintenance or minor alteration of existing facilities, equipment or sources involving negligible or no expansion of use beyond that previously existing.
312.11 Permit applications for a proposed new or modified source or sources or for process changes which will satisfy the “No Net Emission Increase" provisions of District Regulation 2, Rule 2, and for which there is no possibility that the project may have any significant environmental effect in connection with any environmental media or resources other than air quality. Examples of such projects include, but are not necessarily limited to, the following:
11.1 Projects at an existing stationary source for which there will be no net increase in the emissions of air contaminants from the stationary source and for which there will be no other significant environmental effect;
11.2 A proposed new source or stationary source for which full offsets are provided in accordance with Regulation 2, Rule 2, and for which there will be no other significant environmental effect;
11.3 A proposed new source or stationary source at a small facility for which full offsets are provided from a small facility bank established by the APCO pursuant to Regulation 2-4-414, and for which there will be no other significant environmental effect;

11.4 Projects satisfying the "no net emission increase" provisions of District Regulation 2, Rule 2 for which there will be some increase in the emissions of any toxic air contaminant, but for which the District staff's health risk screening analysis shows that the project will not result in a cancer risk (as defined in Regulation 2-5-206) greater than 1.0 in a million (10-6) and will not result in a chronic hazard index (as defined in Regulation 2-5-208) greater than 0.20, and for which there will be no other significant environmental effect.

As previously discussed under the "Background" section, the seals will serve as passive abatement devices by containing the POC emissions emanating from atmospheric vents at junction boxes located throughout the refinery. Therefore, the project to alter S-2010 is categorically exempt from CEQA per Section 2-1-312.2. In addition to the above, installation of the seals at S-2010 qualifies as a minor alteration of an existing source involving negligible or no expansion of use beyond existing levels. Therefore, per Section 2-1-312.6 the minor alterations to S-2010 are categorically exempt from CEQA.

Per Section 2-1-312.11, permit applications for a new or modified source or sources or for process changes, which will satisfy the "No Net Emission Increase" provisions of District Regulation 2, Rule 2 and for which there is no possibility that the project may have any significant environmental effect in connection with any environmental media or resources other than air quality, are exempt from the CEQA review. The reason for this exemption should be apparent on its face: if a facility is given legal permission to emit more air pollutants from certain points while at the same time being disallowed permission for an equivalent amount of the same type of emissions from other points at the facility, then there is deemed to be no net effect on the air environment, and therefore no possibility of a significant effect under CEQA, provided no-air impacts are also examined and deemed to be of no possible significant consequence.

Also, per the CEQA Guidelines in Title 14, California Code of Regulations, Chapter 3, Article 5, Section 15061(b)(3), a project is exempt from CEQA if the activity is covered by the general rule that CEQA applies only to projects, which have the potential for causing a significant effect on the environment. This is commonly known as the "Common Sense Exemption". Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to CEQA. The "no net increase" exemption of 2-1-312.11 is essentially a specific, codified, instance of the Common Sense Exemption.

The proposed alterations to S-2010 will not result in an increase in POC emissions, implying that there will be no cumulative increase in emissions at Shell. As a result, the District has determined that the project to alter S-2010 satisfies the "No Net Emission Increase" provisions of District Regulation 2, Rule 2. Lastly, Shell has completed and submitted to the District CEQA Appendix H, Environmental Information Form, for the project.

The District has reviewed the CEQA Appendix H form. Shell has not checked a "Yes" for any of the items in the above form, implying all items are checked "No". The District concludes that the permit application is exempt from CEQA because it is categorically exempt from CEQA per Sections 2-1-312.2 and 2-1-312.6. In addition, the project also qualifies per Section 2-1-312.11 for the "Common Sense Exemption" of Subsection (b)(3) of the State CEQA Guidelines. Based on all of the information before the District, it can be concluded that there is no possibility that the alterations to S-2010 will have any significant environmental effect.

PERMIT CONDITIONS

None required.

RECOMMENDATION

Issue Shell a PO to perform alterations at the following equipment:

S-2010 LOG Wastewater Junction Boxes
Equipped with low-pressure water seals on select atmospheric vents

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11

Application: 15774

Background

Shell Oil Products US – Martinez Refinery (Shell) has submitted this application under the auspices of Regulation 2-1-106 "Accelerated Permitting Program" to obtain a Permit to Operate (PO) for the following *new* equipment:

S6068 Asphalt Tank
Heated[19] Vertical Fixed Roof Tank
Tank height: 30 feet; Tank diameter: 114.50 feet
Total volume: 55,100 bbl; Annual throughput: 1,983,600 bbl/yr

Source S6068 will replace S22 - an aging and out-of-service 55,100 bbl heated vertical fixed roof asphalt tank that currently exists at a tank farm covering 2.13 acres in the northwest part of the refinery. When constructed, S6068 will occupy 10,300 sq. ft[20], and will be erected at S22's existing location. Shell has not proposed to install any new pumps or piping under this application.

This will result in a minor revision of the Title V permit because:

- The change is not considered a major modification under 40 CFR Parts 51 (NSR) or 52 (PSD).
- The change is not considered a modification under 40 CFR Parts 60 (NSPS), 61 (NESHAPS), or Section 112 of the Clean Air Act (HAP).
- There is no significant change or relaxation of monitoring. Periodic monitoring in accordance with BAAQMD Regulation 2, Rule 6, Sections 2-6-409.2.2 and 2-6-503 will be imposed.
- No term is established to allow the facility to avoid an applicable requirement.
- No case-by-case determination has been made.
- No facility-specific determination for ambient impacts, visibility analysis, or increment analysis on portable sources has been made.
- No new federal requirement has been imposed.

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[19] Heating coils will be used to heat S-6068 in order to maintain the temperature of the asphalt between 280°F and 320°F.

[20] Area of construction = $(\pi d^2/4)$ = 10,300 sq. ft.; where d = 114.5 feet

Emissions Calculations

US EPA TANKS 4.0.9d program was used to estimate the VOC (~ POC[21]) emissions from the new tank using the following inputs:

- **The asphalt would be stored at temperatures up to 320ºF, and will have a liquid density of 9 lbs/gal.**
- **The liquid and vapor molecular weight of the asphalt would be 345.69 lb/lb-mol and 50 lb/lb-mol, respectively.**
- **The "A" and "B" constants used in the "Antoine's Equation (using K)" for the asphalt would be 75350.06 and 9.00346, respectively. In other words, the vapor pressure of the asphalt would be 0.016 psia at 320ºF.**
- **The percent of total liquid weight of toluene and xylene (-m) in the asphalt would be 0.000028% and 0.000032%, respectively. The above percentages are based on speciation information Shell maintains in a database for various process streams at the refinery.**

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Table 1 summarizes results from the TANKS 4.0.9d program.

Table 1
Post-Project Emissions from S6068

Component	Working Loss (lbs/yr)	Breathing Loss (lbs/yr)	Total Emissions (lbs/yr)
Toluene	**10.23**	**0.00**	**10.23**
Xylene (-m)	**5.13**	**0.00**	**5.13**
Unidentified Components	**1,570.95**	**0.00**	**1,570.95**
Total	1,586.31	0.00	1,586.31

Though asphalt is a solid at less than 100ºF, most heavy components contained in it have a melting point greater than 200ºF and a boiling point greater than 500ºF. Materials that would volatilize from S6068, with the exception of toluene and xylene (-m), will most likely condense as particulate matter (PM_{10}) when vented to the atmosphere. Partitioning the above VOC emissions (22% PM_{10} and 78% POC) summarized in Table 1 above using the methodology proposed by David C. Trumbore with the Asphalt Technology Laboratory at Owens Corning in a technical paper entitled "Estimates of Air Emissions from Asphalt Storage Tanks and Truck Loading", the PM_{10} and POC emissions from the new asphalt tank are 349 lbs/yr and 1,237 lbs/yr, respectively.

Using the above methodology, the net increase in PM_{10} and POC emissions were calculated by subtracting the Pre-Project emissions associated with the operation of S22 from the expected Post-Project increase in PM_{10} and POC emissions associated with the operation of S6068. In accordance with the procedures outlined in Regulation 2-2-605 and based on information submitted by Shell in their annual information updates to the District for years 2004, 2005, and 2006, the asphalt throughput for the above time periods were 84,048 bbl, 0 bbl, and 0 bbl, respectively.

[21] POC – Precursor Organic Compound

Table 2 summarizes results from the TANKS 4.0.9d program for year 2004.

Table 2 2004 Emissions from S22			
Component	Working Loss (lbs/yr)	Breathing Loss (lbs/yr)	Total Emissions (lbs/yr)
Toluene	**0.32**	**0.00**	**0.32**
Xylene (-m)	**0.18**	**0.00**	**0.18**
Unidentified Components	**38.26**	**0.00**	**38.26**
Total	38.75	0.00	38.75

It can be seen from Table 2 above that the average combined (PM_{10} and POC) emissions from S22 from 2004 through 2006, was equal to 12.92 lbs/yr (38.75+0+0/3). In other words, using the Owens Corning partitioning methodology the average Pre-Project PM_{10} and POC emissions from S22 were 2.84 lbs/yr and 10.08 lbs/yr, respectively. Therefore, the net increase in PM_{10} and POC emissions associated with the installation of S6068 is 346.15 lbs/yr (348.99 – 2.84) and 1,227.24 lbs/yr (1,237.32 – 10.08), respectively.

Toxic Risk Screen Analysis

Asphalt contains Polynuclear Aromatic Hydrocarbons (PAHs). Based on speciation information Shell maintains in a database for various process streams at the refinery, the asphalt stored in S6068 will contain 0.00012% of benzo(g,h,i)perylene and 0.00198% of benzo(a)pyrene. Consistent with footnote #9 in Table 2-5-1 in Regulation 2, Rule 5 "New Source Review of Toxic Air Contaminants", all PAHs are assumed to be equal to benzo(a)pyrene. In other words, the asphalt stored in S6068 will contain 0.0021% of PAHs expressed as benzo(a)pyrene. Though benzo(g,h,i)perylene is not referenced under footnote#9 in Table 2-5-1 because it is a Polycyclic Aromatic Compound (PAC), it is conservatively included as a PAH for the purposes of estimating the Toxic Air Contaminants (TAC) from the new asphalt tank. PAH emissions are expressed as a percentage of PM_{10} emissions. Therefore, the Post-Project PAH emissions from S6068 are equal to 0.0073 lbs/yr (0.0021% x 346.15).

Table 3 summarizes the TAC emissions from S6068.

Table 3 **Net Increase in TAC Emissions**			
TAC	**CAS Number**	**TAC Emissions (lbs/yr)**	**TAC Emissions (lbs/hr)**[22]
Toluene	108-88-3	7.66	0.0009
Xylene (-m)	1330-20-7	3.82	0.0004
PAHs expressed as benzo(a)pyrene	50-32-8	0.007	0.0000008
Total		**11.49**	**0.0013**

[22] Based on 8,760 hours/yr of operation.

Table 4 compares the TAC emissions summarized in Table 3 above to their corresponding District TAC Trigger Levels (TTL) in Table 2-5-1 of Regulation 2, Rule 5.

Table 4
Net Increase in TAC Emissions versus Reg. 2-5 TAC Trigger Levels

TAC	Acute TTL (lbs/hr)	Does the net increase in TAC emissions from S6068 exceed the Acute TTL?	Chronic TTL (lbs/yr)	Does the net increase in TAC emissions from S6068 exceed the Chronic TTL?
Toluene	82	No	12,000	No
Xylene (-m)	49	No	27,000	No
PAHs expressed as benzo(a)pyrene	NA	NA	0.011	No

Asphalt produced at the refinery will be conveyed to S6068 via existing piping and pumps – implying there will be no deliveries of asphalt to S6068 via diesel fueled delivery trucks. A memo from Dr. Glen Long – Supervising Air Quality Engineer, Toxics Evaluation Section to Barry Young – Manager, Permit Evaluation Section dated October 27, 2005 states that an increase of 21 round-trip diesel fueled delivery trucks per day (42 one-way trips) corresponds to a maximum lifetime cancer risk of 10 in a million and a maximum chronic hazard index of 0.00602. Therefore, an increase in diesel fueled truck traffic below the 21 round-trip diesel fueled delivery trucks per day threshold will not exceed the lifetime cancer risk of 10 in a million, implying a detailed site-specific Health Risk Screening Analysis (HRSA) is not required for such projects.

As previously discussed under the "Background" section above, S6068 will be erected at a location where S22 currently exists. Shell has estimated that the demobilization, mobilization, and construction activities will span over 180 days, during which time there will be at least 25 deliveries of construction related materials via diesel fueled delivery trucks. The demobilization activities, which will mostly entail the removal of construction materials i.e. steel, concrete, etc., will require approximately 5 diesel fueled delivery trucks. Shell plans to employ the services of a diesel fueled crane for at least 75 days i.e. installation of the roof, etc. Based on the 70-year average exposure, it is unlikely that they will have any long-term health impacts significant enough to warrant a HRSA, or change the findings of Dr. Long's October 2005 memo.

In light of the above, and given the fact there will no diesel fueled delivery truck traffic (besides construction related traffic) to S6068, a HRSA is not warranted.

BACT

Per Regulation 2, Rule 2, Section 301, BACT is triggered if emissions from a new source or an increase in emissions from a modified source has the potential to emit 10 lbs or more per highest day of PM_{10} and POC (pollutants of interest in this application).

Because most of the emissions occur from loading, the tank triggers BACT. If it is assumed that 1,237 lb POC/yr will be emitted during the loading of 1,983,600 bbl/yr of asphalt, then approximately 0.000624 lb POC will be emitted per barrel loaded. The capacity of the tank is 55,100 barrels. If 55,100 barrels are loaded in one day, about 34 lb POC would be emitted in one day.

To avoid the BACT requirement, the applicant has proposed to limit the amount loaded into the tank at one time. The applicant has submitted tank calculations to show that the emissions are 914.50 lb/yr if the system is at 300 °F and 1,208.76 if the system is at 310 °F. If emissions are 78% POC, the POC emissions would be 713 and 943 lb/yr, respectively. If the applicant is allowed to

emit 9.5 lb POC/loading event (day), the applicant could load more when the system was cooler as shown below:

Tank Temperature	**Total Emissions**	**VOC Emissions**	**PM10 Emissions**	**VOC Emission Factor**	**Asphalt Throughput in barrels @ 9.5 lb/day**
Deg F	lb/yr	lb/yr	lb/yr		
300	915	713	201	0.00036	26,400
310	1,209	943	266	0.00048	20,000
320	1,586	1,237	349	0.00062	15,200

The applicant has proposed a different limit depending on the temperature of the system. Both the liquid in the tank and the liquid loaded must be at or below each temperature limit for each loading limit.

Since the emissions of particulate are one-quarter of the emissions of POC, the particulate emissions will also be below the BACT trigger.

Cumulative Increase & Offsets

Shell is an existing facility. Table 5 summarizes the cumulative increase in criteria pollutant emissions that will result at Plant 11 from the operation of S6068.

Table 5
Cumulative Increase

Pollutant	Increase in plant emissions prior to April 5, 1991 [23] (TPY)	Increase in plant emissions since April 5, 1991 [24] (TPY)	Increase in plant emissions associated with this application (TPY)[25]	Cumulative increase in emissions (Post 4/5/91 + Current application increase)[26] (TPY)
NOx	0	0	0	0
POC	26.09	0[27]	0.61	0.61
CO	0	298.00	0	298.00
PM	0.05	0	0	0
PM10	0.11	0	0.17	0.17
SO2	0	0[28]	0	0
NPOC	11.00	14.70	0	14.70

[23] In PSDP do the following to obtain emissions data at the plant prior to April 5, 1991: option 3 → option 1 → option 2.

[24] In PSDP do the following steps to get data on the aggregate sum of all increases as defined in Reg. 2-2-212 after April 5, 1991: option 3 → option 1 → type of pollutant (options 3 through 8).

[25] The net increase in PM_{10} and POC emissions associated with the installation of S-6068 is 346.15 lbs/yr (348.99 – 2.84) and 1,227.24 lbs/yr (1,237.32 – 10.08), respectively. Refer to Tables 1 and 2 above.

[26] Per 2-2-212, the cumulative increase in emissions considers only the permitted emission increases Post-4/5/91. The Pre-4/5/91 permitted emission increases will be considered when determining whether Offsets are warranted.

[27] POC emissions listed as –0.001

[28] SO2 emissions listed as –4.310

Table 6
Offsets

Pollutant	Permitted plant emissions (TPY) Pre-April 5, 1991[29] + Post-April 5,	Actual plant emissions [30] (TPY)	Increase in plant emissions associated with this application (TPY)	Total emissions (Higher of Permitted/Actual Emissions + Emissions associated with this application)[31] (TPY)	Regulation 2-2-302 and 2-2-303 Offset Triggers (TPY)
NOx	0	1699.24	0	1699.24	> 35
POC	26.09	1698.61	0.61	1,699.22	> 35
CO	298.00	716.19	0	716.19	NA
PM	0.05	0	0	0.05	NA
PM10	0.11	407.97	0.17	408.14	> 1
SO2	0	1670.31	0	1670.31	> 1
NPOC	25.70	0	0	25.70	NA

It can be seen from Table 6 above that offsets are warranted for POC and PM_{10}, since the emissions of the above pollutants is greater than the 35 TPY and 1 TPY offset trigger levels. It can also be seen that the actual emissions of NOx, CO, and SO2 are above the permitted emissions for the above pollutants. This is so because most sources at refineries are grandfathered (Pre-1971 sources). In light of the above, and for the purposes of determining whether offsets are warranted, only those emission increases, which occurred after April 5, 1991 that have not been offset are added to the emissions expected from S6068. Therefore, Shell will have to surrender to the District 0.7057 TPY of POC Emission Reduction Credits (ERC) at an offset ratio of 1.15:1[32] and 0.17 TPY of PM_{10} ERC at offset ratio of 1:1[33].

Statement Of Compliance

The new asphalt tank is subject to and is expected to comply with Sections 301, 6-310, and 311 in Regulation 6 "Particulate Matter and Visible Emissions." As explained above, the expected particulate emissions from this tank are a maximum of 349 lb/yr assuming 1,983,600 barrels of asphalt throughput. This is a rate of 0.000176 lb/barrel or 3.12 x 10^{-5} lb/cf, which is equivalent to 0.218 gr/cf. Shell plans on installing an abatement device (mist eliminator) to control particulate matter and visible emissions from the tank within 180 days after initial startup. Until the abatement device is installed, Shell will comply with Section 6-310 by limiting the tank temperature to 300 °F. At 300 °F, 201 lb PM10/yr will be emitted during the loading of 1,983,600 bbl/yr of asphalt. Approximately 0.000101 lb PM10 will be emitted per barrel loaded, which is equivalent to 0.126 gr/cf. This grain loading rate complies with Section 6-310. Once the abatement device is installed, Shell may store asphalt in this tank at temperatures up to 320 °F as discussed in the BACT discussion above.

The maximum fill rate is 73,500 gal/hr. At a density of 9 lb/gal for the asphalt, the maximum process rate "P" for the purposes of demonstrating compliance with Regulation 6-311 is 661,500 lbs/hr. Therefore, the

[29] If permitted increases attributable to sources that were permitted prior to April 5, 1991 have been archived, exclude their emissions when considering whether Offsets are warranted.
[30] Db → q2 →p → all
[31] For the purposes of determining whether Offsets are warranted, add the higher of the permitted emissions (Pre-April 5, 1991 + Post-April 5, 1991) and the actual emissions <u>to</u> the increase in emissions resulting from the source that is part of the current application.
[32] Per Regulation 2-2-302 i.e. (0.61) x 1.15 = 0.7057 TPY.
[33] Per Regulation 2-2-303 i.e. (0.17) x 1.00 = 0.17 TPY.

corresponding value of "E" in Table 1 is 40 lbs/hr. At a rate of 0.000176 lb/barrel or 4.19×10^{-6} lb/gal, the emission rate is 0.31 lb/hr. The above emissions rate complies with the 40 lbs/hr emission rate requirement in Reg. 6-311.

It is likely that the new asphalt tank will comply with all the applicable requirements in Regulation 7 "Odorous Substances" with the tank temperature limit or the use of the mist eliminator that is required per NSPS Subpart UU (see next section). Citizen complaints associated with the operation of the new tank will dictate whether odors from the tank will have to be abated further. The other asphalt tanks have not been associated with odor complaints.

Source S6068 is a heated vertical fixed roof tank whose emissions will not be abated by a POC control/abatement device, and the tank is neither pressurized nor blanketed. The vapor pressure of the asphalt within the tank is expected to be at or below 0.016 psia. In light of the above, S6068 is exempt from the requirements of Regulation 8, Rule 5 "Storage of Organic Liquids" per Section 117.

Source S6068 is *potentially subject* to the requirements contained in 40 CFR Part 60, Subpart Kb "Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984" (NSPS Kb) because the new asphalt tank will be constructed after July 23, 1984 (between 2007-2008) and it has a design capacity greater than 39,900 gallons (55,100 bbl ~ 2,314,200 gallons). However, since the maximum true vapor pressure of the asphalt inside the tank has a true vapor pressure less than 3.5 kPa/0.5 psia (0.016 psia) at 320°F, S6068 is *exempt from* NSPS Kb per Section 60.110b(b).

The new asphalt tank is subject to 40 CFR 60, Subpart UU "Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture" because S6068 is located at a petroleum refinery; it will be used to process/store non-roofing asphalts; and it will be constructed after May 26, 1981 (between 2007-2008). The new asphalt tank will be subject to the particulate matter standard outlined in Section 60.472(c) which will prevent the discharge into the atmosphere from S6068 exhaust gases with opacity greater than 0 percent, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for clearing. The standard requires monitoring for initial compliance, but does not have monitoring for ongoing compliance for asphalt tanks. This facility is a Title V facility. Periodic monitoring is required by BAAQMD Regulation 2-6-409.2.2, as shown below.

> 2-6-409.2.2: …Where the applicable requirement does not require periodic monitoring or testing, the permit shall contain periodic monitoring sufficient to yield reliable data from the relevant time periods that is representative of the source's compliance with the permit.

As noted above, a mist eliminator, A57, will be installed within 180 days after startup of the tank. Because the tank will be vented to a mist eliminator and therefore is expected to comply, quarterly monitoring is sufficient. The applicant states that a number of asphalt tanks at the facility are controlled by mist eliminators and that visible emissions are not observed from the tanks.

A "Group 1 storage vessel" is defined in Section 63.641 of 40 CFR Part 63, Subpart CC "National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries" (MACT CC) as follows:
"means a storage vessel at an existing source that has a design capacity greater than or equal to 177 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 10.4 kilopascals and stored-liquid annual average true vapor pressure greater than or equal to 8.3 kilopascals and annual average HAP liquid concentration greater than 4 percent by weight total organic HAP; a storage vessel at a new source that has a design storage capacity greater than or equal to 151 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 3.4 kilopascals and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP; or a storage vessel at a new source that has a design storage capacity greater than or equal to 76 cubic meters and less than 151 cubic meters and stored-liquid maximum true vapor pressure greater than or equal to 77 kilopascals and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP."

As previously discussed under NSPS Kb in the preceding paragraph, the true vapor pressure of asphalt that will be stored in S6068 is 0.016 psia at 320°F. Therefore, the new asphalt tank is a not a Group 1 tank and by default is a Group 2 tank under MACT CC. Per Section 63.640(n)(1), Shell can demonstrate compliance with MACT CC for the new Group 2 tank by complying with the requirements in NSPS Kb. However, since the new tank is exempt from NSPS Kb, S6068 is subject to the recordkeeping requirements contained in Sections 63.642(e) and 63.654(i)[34].

The California Environmental Quality Act (CEQA):

Per Section 2-1-311 of the District Rules and Regulations, a permit application for a proposed new or modified source will be classified as ministerial and will accordingly be exempt from the CEQA requirement of Section 2-1-310 if the District's engineering evaluation and basis for approval of the permit application for the project is limited to the criteria set forth in Section 2-1-428 and to the procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook. The method for determining whether a given permit application will be classified as ministerial is set forth in Section 2-1-427.

Per Section 2-1-427, if the District determines that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook, the District's evaluation of the permit application is classified as ministerial and the engineering evaluation of the permit application by the District will be limited to the use of said specific procedures, fixed standards and objective measurements. For such projects, the District will merely apply the law to the facts as presented in the permit application, and the District's decision regarding whether to issue the permit will be based only on the criteria set forth in Section 2-1-428 and in the District's Permit Handbook and BACT/TBACT Workbook.

For this permit application, the District determined that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook Chapter 4 "Organic Liquid Storage Tank" and the BACT/TBACT Workbook [Document #'s: 167.2.1; dated March 3, 1995. Since the District classified this permit application as ministerial pursuant to Section 2-1-427, and as a result of its evaluation of the permit application, the District determined that all of the criteria for approval of ministerial permit applications pursuant to Section 2-1-428 were met, the issuance by the District of an Authority to Construct and Permit to Operate for the proposed project is a mandatory ministerial duty and is accordingly exempt from the CEQA requirement of Section 2-1-310.

In addition to the ministerial exemption determination above, the District has also determined that the CEQA categorical exemptions of Sections 2-1-312.7 and 2-1-312.11 of the District Rules and Regulations and the CEQA "Common Sense Exemption" apply.

CEQA Categorical Exemptions and CEQA "Common Sense Exemption":

Though the District concludes that the construction and subsequent operation of the new asphalt tank is ministerial, it also concludes that, even if it were not ministerial, certain other exemptions from CEQA apply (see CEQA Guidelines § 15300.1). Section 2-1-312 of the District Rules and Regulations sets forth specific types of projects, which have been determined by the District to be categorically exempt from CEQA.

Per Section 2-1-312.11, permit applications for a new or modified source or sources or for process changes, which will satisfy the "No Net Emission Increase" provisions of District Regulation 2, Rule 2 and for which there is no possibility that the project may have any significant environmental effect in connection with any environmental media or resources other than air quality, are exempt from the CEQA review. The reason for this exemption should be apparent on its face: if a facility is given legal permission to emit more air pollutants from certain points while at the same time being disallowed permission for an equivalent amount of the same type of emissions from other points at the facility, then there is deemed to be no net effect on the air

[34] This determination is consistent with Table IV-Ha in Shell's Rev. 2 Title V permit.

environment, and therefore no possibility of a significant effect under CEQA, provided no-air impacts are also examined and deemed to be of no possible significant consequence.

Also, per the CEQA Guidelines in Title 14, California Code of Regulations, Chapter 3, Article 5, Section 15061(b)(3), a project is exempt from CEQA if the activity is covered by the general rule that CEQA applies only to projects, which have the potential for causing a significant effect on the environment. This is commonly known as the "Common Sense Exemption". Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to CEQA. The "no net increase" exemption of 2-1-312.11 is essentially a specific, codified, instance of the Common Sense Exemption.

Shell will fully offset the 0.17 TPY increase in PM_{10} and 0.61 TPY increase in POC emissions associated with the operation of S6068 by surrendering Emission Reduction Credits for the above pollutants. Therefore, the District has determined that the project satisfies the "No Net Emission Increase" provisions of District Regulation 2, Rule 2. Shell has completed and submitted to the District CEQA Appendix H, Environmental Information Form, for the project.

The District has reviewed the CEQA Appendix H form. Shell only checked "Yes" for item 29 regarding "Use or disposal of potentially hazardous materials, such as toxic substances, flammables or explosives". All other items on the form were checked "No". Shell's rationale in responding "Yes" to item 29 was to shed light on the fact that the asphalt, which will be stored in S6068 is a combustible material and contains traces of toxic substances. Shell has indicated that S6068 will be designed to prevent leaks, spillage, and reduce the risk of fires. The company has stated that it has implemented a contingency program to respond rapidly to fires in tank farms and to protect the environment from leaks and spills.

In addition to the above form and in efforts to address specific CEQA related questions posed by the District during a meeting with Shell staff, Shell submitted the following additional supplemental information in order for the District to determine the project's possible significant effects.

1. *Please provide a completed Appendix H, Environmental Information Form, which contains sufficient information for the District to complete the CEQA Initial Study of the project. For responses in the above form that are either marked "Yes" and/or "NA", please fully explain the relevant issue(s) in detail.*

   Shell has followed the guidelines in the Appendix H, Environmental Information Form provided in the preceding pages of this Appendix D.

2. *Please describe the new tank i.e. is it double-bottomed, relevant attributes, etc., and explain how the tank will be inspected/monitored for compliance with API 653, Regulation 8, Rule 5, NSPS, etc.*

   S6068 will be a double-bottomed fixed roof tank as profiled in Appendix A, Form T and Appendix C, Emissions Calculations, *Tanks 4.09d* Detail Report. The tank will be constructed in accordance with API 653 with asphalt-compatible materials in order to minimize the potential for cracking, corrosion and other integrity issues. Upon replacement, the tank will be entered into the facility-wide inspection program. The tank will be visually inspected each shift (twice per day). The tank will be inspected routinely on intervals established by API 653 guidelines. This will include internal and/or external inspections of the floor, shell, and roof, as well as level gages, vents, drains, manways, stairways, ladders, and handrails. The leak detection system for the tank will also be inspected by operations each operating shift. In addition, the San Francisco Bay Regional Water Quality Control Board (SFBRWQCB) Waste Discharge Requirements Order 95-234 also requires tank leak detection system checks.

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As a fixed roof tank storing a low-vapor pressure material, S6068 is exempt from the inspection and monitoring requirements of Regulation 8-5.

3. *Please describe any new equipment, including pumps and piping that will be installed for this project. Will any new piping be installed aboveground? How often would any project-related aboveground piping and exposed buried piping be inspected for leaks and spills?*

The project does not involve the installation of any new pumps or piping. Existing pumps and piping will continue to be visually inspected each shift (twice per day).

4. *To determine potential impacts to groundwater and surface water quality, please respond to the following:*

   a. *Will this project result in an increase in the risk of an asphalt spill with potential for impacting surface water and groundwater? Please explain.*

   There is minimal potential for S6068 to increase the risk of an asphalt spill that would impact surface water or groundwater, due to the design of the tank and Shell's program of operator training, prevention, mitigation and response. The tank will be constructed with an "El Segundo" bottom – a double-bottom design with ribbing that allows for leak detection. Further, asphalt is a solid under ambient conditions and would not flow to surface waters if released. Shell's response program is based on prevention of environmental impacts. Shell has prepared and implemented a SWPPP and a SPCC to prevent water quality contamination.

   Loading and Withdrawal from S6068:

   The new Asphalt Storage Tank will operate in a manner similar to the existing tank. The tank is loaded from existing refinery processes through existing pumps and piping.

   New Asphalt Storage Tank and Piping:

   The new asphalt storage tank design prevents corrosion and leakage. The filling system is designed to prevent overfilling. The tank and piping are inspected each operating shift (twice per day). The tank will be located in a diked basin with a capacity exceeding 110 percent of the contents of the tank. Storm drains are closed by default, and collected storm water is sent to the Martinez Refinery's effluent wastewater treatment plant.

   b. *What spill prevention measures and monitoring are in place at Shell to limit the potential risk of an asphalt spill due to this project.*

   The tank will be constructed with a double-bottom design with ribbing that allows for leak detection. Further, asphalt is a solid under ambient conditions and would not flow to surface waters if released. Spills are prevented through training, daily inspections and maintenance programs at the refinery. Shell has prepared and implemented a SPCC Plan and SWPPP to prevent spills.

   c. *Is the tank located inside of a contained area large enough to hold the entire contents of a full tank?*

   Yes. As described in the SPCC plan, the tank farm in which S6068 will be located holds more than 110 percent of the contents of the capacity of the new tank.

   d. *Will this tank be equipped with a high level alarm which will automatically shutdown pumps and stop filling line flow when a pre-determined tank level is reached?*

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Yes, the new asphalt storage tank will be equipped with a high level alarm which will automatically shutdown pumps and stop fill pipeline flow when a pre-determined tank level is reached.

e. *To address runoff at the site, does Shell have a Storm Water Pollution Prevention Plan and Spill Control and Countermeasures Plan*

Shell has prepared the SWPPP and SPCC Plan, as required. The plans are available onsite for inspection during normal business hours in accordance with the applicable regulations.

f. *How frequently does Shell conduct groundwater monitoring and how often are the analytical results to the Regional Water Quality Control Board?*

If a leak of asphalt were to occur from the tank or related piping, it would immediately harden on the ground surface. Hence, there would be no impact to groundwater.

Shell performs quarterly groundwater monitoring as required by Waste Discharge Requirements (WDR) Order 95-234, issued by the SFBRWQCB. Results are submitted to the SFBRWQCB twice a year. The test records are available onsite for inspection during normal business hours in accordance with the applicable regulations.

Additionally, Shell is required to perform a capture zone analysis on the facility. The WDR order requires that an ongoing hydraulic groundwater capture program be installed, operated, and maintained. Groundwater extraction systems are installed at the perimeter of the facility and serve to capture the groundwater before it leaves the site.

g. *What is direction of the groundwater flow beneath the Shell refinery site?*

The new asphalt storage tank will be located in the West Valley groundwater basin of the facility. Groundwater flows from South to North at a velocity of approximately four feet per year.

1. *To determine potential impacts due to diesel-fueled trucks associated with the project, please respond to the following:*

a. *How and from where will asphalt be delivered to the new tank?*

Asphalt will be delivered to S6068 through existing piping using existing pumps. Asphalt is not delivered by truck to this tank.

b. *If diesel-fueled trucks are used to deliver asphalt, what is the average storage capacity of a typical delivery truck, and how many delivery trucks will be making deliveries to the new tank on any given day (worst case)?*

Not applicable; asphalt is not delivered by truck to the tank.

c. *Would the installation of the new tank result in an increase in existing diesel-fueled truck traffic to and from the truck loading racks?*

No. The new Asphalt Storage Tank will operate in the same manner as the tank it replaces; no new truck traffic will occur as a result of the proposed project.

d. *For construction, how many diesel-fueled trucks will be used for mobilization, construction, and demobilization of the project?*

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The mobilization, construction and demobilization activities related to S6068 will require up to about 180 days. During this time, approximately 25 diesel-fueled truck deliveries of materials will occur. During construction, a diesel-fueled crane will be used for up to about 75 days. Demobilization, which consists of the removal of construction materials, will require approximately five diesel-fueled trucks.

e. *What is the likely route that the diesel-fueled trucks will take from the nearest freeway to the Shell gate?*

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The most likely route for delivery of construction materials to the S6068 construction site will be via Highway 680 to Marina Vista Avenue.

The District finds the above assertions and arguments to be credible. Thus, the District concludes that the permit application is exempt from CEQA because it is ministerial, it is categorically exempt from CEQA, and the project qualifies for the "Common Sense Exemption" of Subsection (b)(3) of the State CEQA Guidelines.

Based on the information contained in the Appendix H form submitted and Shell's responses to the District's supplemental questions regarding possible water impacts and the number of diesel-fueled truck trips associated with the project, the District does not expect either to be significant.
Based on all of the information before the District and the District's review of the information submitted, the District has determined that there is no possibility that the project may have any significant environmental effect.

The District has considered whether the construction and subsequent operation of the new asphalt tank is part of a larger project for CEQA purposes, and has concluded that it is not. Although other Shell refinery permitting applications have been acted on or are currently pending before the District, the construction and operation of the new asphalt tank is not necessarily linked to any of these. Specifically, construction of the new asphalt tank is not necessary in order for Shell to proceed with other permit applications, nor are any changes proposed in this application a foreseeable consequence of other permit applications. In reaching this conclusion, the District is relying in part on Shell's responses to the supplemental questions.

On a general level, the stated purpose of the construction of the new asphalt tank does not imply any necessary relationship to other projects, in the sense of being prerequisite to other projects or a foreseeable consequence of them.

PERMIT CONDITIONS

The new asphalt tank S6068 will be replacing an aging asphalt tank S22. Therefore, all references to S22 in part 1 of permit condition 18618 will be deleted and replaced by S6068 as follows:

S#	**Description**	**Daily Limit**	**Annual Limit**
21	Tank 21 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x 365
22	Tank 22 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x 365
23	Tank 23 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x 365
24	Tank 24 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x 365
26	Tank 26 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x 365
497	Tank 497 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x 365
560	Tank 560 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160

S#	Description	Daily Limit	Annual Limit
			+ S6068 < 42,000 bbl/day x 365
561	Tank 561 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x 365
572	Tank 572 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x 365
573	Tank 573 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x 365
598	Tank 598 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x 365
815	Tank 815 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x 365
985	Tank 985 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x 365
1043	Tank 1043 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x

S#	Description	Daily Limit	Annual Limit
			365
1044	Tank 1044 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x 365
1045	Tank 1045 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x 365
1160	Tank 1160 Asphalt Storage		S21~~+S22~~+S23+S24+S26+ S497+S560+S561+S572+ S573+S598+S815+S985+ S1043+ S1044+S1045+ S1160 + S6068 < 42,000 bbl/day x 365

In addition, the following permit condition will be imposed on the new asphalt tank:

Condition 23605:

1. The owner/operator of S6068 shall not exceed 1,983,600 bbl of asphalt throughput during any twelve-month period. The owner operator may store materials other than asphalt provided that the owner/operator demonstrates by submitting to the District a Data Form X, an MSDS, and a demonstration that there is no increase in emissions and the toxic emissions will not exceed the respective toxic trigger levels in Rule 2-5.
(Basis: Cumulative increase, Regulation 2, Rule 5)

2. The owner/operator of S6068 shall not exceed the following loading rates. Each loading rate is associated with a temperature. Both the liquid in the tank and the liquid that is loaded shall be at or below the temperature associated with each loading rate during loading.

Temperature, degrees F	Loading rate, bbls/day
300	26,400
310	20,000
320	15,200

(Basis: 2-1-403)

3. The owner/operator of S6068 shall not store asphalt in this tank at a temperature above 320 degrees F. (Basis: 2-1-305)

4. Within 60 days of maximum production rate but no more than 180 days after initial startup, the owner/operator of S6068 shall control the tank with mist eliminator A57 during all loading operations. Prior to startup of the mist eliminator, the owner/operator of S6068 shall not store asphalt in this tank at a temperature above 300 degrees F. (Basis: 6-310 and 40 CFR 60, Subpart UU, Section 60.472(c).

5. The owner/operator of S6068 shall prevent the discharge into the atmosphere exhaust gases with opacity greater than 0 percent, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for clearing. If any opacity is observed, the owner/operator shall cease loading immediately and take corrective action. (Basis: 40 CFR 60, Subpart UU, Section 60.472 (c))

6. In order to demonstrate initial compliance with the NSPS standard, the owner/operator shall use EPA Method 9 and the procedures in 40 CFR 60.11. The owner/operator shall demonstrate compliance during loading. (Basis: 40 CFR 60, Subpart UU, Section 60.474(c)(5))

7. In order to demonstrate ongoing compliance with the NSPS standard, the owner/operator shall use EPA Method 22 once every quarter. The owner/operator shall demonstrate compliance during loading. If loading does not occur during the quarter, the owner/operator shall use EPA Method 22 at the next loading event and resume the quarterly schedule thereafter. The owner/operator shall maintain visible emissions monitoring logs on site for a period of up to 5 years from the first date of entry. The owner/operator shall include the name of the person performing the visible emission check, the results of each inspection and the other records requirements listed in EPA Method 22. (Basis: BAAQMD Regulation 2-6-409.2.2, 2-6-503)

8. The owner/operator of S6068 shall maintain records of storage tank throughput, temperature of the tank, temperature of the loaded asphalt during loading, material type, and all inspection records. These records shall be summarized on a monthly basis, and may be in the form of computer-generated data, which is available to District personnel on short notice (rather than actual paper copies of throughput data). These records shall be kept on file for a minimum of 5 years. (Basis: Cumulative Increase, Regulation 2, Rules 5 and 6)

RECOMMENDATION

Modify permit condition 18618 as proposed.

Impose condition 23605 on S6068.

Archive Source S22, Asphalt Tank.

Issue an Authority to Construct for the following equipment:

S6068 Asphalt Tank abated by A57, Mist Eliminator[35]
Heated Vertical Fixed Roof Tank
Tank height: 30 feet; Tank diameter: 114.50 feet
Total volume: 55,100 bbl; Annual throughput: 1,983,600 bbl/yr

____
K. R. Bhagavan/B. Cabral

[35] Per Condition 23605 no. 4, asphalt tank S6068 must be abated by mist eliminator A57 during loading operations beginning 180 days after initial startup of the tank.

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11

Application: 16726

Background

Shell Oil Products US – Martinez Refinery (Shell) has submitted this application under the auspices of Regulation 2-1-106 "Accelerated Permitting Program" to obtain a Permit to Operate (PO) to replace one Stratco® Contactor Reactor (Reactor) at the following source:

S-1430 CP Alkylation Plant (ALKY)
14,000 bbl/day alkylate produced

The ALKY unit is made up of four simultaneously operating Reactors (Reactor #'s 1 through 4), dedicated acid settlers for each of the four Reactors, 3 chillers, and 2 coalescers. Shell has proposed to replace Reactor #4 under this application, which is similar to the Reactor #1 replacement project that was reviewed by the District under Application 7770 in 2003. As was the case with Reactor #1's predecessor which was replaced in 2003, the existing Reactor #4 has reached the end of its useful life and needs to be replaced. In comparison to the reactor it will replace, the new Reactor #4 will have a different metallurgy, larger capacity (13,000 gallons versus 11,000 gallons), and a smaller tube diameter (3/4" versus 1") for increased surface area.

The alkylation reaction combines isobutane with light olefins in the presence of a strong acid catalyst within the Reactor to form a low vapor pressure, high octane-blending component (alkylate). Each one of Shell's four Reactors is a horizontal pressure vessel containing an inner circulation tube, a tube bundle to remove the heat of the reaction, and a mixing impeller. The hydrocarbon feed and sulfuric acid enter the Reactor via separate nozzles on the suction side of the impeller inside the circulation tube. As the feeds pass across the impeller, an emulsion of hydrocarbon and acid is formed. The emulsion in the Reactor is continuously circulated at very high rates around the tube bundle to convert the olefins to alkylate. A portion of the acid emulsion in the Reactor is withdrawn from the discharge side of the impeller and flows to an acid settler, where the hydrocarbon phase (reactor effluent) is separated from the acid emulsion. The acid, being the heavier of the two phases, settles to the lower portion of the settler vessel. The acid leaving the settler vessel is recycled back to the suction side of the impeller in the form of an emulsion, which is richer in acid than the emulsion entering the settler. When the acid loses its strength, the spent acid is shipped offsite to an acid reprocessing facility.

The purpose of the tube bundle is to remove the heat of reaction and minimize temperature differences between any two points in the reaction zone. This reduces the possibility of localized hot spots that could potentially cause side reactions which could degrade the alkylate product and increase the chances of corrosion within the Reactor vessel. The intense mixing in the Reactor also provides uniform distribution of the hydrocarbons in the acid emulsion, which prevents localized areas of non-optimum isobutane to olefin ratios and acid to olefin ratios, both of which promote olefin polymerization reactions. In the absence of the intense mixing in the Reactor described above, higher reaction temperatures would dramatically favor the side polymerization reactions which would dilute the acid and require more fresh acid to be added to get the same alkylate quality. Therefore, the better the mixing and greater the cooling surface area, the less catalyst (acid) is needed to get the best quality product.

Shell achieved all of the above benefits when it replaced Reactor #1 in 2003. Specifically, after increasing the reactor volume and tube bundle surface area at a constant feed rate, the overall temperature within Reactor #1 was lowered, acid consumption was reduced, and alkylate quality was improved (higher octane). In other words, the overall lower temperature and fewer hot spots from the larger reactor volume combined with the increased tube bundle surface area caused less acid to be wasted on side reactions, and therefore decreased acid consumption.

Regulation 2-1-234.1 states the following:

"2-1-234 Modified Source: Any existing source that undergoes a physical change, change in method of operation, increase in throughput or production, or addition and that results or may result in any of the following:

234.1 An increase in either the daily or annual emission level of any regulated air pollutant, or an increase in the production rate or capacity that is used to estimate the emission level, that exceeds emission or production levels approved by the District in any authority to construct."

Part 1 of permit condition 18618 in Shell's Title V permit[36] limits alkylate produced at the ALKY unit to 14,000 bbl/day. Shell's proposal to replace Reactor #4 under this application will not result in an increase in alkylate production beyond the above limit, nor would it de-bottleneck any units upstream/downstream of the ALKY. Therefore, per Regulation 2-1-234.1 the ALKY unit is not considered a modified source.

Based on information contained in Shell's Flare Minimization Plan which was approved by the District in July 2007, the ALKY unit is serviced by the LOP Flare (S-1471). It is highly unlikely that the proposed Reactor #4 replacement project would result in flaring beyond existing levels at S-1471.

Emissions Calculations

Process units such as the ALKY are closed processes, implying that the only sources of emissions from such units are from fugitive leaks. No pumps, compressors, or pressure relief valves will be replaced as a result of the proposed project. Valves and flanges will be replaced as needed. An increase in the number of valves and flanges at Reactor #4 is not anticipated to increase. However, it is conservatively assumed that there would be an increase of up to 40 new valves and 40 new flanges in "light liquid" service. Table 1 summarizes leak rates for the above fugitive components, which are similar to those that were used by the District under Application 1821[37].

Table 1

Note:

Type/service	Number of components[1]	Emission factor (Lb/hr/component)	POC[38], lb/hr	POC, lb/day	POC, lb/yr	POC, TPY
Valves/Gas/Light Liquid	40	0.00016[2]	0.0064	0.1536	56.064	0.028
Flanges/All[3]	40	0.000174	0.0068	0.1632	59.568	0.030
Totals	**80**		**0.0132**	**0.3168**	**115.632**	**0.058**

1) Component counts estimated by Shell.

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[36] All references to "Shell's Title V permit" in this evaluation refer to the Title V permit that was issued by the District to Shell on May 17, 2007.

[37] The District issued Shell an AC and PO for Application 1821 on January 2002 and August 2002, respectively.

[38] POC – Precursor Organic Compounds

2) Correlation equation used to derive the emission factor excerpted from Table IV-3a (page 20) of the "California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities", February 1999. Specifically, the following correlation equation "2.27E-6*(SV)^0.747" was used in concert with a Screening Value (SV) of 100 ppmv. Please note that the SV of 100 ppmv is based on the maximum leak rate allowed by Regulation 8 "Organic Compounds", Rule 18 "Equipment Leaks".
3) Flange counts include connectors.
4) Excerpted from Appendix IX B-2 "BACT Fugitive Emission Factors" in Shell's Clean Fuels Project (CFP) permit condition # 12271. Though a flanged valve requires at least two flanges i.e. valves leak at a higher rate than flanges, it can be seen from the leak rates outlined in Table 1 that the leak rates for flanges is far greater than those for flanged valves. This is so because Shell used a conservative flange leak rate in their CFP permit, which was reviewed by the District under Application 8407[39]. In contrast, socket-welded valves don't require flanges. The 40 valves that will be installed for the purposes of this application will consist of 20 flanged valves and 20 socket-welded valves.

It can be seen from Table 1 above that the proposed modifications/alterations to process units that are part of this application would result in an increase of less than a pound (0.3168 lbs/day) of fugitive POC emissions per day.

Toxic Risk Screen Analysis

Toxic Air Contaminant (TAC) emissions from fugitive components summarized in Table 2 below were estimated using organic gas speciation profiles listed under Profile ID 316 "Refinery – pipes, valves & flanges – composite" in CARB's spreadsheet entitled "ORGPROF.xls" for those compounds for which the District has established TAC Trigger Levels (TTLs) in Table 2-5-1 in Regulation 2, Rule 5 "New Source Review of Toxic Air Contaminants". A copy of the above spreadsheet can be found from the following URL: http://www.arb.ca.gov/ei/speciate/dnldopt.htm#specprof

Table 2

TAC	**Organic Fraction**	**TAC Emissions**			
		Lbs/hr	**Lbs/day**	**Lbs/yr**	**TPY**
Propylene	0.001	0.0000132	0.00032	0.1168	0.00006
n-hexane	0.034[40]	0.00045	0.0108	3.942	0.002
Isomers of xylene	0.002	0.00003	0.00072	0.2628	0.0001
Benzene	0.001	0.0000132	0.00032	0.1168	0.00006
Toluene	0.005	0.00007	0.00168	0.6132	0.0003

Note:
For example, n-hexane emissions summarized in Table 2 above were estimated as follows:
From Table 1, the daily POC emissions from the 80 new fugitive components is equal to 0.0132 lb/hr. The organic fraction of n-hexane in CARB's "ORGPROF.xls" spreadsheet is 0.034. Therefore, the hourly n-hexane emissions are equal to 0.0132 x 0.034 = 0.00045 lbs/hr, and the daily & annual n-hexane emissions are 0.0108 lbs/day (0.00045 x 24) & 3.942 lbs/yr (0.0108 x 365), respectively.

Table 3 below summarizes the Acute and Chronic TTL's for TAC's summarized in Table 2, and compares the emissions summarized in the above table to the TTL's outlined in Table 2-5-1 in Regulation 2, Rule 5 to verify if a Toxic Health Risk Screening Analysis (HRSA) is warranted.

[39] The District issued Shell an AC and PO for Application 8407 on December 1993 and November 1996, respectively.
[40] Shell maintains a database containing speciation information for various process streams at the refinery. This data is used for a variety of reports, such as the Toxic Release Inventory (TRI) reports among others. The organic fraction of n-hexane, the only TAC contained in streams associated with the ALKY unit, is 3.9% by wt.

Table 3						
TAC	Acute TTL (lbs/hr)	Emissions (lbs/hr)	Exceeds Acute TTL?	Chronic TTL (lbs/yr)	Emissions (lbs/yr)	Exceeds Chronic TTL?
Propylene	NA	0.0000132	NA	125,000	0.1168	No
n-hexane	NA	0.00045	NA	270,000	3.942	No
Isomers of xylene	49	0.00003	No	27,000	0.2628	No
Benzene	2.9	0.0000132	No	6.4	0.1168	No
Toluene	82	0.00007	No	12,000	0.6132	No

It can be seen from Table 3 above, that this application does not warrant a Toxic HRSA.

Regulation 2-1-128.21 Exemption
Regulation 2-1-128.21 states the following:
"2-1-128 Exemption, Miscellaneous Equipment: The following equipment is exempt from the requirements of Sections 2-1-301 and 302, provided that the source does not require permitting pursuant to Section 2-1-319.
128.21 Modification, replacement, or addition of fugitive components (e.g. valves, flanges, pumps, compressors, relief valves, process drains) at existing permitted process units at petroleum refineries, chemical plants, bulk terminals or bulk plants, provided that the cumulative emissions from all additional components installed at a given process unit during any consecutive twelve month period do not exceed 10 lb/day, and that the components meet applicable requirements of Regulation 8 rules."

It can be seen from emission calculations summarized in Table 1 above that the cumulative emissions from the 80 new fugitive components that will be installed at the ALKY unit as part of this application is below 10 lb/day i.e. 0.3168 lb/day. In addition, the new fugitive components, summarized in Table 1 will meet the requirements of Regulation 8 "Organic Compounds", Rule 18 "Equipment Leaks" and will be incorporated into Shell's Leak Detection and Repair (LDAR) program.

The proposed alteration to the ALKY unit that is part of this application also meets the requirements outlined in Regulation's 2-1-316 through 319 as follows:

- ***Regulation 2-1-316:***
  The hazardous air pollutant (HAP) emissions from fugitive components summarized in Table 2 above will neither result in the emission of 2.5 TPY or more of a single HAP emissions, or 6.5 TPY or more of a combination of HAPs.
- ***Regulation 2-1-317:***
  The ALKY unit is not a source of public nuisance.
- ***Regulation 2-1-318:***
  It can be seen from Table's 2 and 3 above that the ALKY unit doesn't contain any of the compounds listed in Sections 318.1 through 318.8 of the above regulation.
- ***Regulation 2-1-319:***
  It can be seen from Table 1 above that the "post-control" POC emissions from the 80 new fugitive components is below 5 TPY (0.058TPY), and all the requirements contained in Regulation 2-1-316 through 2-1-318 are satisfied.

Therefore, it is safe to conclude that the additional fugitive components summarized in Table 1 above qualify for the exemption under Regulation 2-1-128.21.

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BACT

Per Regulation 2, Rule 2, Section 301, BACT is only triggered if emissions from a new source or an increase in emissions from a modified source has the potential to emit 10 lbs or more per highest day of emissions. Replacement of Reactor #4 at the ALKY unit does not constitute a modification of the above process unit (please refer to the Reg. 2-1-234.1 discussion in the "Background" section), and the fugitive components summarized in Table 1 above are exempt per Regulation 2-1-128.21. Therefore, BACT is not triggered for the increase in emissions from fugitive components that are part of this application.

Cumulative Increase & Offsets

Shell is an existing facility. Since the additional fugitive components summarized in Table 1 above are exempt under Regulation 2-1-128.21, the ALKY Reactor #4 replacement project will not result in a cumulative increase in criteria pollutant emissions. Therefore, offsets are also not warranted. Tables 4 and 5 summarize data relating to the cumulative increase in criteria pollutant emissions and offsets at Plant 11 for information purposes only.

Table 4

Cumulative Increase

Pollutant	Increase in plant emissions prior to April 5, 1991 [41] (TPY)	Increase in plant emissions since April 5, 1991 [42] (TPY)	Increase in plant emissions associated with this application (TPY)	Cumulative increase in emissions (Post 4/5/91 + Current application increase)[43] (TPY)
NOx	0	0	0	0
POC	26.09	0[44]	0	0
CO	0	298.00	0	0
PM	0.05	0	0	0
PM10	0.11	0	0	0
SO2	0	0[45]	0	0
NPOC	11.00	14.70	0	0

[41] In PSDP do the following to obtain emissions data at the plant prior to April 5, 1991: option 3 → option 1 → option 2.

[42] In PSDP do the following steps to get data on the aggregate sum of all increases as defined in Reg. 2-2-212 after April 5, 1991: option 3 → option 1 → type of pollutant (options 3 through 8).

[43] Per 2-2-212, the cumulative increase in emissions considers only the permitted emission increases Post-4/5/91. The Pre-4/5/91 permitted emission increases are considered when determining whether Offsets are warranted.

[44] POC emissions listed as –0.001

45 SO2 emissions listed as –4.310

Table 5 Offsets					
Pollutant	**"Pre-Project" Permitted plant emissions (TPY) Pre-April 5, 1991[46] + Post-April 5, 1991**	**Actual plant emissions[47] (TPY)**	**Increase in plant emissions associated with this application (TPY)**	**"Post-Project" Permitted plant emissions ("Pre-Project" Permitted Emissions + Increase in plant emissions associated with this application) (TPY)**	**Regulation 2-2-302 and 2-2-303 Offset Triggers (TPY)**
NOx	0	1,818.12	0	1,818.12	> 35
POC	26.09	1,298.38	0	1,298.38	> 35
CO	298.00	769.93	0	769.93	NA
PM	0.05	0	0	0	NA
PM10	0.11	407.82	0	407.82	> 1
SO2	0	1,538.20	0	1,538.20	> 1
NPOC	25.70	0	0	0	NA

It can be seen from Table 5 above that the actual emissions of NOx, POC, CO, PM10, and SO2 are above the permitted emissions for the above pollutants. This is so because most sources at refineries are grandfathered (Pre-1971 sources). In light of the above, and for the purposes of determining whether offsets are warranted, only those emission increases, which occurred after April 5, 1991 (0 TPY) are considered.

Statement Of Compliance

The fugitive components summarized in Table 1 above will be subject to Sections 301, 302, 304, 306, and 307 in Regulation 8 "Organic Compounds", Rule 18 "Equipment Leaks". Sections 301, 302, and 304 require, among other things, that organic compound leaks, not exceed 100 ppm for general components, valves, and connections. Section 8-5-306 limits the percentages of non-repairable equipment allowed. Section 8-5-307 requires that leaking equipment not be used unless the leak discovered by the operator, is minimized within 24 hours and repaired within 7 days.

The four existing Reactors at the ALKY unit are not equipped with Atmospheric Pressure Relief Devices (APRDs), nor would the replacement of Reactor #4, which is the subject of this evaluation, result in the addition of any new APRDs. For the purposes of Regulation 8 "Organic Compounds", Rule 28 "Episodic Releases from Pressure Relief Devices at Petroleum Refineries and Chemical Plants", it should be noted that three columns downstream of the four Reactors are equipped with APRDs. Specifically, the Deisobutanizer (Column #: C-111; APRD #s: SVM-34 & SVM-37), the Depropanizer (Column #: C-112; APRD #: SVJ-143), and the C4/C5 Splitter (Column #: 129; APRD #: SVH-288). The replacement of Reactor #4 will not impact the relief scenarios at the above columns, because the flows to the columns will remain unchanged and there will be no increase in the amount of alkylate produced[48] at he ALKY unit. Please refer to a copy of a letter dated July 28, 2006 which is attached with this evaluation from Shell to Mr. Kelly Wee, Director of Compliance and Enforcement Division which summarizes information on PRDs at pressure related systems at process units & non-process units at the refinery for the purposes of Regulation 8, Rule 28.

Regulation 11 "Hazardous Pollutants", Rule 7 "Benzene" limits the emission of benzene from sources (such as pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines,

[46] If permitted increases attributable to sources that were permitted prior to April 5, 1991 have been archived, exclude their emissions when considering whether Offsets are warranted.
[47] Db → q2 → p → all
[48] Part 1 of permit condition 18618 in Shell's Title V permit limits the alkylate produced to 14,000 bbl/day.

valves, flanges and other product accumulator vessels, and control devices) intended to operate in benzene service. Regulation 11-7-207 defines "In Benzene service" to be any equipment which either contains or contacts a fluid (liquid or gas) that is at least 10 percent benzene by weight. The proposed project will not involve process streams, which will either contain or contact a fluid that is at least 10 percent benzene by weight. Therefore, Regulation 11, Rule 7 does not apply to the ALKY Reactor #4 replacement project

The increase in the number of fugitive components associated with Shell's "MTBE Removal Project", which was reviewed by the District under Application 1821[49], made the ALKY unit subject to the requirements of 40 CFR Part 60, Subpart GGG "Equipment Leaks of VOC in Petroleum Refineries" (NSPS GGG) on November 19, 2002. Though Table's IV-AL & AN in Shell's Title V permit don't explicitly list NSPS GGG as the applicable requirements for the ALKY unit, it is implied that the requirements of the above rule summarized in Table IV-DP apply to the above process unit at all times. In light of the above applicability determination, the new Reactor and the fugitive components summarized in Table 1 above are subject to and are expected to comply with the requirements of NSPS GGG.

Please note that Table IV-DP contains references to 40 CFR Part 60 Subpart VV "Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry" (NSPS VV) only because NSPS GGG references NSPS VV. The US EPA intent was to subject a facility (Shell in this case) to either NSPS GGG or NSPS VV and not both of the above rules. In other words, the NSPS GGG requirements applied to refinery process units, and chemicals plants were expected to comply with the requirements in NSPS VV[50].

As it currently exists in Shell's Title V permit (refer to Table's IV-AL & AN), the ALKY unit is not subject to any National Emissions Standards for Hazardous Air Pollutants (NESHAP) in 40 CFR Part 61, since the above rule regulates sources of specific pollutants. The proposed ALKY Reactor replacement will not result in emissions of any new pollutants that are subject to the NESHAPs. Therefore, the ALKY unit is not subject to 40 CFR Part 61.

Maximum Achievable Control Technology (MACT) standards in 40 CFR Part 63 is applicable to toxic air emissions emanating from specific source categories at facilities, which are major sources of HAPs. The MACT standards that potentially are applicable to the ALKY unit include 40 CFR Part 63, Subpart A "General Requirements", and 40 CFR Part 63, Subpart CC "National Emissions Standards for Hazardous Air Pollutants from Petroleum Refineries" (MACT CC). Though Table's IV-AL & AN in Shell's Title V permit don't explicitly list MACT CC as the applicable requirements for the ALKY unit, it is implied that the requirements of the above rule summarized in Table's IV DS apply to various refinery operations (such as the ALKY unit) including equipment leaks at all times. As previously discussed in the preceding paragraphs, though NSPS VV is not applicable to petroleum refineries, Table IV-DS contains references to sections from the above rule only because MACT CC references NSPS VV.

In light of the above, the fugitive components similar to those summarized in Table 1 above, which will be added to the ALKY unit, must comply with NSPS VV if they will be used in organic HAP (OHAP) service. "In organic hazardous air pollutant service" is defined in MACT CC as follows:
"means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP's as determined according to the provisions of § 63.180(d) of subpart H of this part and table 1 of this subpart. The provisions of § 63.180(d) of subpart H also specify how to determine that a piece of equipment is not in organic HAP service."

Of the TAC's summarized in Table's 2 & 3 above, benzene (0.1%), hexane (3.4%), toluene (0.5%), and the mixed isomers of xylene (0.2%) appear in Table 1 of MACT CC. Since the total percent by

[49] The District issued Shell an AC and PO for Application 1821 on January 16, 2002 and August 1, 2002, respectively.
[50] Refineries that produce MTBE are subject to NSPS VV. Since Shell does not produce MTBE, it is not subject to NSPS VV.

weight of the above OHAP's is below 5% i.e. 4.2% or 4.7% when using Shell's stream specific speciation information (refer to footnote #5), the new fugitive components that will be added as part of the proposed ALKY Reactor replacement are not subject to MACT CC. However, the requirements of MACT CC in Table IV-DS would apply to the new fugitive components even if they contain/contact fluids containing less than 5% by wt. This is so because when MACT CC went into effect in 1998, Shell decided to eliminate the guesswork/un-certainty surrounding whether a certain OHAP stream(s) was subject to the MACT CC or not. Given that the District's Regulation 8, Rule is at least as stringent if not more stringent than MACT CC, the company decided to subject their process units and associated components to the MACT CC requirements at all times.

PSD is not applicable to this project because there is no cumulative increase in emissions at the plant, since the increase in emissions associated with the new fugitive components that will be added as part of the proposed ALKY Reactor replacement are exempt from Regulation 2-1-301 per Regulation 2-1-128.21.

The California Environmental Quality Act (CEQA):

Per Section 2-1-311 of the District Rules and Regulations, a permit application for a proposed new or modified source will be classified as ministerial and will accordingly be exempt from the CEQA requirement of Section 2-1-310 if the District's engineering evaluation and basis for approval of the permit application for the project is limited to the criteria set forth in Section 2-1-428 and to the procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook. The method for determining whether a given permit application will be classified as ministerial is set forth in Section 2-1-427.

Per Section 2-1-427, if the District determines that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook, the District's evaluation of the permit application is classified as ministerial and the engineering evaluation of the permit application by the District will be limited to the use of said specific procedures, fixed standards and objective measurements. For such projects, the District will merely apply the law to the facts as presented in the permit application, and the District's decision regarding whether to issue the permit will be based only on the criteria set forth in Section 2-1-428 and in the District's Permit Handbook and BACT/TBACT Workbook.

For this permit application, the District determined that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook Chapter 3.4 "Petroleum Refinery Fugitive Emissions". Since the District classified this permit application as ministerial pursuant to Section 2-1-427, and as a result of its evaluation of the permit application, the District determined that all of the criteria for approval of ministerial permit applications pursuant to Section 2-1-428 were met, the issuance by the District of an Authority to Construct and Permit to Operate for the proposed project is a mandatory ministerial duty and is accordingly exempt from the CEQA requirement of Section 2-1-310.

In addition to the ministerial exemption determination above, the District has also determined that the CEQA categorical exemptions of Sections 2-1-312.7 and 2-1-312.11 of the District Rules and Regulations and the CEQA "Common Sense Exemption" apply.

CEQA Categorical Exemptions and CEQA "Common Sense Exemption":

Though the District concludes that the modifications/alterations that are part of this application are ministerial, it also concludes that, even if it were not ministerial, certain other exemptions from CEQA apply (see CEQA Guidelines § 15300.1). Section 2-1-312 of the District Rules and Regulations sets forth specific types of projects, which have been determined by the District to be categorically exempt from CEQA.

Per Section 2-1-312.7, permit applications for the replacement or reconstruction of existing sources or facilities, where the new source or facility will be located on the same site as the source or facility replaced and will have substantially the same purpose and capacity as the source or facility replaced, are exempt from the CEQA review.

Per Section 2-1-312.11, in addition to ministerial projects, permit applications for a new or modified source or sources or for process changes, which will satisfy the "No Net Emission Increase" provisions of District Regulation 2, Rule 2 and for which there is no possibility that the project may have any significant environmental effect in connection with any environmental media or resources other than air quality, are exempt from the CEQA review. The reason for this exemption should be apparent on its face: if a facility is given legal permission to emit more air pollutants from certain points while at the same time being disallowed permission for an equivalent amount of the same type of emissions from other points at the facility, then there is deemed to be no net effect on the air environment, and therefore no possibility of a significant effect under CEQA, provided no-air impacts are also examined and deemed to be of no possible significant consequence.

Also, per the CEQA Guidelines in Title 14, California Code of Regulations, Chapter 3, Article 5, Section 15061(b)(3), a project is exempt from CEQA if the activity is covered by the general rule that CEQA applies only to projects, which have the potential for causing a significant effect on the environment. This is commonly known as the "Common Sense Exemption". Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to CEQA. The “no net increase” exemption of 2-1-312.11 is essentially a specific, codified, instance of the Common Sense Exemption.

The new fugitive components that will be added as part of the proposed ALKY Reactor replacement project are exempt from Regulation 2-1-301 per Regulation 2-1-128.21. As a result, the 0.058 TPY increase in POC emissions summarized in Table 1 above will not be counted toward the cumulative increase in emissions at Shell. Therefore, the District determined that the project satisfies the "No Net Emission Increase" provisions of District Regulation 2, Rule 2. Shell has completed and submitted to the District CEQA Appendix H, Environmental Information Form, for the project.

The District has reviewed the CEQA Appendix H form. Shell did not provide a “Yes” response to any of the questions in the above form. Shell submitted the following additional information to enable the District to determine the project's possible significant effects:

5. *Please describe any new equipment, including pumps and piping that will be installed for this project. Will any new piping be installed aboveground? How often would any project-related aboveground piping and exposed buried piping be inspected for leaks and spills?*
   The new Alkylation reactor replaces an existing reactor of approximately the same size. The new reactor will have a different metallurgy, a slightly larger capacity (13,000 gallons versus the existing 11,000 gallons), and smaller tube diameter (3/4” versus the existing 1”) for increased surface area. The new reactor will be built in the same location as the existing reactor, with substantially the same purpose and capacity. All piping will be above ground. Prior to usage, the piping will be inspected and pressure tested in order to verify adequate integrity of the system. The associated piping components will also be entered into the facility-wide leak detection and repair program and maintained per BAAQMD Regulation 8-18.

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6. *To determine potential impacts to groundwater and surface water quality, please respond to the following:*

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   g. *Will this project result in an increase in the risk of a spill with potential for impacting surface water and groundwater? Please explain.*
      There is minimal potential for the Alkylation Project to increase the risk of a spill that would impact surface water or groundwater due to Shell’s program of operator

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training, prevention, mitigation and response. The system is designed to prevent leakage and spillage. Shell's response program is based on prevention of environmental impacts.

h. *What spill prevention measures and monitoring are in place at Shell to limit the potential risk of a spill due to this project.*
Spills are prevented through the training, daily inspections and maintenance programs at Shell. Shell has an approved Spill Prevention, Control, and Countermeasure (SPCC) Plan and Stormwater Pollution Prevention Plan (SWPPP), which are available upon request.

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i. *To address runoff at the site, does Shell have a Storm Water Pollution Prevention Plan and Spill Control and Countermeasures Plan?*
Shell has an approved SWPPP and SPCC Plan, as required, which are available onsite for inspection during normal business.

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j. *How frequently does Shell conduct groundwater monitoring and how often are the analytical results to the Regional Water Quality Control Board?*
Shell performs quarterly groundwater monitoring as required by Waste Discharge Requirements (WDR) Order 95-234, issued by the San Francisco Bay Regional Water Quality Control Board (SFBRWQCB). Results are submitted to the SFBRWQCB twice a year. A recent copy is available upon request.

Additionally, Shell is required to perform a capture zone analysis on the facility. The WDR order requires that an ongoing hydraulic groundwater capture program be installed, operated, and maintained. Groundwater extraction systems are installed at the perimeter of the facility and serve to capture the groundwater before it leaves the site. The Alkylation Reactor No. 4 will be located in the East Valley groundwater basin. A copy of the most recent annual capture zone report is available upon request.

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k. *What is direction of the groundwater flow beneath the Shell refinery site?*
Groundwater flows from South to North at a velocity of approximately four feet per year.

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7. *To determine potential impacts due to diesel-fueled trucks associated with the project, please respond to the following:*

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a. *How and from where will materials be delivered to the new reactor?*

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The process feed is delivered to and product is delivered from the Alkylation Plant using existing piping. No diesel trucks are used as part of the process.

b. *If diesel-fueled trucks are used to deliver materials, what is the average storage capacity of a typical delivery truck, and how many delivery trucks will be making deliveries to the new reactor on any given day (worst case)?*
The process feed is delivered to and product is delivered from the Alkylation Plant using existing piping. No diesel trucks are used as part of the process.

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c. *Would the installation of the new reactor result in an increase in existing diesel-fueled truck traffic to and from the truck loading racks?*
No, the Alkylation project will not impact existing diesel-fueled truck traffic.

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d. *For construction, how many diesel-fueled trucks will be used for mobilization, construction, and demobilization of the project?*

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Construction, mobilization, and demobilization of the project will require up to 7 total diesel-fueled truck round trips. The following diesel-fueled truck round trips are expected:

i. **Delivery of the new reactor – 1 round trip**
ii. **Removing old reactor – 1 round trip**
iii. **Shipments of pipes and fittings – 1-2 round trips**
iv. **Shipments of structural materials – 1-2 round trips**
v. **Shipments of instruments – 1 round trip**

e. *What is the likely route that the diesel-fueled trucks will take from the nearest freeway to the Shell gate?*
All trucks will exit 680 at Pacheco Boulevard and come to the receiving yard through the P3 gate.

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The District finds these assertions and arguments to be credible. Thus, the District concludes that the permit application is exempt from CEQA because it is ministerial, it is categorically exempt from CEQA, and the project qualifies for the "Common Sense Exemption" of Subsection (b)(3) of the State CEQA Guidelines.

Based on all of the information before the District and the District's review of the information submitted, the District has determined that there is no possibility that the project may have any significant environmental effect.

The District has considered whether the proposed ALKY Reactor replacement project is part of a larger project for CEQA purposes, and has concluded that it is not. On a general level, the stated purpose of the proposed ALKY Reactor replacement project is that the existing Reactor #4 has reached the end of its useful life and needs to be replaced. This purpose does not imply any necessary relationship to other projects, in the sense of being prerequisite to other projects or a foreseeable consequence of them.

Permit Conditions

Part 1 of permit condition 18618 in Shell's Title V permit limits alkylate produced at the ALKY unit to 14,000 bbl/day. Shell's proposal to replace Reactor #4 under this application will not result in an increase in alkylates beyond the permitted limit. Therefore, no changes to permit condition 18618 are warranted at this time.

Recommendation

Waive the AC and issue Shell a PO to perform the following alterations:

- Replace an existing 11,000 gallon Reactor #4 with a new 13,000 gallon reactor.
- Install 40 new flanges and 40 new valves.

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At the following source:

S-1430 CP Alkylation Plant (ALKY)
14,000 bbl/day alkylate produced

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11
Application: 17633

Background

Shell Oil Products US – Martinez Refinery (Shell) has submitted this application under the auspices of Regulation 2-1-106 "Accelerated Permitting Program" to obtain a Permit to Operate (PO) to replace the existing burners at the following sources:

S-1486 DH F-40 CU Feed; 374 MMBTU/hr
S-1763 DH F-126 CU Feed Heater; 220 MMBTU/hr

Per Regulation 2-1-233.1, the replacement of the burners at the above sources, which is currently scheduled to occur in the second quarter of 2009, is an alteration.

Shell has proposed to replace *all* the existing burners at the above sources with the Callidus Ultra Blue Low (CUBL) -Flex NOx Burners, and make modifications to the associated furnace support steel, refractory, fuel piping, heater instrumentation, plenums and dampers in order to enhance control, energy efficiency, and to minimize NOx emissions. The net effect of the above alterations will enhance the compliance of sources S-1486 and S-1763 with Regulation 9, Rule 10 "Nitrogen Oxides And Carbon Monoxide From Boilers, Steam Generators and Process Heaters In Petroleum Refineries", and will not result in the increase of any regulated air pollutant at Shell.

Sources S-1486 and S-1763 are equipped with NOx and O_2 CEMS[51] and are governed by permit condition 18265, which outlines Shell's "IERC[52] Alternative Compliance Plan". The proposed alterations to sources S-1486 and S-1763 will not result in any changes to the above permit condition. Because of the use of NOx and O_2 CEMs, no additional permit conditions are proposed to require source testing of the above sources for compliance.

Emissions Summary

Table 1 below summarizes information on the existing burners at sources S-1486 and S-1763, and their corresponding NOx and CO emission rates/concentrations.

Table 1: "Pre-Project" Summary[53]

Source ID	Burner Manufacturer	Burner Model(s)	NOx (ppm @ 3% O_2)	NOx (lb/MMBTU)	CO (ppm @ 3% O_2)
S-1486	John Zink	EFX-PC-24	51.5	0.082	0
S-1763	John Zink	EFX-PC-24	113.5	0.157	2.1

Table 2 below summarizes information on the proposed alterations at sources S-1486 and S-1763, and their corresponding NOx and CO emission rates/concentrations. The CO concentrations i.e.

[51] CEMS – Continuous Emission Monitoring Systems
CEMS information for Shell summarized in P:\GENERAL\ST\CEMLIST.pdf
[52] IERC – Interchangeable Emission Reduction Credits
[53] The NOx and CO concentrations summarized in Table 1 are based on tests conducted by Shell for the Initial Demonstration of Compliance with Regulation 9, Rule 10.

less than 50 ppm @ 3% O_2, summarized in Table 2 are vendor guarantees. However, Shell has indicated that the actual CO concentrations are expected to be in the order of 10 ppm or less.

Table 2: "Post-Project" Summary

Source ID	"Callidus"Burner Model(s)	Number of burners	Burner design firing rates (MMBTU/hr)	NOx (lb/MMBTU)	CO (ppm @ 3% O_2)
S-1486	CUBL-16P-Flex	20	14.50	0.040	< 50
S-1763	CUBL-16P-Flex	8	15.00	0.040	< 50
	CUBL-12P-Flex	4	10.80		

It can be seen from Tables 1 and 2 above that the proposed alterations at sources S-1486 and S-1763 will not result in a net increase in NOx emissions at Shell. In addition, the maximum firing rates of the above furnaces will not increase above their respective maximum firing rates outlined in part 1 of permit condition 16688 (S-1486 – 374 MMBTU/hr and S-1763 – 220 MMBTU/hr).

Statement Of Compliance

The proposed project will enhance Shell's compliance with Regulation 9, Rule 10, by reducing NOx emission from sources S-1486 and S-1763.

The proposed alterations to sources S-1486 and S-1763 will not result in any increase in daily or annual emissions, implying there will be no "Cumulative Increase" in emissions. As a result, a "PSD" review is not required.

A reduction in NOx emissions – the primary pollutant abated by the CUBL-Flex retrofit project, could potentially result in an increase in CO emissions – the secondary pollutant of the retrofit project. However, per Regulation 2-2-112, the installation of the CUBL-Flex burners at sources S-1486 and S-1763 is considered an emission reduction technique. Therefore, the potential increase in CO emissions (if any) is exempt from "BACT". Also, since Regulation 2, Rule 2 "New Source Review" does not contain any requirements to provide/surrender emission reduction credits (ERCs) to offset increases in CO emissions, "Offsets" are not warranted. In addition, none of the proposed changes will result in an increase in Toxic Air Contaminant emissions, implying a Toxic Risk Screening Analysis is not required. Lastly, CUBL-Flex retrofit project will not trigger any changes to any of the applicable requirements contained in Shell's Title V permit for the above sources.

Sources S-1486 and S-1763 are subject to 40 CFR Part 60, Subpart J "New Source Performance Standard for Petroleum Refineries" (NSPS J). Table's IV-BA and BG in Shell's Title V permit contain the NSPS J applicable requirements for sources S-1486 and S-1763, respectively. Therefore, it is not necessary to perform an NSPS J applicability determination to determine whether changes that are part of this evaluation are a "reconstruction" in accordance with 40 CFR 60.15.

The California Environmental Quality Act (CEQA):

Per Section 2-1-311 of the District Rules and Regulations, a permit application for a proposed new or modified source will be classified as ministerial and will accordingly be exempt from the CEQA requirement of Section 2-1-310 if the District's engineering evaluation and basis for approval of the permit application for the project is limited to the criteria set forth in Section 2-1-428 and to the procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook. The method for determining whether a given permit application will be classified as ministerial is set forth in Section 2-1-427.

Per Section 2-1-427, if the District determines that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook, the District's evaluation of the permit application is classified as ministerial and the engineering evaluation of the permit application by the District will be limited to the use of said specific procedures, fixed standards and objective measurements. For such projects, the District will merely apply the law to the facts as presented in the permit application, and the District's decision regarding whether to issue the permit will be based only on the criteria set forth in Section 2-1-428 and in the District's Permit Handbook and BACT/TBACT Workbook.

For this permit application, the District determined that its evaluation of the permit application is **not**[54] covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook. Therefore, the District cannot classify this permit application as ministerial pursuant to Section 2-1-427. As a result of its evaluation of the permit application, the District has determined that all of the criteria for approval of ministerial permit applications pursuant to Section 2-1-428 were **not** met. In light of the above, the issuance by the District of a Permit to Operate for the proposed alterations (~ project) does not qualify as a mandatory ministerial duty and is therefore **not** exempt from the CEQA requirement of Section 2-1-310.

CEQA Categorical Exemptions and CEQA "Common Sense Exemption":
Though the District concludes that the alterations to sources S-1486 and S-1763 are **not** ministerial, it also concludes that certain other exemptions from CEQA apply (see CEQA Guidelines § 15300.1). Section 2-1-312 of the District Rules and Regulations sets forth specific types of projects, which have been determined by the District to be categorically exempt from CEQA. Specifically, the alterations to sources S-1486 and S-1763 qualify under the CEQA categorical exemptions of Sections 2-1-312.6, and 2-1-312.11 of the District Rules and Regulations and the CEQA "Common Sense Exemption".

Following is a textual description of the above referenced sections:
2-1-312 Other Categories of Exempt Projects: In addition to ministerial projects, the following categories of projects subject to permit review by the District will be exempt from the CEQA review, either because the category is exempted by the express terms of CEQA (subsections 2-1-312.1 through 312.9) or because the project has no potential for causing a significant adverse environmental impact (subsections 2-1- 312.10 and 312.11). Any permit applicant wishing to qualify under any of the specific exemptions set forth in this Section 2-1-312 must include in its permit application CEQA-related information in accordance with subsection 2-1-426.1. In addition, the CEQA-related information submitted by any permit applicant wishing to qualify under subsection 2-1-312.11 must demonstrate to the satisfaction of the APCO that the proposed project has no potential for resulting in a significant environmental effect in connection with any of the environmental media or resources listed in Section II of Appendix I of the State CEQA Guidelines.
312.6 Permit applications relating exclusively to the repair, maintenance or minor alteration of existing facilities, equipment or sources involving negligible or no expansion of use beyond that previously existing.

[54] Previous versions of the District's Permit Handbook contained Chapter 2.4 "Process Heaters".

312.11 Permit applications for a proposed new or modified source or sources or for process changes which will satisfy the "No Net Emission Increase" provisions of District Regulation 2, Rule 2, and for which there is no possibility that the project may have any significant environmental effect in connection with any environmental media or resources other than air quality. Examples of such projects include, but are not necessarily limited to, the following:
11.1 Projects at an existing stationary source for which there will be no net increase in the emissions of air contaminants from the stationary source and for which there will be no other significant environmental effect;
11.2 A proposed new source or stationary source for which full offsets are provided in accordance with Regulation 2, Rule 2, and for which there will be no other significant environmental effect;
11.3 A proposed new source or stationary source at a small facility for which full offsets are provided from a small facility bank established by the APCO pursuant to Regulation 2-4-414, and for which there will be no other significant environmental effect;
11.4 Projects satisfying the "no net emission increase" provisions of District Regulation 2, Rule 2 for which there will be some increase in the emissions of any toxic air contaminant, but for which the District staff's health risk screening analysis shows that the project will not result in a cancer risk (as defined in Regulation 2-5-206) greater than 1.0 in a million (10-6) and will not result in a chronic hazard index (as defined in Regulation 2-5-208) greater than 0.20, and for which there will be no other significant environmental effect.

Retrofitting sources S-1486 and S-1763 with Callidus CUBL-Flex Low NOx burners will enhance Shell's compliance with Regulation 9, Rule 10, by reducing NOx emissions. Therefore, the project qualifies as a minor alteration of an existing source involving negligible or no expansion of use beyond existing levels. Therefore, per Section 2-1-312.6 the proposed alterations to sources S-1486 and S-1763 are categorically exempt from CEQA.

Per Section 2-1-312.11, permit applications for a new or modified source or sources or for process changes, which will satisfy the "No Net Emission Increase" provisions of District Regulation 2, Rule 2 and for which there is no possibility that the project may have any significant environmental effect in connection with any environmental media or resources other than air quality, are exempt from the CEQA review. The reason for this exemption should be apparent on its face: if a facility is given legal permission to emit more air pollutants from certain points while at the same time being disallowed permission for an equivalent amount of the same type of emissions from other points at the facility, then there is deemed to be no net effect on the air environment, and therefore no possibility of a significant effect under CEQA, provided no-air impacts are also examined and deemed to be of no possible significant consequence.

Also, per the CEQA Guidelines in Title 14, California Code of Regulations, Chapter 3, Article 5, Section 15061(b)(3), a project is exempt from CEQA if the activity is covered by the general rule that CEQA applies only to projects, which have the potential for causing a significant effect on the environment. This is commonly known as the "Common Sense Exemption". Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to CEQA. The "no net increase" exemption of 2-1-312.11 is essentially a specific, codified, instance of the Common Sense Exemption.

The proposed alterations to sources S-1486 and S-1763 will not result in any increase in daily or annual emissions, implying there will no "Cumulative Increase" in emissions. Therefore, the District determined that the project satisfies the "No Net Emission Increase"

of District Regulation 2, Rule 2. Shell has completed and submitted to the District CEQA Appendix H, Environmental Information Form, for the project.

The District has reviewed the CEQA Appendix H form. Shell only checked "Yes" for item 32 regarding "Relationship to a larger project or series of projects", and provided the following response:
"*Yes. This project is part of Shell's continuing efforts to meet requirements of BAAQMD Regulation 9, Rule 10 (NOx from Refinery Combustion Devices).*"
All other items on the form were checked either "No", or "Not Applicable".

Thus, the District concludes that the permit application is exempt from CEQA because it is categorically exempt from CEQA per Section 2-1-312.6. In addition, the project also qualifies per Section 2-1-312.11 for the "Common Sense Exemption" of Subsection (b)(3) of the State CEQA Guidelines. Based on all of the information before the District, it can be concluded that there is no possibility that the alterations to sources S-1486 and S-1763 will have any significant environmental effect.

Permit Conditions

Sources S-1486 and S-1763 are currently subject to permit condition 16688, which limits the maximum firing rate at the above sources to 374 MMBTU/hr and 220 MMBTU/hr, respectively. As previously discussed in the "Background" section above, sources S-1486 and S-1763 are equipped with NOx and O_2 CEMS and are governed by permit condition 18265, which outlines Shell's "IERC Alternative Compliance Plan". The proposed alterations to sources S-1486 and S-1763 will not result in any changes to either of the above two permit conditions. Because of the use of NOx and O_2 CEMs, no additional permit conditions are proposed to require source testing of the above sources for compliance.

Recommendation

Waive the Authority to Construct and issue Shell a Permit to Operate to alter the following sources:

S-1486 DH F-40 CU Feed
Callidus "CUBL-16P-Flex" Burners Ultra Low-NOx Burners
Maximum Firing Rate: 374 MMBTU/hr

S-1763 DH F-126 CU Feed Heater
Callidus "CUBL-16P-Flex" and "CUBL-12P-Flex" Ultra Low-NOx Burners
Maximum Firing Rate: 220 MMBTU/hr

Emissions from S-1486 exhausts along with several other sources via a common exhaust stack Chimney 1 (BAAQMD Emission Point #: P-23) that is equipped with NOx and O_2 CEMs, whereas emissions from S-1763 exhaust via a dedicated exhaust stack that is equipped with NOx and O_2 CEMs. Information in DataBank incorrectly states that S-1763 exhausts via P-23. To correct the above mistake, source S-1763 needs to be assigned its own emission point number (P-1763), and S-1763's pollutant train needs to be amended accordingly. Shell has submitted the original "P" form they submitted to the District in 1978 and a new "P" form for P-1763.

Shell's Title V permit does not explicitly list the type of burners that a source(s) is equipped with, nor does the permit list the "P" numbers. Therefore, the District's issuance of a PO to alter sources S-1486 & S-1763 coupled with the issuance of a new "P" number to S-1763 will not trigger any changes to Shell's Title V permit. In light of the above, Application 17634 (Title V counterpart of Application 17633) should be cancelled.

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11

Application: 18034

Background

Shell Oil Products US – Martinez Refinery (Shell) has submitted this application to obtain a Permit to Operate (PO) for a *new* abatement device that is described as follows:

A-2023 Thermal Oxidizer for Sulfur Plant 3
11 MMBTU/hr HHV[55] (~10 MMBTU/hr LHV)

Shell operates four Sulfur Recovery Units (S-1431, S-1432, S-1765, and S-4180). With the exception of Sulfur Recovery Unit (SRU) # 3, tailgas emissions from the remaining three SRUs are abated by Thermal Oxidizers (TO). In contrast, a Catalytic Oxidizer (CATOX) abates tail gas emissions from SRU #3 (S-1765). The proposed project to replace the CATOX (A-1518)[56] had its genesis in an office conference between the District and Shell in 2006 as a result of excesses of SO_2 emissions from SRU #3. The excess SO_2 emissions occurred when the media in the catalyst bed made up of bismuth and copper (among other materials) caught on fire. The combustion of the above materials led to the oxidation of approximately 40 pounds of sulfur available on the catalyst bed to SO_2. SRU #3 is a 150 LTD[57] sulfur plant located in the Operation Central (OPCEN) area of the refinery and was constructed in the early 1980s. SRU #3 was equipped with a CATOX rather than a TO for energy saving reasons. Because sulfur tends to accumulate on the catalyst (~makes it unstable by reducing its efficacy), the CATOX turned out to be a poor application. As a result, most SRUs at US refineries are either equipped with TO, or have converted from CATOX to TO.

A-1518 is located downstream of S-1765 and the Shell Claus Off-gas Treating (SCOT) unit. The proposed replacement of A-1518 with A-2023 will not result in modifications to either S-1765 and/or SCOT #3 (A-76). Therefore, permit conditions (7618 and 18618) in Shell's Title V permit[58] that currently govern the operation of S-1765 will not be modified. However some changes are warranted to permit condition 19748, which will be discussed in the later sections of this evaluation. The installation of A-2023 will not result in any changes to Tables IV-B, AQ, and AQa, and/or to Tables VII-AH, and AHb in Shell's Title V permit relating to S-1765. All references to A-1518 will be deleted from Shell's Title V permit following the District's issuance of a PO for A-2023.

Simplified Process Overview of a Typical SRU:

Acid gases, consisting of hydrogen sulfide (H_2S) and ammonia (NH_3), liberated by the Diethanolamine (DEA) strippers and the Sour Water Strippers (SWS) that are downstream of the refinery's hydrotreaters are processed at SRUs. The SRU is made up of the Claus unit and the SCOT unit. The conversion of H_2S (a toxin) to molten sulfur (which is harmless) is

[55] Routine measurements taken by Shell on natural gas combusted at the refinery indicate that the ratio of HHV/LHV is generally 1.1:1. The difference is that the HHV (~Gross Heating Value) includes the energy required to vaporize water (the water created during the combustion process). Most heat transfer calculations and heater duties are calculated using LHV (~Net Heating Value) because this is the energy available to the process. The energy content (the difference between HHV and LHV) of the water vapor as it condenses back to liquid would have to be captured in order to use HHV values. Combustion units such as furnaces, boilers, and others do not typically capture this energy.

[56] The CATOX (A-1518) includes an Oxidizer Preheater (F-109), which will be taken out of service when A-1518 is replaced. F-109 is the combustion unit for the CATOX, and no combustion occurs at the CATOX itself.

[57] LTD = Long Ton per Day; 1 Long Ton = 2,240 pounds

[58] All references to "Shell's Title V permit" in this evaluation refer to the Title V permit that was issued by the District to Shell on May 17, 2007.

performed using a basic two-step, split-stream process. In the combustion step, the first of the two steps, part of the H_2S laden acid gas stream is combusted in a thermal reactor that upstream of the Claus unit. The H_2S is oxidized to Sulfur Dioxide (SO_2) and water. In the reaction step, the second of the two steps, the remainder of the H_2S laden acid gas stream is combined with the oxidized products from the combustion step and enters the Claus unit. The Claus unit consists of three main sections namely the Pre-Heater, the Catalytic and the Sulfur Condensor. In the Claus unit, the H_2S reacts with SO_2 formed in the combustion step in the presence of an aluminum oxide catalyst to form molten sulfur and water. The molten sulfur drops out of the reaction vessel and is stored in sulfur pits. Most Claus plants convert over 90% of the H_2S to molten sulfur, and destruct the NH_3 to

Unconverted acid gas (a.k.a. Claus off-gas) from the Claus unit is routed to the SCOT unit and is converted back to H_2S. Simply stated, remnants of SO_2 in the Claus off-gas[59] react with hydrogen in the SCOT reactor to form H_2S. The H_2S in the streams exiting the SCOT reactor is absorbed in Methyldiethanolamine (MDEA) absorbers and is liberated at the MDEA strippers. The H_2S liberated at the MDEA strippers is sent back to the Claus unit as SCOT recycle for further processing. Remnants of H_2S, that are not part of the SCOT recycle stream, are routed to an oxidizer downstream of the SCOT reactor to be oxidized to SO_2.

To recap, the proposed project to replace the existing oxidizer (~CATOX; A-1518) with a new oxidizer (~TO; A-2023) will not result in any alterations/modifications to either SRU#3 (S-1765) and/or SCOT#3 (A-76) that are upstream of it.

Based on information contained in Shell's Flare Minimization Plan (FMP), which was approved by the District in July 2007 and the 1st FMP update that was submitted to the District in July 2008, SRU#3 is serviced by the OPCEN Hydrocarbon Flare (S-1772). It is unlikely that the proposed installation of A-2023 would result in flaring beyond existing levels at S-1772.

Emission Calculations

Regulation 2-2-112 states:

"**Exemption, Secondary Emissions From Abatement:** The BACT requirements of Section 2-2-301 shall not apply to emissions of secondary pollutants which are the direct result of the use of an abatement device or emission reduction technique which complies with the BACT or BARCT requirements for control of another pollutant. However, the APCO shall require the use of Reasonably Available Control Technology (RACT) for control of these secondary pollutants. The Air Pollution Control Officer shall determine which pollutants are primary and which are secondary for the equipment being evaluated." (Amended 6/15/94; 10/7/98)

In light of the above rule, the following methodology was adopted to perform the emission calculations discussed below:

- Step 1: Verify whether the use of an abatement device, such as A-2023, meets the District's Best Available Control Technology (BACT) requirement for SRU.
- Step 2: Estimate the secondary pollutant emissions from A-2023.

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59 Claus off-gas contains about <1% H_2S and <0.5% SO_2

- Step 3: Subject A-2023 to the RACT requirements for those secondary pollutants that will be emitted at a rate which is greater than the 10 lbs/day BACT trigger level.

Shell's proposal to abate SRU#3 with A-2023 is consistent with the District's BACT guidelines found in Document# 169.1 (dated January 10, 1992). Emission factors summarized in Table 1 below were used to estimate the "Pre-Project" and "Post-Project" secondary pollutant emissions summarized in Table 2.

Table 1

Emission factor	Pollutant				
	NOx	CO	PM (Total)	SO2	VOC
lb/MMSCF	100	84	7.6	0.6	5.5
lb/MMBTU	0.098	0.082	0.007	0.001	0.005

Note:
1. Emission factors (in lb/MMSCF) excerpted from US EPA AP-42 Tables 1.4-1 and 1.4-2 in Chapter 1.4 "Introduction to External Combustion Sources – Natural Gas Combustion".
2. The emission factor (in lb/MMBTU) was derived by dividing the emission factor (in lb/MMSCF) by the heating value of natural gas i.e. 1,020 BTU/scf.

Table 2

Abatement device	Pollutant									
	NOx		CO		PM (Total)		SO2		VOC	
	lbs/day	TPY	lbs/day	TPY	lbs/day	TPY	lbs/day	TPY	Lbs/day	TPY
Pre-Project (A-1518)	8.41	1.54	7.07	1.29	0.64	0.12	0.05	0.01	0.46	0.08
Post-Project (A-2023)	25.88	4.72	21.74	3.97	1.97	0.36	0.16	0.03	1.42	0.26
Net increase	17.47	3.19	14.68	2.68	1.33	0.24	0.10	0.02	0.96	0.18

Note:
1. The Oxidizer Preheater (F-109) for A-1518 is rated at 3.25 MMBTU/hr LHV (3.575 MMBTU/hr HHV)
2. The maximum firing rates (in MMBTU/hr) for A-1518 and A-2023 are 3.575 and 11, respectively.

As an example, consider the "Post-Project" emissions calculation for NOx:
= (0.098 lb NOx/MMBTU) x (11 MMBTU/hr) x (24 hrs/day)
= 25.872 lbs/day (4.72 TPY)

Since the daily "Post-Project" emissions and the "net increase" in emissions for NOx and CO, summarized in Table 2 above, are above 10 lbs/day A-2023 is subject to RACT for the above pollutants. Consistent with guidance provided in a District memo entitled "NOx and CO RACT levels for Thermal Oxidizers" dated April 13, 1999 and for oxidizers such as A-2023, which are rated at greater than 7.5 MMBTU/hr, the memo requires the following RACT control levels for secondary pollutant emissions:

- 50 ppmvd NOx @ 15% O_2 (0.20 lbs/MMBTU) and
- 350 ppmvd CO @ 15% O_2 (0.80 lbs/MMBTU)

A-2023 will consume more fuel (~natural gas) and will also operate at a higher temperature than its predecessor (A-1518). Specifically, A-2023 will operate at ≥ 1,000°F in comparison to A-1518 which operates at ≥ 615°F. Shell has assured the District that A-2023 will meet the District's RACT

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requirements. Table 3 below summarizes the "Post-Project" RACT-adjusted NOx and CO emissions from A-2023.

Table 3							
Abatement device	Maximum Firing Rate (MMBTU/hr)	NOx emissions			CO emissions		
		Lbs/day	Lbs/yr	TPY	Lbs/day	Lbs/yr	TPY
A-2023	11	52.80	19,272.00	9.64	211.20	77,088.00	38.54

As an example, consider the RACT-adjusted emissions calculation for NOx:
= (0.20 lb NOx/MMBTU) x (11 MMBTU/hr) x (24 hrs/day)
= 52.80 lbs/day (9.64 TPY)

It can be seen from Table's 2 and 3 that Shell's proposal to install A-2023 will result in a "net increase" of 8.10 TPY of NOx (9.64-1.54), 37.25 TPY of CO (38.54-1.29), 0.24 TPY of Total PM (0.36-0.12), 0.02 TPY of SO_2 (0.03-0.01), and 0.18 TPY of VOC (0.26-0.08).

The NOx emissions for the catalytic oxidizer are calculated using AP42 factors for External Combustion Sources – Natural Gas Combustion, while the emissions for the new thermal oxidizer are calculated using RACT factors. This is proper because the catalytic oxidizer would be expected to have lower NOx emissions due to the lower operating temperature.

Replacing A-1518 with A-2023 will entail installing valves, flanges, piping and associated components. Specifically, the project will result in the installation of at least 31 new valves and 30 new flanges in "light liquid" service. To ensure fugitive emissions from the above components are not underestimated, Shell adjusted the component counts upwards by 20 percent i.e. 37 new valves and 36 new flanges. Table 4 below summarizes leak rates for the above fugitive components.

Table 4						
Type/service	Number of components[1]	Emission factor (Lb/hr/ component)	POC, lb/hr	POC, lb/day	POC, lb/yr	POC, TPY
Valves/Gas/Light Liquid	37	0.00016[2]	0.006	0.144	52.56	0.03
Flanges/All[3]	36	0.00026[2]	0.0094	0.226	82.49	0.04
Totals	**73**		**0.0154**	**0.37**	**135.05**	**0.07**

5) Component counts estimated by Shell.
6) Correlation equation used to derive the emission factor excerpted from Table IV-3a (page 20) of the "California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities", February 1999. Specifically, the following correlation equation "2.27E-6*(SV)^0.747" was used in concert with a Screening Value (SV) of 100 ppmv to deduce an emission factor for valves. Likewise, the following correlation equation "4.53E-6*(SV)^0.706" was used in concert with a SV of 100 ppmv to deduce an emission factor for flanges. Please note that the SV of 100 ppmv used in both cases is based on the maximum leak rate allowed by Regulation 8 "Organic Compounds", Rule 18 "Equipment Leaks" for the above equipment.
7) Flange counts include connectors.

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It can be seen from Table 4 that the installation & subsequent operation of A-2023 would result in an increase of less than a pound (0.37 lbs/day) of fugitive POC emissions per day.

Toxic Risk Screen Analysis

Table 5 below summarizes Toxic Air Contaminant (TAC) emissions associated with natural gas combustion at A-2023 using emission factors provided by Jane Lundquist – Principal Air Engineer in the Toxics Evaluation Section, in her August 19, 2005 e-mail to the District's Engineering Division staff.

Table 5

TAC	***Emission factor***			***Emissions***	
	(lbs/Mscf)	**(lbs/MMscf)**	**(lbs/MMBTU)**	**(lbs/hr)**	**(lbs/yr)**
Benzene	2.10E-06	0.0021	2.06E-06	*2.26E-05*	*0.20*
Formaldehyde	7.50E-05	0.075	7.35E-05	*8.09E-04*	*7.09*
Toluene	3.40E-06	0.0034	3.33E-06	*3.67E-05*	*0.32*

Note:

1. *Heating value of natural gas = 1,020 BTU/scf*
2. *Maximum firing rate of A-2023 = 11 MMBTU/hr*
3. *Hours of operation = 8,760 hours/year (24 hrs/day; 365 days/yr)*

As an example, consider the benzene emissions summarized in the above table:
= (2.06E-06 lb benzene/MMBTU) x (11 MMBTU/hr)
= 2.26E-05 lbs/hr (0.20 lbs/yr)

Section C of Pacific Gas and Electric (PG&E) Rule 21 provides the following quality specifications for natural gas delivered into the PG&E pipeline system from California gas wells and generally governs the gas quality from interconnecting pipelines:

- Total Sulfur ≤1 grain/100 scf (17 ppm)
- Mercaptan Sulfur ≤0.5 grain/100 scf (8 ppm)
- Hydrogen Sulfide ≤0.25 grain/100 scf (4 ppm)

For the purposes of estimating the fugitive emissions of Hydrogen Sulfide (H_2S) from the 37 new valves and 36 new flanges that will be installed as part of the CATOX replacement project, it is conservatively assumed that all of the Total Sulfur (TS) in the natural gas would leak from the new fugitive components as H_2S as discussed below.
Density of air = 0.075 lbs/scf;
The specific gravity of natural gas[60] = 0.58
Therefore, the density of natural gas = 0.0435 lbs/scf
Assuming 1 grain of TS is equal to a grain of H_2S, each scf of natural gas (ng) would contain 0.01 grains of H_2S.
The % by wt. of H_2S in each scf of ng leaking from the fugitive components is equal to 0.00328% by wt, i.e. [(0.01 gr H_2S/scf ng) x (1 lb H_2S/7,000 gr H_2S)] /(0.0435 lbs ng/scf ng).

[60] Based on data for natural gas maintained by Shell.

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Assuming H_2S is a component of the POC emissions summarized in Table 4 above, the hourly and annual H_2S emissions from the fugitive components summarized in the above table are estimated as follows:
= (0.00328 lbs H_2S/100 lbs POC) x (0.0154 lbs POC/hr)
= (5.05E-07 lbs H_2S/hr) x (8,760 hrs/yr)
= 0.0044 lbs H_2S/yr

Table 6 below summarizes the Acute and Chronic TAC Trigger Levels (TTL's) for TAC's summarized in Table 5 and for H_2S, and compares the emissions to the TTL's outlined in Table 2-5-1 in Regulation 2, Rule 5 to verify if a Toxic Health Risk Screening Analysis (HRSA) is warranted.

Table 6						
TAC	**Acute TTL (lbs/hr)**	**Emissions (lbs/hr)**	**Exceeds Acute TTL?**	**Chronic TTL (lbs/yr)**	**Emissions (lbs/yr)**	**Exceeds Chronic TTL?**
Benzene	2.9	*2.26E-05*	No	6.4	*0.20*	No
Formaldehyde	0.21	*8.09E-04*	No	30	*7.09*	No
Toluene	82	*3.67E-05*	No	12,000	*0.32*	No
Hydrogen Sulfide	0.093	5.05E-07	No	390	0.0044	No

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It can be seen from Table 6 that Shell's proposal to install A-2023 does not warrant a Toxic HRSA.

BACT

Per Regulation 2, Rule 2, Section 301, BACT is only triggered if emissions from a new source or an increase in emissions from a modified source has the potential to emit 10 lbs or more per highest day of emissions. Simply stated, BACT is a source and pollutant specific requirement. Under this application, Shell has proposed to replace an existing abatement device (A-1518) with a new one (A-2023). Neither the installation of A-2023 nor its subsequent operation will result in any alterations/modifications to either SRU#3 (S-1765) and/or SCOT#3 (A-76) that are upstream of it. Therefore, Shell's proposal to install A-2023 does not trigger BACT.

Permit conditions 7618, 18618, and 19748 govern the operation of SRU#3 (S-1765). Sources at Shell that were part of Application 26786[61] (the REFEMS permit) operate under the REFEMS emission bubble and are governed by permit condition 7618. The above permit condition contains, among other requirements, the baseline emissions profile for various criteria pollutants. The daily sulfur make at S-1765 is limited by part 1 of permit condition 18618 to not exceed 150 LTD, and part 8 requires Shell to conduct a District approved source test at its four SRU's (S-1431, S-1432, **S-1765**, and S-4180) once a year, to determine the concentration of SO_3 or H_2SO_4, or both, expressed as 100% H_2SO_4, for compliance with 0.08 gr/dscf limit in Regulation 6-1-330. Shell's proposal to install A-2023 will not result in any alterations/modifications to either SRU#3 (S-1765) and/or SCOT#3 (A-76) that are upstream of it. Therefore, the installation & subsequent operation of A-2023 will not result in any changes to permit conditions 7618 and 18618.

In order to ensure that there is a "no net increase" in emissions at S-1765 merits discussing permit condition 19748. Permit condition 19748 was authored under Application 4106[62] when Shell

[61] The District issued Shell an AC and PO under AN 26786 on May 19, 1980 and August 1, 1991, respectively.
[62] The District issued Shell an AC and PO under AN 4106 on July 24, 2002 and August 1, 2003, respectively.

replaced an existing Stretford Unit (A-75) with an Exxon Mobil Flexsorb® Gas System (A-751). Supporting information furnished by Shell with the above application indicated that the SO_2 mass emission limit of 34 TPY in part 3 of permit condition 19748 was derived using a CATOX exhaust flow rate of 4.41 MMSCFD in concert with a SO_2 concentration of 250 ppmvd @ 0% O_2. The above SO_2 concentration limit is outlined in part 1 of permit condition 19748. In addition to the above, part 2 of permit condition 19748 required Shell to ensure that the concentration of H_2S in the CATOX exhaust was below 13.2 ppmvd @ 0% O_2. Table 7 below summarizes the "Pre-Project" and "Post-Project" emissions that were part of Application 4601.

Table 7

Project Scenario	**Exhaust flow rate (MMSCFD)**	**SO_2**			**H_2S**		
		ppmvd @ 0% O_2	**Lbs/day**	**TPY**	**ppmvd @ 0% O_2**	**Lbs/day**	**TPY**
Pre-Project	4.41	250	186	34	13.2	5.22	0.95
Post-Project	3.60	250	152	28	13.2	4.26	0.78
Net Increase/Decrease				-6			-0.17

It can be seen from Table 7 above that the installation of A-751 resulted in a "net decrease" of 6 TPY of SO_2 emissions and 0.17 TPY of H_2S emissions. As an example, consider the "Pre-Project" emissions calculation for SO_2:
= (250 scf SO_2 /10E06 scf fg) x (4.41E06 scf fg/day) x (lb-mole SO_2/379.4 scf SO_2) x (64 lbs SO_2/lb-mole SO_2)
= 186 lbs/day (34 TPY)

Emissions from SRU#3 were fully offset under Application 26786 (the REFEMS permit) in 1980. Per information contained in the above application, SRU#3 was originally permitted to emit 48.5 TPY (266 lbs/day) of SO_2 emissions. The above mass emissions were part of permit condition 7618 that outlined, among other requirements, Shell's SO_2 baseline emissions profile for each day of the year for sources that were part of Shell's REFEMS permit. The modification to the SRU#3 to install A-751 required that the above emissions be RACT adjusted i.e. 250 ppmvd @ 0% O_2. Therefore, the RACT adjusted "Pre-Project" SO_2 emissions were 34 TPY (186 lbs/day) as outlined in Table 7 above. Since Shell wanted to retain SRU#3 in the REFEMS emissions cap, the SO_2 baseline emissions profile in permit condition 7618 was reduced by 80 lbs/day (48.5 TPY – 34 TPY = 14.5 TPY) in the above permit condition. Though the "Post-Project" H_2S emissions of 4.26 lbs/day (0.78 TPY) estimated under Application 4601 were below the "Pre-Project" H_2S emissions of 5.22 lbs/day, Shell requested the District to subject SRU#3 to the "Pre-Project" emissions level.

As previously stated, the new Thermal Oxidizer (A-2023) will operate at a higher temperature (≥ 1,000°F) than its predecessor A-1518 (≥ 615°F), and as a result will also exhaust higher volumes of exhaust gases from its stack (8.40 MMSCFD versus 4.41 MMSCFD). Therefore, it is safe to conclude that the H_2S concentration limit of 13.2 ppmvd @ 0% O_2 in part 2 of permit condition 19748 needs to be converted to its appropriate H_2S mass emission limit to reflect the proposed installation & subsequent operation of A-2023. Simply stated, the above H_2S concentration limit will be replaced with a mass emission limit of 5.22 lbs/day (0.95 TPY) to ensure a "no net increase" in emissions at SRU#3. Table 8 below compares the "Pre-Project" SO_2 and H_2S emissions under Application 4106 to the "Post-Project" emissions under this application (#18034) to highlight the emissions increase that could be perceived as having occurred at SRU#3 in the absence of the proposed change to part 2 of permit condition 19748.

Table 8							
Project Scenario	**Exhaust flow rate (MMSCFD)**	**SO_2**			**H_2S**		
		ppmvd @ 0% O_2	**Lbs/day**	**TPY**	**ppmvd @ 0% O_2**	**Lbs/day**	**TPY**
Pre-Project (AN 4106)	4.41	250	186	34	13.2	5.22	0.95
Post-Project (AN 18034)	8.40	250	354	65	13.2	9.94	1.81
Net Increase/Decrease				+31			+0.86

Emissions summarized in Table 8 for entries corresponding to the "Post-Project (AN 18034)" project scenario assume the design molecular weight for flue gases exhausting out of A-2023's stack to be 31.01 lbs/lb-mole. As an example, consider the "Post-Project" emissions calculation for SO_2:
Determine the mass of flue gases (fg) exhausting out of the A-2023's stack per day
= (8.40E06 scf fg/day) x (lb-mole fg/379.4 scf fg) x (31.01 lbs fg/lb-mole fg)
= 686,568 lbs fg/day →**A**
Determine the mass of SO_2 in each standard cubic feet of fg
= (250 scf SO_2 /10E06 scf fg) x (lb-mole SO_2/379.4 scf SO_2) x (64 lbs SO_2/lb-mole SO_2)
= 4.22E-05 lbs SO_2/scf fg
Determine the mass of SO_2 in pound of fg
= [(4.22E-05 lbs SO_2/scf fg) x (379.4 scf fg/lb-mole fg)] / (31.01 lbs fg/lb-mole fg)
= 5.16 E-04 lbs SO_2/lb fg →**B**
Multiply **A** and **B** together
= 354 lbs SO2/day (65 TPY)

It can be seen from Table 8 above that installation & subsequent operation of A-2023 could result in a net increase of 31 TPY of SO_2 emissions and 0.86 TPY of H_2S emissions at SRU#3. However, instantaneous readings obtained from the Continuous Emissions Monitoring (CEM)[63] installed at the CATOX stack, which will remain in service as part of this application, will ensure that the 34 TPY SO_2 emission limit in part 3 of the existing permit condition 19748 and part 9 of the proposed permit condition 19748 is complied with at all times. Likewise, the annual source test requirement in part 2 of the existing permit condition 19748 and part 12 of the proposed permit condition 19748 will ensure that SRU#3 will also comply with the proposed mass emission limit of 5.22 lbs/day (0.95 TPY).

The District has also proposed to impose a new Sulfuric Acid Mist (SAM) limit for SRU #3 (S-1765) to ensure there is a "no net increase" in SAM emissions from S-1765 following the installation and subsequent operation of A-2023. As it currently exists, Shell is required by part 8 of permit condition 18618 to conduct a District approved source test at S-1765 once a year, to determine the concentration of SO_3 or H_2SO_4, or both, expressed as 100% H_2SO_4, for compliance with 0.08 gr/dscf limit in Regulation 6-1-330. Given that A-2023 would operate at a higher temperature (≥ 1,000°F), and as a result would also exhaust higher volumes of exhaust gases from its stack (8.40 MMSCFD), the proposed SAM limit will be based on the results of a recent source test conducted at S-1765. Specifically, the SAM concentration measured at the exhaust stack of the soon-to-be replaced CATOX (A-1518) abating S-1765 was determined to be 0.065 gr/dscf[64]. In light of the above, the "Pre-Project" and "Post-Project" mass SAM emissions using the above concentration in

[63] SO_2 and O_2 CEM monitor ID #'s at SRU#3 are 17 A 254 and 17 A 256, respectively.
[64] OS-1865 conducted on March 6, 2007.

concert with the "Pre-Project" (4.41 MMSCFD) and "Post-Project" (8.40 MMSCFD) exhaust flow rates from A-1518 and A-2023 are 7.47 TPY and 14.24 TPY, respectively. As an example, consider the "Pre-Project" mass SAM emissions:
= [(0.065 gr/dscf) x (4.41E06 dscf/day) x (365 days/yr)] / [(7,000 gr/lb) x (2,000 lb/ton)]
= 7.47 TPY

It can be seen from above, that a net increase of 6.77 TPY (14.24 – 7.47) of SAM emissions could occur at S-1765 in the absence of the proposed SAM limit. Please refer to parts 13 and 14 of the proposed permit condition 19748.

Cumulative Increase:

Shell's proposal to install A-2023 will not result in alterations/modifications to either SRU#3 (S-1765) and/or SCOT#3 (A-76) that are upstream of it. As previously discussed in the preceding section, the 34 TPY SO_2 emission limit in part 3 of permit condition 19748 will remain unchanged. Therefore, there will be no cumulative increase in emissions from SRU#3. The 34 TPY SO_2 emission limit was fully offset by Shell in Application 26786 in 1980. This is the reason that the change from 28 TPY that resulted from the combination of effluent volume and the 250 ppm SO_2 concentration limit to 34 TPY is not considered to be an increase in SO2 emissions. Please refer to Table 7 above.

Per emissions summarized in Table's 2, 3, and 4 above, the operation of A-2023 will result in a cumulative increase in 8.10 TPY of NOx, 37.25 TPY of CO, 0.24 TPY of PM_{10}, 0.02 TPY of SO_2 and 0.25 TPY[65] of POC emissions, respectively.

Offsets:

The requirement to offset NOx and POC emission increases from a new/modified source and any pre-existing cumulative increase at a 1.15 : 1 ratio is triggered when the Actual plant emissions and the "Post-Project" Permitted plant emissions are greater than 35 TPY. Likewise, the requirement to offset SO_2 and PM_{10} emissions from a new/modified source and any pre-existing cumulative increase at a 1:1 ratio is triggered when the Actual plant emissions and the "Post-Project" Permitted plant emissions are greater than 1 TPY. In addition, per Regulation 2-2-303 an increase in SO_2 and PM_{10} emissions from a new or modified source at a Major Facility (such as Shell) needs to be offset only if the cumulative increase in emissions for the above pollutant minus any contemporaneous emission reduction credits provided by a facility for that pollutant since April 5, 1991 exceeds 1 TPY. There is no CO offset requirement. Table 9 below summarizes emissions at Shell to determine if offsets are warranted for NOx, POC, SO_2 and PM_{10} emissions.

[65] The cumulative increase in POC emissions of 0.25 TPY is the sum of the net increase of 0.18 TPY (from Table 2) and 0.07 TPY (from Table 4)

Table 9
Offsets

Pollutant	"Pre-Project" Permitted plant emissions (TPY)	Actual plant emissions[66] (TPY)	Increase in plant emissions associated with this application (TPY)	"Post-Project" Permitted plant emissions (TPY)	Regulation 2-2-302 and 2-2-303 Offset Triggers (TPY)
NOx	204	1,780.75	8.10	212.10	> 35
POC	398.471	1,368.48	0.25	398.721	> 35
CO	298.00	1,182.77	37.25	335.25	NA
PM10	76.604	528.36	0.24	76.844	> 1
SO2	213.77	1,588.99	0.02	213.79	> 1

It can be seen from the emissions summarized in Table 9 that both the "Post-Project" Permitted plant emissions and the "Actual" plant emissions for NOx, POC, SO_2 and PM_{10} are above their corresponding offset trigger levels for the above pollutants. Therefore, offsets are warranted for the above pollutants.

Though Regulation 2-2-112, which was discussed in the "Emissions Calculation" above, exempts A-2023's secondary emissions from the BACT requirements, it does not exempt them from the offset requirements contained in Regulation's 2-2-302 and 2-2-303. In other words, if the NOx, POC, SO_2 and PM_{10} emissions summarized in Table 9 were above their respective offset trigger levels, the District would have required Shell to surrender the required Emission Reduction Credits (ERCs) to offset A-2023's secondary emissions. However, Section 42301.2[67] in the California Health and Safety Code, which states the following, would have prevented the District from requiring Shell to provide the required offsets:
"A district shall not require emission offsets for any emission increase at a source that results from the installation, operation, or other implementation of any emission control device or technique used to comply with a district, state, or federal emission control requirement, including, but not limited to, requirements for the use of reasonably available control technology or best available retrofit control technology, unless there is a modification that results in an increase in capacity of the unit being controlled."
Following is an excerpt from a June 19, 2008 District Policy memo from Carol Allen – Senior Air Quality Engineer, Toxics Evaluation Section to the Engineering Division staff: "Although H&S Code 42301.2 states: "A district shall not require emission offsets..." for qualifying control device projects, the District is concerned that eliminating the offset requirement for secondary NO_x and POC emissions from new/modified abatement devices would be in conflict with the District's no net increase provisions and could potentially compromise the District's ozone related air quality improvement goals. To alleviate these concerns while still providing the state required offset relief for industry, the District shall continue to require offsets for any qualifying control device project (as stated in current District regulations), but the District will provide any necessary offsets, on behalf of the facility from the small facility banking account, for each qualifying abatement device project, even if that project is located at a facility that does not qualify for the small facility banking account.

[66] Actual emissions estimated based on last permit renewal Db → q2 →p → all
[67] AB 2525 Chapter 771, September 23, 1996

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The District has adopted a similar policy for resource recovery projects that comply with H&S Code Section 42314 and that are located at sites that do not qualify for the small facility banking account.

This policy is also intended to clarify - for landfills in particular - when an air pollution control project qualifies for offset relief pursuant to H&S Code 42301.2, when it does not, and when it may qualify for partial relief.

In order to qualify for H&S Code 42301.2 offset relief, the project must satisfy all of the following qualifying criteria:

- The applicant shall have submitted a BAAQMD permit application for the abatement device project on or after September 23, 1996.
- The project shall include a new or modified abatement device that is controlling an existing permitted source.
- The source being controlled shall have been initially permitted prior to September 23, 1996 and shall now have a valid BAAQMD permit.
- The source being controlled shall not have undergone any type of physical modification, change in the method of operation, or permit limit change, on or after September 23, 1996, unless this post 9/23/96 alteration did not result in an increase in capacity of the source, and did not allow a throughput increase at the source, and did not allow an increase in the primary pollutant being controlled at that source.
- The abatement device shall be required to control a primary pollutant from the source due to a BARCT, BACT, TBACT, NSPS, or MACT requirement.
- The abatement shall use RACT for all secondary pollutants with an emission rate of more than 10 pounds/day.

If the source being controlled is a new source that was initially permitted after September 23, 1996, the H&S Code 42301.2 offset exemption does not apply. The secondary pollutant emission increases from the new/modified abatement device are subject to District offset requirements. If the site does not qualify for the SFBA, the site shall provide all required offsets for the secondary pollutant emission increases resulting from the new/modified abatement device.

If the source being controlled is modified after September 23, 1996, the permit holder shall be responsible for providing any required offsets for both the primary and secondary pollutant emission increases that result from that modification. In the case of landfills, the engineer shall compare the proposed maximum projected landfill gas generation rate to the projected gas generation rate for the baseline period. This difference between the projected and baseline gas generation rates is also the increase in control capacity that is associated with the landfill modification. Unless the site continues to qualify for the SFBA, the applicant shall provide offsets for the secondary pollutant emission increases that will result from controlling the gas generation rate increase determined above."

Shell's proposal to install A-2023 qualifies for offset relief pursuant to H&S Code 42301.2 for the following reasons:

- Shell submitted Application 18034 on May 5, 2008.
- A-2023 will abate SRU#3 (S-1765) and/or SCOT#3 (A-76) that are upstream of it. The SRU and the SCOT were permitted under Application 26786 (the REFEMS permit).

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- The District issued Shell an AC and PO for sources (including S-1765 and A-76) that were part of the REFEMS permit on May 19, 1980 and August 1, 1991, respectively. The PO for the above source is valid until August 1, 2009.
- As previously discussed in the "BACT" section above, the post-9/23/96 alteration to S-1765 and A-76 under Application 4106 (in the 2002-2003 timeframe) to replace A-75 (Stretford Unit) with A-751 (Exxon Mobil Flexsorb® Gas System) did not result in an increase in capacity of the source, did not allow a throughput increase at the source, and did not allow an increase in the primary pollutant being controlled at that source. Installing A-751 resulted in a "net decrease" of 6 TPY of SO_2 emissions and 0.17 TPY of H_2S emissions. Please refer to Table 7.
- ***The District's BACT guidelines found in Document# 169.1 (dated January 10, 1992) requires the use of an abatement device such as A-2023 to abate H_2S that is not part of A-76's recycle stream to be routed to an oxidizer to be oxidized to SO_2.***
- As previously discussed in the "Emission Calculations" section above, the NOx and CO emissions from A-2023 are subject to RACT because the daily "Post-Project" emissions for the above pollutants are more than 10 lbs/day. Please refer to Table's 2 and 3.

Consistent with recent District permitting actions concerning offsets for secondary emissions from abatement devices (such as A-2023), which qualify for offset relief pursuant to H&S Code 42301.2, the increase in emissions associated with this application summarized in Table 9 will be offset by the District's Small Facility Banking Account.

Statement Of Compliance

SRU#3 (S-1765) is subject to applicable requirements contained in Tables IV-B, AQ, AQb, and AR in Shell's Title V permit. Specifically, S-1765 is subject to and is expected to comply with Regulation 6 "Particulate Matter", Rule 1 "General Requirements", and Regulation 9 "Inorganic Gaseous Pollutants", Rule 1 "Sulfur Dioxide".

Section 330 in Regulation 6, Rule 1 prevents sources such as S-1765 from emitting any emission having a concentration of SO_3 or H_2S0_4, or both, expressed as 100% H_2S0_4, exceeding 183 mg per dscm (0.08 gr/dscf) of exhaust gas volume. Shell will demonstrate compliance with the above section by performing an annual District approved source test at S-1765 as required by part 8 of permit condition 18618.

Area monitoring to demonstrate compliance with the ground level SO_2 concentrations in excess of 0.5 ppm continuously for 3 consecutive minutes or 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours in Regulation 9-1-301 is at the APCO's discretion (per BAAQMD Regulation 9-1-501). The Petroleum refineries in the Bay Area have ground level monitors; yet they rarely exceed the above limits.

In addition to the above, S-1765 is also subject to 40 CFR Part 60, Subpart J "Standards of Performance for Petroleum Refineries" (NSPS J), and 40 CFR 63, Subpart UUU (MACT UUU) "National Emission Standards For Hazardous Air Pollutants For Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, And Sulfur Recovery Units". Claus sulfur recovery plants, such as S-1765, which were constructed, reconstructed or modified after October 4, 1976 and on/before May 14, 2007 that consist of an oxidation control system followed by incineration are required by section 60.104(a)(2)(i) to limit the discharge or cause the discharge of gases into the atmosphere containing concentrations of SO_2 in excess of 250 ppmv (dry basis) at zero percent excess air. The SO_2 CEMS in the exhaust stack of SRU #3 will ensure compliance with the above NSPS J limit.

MACT UUU applies to, among other things, a process vent or group of process vents on Sulfur Recovery Units (such as S-1765). Bypass lines on vent systems located at S-1765 that are capable of diverting vent streams away from the control device (new Thermal Oxidizer) abating it are also subject to MACT UUU. The rule allows sources such as S-1765, which are already subject to section 60.104 in NSPS J, to demonstrate compliance with the MACT UUU HAP emission limit in section 63.1568 by meeting the NSPS J emission limit for sulfur oxides. Section 63.1569 outlines the requirements for HAP emissions from bypass lines.
Shell opted to seal the bypass lines at S-1765. Therefore, sections 63.1569(a), (a)(1)(iii), (a)(3), and (c) are included as applicable requirements in Table IV-AQb in Shell's Title V permit.

Regulation 2-2-112 contains the requirements for the application of Reasonably Available Control Technology (RACT) to secondary pollutants, which are a direct result of the use of an abatement device or emission reduction technique that complies with the BACT or BARCT requirements for control of another pollutant. The use of thermal oxidizers (such as A-2023) to control H_2S emissions is consistent with control technologies typically prescribed for sources such as S-1765. As previously discussed under the "Emission Calculations" section above, A-2023 will meet the following RACT control levels for secondary pollutant emissions: 50 ppmvd NOx @ 15% O_2 (0.20 lbs/MMBTU) and 350 ppmvd CO @ 15% O_2 (0.80 lbs/MMBTU).

On December 1, 2003, the District issued Shell a Title V operating permit ("initial permit"). The proposed changes to Shell's Title V permit stemming from incorporating A-2023 into Shell's Title V permit will affect Table II-B "Abatement Devices", Table IV-AR, permit condition #19748 in Section VI, and Table VII-AI. The above changes, which will be made to Shell's Title V permit under Application 18063 (the Title V counterpart to this NSR application), qualify as a minor permit revision, i.e. a revision to an existing Title V permit that is neither an administrative amendment as defined in Section 2-6-201, nor a significant permit revision as defined in Section 2-6-226. Minor revisions to an existing Title V permit are subject to a 45-day US EPA review, but are not subject to a public notice. Shell's initial permit is in the process of being renewed. The proposed changes discussed above will be incorporated into the renewed permit before it is issued.

The California Environmental Quality Act (CEQA):

Per Section 2-1-311 of the District Rules and Regulations, a permit application for a proposed new or modified source will be classified as ministerial and will accordingly be exempt from the CEQA requirement of Section 2-1-310 if the District's engineering evaluation and basis for approval of the permit application for the project is limited to the criteria set forth in Section 2-1-428 and to the procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook. The method for determining whether a given permit application will be classified as ministerial is set forth in Section 2-1-427.

Per Section 2-1-427, if the District determines that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook, the District's evaluation of the permit application is classified as ministerial and the engineering evaluation of the permit application by the District will be limited to the use of said specific procedures, fixed standards and objective measurements. For such projects, the District will merely apply the law to the facts as presented in the permit application, and the District's decision regarding whether to issue the permit will be based only on the criteria set forth in Section 2-1-428 and in the District's Permit Handbook and BACT/TBACT Workbook.

For this permit application, the District determined that its evaluation of the permit application as it relates to the installation of the new fugitive components summarized in Table 4 above is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook Chapter 3.4 "Petroleum Refinery Fugitive Emissions". However, the District finds that the installation of the new thermal oxidizer (A-2023) is not ministerial pursuant to Section 2-1-427 because there is no dedicated chapter in the District's Permit Handbook at this time. The installation of A-2023 is categorically exempt from CEQA review per Section 2-1-312.2, which pertains to the installation of air pollution control or abatement equipment.

The District has reviewed the CEQA Appendix H form. Shell responded to all the questions on the above form by stating either "No", or "Not Applicable". In addition to the above form, Shell also submitted the following additional information in order for the District to determine the project's possible significant effects:

8. *Please provide a completed Appendix H, Environmental Information Form, which contains sufficient information for the District to complete the CEQA Initial Study of the project. For responses in the above form that are either marked "Yes" and/or "NA", please fully explain the relevant issue(s) in detail.*

Shell has followed the guidelines in Appendix H of the BAAQMD Permit Handbook (Environmental Information Form), which is included in the preceding pages of this Appendix C.

9. *Please describe any new equipment, including pumps and piping that will be installed for this project. Will any new piping be installed aboveground?*

The changes proposed for the SRU-3 Catalytic Oxidizer Replacement Project involves replacing the catalytic oxidizer at SRU-3 with a thermal oxidizer and installation of new valves and flanges. The new piping will be installed aboveground in existing pipe racks.

10. *To determine potential impacts to groundwater and surface water quality, please respond to the following:*

l. *Will this project result in an increase in the risk of a spill with potential for impacting surface water and groundwater? Please explain.*

There is minimal potential for the SRU-3 Catalytic Oxidizer Replacement Project to increase the risk of a spill that would impact surface water or groundwater. The project involves replacing the catalytic oxidizer at SRU-3 with a thermal oxidizer and installation of new valves and flanges. The probability of failure that would allow a release of hazardous materials is no greater than for the existing equipment.

m. *What spill prevention measures and monitoring are in place at Shell to limit the potential risk of a spill due to this project.*

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The proposed project involves replacing the catalytic oxidizer at SRU-3 with a thermal oxidizer and installation of new valves and flanges. These replacements are not expected to affect the probability or consequences of a spill compared to current operations.

Shell's existing program of operator training, prevention, mitigation, and response is based on prevention of environmental impacts, and will further reduce the risk of a spill. Shell has prepared and implemented a Storm Water Pollution Prevention Plan (SWPPP) and a Spill Prevention Control and Countermeasures (SPCC) plan to prevent water quality contamination. Storm drains are closed by default, and collected storm water is sent to the Refinery's effluent wastewater treatment plant.

n. To address runoff at the site, does Shell have a Storm Water Pollution Prevention Plan and Spill Prevention Control and Countermeasures Plan?

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Shell has prepared the SWPPP and SPCC Plan, as required. The plans are available on site for inspection in accordance with the applicable regulations.

o. How frequently does Shell conduct groundwater monitoring and how often are the analytical results submitted to the Regional Water Quality Control Board?

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Shell performs quarterly groundwater monitoring as required by Waste Discharge Requirements (WDR) Order 95-234, issued by the San Francisco Bay Regional Water Quality Control Board (SFBRWQCB). Results are submitted to the SFBRWQCB twice a year.

Additionally, Shell is required to perform a capture zone analysis on the facility. The WDR order requires that an ongoing hydraulic groundwater capture program be installed, operated, and maintained. Groundwater extraction systems are installed at the perimeter of the facility and serve to capture the groundwater before it leaves the site.

p. What is the direction of the groundwater flow beneath the Shell refinery site?

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The equipment to be changed is located in the Central Valley groundwater basin of the facility. Groundwater flows from south to north at a velocity of approximately four feet per year.

11. To determine potential impacts due to diesel-fueled trucks associated with the project, please respond to the following:

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a. How and from where will water be delivered to the project?

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The proposed project will not increase water demand.

b. Would the installation of the new equipment result in an increase in existing diesel-fueled truck traffic to and from the truck loading racks?

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No increase in existing diesel-fueled traffic to and from the truck loading racks.

c. *For construction, how many diesel-fueled trucks will be used for mobilization, construction, and demobilization of the project?*

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The projected construction requirements are provided in Table C-1.

Table C-1
SRU-3 Catalytic Oxidizer Replacement Project Construction Requirements

	Mobilization	**Construction**	**Demobilization**
Number of Diesel Trucks[1]	3	1	1
Number of Days[2]	2	5	3
Total Days of Diesel Operated Cranes and Equipment[2]	19		
Maximum Number of Construction Workers	40		
Route Taken for Equipment Truck Deliveries	P-3		

Notes:
1. Maximum trucks on site on any given construction day.
2. Construction days may not be consecutive.

d. *What is the likely route that the diesel-fueled trucks will take from the nearest freeway to the Shell gate?*

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The most likely route for delivery of construction materials to the SRU-3 Catalytic Oxidizer Replacement Project construction site will be via Highway 680 to Marina Vista Avenue. The diesel-fueled trucks will enter the Refinery through Gate P-3.

The District finds these assertions and arguments to be credible and concludes that this permit application is exempt from CEQA because it is categorically exempt from CEQA review per Section 2-1-312.2.

A memo from Dr. Glen Long – Supervising Air Quality Engineer, Toxics Evaluation Section to Barry Young – Air Quality Engineering Manager, Permit Evaluation Section dated October 27, 2005 stated that an increase of 21 round-trip diesel fueled delivery trucks per day (42 one-way trips) corresponds to a maximum lifetime cancer risk of 10 in a million and a maximum chronic hazard index of 0.00602. Therefore, an increase in diesel fueled truck traffic below the 21 round-trip diesel fueled delivery trucks per day threshold will not exceed the lifetime cancer risk of 10 in a million, implying a detailed site-specific Health Risk Screening Analysis (HRSA) is not required for such projects. It can be seen from Table C-1 above that an HRSA is not required for the increase in diesel fueled truck traffic associated with this project.

Permit Conditions

Following is the textual description of permit condition 19748 as it currently exists in Shell's Title V permit:

1. The owner/operator shall operate the catalytic oxidizer (A1518) such that the concentration of SO2 in the exhaust from the catalytic oxidizer (A1518) shall not exceed 250 ppmvd at 0 percent oxygen, averaged over 24 hours.

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(basis: Cumulative Increase; NSPS)

2. The owner/operator shall operate the catalytic oxidizer (A1518) such that the concentration of H2S in the exhaust from the catalytic oxidizer (A1518) shall not exceed 13.2 ppmvd at 0 percent oxygen, averaged over 24 hours (95 weight percent conversion of H2S to SO2). Compliance shall be confirmed by a District approved start-up and annual source test. (basis: Cumulative Increase)

3. The owner/operator shall operate the catalytic oxidizer (A1518) such that the SO2 emissions from the catalytic oxidizer (A1518) shall not exceed 34.0 tons per consecutive twelve-month period.
(basis: Cumulative Increase)

4. In the event that SRU-3 (S1765), SCOT-3 (A76), and/or the catalytic oxidizer (A1518) are shut down, the owner/operator shall curtail all acid gas feed to SRU-3 or reallocate the acid gas to other sulfur recovery units such that no acid gas is vented to the flare and unabated SRU-3 tailgas (tailgas not treated in SCOT-3) is not routed to the catalytic oxidizer. This shall be completed prior to any planned shutdown or within 24 hours of any unplanned shutdown. The District shall be notified of all such occurrences within 48 hours. The flaring emissions shall be calculated and included in the baseline profile (REFEMS cap). Prior to issuance of the Permit to Operate for S1765, the owner/operator shall submit an emission calculation protocol to the District for approval.
(basis: Cumulative Increase)

5. To determine compliance with Part 1 and 3, the owner/operator of the catalytic oxidizer (A1518) shall operate a SO2 continuous emission monitor/recorder in conjunction with a flow rate monitor/recorder at the exhaust of the catalytic oxidizer to calculate mass emissions in order to demonstrate compliance.
(basis: Cumulative Increase)

6. To determine compliance with Part 2, the owner/operator of the catalytic oxidizer (A1518) shall conduct a District-approved source test to the exhaust of the catalytic oxidizer for the concentration of H2S within 60 days of startup of the modified SRU-3 (S1765) and annually thereafter. Prior to the source test, the owner/operator shall notify and obtain approval of the source test procedures from the District's Source Test Section.
(basis: Cumulative Increase)

As it currently exists, part 3 of permit condition 19748 limits the SO_2 emissions from the soon-to-be replaced CATOX (A-1518) to not exceed 34.0 tons per consecutive 12-month period. Shell demonstrates compliance with the above SO_2 mass emission limit by using the concentration recorded by the SO_2 CEMS located on the exhaust stack of SRU #3 (S-1765) in concert with exhaust flow data obtained from an annubar meter located on the ducting between A-1518 and the base of the exhaust stack.

Going forward and in part due to the TO (A-2023) inherent design, Shell has proposed a different calculation methodology to demonstrate compliance with the SO_2 mass emission limit outlined in part 9 of the proposed permit condition 19748. Specifically, the TO will exhaust directly into the base of the stack (instead of via the ducting) thereby, causing cyclonic flows within the exhaust stack. Cyclonic (or swirling) flow characteristics are expected in vertical stack configurations with

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relatively low exhaust gas volumes anticipated from the installation of A-2023. The existing horizontal ducting used in the CATOX design is not typical with most TO installations.

Cyclonic flow by its definition is not consistent and cannot be measured accurately by a cross sectional pitot tube used in the annubar design. Meters such as annubars (using pitot tubes) in which only a small portion of the actual flow is used to determine the total flow are not "full flow" meters. Non-full flow meters such as annubars only use a fraction of the total exhaust to quantify flow. Annubar flow meters are designed for conditions in which there is consistent flow because the pitot tube, inherent in the annubar design, only samples a cross section of the flow. As a result, the use of an annubar meter to measure exhaust flows in an exhaust stack that is expected to experience cyclonic flows will result in inaccurate exhaust flow measurements.

As previously discussed under the "Simplified Process Overview of a Typical SRU" in the "Background" section, the "Absorber Overhead Flow" is tail gas flow from the MDEA absorber exiting SCOT #3 (A-76) that is upstream of A-2023. Flow meters used to measure the absorber overhead flows, natural gas flows, and combustion air flows are "full flow meters" (either venturi or orifice plate meters), which use the "entire flow" to determine the flow measurement. All of the flow passes through the measurement device and unlike annubar meters full flow meters don't sub-sample the flow to determine the measurement. Installing a full flow meter in SRU #3's exhaust stack to measure the total stack flow in lieu of the proposed calculations would amount to installing impedance in the stack, which would cause pressure drop problems.

In light of the above discussion, the annubar flow meter will no longer be used. Instead, Shell will determine the exhaust flow by summing three inputs to SRU #3's exhaust stack as shown below:

Stack flow in MMSCFD (dry, 0% excess O_2 basis)
= (Absorber Overhead Flow) + (Natural Gas Combustion Gases) + (Sulfur Pit Vent Flow)

The measured Absorber Overhead Flow is 3.375 MMSCFD. The proposed natural gas flow is between 0.15 MMSCFD and 0.26 MMSCFD.

Calculations to estimate the resulting flows from the absorber overhead and natural gas inputs will utilize the "F_d"[68] factor methodology prescribed in 40 CFR Part 60, Appendix A, Method 19. In contrast, the stack flow associated with sulfur pit vent will be based on SRU #3's design and is typically 1% of total flow. The absorber overhead flows and natural gas flows are measured by full flow meters "17F1317.PV" and "17FC237.PV", respectively. Based on information submitted by Shell, the proposed calculations assume the heating value and F_d factor for absorber overhead gas to be 4.63 BTU/scf and 211,400 dscf/MMBTU, respectively. The heating value and F_d factor for the absorber overhead flows vary somewhat over time, and are dependent upon the combustible components (primarily H_2) in the stream. Because the combustible components are a small fraction of the composition compared to the total composition including the inert components (CO_2 and N_2), the overall impact to slight changes in the combustible components will have a minimal effect on the overall flow calculation.

The heating value and F_d factor for natural gas that will be combusted in A-2023 is assumed to be 1,020 BTU/scf and 8,710 dscf/MMBTU, respectively. Though A-2023 has a maximum firing rate of

[68] Fd "dry flue gas factor" - ratio of the volume of the dry flue gas to the heating value of the fuel that is used to produce the flue gas (in dscf/MMBTU).

11 MMBTU/hr, it will typically operate at/about 6.40 MMBTU/hr. In light of the above and as discussed in the calculations that follow, the maximum and typical stack flows from natural gas combustion at A-2023 is expected to be 0.26 MMSCFD and 0.15 MMSCFD, respectively.

In light of the significant variation in the F_d factor for absorber overhead gas of 211,400 dscf/MMBTU versus 8,710 dscf/MMBTU for natural gas, it should be noted that the F_d factor represents the stoichiometric combustion of any fuel with air to end products of CO_2, SO2, and water. Given the very different nature of the above fuels, it is unreasonable to expect this ratio to be the same. In contrast, it is reasonable to expect similar F_d factors and ratio of F_d factor to heat content for similar fuels such as methane, ethane and refinery fuel gas (e.g. reduced hydrocarbon fuels), but the absorber overhead gas is very different than a conventional "fuel". Tail gas (~absorber overhead gas) is a waste gas, but by fuel standards the closest comparison would probably be a synthesis gas. The composition of the tail gas is primarily carbon dioxide and nitrogen with minor amounts of hydrogen, carbon monoxide, hydrogen sulfide, oxygen, and water. The heat content of this fuel is primarily from hydrogen, which does not factor into the dry flue gas volume at all. The only other component that would add some heat content would be carbon monoxide, which has a very different combustion stoichiometry than reduced hydrocarbon fuels. As a result, the ratio of the F_d factor to BTU content of absorber overhead gas and natural gas is quite different, as would be expected given their very different compositions and combustion stoichiometry.

The estimated un-metered flow rate from the sulfur pit is assumed to be 0.132 MMSCFD (wet). The actual flow value is based on the design of the pit vent and steam eductor configuration and corresponds to a maximum expected flow. Numerically, the 0.132 MMSCFD sulfur pit vent flow (wet) corresponds to 0.064 MMSCFD flow (dry). Assuming a total oxidizer exhaust flow of 4.694 MMSCFD, the pit vent flow represents approximately 1% of the total exhaust flow i.e. (0.064/4.694) x 100% = 1.4%. Shell does not have data indicating the variability of the dry gas portion of the sulfur pit flow. Based on their understanding of the process, minimal variability is expected. Because the overall sulfur pit flow is negligible, the flow values used in the calculations that follow are conservative and the sulfur pit vent variability will have a minimal effect on the overall exhaust flow calculation.

Based on "actual" (measured by "17F1317.PV") and "expected" (that will be measured by "17FC237.PV") flow data, the "typical" exhaust flow from SRU #3 stack following A-2023's installation can be calculated in lieu of the annubar meter as follows:
Absorber overhead flow measured by "17F1317.PV" = 3.375 MMSCFD (wet)
Absorber overhead (AO) stack flow
= (3.375 x 10E6 scf AO/day) x (4.63 BTU AO/scf AO) x (211,400 scf dry flue gas/MMBTU AO) x (MMBTU AO/10E6 BTU AO)
= 3,303,389.25 scf dry flue gas/day (~3.30 MMSCFD (dry))

The dry flowrate resulting from the absorber overhead flow is slightly lower than the absorber overhead flow as measured because the absorber overhead flow is a wet measurement and the resulting calculation excludes water.

Natural gas flow that will be measured by "17FC237.PV"
= 0.15 MMSCFD (typical); 0.26 MMSCFD (maximum)
Typical Natural Gas (NG) stack flow
= (0.15 x 10E6 scf NG/day) x (1,020 BTU NG/scf NG) x (8,710 scf dry flue gas/MMBTU NG) x (MMBTU NG/10E6 BTU NG)
= 1,332,630 scf dry flue/day (~1.33 MMSCFD)
Maximum Natural Gas (NG) stack flow
= (0.26 x 10E6 scf NG/day) x (1,020 BTU NG/scf NG) x (8,710 scf dry flue gas/MMBTU NG) x (MMBTU NG/10E6 BTU NG)
= 2,309,892 scf dry flue/day (~2.31 MMSCFD)

Un-metered dry gas sulfur pit flow (dry) to stack = 0.064 MMSCFD

"Typical" total stack flow (dry, 0% excess O_2 basis)
= 3.30 + 1.33 + 0.064 = 4.694 MMSCFD

"Maximum" total stack flow (dry, 0% excess O_2 basis)
= 3.30 + 2.31 + 0.064 = 5.674 MMSCFD

In order to demonstrate compliance with the SO_2 mass emission limit of 34 tons/yr and for a given concentration (say 120 ppm, dry, 0% excess O_2 basis), the typical "Post-Project" SO_2 emissions can be derived as follows:
= (120 scf SO_2/10E6 scf dry flue gas) x (64 lb SO_2/lbmol SO_2) x (1 lbmol SO_2/379.4 scf SO_2) x (4.694E6 scf dry flue gas/day)
= (95 lbs SO_2/day) x (365 days/yr) x (ton SO_2/2000 lbs SO_2)
= 17.34 tons SO_2/yr.

The maximum "Post-Project" SO_2 emissions would be equal to 115 lbs/day (~21 tons SO_2/yr). Stated differently, an average annual concentration at/above ~195 ppm measured by the SO_2 CEMS would result in an exceedance of the 34 tons/yr mass emissions limit.

In light of the above discussion, the proposed changes to permit condition 19748 are as shown below:

1. The owner/operator shall ensure that SCOT-3 (A76), and Thermal Oxidizer (A2023) abate SRU-3 (S1765) all times of operation. (Basis: Cumulative Increase)

2. The owner/operator shall ensure that the supplemental fuel used at A2023 is PUC quality natural gas. (Basis: Cumulative Increase)

3. The owner/operator shall not emit more than 50 ppmvd NOx @ 15% O2 (0.20 lb/MMBTU) from A2023. (Basis: RACT, Source Test Method 13A)

4. The owner/operator shall not emit more than 350 ppmvd CO @ 15% O2 (0.80 lb/MMBTU) from A2023. (Basis: RACT, Source Test Method 6)

5. No later than 60 days from the startup of A2023, the owner/operator shall conduct District approved source tests to determine initial compliance with the limits in parts 3 and 4 of this permit condition. The owner/operator shall submit the source test results to the District staff no later than 60 days after the source test. (Basis: RACT, Cumulative Increase)

6. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section prior to conducting any tests to demonstrate compliance with the limits in parts 3 and 4 of this permit condition. The owner/operator shall comply with all applicable testing requirements as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section, in writing, of the source test protocols and projected test dates at least 7 days prior to testing. (Basis: RACT, Cumulative Increase)

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7. The owner/operator shall operate A2023 in such a manner, which ensures that the concentration of SO2 in gases exhausting out of its stack does not exceed 250 ppmvd at 0 percent oxygen, averaged over 24 hours.
(Basis: Cumulative Increase; NSPS Subpart J)

8. To demonstrate compliance with Part 7 of this permit condition, the owner/operator of A2023 shall operate a SO2 continuous emission monitor/recorder (SO2 CEMS) at its exhaust stack.
(Basis: Cumulative Increase; NSPS Subpart J)

9. The owner/operator shall operate A2023 in such a manner, which ensures that the SO2 emissions associated with gases exhausting out of its stack does not exceed 34.0 tons per consecutive twelve-month period.
(Basis: Cumulative Increase)

10. To demonstrate compliance with Part 9 of this permit condition, the owner/operator shall calculate the SO2 mass emissions on a daily basis using the SO2 CEMS data in concert with total stack flow data obtained from a flow rate monitor/recorder at A2023's exhaust stack, or by employing calculations to estimate the total stack flow approved by the APCO. The total stack flow calculation methodology approved by the APCO must utilize the absorber overhead flow meter and the thermal oxidizer natural gas flow meter in conjunction with the methodology prescribed in 40 CFR Part 60, Appendix A, Method 19. These records, including the total stack flow calculations, shall be summarized on a monthly basis, and may be in the form of computer-generated data, which is available to District personnel on short notice (rather than actual paper copies of throughput data). These records shall be kept on file for a minimum of 5 years from the date of entry.
(Basis: Cumulative Increase, Regulation 2-1-403)

11. The owner/operator shall operate A2023 in such a manner, which ensures that the mass emissions of H2S in gases exhausting out of its stack do not exceed 5.22 pounds per day (0.95 tons per consecutive twelve-month period).
(Basis: Cumulative Increase)

12. The owner/operator of A2023 shall conduct a District-approved source test at its exhaust stack to determine the concentration of H2S within 60 days following the installation of A2023 and annually thereafter. The owner/operator shall use the results from the source tests to demonstrate compliance with Part 11 of this permit condition, and shall submit supporting calculations verifying compliance with the daily and annual mass emission limits to the District's Permit Evaluation Section. Prior to each source test, the owner/operator shall notify the District's Source Test Section in writing of the projected test dates at least 7 days prior to testing and obtain their approval of the source test procedures. The frequency of source testing required under this condition shall be reduced to once every five years if three consecutive annual source tests document that emissions are less than 50% of the standard. The frequency of source testing shall revert back to once per year, if a source test documents that emissions are 50% of the standard or more. The source testing frequency may again be reduced to once every five years if three consecutive annual source tests document that emissions are less than 50% of the standard.
(Basis: Cumulative Increase)

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13. The owner/operator shall operate A2023 in such a manner, which ensures that the Sulfuric Acid Mist emissions associated with gases exhausting out of its stack does not exceed 7.47 tons per consecutive twelve-month period.
    (Basis: Cumulative Increase)

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14. The owner/operator of A2023 shall conduct a District-approved source test at its exhaust stack to determine the concentration of Sulfuric Acid Mist emissions (in grains/dry standard cubic feet @ 0% oxygen) within 60 days following the installation of A2023 and annually thereafter. The owner/operator shall use the results from the source tests to demonstrate compliance with Part 13 of this permit condition, and shall submit supporting calculations verifying compliance with the annual Sulfuric Acid Mist mass emission limit to the District's Permit Evaluation Section. Prior to each source test, the owner/operator shall notify the District's Source Test Section in writing of the projected test dates at least 7 days prior to testing and obtain their approval of the source test procedures.
    (Basis: Cumulative Increase, Regulation 6-1-330)

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15. In the event that SRU-3 (S1765), SCOT-3 (A76), and/or the thermal oxidizer (A2023) are shut down, the owner/operator shall curtail all acid gas feed to SRU-3 or reallocate the acid gas to other sulfur recovery units such that no acid gas is vented to the flare and unabated SRU-3 tailgas (tailgas not treated in SCOT-3) is not routed to the thermal oxidizer. The owner/operator shall complete the above actions prior to any planned shutdown or within 24 hours of any unplanned shutdown. The owner/operator shall notify the District of all such occurrences within 48 hours of an event. Flaring emissions associated with such events, shall be calculated and included into the SO2 baseline emissions profile (of the REFEMS cap) by the owner/operator. (Basis: Cumulative Increase)

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16. The owner/operator shall operate A2023 at or above 1,000 degrees F. The District may adjust this minimum temperature, if source test data demonstrates that an alternate temperature is necessary for or capable of maintaining compliance with Parts 7 and 11 of this permit condition.
    (Basis: Cumulative Increase; BACT/TBACT)

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17. To determine compliance with the temperature requirement in Part 16 of this permit condition, the owner/operator of A2023 shall be equipped with a temperature measuring device capable of continuously measuring and recording the temperature in A2023. The owner/operator shall install, and maintain in accordance with manufacturer's recommendations, a temperature measuring device that meets the following criteria: the minimum and maximum measurable temperatures with the device are 0 degrees F and 2,000 degrees F, respectively, and the minimum accuracy of the device over this temperature range shall be 1.0 percent of full-scale. (Basis: Regulation 1-521)

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18. The owner/operator shall report any non-compliance with Parts 7, 9, 11, 13, and 16 of this permit condition to the Director of the Compliance & Enforcement Division within 96 hours from the time that it is discovered. The submittal shall detail the corrective action taken and shall include the data showing the exceedance as well at the time of occurrence.
    (Basis: Regulations 1-523.8 and 2-1-403)

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19. The temperature limit in Part 16 of this permit condition shall not apply during an "Allowable Temperature Excursion", provided that the temperature controller setpoint

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complies with the temperature limit. An Allowable Temperature Excursion is one of the following:

a. A temperature excursion not exceeding 20 degrees F; or
b. A temperature excursion for a period or periods which when combined are less than or equal to 15 minutes in any hour; or
c. A temperature excursion for a period or periods which when combined are more than 15 minutes in any hour, provided that all three of the following criteria are met.
   i. the excursion does not exceed 50 degrees F;
   ii. the duration of the excursion does not exceed 24 hours; and
   iii. the total number of such excursions does not exceed 12 per calendar year (or any consecutive 12 month period).

d. Any temperature excursion of more than 50 degrees Fahrenheit for more than 15 minutes in any hour is not an "Allowable Temperature Excursion".

Two or more excursions greater than 15 minutes in duration occurring during the same 24-hour period shall be counted as one excursion toward the 12-excursion limit.
(Basis: Regulation 2-1-403)

20. For each Allowable Temperature Excursion that exceeds 20 degrees F and 15 minutes in duration, the Permit Holder shall keep sufficient records to demonstrate that they meet the qualifying criteria described above. Records shall be retained for a minimum of five years from the date of entry, and shall be made available to the District upon request. Records shall include at least the following information:
   a. Temperature controller setpoint;
   b. Starting date and time, and duration of each Allowable Temperature Excursion;
   c. Measured temperature during each Allowable Temperature Excursion;
   d. Number of Allowable Temperature Excursions per month, and total number for the current calendar year; and
   e. All strip charts or other temperature records.
   (Basis: Regulation 2-1-403)

21. For the purposes of Parts 19 and 20 of this permit condition, a temperature excursion refers only to temperatures below the limit.
   (Basis: Regulation 2-1-403)

1. The owner/operator shall operate the catalytic oxidizer (A1518) such that the concentration of SO2 in the exhaust from the catalytic oxidizer (A1518) shall not exceed 250 ppmvd at 0 percent oxygen, averaged over 24 hours.
   (basis: Cumulative Increase; NSPS)

2. The owner/operator shall operate the catalytic oxidizer (A1518) such that the concentration of H2S in the exhaust from the catalytic oxidizer (A1518) shall not exceed 13.2 ppmvd at 0 percent oxygen, averaged over 24 hours (95 weight percent conversion of H2S to SO2). Compliance shall be confirmed by a District approved start-up and annual source test.
   (basis: Cumulative Increase)

3. The owner/operator shall operate the catalytic oxidizer (A1518) such that the SO2 emissions from the catalytic oxidizer (A1518) shall not exceed 34.0 tons per consecutive twelve-month period.
   (basis: Cumulative Increase)

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4. In the event that SRU-3 (S1765), SCOT-3 (A76), and/or the catalytic oxidizer (A1518) are shut down, the owner/operator shall curtail all acid gas feed to SRU-3 or reallocate the acid gas to other sulfur recovery units such that no acid gas is vented to the flare and unabated SRU-3 tailgas (tailgas not treated in SCOT-3) is not routed to the catalytic oxidizer. This shall be completed prior to any planned shutdown or within 24 hours of any unplanned shutdown. The District shall be notified of all such occurrences within 48 hours. The flaring emissions shall be calculated and included in the baseline profile (REFEMS cap). Prior to issuance of the Permit to Operate for S1765, the owner/operator shall submit an emission calculation protocol to the District for approval.
(basis: Cumulative Increase)

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5. To determine compliance with Part 1 and 3, the owner/operator of the catalytic oxidizer (A1518) shall operate a SO2 continuous emission monitor/recorder in conjunction with a flow rate monitor/recorder at the exhaust of the catalytic oxidizer to calculate mass emissions in order to demonstrate compliance.
(basis: Cumulative Increase)

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6. To determine compliance with Part 2, the owner/operator of the catalytic oxidizer (A1518) shall conduct a District-approved source test to the exhaust of the catalytic oxidizer for the concentration of H2S within 60 days of startup of the modified SRU-3 (S1765) and annually thereafter. Prior to the source test, the owner/operator shall notify and obtain approval of the source test procedures from the District's Source Test Section.
(basis: Cumulative Increase)

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Recommendation

Modify permit condition #19748 as proposed, and issue Shell an Authority to Construct for the following abatement device:

A-2023 Thermal Oxidizer for Sulfur Plant 3
11 MMBTU/hr HHV

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11

Application: 18062

Background

Shell Oil Products US – Martinez Refinery (Shell) has submitted this application to obtain a Permit to Operate (PO) to modify the following source:

S-1424 DH Naphtha Straightrun Hydrotreater (NHT)
28,500 bbl/day; 9,599,500 bbl/yr

Hydrotreating units are used to remove sulfur and nitrogen (to some extent) from process feeds and product streams. Most hydrotreaters, such as the NHT, process feeds upstream of conversion units. Hydrotreaters that process feeds ahead of conversion units include the CP Catalytic Feed Hydrotreater (S-1428), the DC Distillate Hydrotreater (S-4020), and others. In contrast, hydrotreaters such as the CP Catalytic Gasoline Hydrotreater (S-1429) and the DH Gas Oil Straightrun Hydrotreater (S-1423) are used to treat product streams downstream of conversion units.

Shell's proposal to modify the NHT stems from the company's intent to produce additional motor gasoline in lieu of heavier products (e.g., jet fuel and diesel fuel). In light of the above, Shell has proposed to modify the NHT to process an additional 3,000 bbl/day (BPD) of naphtha-range material. The net effect of the proposed modifications, discussed below, would increase the NHT's throughput from 28,500 BPD to 31,500 BPD, i.e. 28,500 + 3,000.

As it currently exists, Shell is not physically configured to process the additional volume of naphtha-range material at the NHT. In light of the above and in their efforts to increase the refinery's gasoline production, Shell has proposed to perform the following modifications to the NHT and associated equipment (Please refer to Figures 1 and 2):

1. Replace the Naphtha Cold Reflux Pump (P-2008) with a bigger pump to increase the hydraulic capacity of the naphtha system. This upgrade would enable higher total naphtha volume to the NHT.

2. Replace the internals of the Naphtha Feed Surge Drum (V-418) to reduce/eliminate water carryover. As it currently exists, the separation of sour water carryover from the hot or cold overhead accumulators in the feed surge drum is inefficient, allowing sour water droplets to be carried over with the feed naphtha into the heat exchange train. At the point these droplets vaporize as they are heated, the concentration of salts in the water causes high corrosion rates in the heat exchanger tubes. Therefore, upgrading the feed surge drum internals will significantly reduce this water carryover.

3. Reroute the NHT Hydrogen Recycle Compressor (J-76) discharge from the inlet of the heat exchange train to the inlet/outlet of the Naphtha Guard Reactor (C-87). In its current configuration, the pressure drop across the heat exchanger train restricts the quantity of hydrogen recycled. In order to process the additional naphtha volume of 3,000 BPD proposed under this application, the flow rate through the heat exchanger train would increase, thereby increasing the pressure drop across the heat exchanger train. The net effect of the above would result in reduced recycle hydrogen flow through the heat exchanger train below the required rates. To avoid this problem, hydrogen will be injected downstream of the heat exchanger train.

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4. Install a new two-shell Feed/Effluent Heat Exchanger downstream of Naphtha Guard Reactor (C-87) and rearrange heat exchanger E-535A to be directly in series with heat exchangers E-535 B and E-535C to provide improved heat recovery. With the proposed arrangement, the "Post-Project" heat exchanger train into the NHT would be E-537→E-535C→E-535B→E-535A→E-NEW. Likewise, the "Post-Project" heat exchanger train from the NHT to the SRHT would be E-NEW→E-535A→E-535B→E-535C→E-536→E-537. Though the naphtha throughput through the DH F-44 NHT Feed Heater (S-1491) will increase by 3,000 BPD, no changes in heater firing rates from existing levels are anticipated due to the heat recovery realized from the new heat exchanger and the "Post-Project" heat exchanger train set-up.

5. Replace the internals of Naphtha High Pressure Separator Vessel (V-421) to reduce/eliminate water carryover. As it currently exists, the high-pressure separator currently has sour water carryover with the hydrocarbons into the low-pressure separator, and subsequently to the heat exchangers and the SRHT primary column. The increased naphtha throughput of 3,000 BPD proposed under this application would exacerbate this problem. In light of the above, the vessel internals of the high-pressure separator will be renovated to improve the separation efficiency of sour water from hydrocarbons.

6. Replace the SRHT Primary Column Overhead Pump (P-2054) with a bigger pump to increase the hydraulic capacity of the SRHT Primary Column overhead naphtha system.

7. Upgrade SRHT Stabilizer Bottoms piping to bypass air coolers and run hot to the Decylohexanizer Unit (DCH). The SRHT Stabilizer Bottoms hydraulic capacity will be increased by rerouting through larger piping to the DCH feed drum, bypassing the air coolers, and thereby retaining the heat into the DCH column. This additional heat will lower its reboiler steam consumption and hence associated steam generation emissions.

8. Interconnect DCH Bottoms rundown piping to allow excess production associated with the additional naphtha volume of 3,000 BPD proposed under this application, to combine with Heavy Gasoline Hydrotreater (HGHT) Sidecut Stripper Bottoms run down piping en route to storage at Tank 611 (S-611).

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Regulation 2-1-234.1 states the following:
"2-1-234 Modified Source: Any existing source that undergoes a physical change, change in method of operation, increase in throughput or production, or addition and that results or may result in any of the following:
234.1 An increase in either the daily or annual emission level of any regulated air pollutant, or an increase in the production rate or capacity that is used to estimate the emission level, that exceeds emission or production levels approved by the District in any authority to construct."
Part 1 of permit condition 18618 in Shell's Title V permit[69] limits the NHT's throughput to 28,500 bbl/day. As previously discussed, the proposed modifications to S-1424, to accommodate the increased naphtha throughput, would allow Shell to produce more motor gasoline by increasing the NHT's throughput by 3,000 BPD. Therefore, permit condition 18618 will have to be modified to reflect the "Post-Project" throughput of 31,500 BPD. In light of the above and per Regulation 2-1-234.1 the NHT is considered a modified source.

[69] All references to "Shell's Title V permit" in this evaluation refer to the Title V permit that was issued by the District to Shell on May 17, 2007.

The NHT is located in the Light Oils Processing (LOP) area of the refinery. Based on information contained in Shell's Flare Minimization Plan (FMP) which was approved by the District in July 2007 and the 1st FMP update that was submitted to the District in July 2008, the NHT is serviced by the LOP Flare (S-1471). It is unlikely that the proposed modifications to the NHT to accommodate the increased naphtha throughput of 3,000 BPD proposed under this application would result in flaring beyond existing levels at S-1471.

De-bottlenecking Analysis:

Please refer to Figure's 1 & 3 and Table 1.

Table 1

Source # and Description	**Upstream/Downstream of NHT**	**Existing Title V permit throughput[70]**	**Proposed Title V permit throughput**	**Net Change**
S-1420: Crude Unit	Upstream	178,800 BPD	178,800 BPD	None
S-1759: Flexicoker Unit		48,300 BPD	48,300 BPD	None
S-4001: Delayed Coking Unit		65,000 BPD	65,000 BPD	None
S-4020: Distillate Hydrotreater		60,000 BPD	60,000 BPD	None
S-4140: Heavy Cracked Gasoline Hydrotreater		23,200 BPD	23,200 BPD	None
S-4080: Isomerization Unit (with Decyclohexanizer vessel)	Downstream	15,100 BPD	15,100 BPD	None
S-1425: Catalytic Reformer Unit		32,000 BPD	32,000 BPD	None
S-4140: Heavy Cracked Gasoline Hydrotreater		23,200 BPD	23,200 BPD	None
S-611: Intermediate Product Storage Tank		82,217 BPD	82,217 BPD	None
S-612: Finished Gasoline Storage Tank		Combined throughput < 210,686 BPD	Combined throughput < 210,686 BPD	None
S-613: Finished Gasoline Storage Tank				

Sources at the Shell operate under two separate emission bubbles called the "REFEMS" and "Clean Fuels Permit" bubbles. Sources outlined in Table 1 with source numbers below "4000" are part of the REFEMS bubble and are governed by permit condition 7618. As an example, consider S-1759 "Flexicoker Unit". Likewise, sources outlined in Table 1 with source numbers above "4000" are part of the CFP bubble and are governed by permit condition 12271. As an example consider S-4001 "Delayed Coking Unit". The proposed modifications to the NHT, will result in a "net increase" in hydrogen make at S-1445 "DH Hydrogen Plant 1" to hydrotreat the additional 3,000 BPD of naphtha-range material, result in increased utilization & product outflows from the Decyclohexanizer vessel, cause increased sulfur make at the Sulfur Recovery Plants (SRPs), and others. The increase in sulfur make at the SRPs, stemming from modifications to the NHT, will be offset by a corresponding decrease in sulfur make at the SRPs associated with reduced desulfurized flows of heavier products (e.g., jet fuel and diesel fuel) from the the facility's other hydrotreaters, particularly the Gas Oil Straightrun Hydrotreater (GOHT).

[70] Throughputs for sources in Table 1 excerpted from permit condition 18618 in Shell's Title V permit.

There are two fates of the incremental H2S and NH3 increase generated at the NHT. One fate is sour water. The incremental increase in H2S and NH3 generated at the NHT will be absorbed by water injection downstream of the NHT reactor. The net effect of the above will increase the concentration of the above pollutants in the sour water streams leaving the NHT and there will be no increase in the volume of water injected. Almost all of the NH3 formed in the NHT is entrained in the sour water, and the remaining NH3 combines with H2S formed in the hydrotreating step to form Ammonium Hydrosulfide $(NH_4)SH$. Sour water laden with NH3 and $(NH_4)SH$ is sent to the Sour Water Strippers (SWS). The H2S and NH3 that is not absorbed by the sour water described above is routed via vents on the Naphtha High Pressure Separator Vessel (V-421), the Naphtha Low Pressure Separator Vessel (V-422), the Primary Column Overhead Accumulator (V-424), and the Stabilizer Column Overhead Accumulator (V-426) to the DH Saturates Gas Plant (S-1446) to be absorbed by the DEA absorbers. Sulfur plants process the H2S and NH3 liberated by the DEA strippers and SWS.

However, none of increases discussed in the preceding paragraphs will result in modifications to either permit condition 7618 or 12271, since the affected sources that are part of the above permit conditions were fully offset in previous NSR permitting actions under Applications 26786 and 8407, respectively.

Sources upstream of the NHT:

It can be seen from Table 1 above that the NHT is downstream of the Crude Unit, the Flexicoker Unit, the Delayed Coking Unit, the Distillate Hydrotreater, and the Heavy Cracked Gasoline Hydrotreater. . As it currently exists (~Pre-Project), naphtha-range materials are hydrotreated at the NHT and heavier products (e.g., jet fuel and diesel fuel) are hydrotreated at the facility's other hydrotreaters, particularly the GOHT. The Post-Project "net increase" in the NHT's throughput by 3,000 BPD will be made up by associated increases of naphtha-range material sent to the NHT from the Crude Unit and by increases in the naphtha draw at the Flexicoker, the Delayed Coker, the Distillate Hydrotreater, and the Heavy Cracked Gasoline Hydrotreater. However, all of the afore-referenced units will be operated within their Title V throughput limits outlined in Table 1 above and will not be de-bottlenecked.

Sources downstream of the NHT:

It can be seen from Table 1 above that the NHT is upstream of the Isomerization Unit (with Decyclohexanizer vessel), the Catalytic Reformer Unit, the Heavy Cracked Gasoline Hydrotreater, and the three storage tanks. The NHT hydrotreats (~removes sulfur and nitrogen) from the naphtha-range material it receives from units upstream of it and produces hydrotreated feed for the Straight Run Hydrotreater (SRHT). The SRHT system is a series of distillation/separation processes and consists of a collection of vessels such as the SRHT Primary Column, SRHT Secondary Column, and the SRHT Stabilizer Column. Though the NHT and SRHT are interconnected units, they significantly differ from each other in that no hydrotreating is performed at the SRHT, i.e. H2S and NH3 are not formed at the SRHT. The SRHT fractionates the hydrotreated NHT product streams and separates the naphtha range (gasoline range) hydrocarbons from distillate (jet fuel, diesel) using distillation. Naphtha streams from the SRHT serve as feed to the DCH vessel. The DCH vessel fractionates and decyclohexanizes (~removes benzene and benzene precursors) from the NHT/SRHT hydrotreated product streams. The DCH tops are routed to the ISOM unit and the DCH bottoms (consisting of gasoline/gasoline components) are routed either to the CRU or to intermediate storage at S-611. The DCH bottoms (not routed to the CRU) stored in S-611 are blended into motor gasoline at S-612 and S-613 by commingling it with the ISOM and CRU product streams, i.e. isomerate and reformate.

The proposed modifications to the NHT will not change the overall throughput through tankage at Shell. Specifically, the increased utilization of the refinery's gasoline storage tanks will result in a corresponding decrease in utilization of the heavier product storage tanks.

Other units:

The proposed modifications to the NHT will result in the increased utilization of some units, such as but not limited to, the DH F-44 NHT Feed heater (S-1491). However, none of the affected units will be physically modified, and they will continue to operate within their respective Title V throughput limits. In addition, per Regulation 2-2-604 there will no emission increases from any of the affected units, and they will continue to comply with their respective emission limits

Emissions Calculations

Hydrotreaters, such as the NHT, are closed units – implying, fugitive leaks are their only source of emissions. As previously discussed in the "Background" section above, the modifications to the NHT/SRHT will involve replacing existing pumps (P-2008 and P-2054) with larger pumps, installing valves, flanges, piping and associated components. Shell will replace each pump or valve with a new pump or valve on a one for one basis; and replace sections of small diameter pipes with larger diameter pipes. Shell has contented that the modifications to the NHT/SRHT will not result in a "net increase" in the number of flanges and connectors. However, the installation of a new two-shell Feed/Effluent Heat Exchanger downstream of Naphtha Guard Reactor (C-87) will require the installation of at least 24 new valves and 73 new flanges in "light liquid" service. To ensure fugitive emissions from the above components are not underestimated, the component counts were adjusted upwards by 50 percent i.e. 36 new valves and 110 new flanges.

Table 2 summarizes leak rates for the above fugitive components.

Table 2

Note:

Type/service	Number of components[1]	Emission factor (Lb/hr/ component)	POC[71], lb/hr	POC, lb/day	POC, lb/yr	POC, TPY
Valves/Gas/Light Liquid	36	0.00016[2]	0.006	0.14	50.46	0.025
Flanges/All[3]	110	0.00026[2]	0.029	0.69	250.54	0.125
Totals	**146**		**0.035**	**0.83**	**301.00**	**0.15**

8) Component counts estimated by Shell.

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[71] POC – Precursor Organic Compounds

9) Correlation equation used to derive the emission factor excerpted from Table IV-3a (page 20) of the "California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities", February 1999. Specifically, the following correlation equation "2.27E-6*(SV)^0.747" was used in concert with a Screening Value (SV) of 100 ppmv to deduce an emission factor for valves. Likewise, the following correlation equation "4.53E-6*(SV)^0.706" was used in concert with a SV of 100 ppmv to deduce an emission factor for flanges. Please note that the SV of 100 ppmv used in both cases is based on the maximum leak rate allowed by Regulation 8 "Organic Compounds", Rule 18 "Equipment Leaks" for the above equipment.
10) Flange counts include connectors.

It can be seen from Table 2 above that the proposed modifications to the NHT would result in an increase of less than a pound (0.83 lbs/day) of fugitive POC emissions per day.

Toxic Risk Screen Analysis
Shell maintains a database containing speciation information for various process streams, such as naphtha, at the refinery. This data is used by Shell to generate a variety of reports, such as the Toxic Release Inventory (TRI) reports among others. Toxic Air Contaminant (TAC) emissions summarized in Table 3 below were estimated using the species concentration data Shell maintains in its TRI database for naphtha in concert with POC emissions summarized in Table 2 above.

Table 3

TAC	Maximum Concentration (% by wt.)	TAC Emissions			
		Lbs/hr	Lbs/day	Lbs/yr	TPY
1,2,4-Trimethylbenzene	0.92	0.0003	0.008	2.77	0.001
Benzene	0.29	0.0001	0.002	0.88	0.0004
Cumene	0.13	0.00005	0.001	0.39	0.0002
Cyclohexane	1.4	0.0005	0.01	4.21	0.002
Ethylbenzene	0.47	0.0002	0.004	1.41	0.0007
Naphthalene	0.28	0.0001	0.002	0.84	0.0004
Toluene	1.3	0.0005	0.01	3.91	0.002
Xylene (Mixed Isomers)	2	0.0007	0.02	6.02	0.003

Note:
For example, benzene emissions summarized in Table 3 above were estimated as follows:
From Table 2, the daily POC emissions from the 146 new fugitive components is equal to 0.035 lb/hr. The max. concentration of benzene in naphtha streams, per Shell's TRI database, is 0.29% by wt. Therefore, the hourly benzene emissions are equal to 0.035 x (0.29/100) = 0.0001 lbs/hr. Likewise the daily & annual benzene emissions are 0.0024 lbs/day (0.0001 x 24) & 0.88 lbs/yr (0.0024 x 365), respectively.

Table 4 below summarizes the Acute and Chronic TAC Trigger Levels (TTL's) for TAC's summarized in Table 3, and compares the emissions summarized in the above table to the TTL's outlined in Table 2-5-1 in Regulation 2, Rule 5 to verify if a Toxic Health Risk Screening Analysis (HRSA) is warranted.

Table 4

TAC	Acute TTL (lbs/hr)	Emissions (lbs/hr)	Exceeds Acute TTL?	Chronic TTL (lbs/yr)	Emissions (lbs/yr)	Exceeds Chronic TTL?
1,2,4-Trimethylbenzene	NA	0.0003	No	NA	2.77	No
Benzene	2.9	0.0001	No	6.4	0.88	No
Cumene	NA	0.00005	No	NA	0.39	No
Cyclohexane	NA	0.0005	No	NA	4.21	No
Ethylbenzene	NA	0.0002	No	77,000	1.41	No
Napthalene	NA	0.0001	No	5.3	0.84	No
Toluene	82	0.0005	No	12,000	3.91	No
Xylene (Mixed Isomers)	49	0.0007	No	27,000	6.02	No

It can be seen from Table 4 above, that this application does not warrant a Toxic HRSA.

Regulation 2-1-128.21 Exemption

Regulation 2-1-128.21 states the following:

"2-1-128 Exemption, Miscellaneous Equipment: The following equipment is exempt from the requirements of Sections 2-1-301 and 302, provided that the source does not require permitting pursuant to Section 2-1-319. 128.21 Modification, replacement, or addition of fugitive components (e.g. valves, flanges, pumps, compressors, relief valves, process drains) at existing permitted process units at petroleum refineries, chemical plants, bulk terminals or bulk plants, provided that the cumulative emissions from all additional components installed at a given process unit during any consecutive twelve month period do not exceed 10 lb/day, and that the components meet applicable requirements of Regulation 8 rules."

It can be seen from emission calculations summarized in Table 2 above that the cumulative emissions from the 146 new fugitive components that will be installed at the NHT/SRHT as part of this application is below 10 lb/day i.e. 0.83 lb/day. In addition, the new fugitive components, summarized in Table 1 will meet the requirements of Regulation 8 "Organic Compounds", Rule 18 "Equipment Leaks" and will be incorporated into Shell's Leak Detection and Repair (LDAR) program.

The proposed modifications to the NHT also meet the requirements outlined in Regulation's 2-1-316 through 319 as follows:

- ***Regulation 2-1-316:***
  The hazardous air pollutant (HAP) emissions from fugitive components in Table 3 above will neither result in the emission of 2.5 TPY or more of a single HAP emissions, or 6.5 TPY or more of a combination of HAPs.
- ***Regulation 2-1-317:***
  The NHT is not a source of public nuisance.

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- ***Regulation 2-1-318:***
  It can be seen from Table's 3 and 4 above that the NHT does not contain any of the compounds listed in Sections 318.1 through 318.8 of the above regulation.
- ***Regulation 2-1-319:***
  It can be seen from Table 2 above that the "post-control" POC emissions from the 146 new fugitive components is below 5 TPY (0.15 TPY), and all the requirements contained in Regulation 2-1-316 through 2-1-318 are satisfied.

Therefore, it is safe to conclude that the additional fugitive components summarized in Table 2 above qualify for the exemption under Regulation 2-1-128.21.

BACT

As previously discussed in the preceding discussion, the fugitive components summarized in Table 2 above are exempt per Regulation 2-1-128.21. Therefore, BACT is not triggered for the increase in emissions from fugitive components that are part of this application.

However, Shell has indicated that it will voluntarily meet the District's BACT 2 level of control for the process valves (100 ppm expressed as methane) outlined in BACT Guidance Document #136.1 dated January 18, 2006; the BACT 2 level of control for the flanges (100 ppm expressed as methane) outlined in BACT Guidance Document # 78.1 dated January 18, 2006; and the BACT 1 level for the pumps (100 ppm expressed as methane) outlined in BACT Guidance Document #137.1 dated January 18, 2006.

Cumulative Increase & Offsets

It can be seen from Table 2 above that the proposed modifications to the NHT will result in an increase of 0.15 TPY of POC emissions. As previously discussed in the preceding sections of this evaluation the additional fugitive components summarized in Table 2 above are exempt under Regulation 2-1-128.21. As a result, the proposed modifications to the NHT will not result in a cumulative increase in criteria pollutant emissions at Shell. Therefore, though the NHT is considered a modified per Regulation 2-1-234.1, offsets are not warranted.

Statement Of Compliance

Regulation 8 "Organic Compounds", Rule 5 "Storage of Organic Liquids" requires tanks storing organic liquids with a vapor pressure over 0.5 psia, such as S-611, S-612, and S-613, to be equipped with an appropriate vapor loss control device, such as a submerged fill pipe, a pressure vacuum valve, or primary and secondary seals. The tanks are fixed-roof tanks that are controlled by A-25, Vapor Recovery System J, which sends any vapors to the fuel gas system.

Monitoring and reporting of the liquids stored and the throughput is also required for each of the above 5,614,400 gallon fixed roof tanks. The proposed 3,000 BPD increase in DCH bottoms sent to S-611 which is later blended into motor gasoline at S-612 and S-613 will not result in changes to the existing applicable requirements contained in Table's IV-B and Ea for the above tanks in Shell's Title V permit.

Permit condition 18618 limits the daily throughput at S-611 to 82,217 BPD. Based on information contained in Shell's annual information update for the past year, the "actual" daily throughput at S-

611 was 4,645 BPD (~6% of the permitted daily throughput limit). Likewise, the combined daily throughputs at S-612 and S-613 are limited by the above permit condition to not exceed 210,686 BPD. Per information contained in Shell's annual information update for the past year, the "actual" combined daily throughput at the above sources was 14,468 BPD (~7% of the combined permitted daily throughput limit). In light of the above, it is safe to conclude that the proposed modifications to the NHT will not result in an exceedance of the throughput limits for either S-611 and/or S-612 & S-613. Moreover, since the emissions routed to the fuel gas system will simply displace the use of natural gas at the refinery, no increase in actual emissions is assumed.

Regulation 8 "Organic Compounds", Rule 10 "Process Vessel Depressurization" requires organic compound emissions from depressurizing any process vessel at a petroleum refinery to be controlled by venting them to a fuel gas system, firebox, incinerator, thermal oxidizer, flare, or otherwise containing and treating so as to prevent emissions to the atmosphere. The above rule also restricts when a process vessel may be opened to the atmosphere, and requires monitoring & reporting of actual emissions. The proposed modifications to the NHT may require certain pressure vessels to be opened during the construction phase of the project. Shell will comply with all the applicable requirements of the above rule that are contained in Table IV-AL (for S-1424) in Shell's Title V permit.

The fugitive components summarized in Table 2 above and the two new pumps (replacements for P-2008 and P-2054) will be subject to Sections 301, 302, 303, 304, 306, and 307 in Regulation 8 "Organic Compounds", Rule 18 "Equipment Leaks". Sections 301, 302, and 304 require, among other things, that organic compound leaks, not exceed 100 ppm for general components, valves, and connections. Likewise, Sections 303 requires, among other things, that organic compound leaks, not exceed 500 ppm for pumps and compressors. Section 8-5-306 limits the percentages of non-repairable equipment allowed. Section 8-5-307 requires that leaking equipment not be used unless the leak discovered by the operator, is minimized within 24 hours and repaired within 7 days.

Section 302 in Regulation 8 "Organic Compounds", Rule 28 "Episodic Releases from Pressure Relief Devices at Petroleum Refineries and Chemical Plants" requires any person (~Shell) installing a new refinery source or modifying an existing refinery source (S-1424), that is equipped with at least one pressure relief device in organic compound service, to meet all applicable requirements of Regulation 2, Rule 2, including Best Available Control Technology. The proposed modifications to the NHT will not result in the installation of any new pressure relief valves, nor will any existing pressure relief valves be replaced. Shell will comply with all the applicable requirements of the above rule that are contained in Table IV-AL (for S-1424) in Shell's Title V permit.

Regulation 11 "Hazardous Pollutants", Rule 7 "Benzene" limits the emission of benzene from sources (such as pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, flanges and other product accumulator vessels, and control devices) intended to operate in benzene service. Regulation 11-7-207 defines "In Benzene service" to be any equipment which either contains or contacts a fluid (liquid or gas) that is at least 10 percent benzene by weight. The proposed modifications to the NHT will not involve process streams, which will either contain or contact a fluid that is at least 10 percent benzene by weight. Therefore, Regulation 11, Rule 7, does not apply.

The NHT is located in the Light Oils Processing (LOP) area of the refinery. Based on information contained in Shell's Flare Minimization Plan (FMP) which was approved by

District in July 2007 and the 1st FMP update that was submitted to the District in July 2008, the NHT is serviced by the LOP Flare (S-1471). The proposed modifications to the NHT will not result in flaring beyond existing levels at S-1471. Therefore, it is safe to conclude no changes to Shell's FMP are warranted, and that requirements in Regulation 12 "Miscellaneous Standards of Performance", Rule's 11 "Flare Monitoring at Petroleum Refineries" and 12 "Flares at Petroleum Refineries" will be complied with at all times.

The increase in the number of fugitive components associated with Shell's "MTBE Removal Project", which was reviewed by the District under Application 1821, made the ALKY unit subject to the requirements of 40 CFR Part 60, Subpart GGG "Equipment Leaks of VOC in Petroleum Refineries" (NSPS GGG) on November 19, 2002. Though Table IV-AL in Shell's Title V permit does not explicitly list NSPS GGG as the applicable requirements for the NHT, it is implied that the requirements of the above rule summarized in Table IV-DP apply to the above unit at all times. In light of the above applicability determination, the new fugitive components summarized in Table 2 and the two pumps (replacements for P-2008 and P-2054) are subject to and are expected to comply with the requirements of NSPS GGG.

Please note that Table IV-DP contains references to 40 CFR Part 60 Subpart VV "Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry" (NSPS VV) only because NSPS GGG references NSPS VV. The US EPA's intent was to subject a facility (Shell in this case) to either NSPS GGG or NSPS VV and not both of the above rules. In other words, the NSPS GGG requirements applied to refinery process units, and chemicals plants were expected to comply with the requirements in NSPS VV.

40 CFR 61, Subpart J "National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene" applies to the following sources that are intended to operate in benzene service: pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems required by this subpart. The fugitive components summarized in Table 2 and the two pumps (replacements for P-2008 and P-2054) will not contain or contact a fluid (liquid or gas) that is at least 10 percent benzene by weight. Therefore, they are not subject to 40 CFR 61, Subpart J.

40 CFR 61, Subpart V "National Emission Standard for Equipment Leaks (Fugitive Emission Sources)" applies to the following sources that are intended to operate in Volatile Hazardous Air Pollutant (VHAP) service: pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems required by this subpart. The fugitive components summarized in Table 2 and the two pumps (replacements for P-2008 and P-2054) will not contain or contact a fluid (liquid or gas) that is at least 10 percent VHAP by weight. Therefore, they are not subject to 40 CFR 61, Subpart V.

40 CFR 61, Subpart FF "National Emission Standard for Benzene Waste Operations" applies to chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries. The rule details how to manage benzene wastes in a range of operations throughout the refinery, and also defines the recordkeeping & reporting requirements. Currently, the NHT periodically generates benzene-containing waste materials and the proposed modifications to this unit could potentially affect the quantity of the wastes generated, or the benzene concentration in the wastes. However, it is unlikely that the proposed modifications to the NHT will generate any new categories of benzene-containing wastes. Shell's Benzene Waste Operations NESHAP program and the Subpart FF

applicable requirements contained in Table's IV-Y, AC, CG, DT, DU, and DV will ensure continued compliance with the above subpart.

Maximum Achievable Control Technology (MACT) standards in 40 CFR Part 63 is applicable to toxic air emissions emanating from specific source categories at facilities, which are major sources of HAPs. The MACT standards that potentially are applicable to the ALKY unit include 40 CFR Part 63, Subpart A "General Requirements", and 40 CFR Part 63, Subpart CC "National Emissions Standards for Hazardous Air Pollutants from Petroleum Refineries" (MACT CC). Though Table IV-AL in Shell's Title V permit does not explicitly list MACT CC as an applicable requirement for the NHT, it is implied that the requirements of the above rule summarized in Table IV-DS apply to various refinery operations (such as the NHT) including equipment leaks at all times. As previously discussed in the preceding paragraphs, though NSPS VV is not applicable to petroleum refineries, Table IV-DS contains references to sections from the above rule only because MACT CC references NSPS VV.

In light of the above, the fugitive components similar to those summarized in Table 2 above and the two pumps (replacements for P-2008 and P-2054), which will be added to the modified NHT, must comply with NSPS VV if they will be used in organic HAP (OHAP) service. "In organic hazardous air pollutant service" is defined in MACT CC as follows:
"means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP's as determined according to the provisions of § 63.180(d) of subpart H of this part and table 1 of this subpart. The provisions of § 63.180(d) of subpart H also specify how to determine that a piece of equipment is not in organic HAP service."

Of the TAC's summarized in Table's 3 & 4 above, benzene (0.29%), cumene (0.13%), ethylbenzene (0.47%), naphthalene (0.28%), toluene (1.3%), and the mixed isomers of xylene (2%) appear in Table 1 of MACT CC. Since the total percent by weight of the above OHAP's is below 5%, i.e. 4.47% when using Shell's stream specific speciation information, the new fugitive components that will be added as part of the proposed modifications to the NHT are not subject to MACT CC. However, the requirements of MACT CC in Table IV-DS would apply to the new fugitive components even if they contain/contact fluids containing less than 5% by wt. This is so because when MACT CC went into effect in 1998, Shell decided to eliminate the guesswork/un-certainty surrounding whether a certain OHAP stream(s) was subject to the MACT CC or not. Given that the District's Regulation 8, Rule 18 is at least as stringent if not more stringent than MACT CC, the company decided to subject their process units and associated components to the MACT CC requirements at all times.

PSD is not applicable to this project because there is no cumulative increase in emissions at the plant. This is so because the increase in emissions associated with the new fugitive components that will be added as part of the proposed modifications to the NHT are exempt from Regulation 2-1-301 per Regulation 2-1-128.21.

The California Environmental Quality Act (CEQA):

Per Section 2-1-311 of the District Rules and Regulations, a permit application for a proposed new or modified source will be classified as ministerial and will accordingly be exempt from the CEQA requirement of Section 2-1-310 if the District's engineering evaluation and basis for approval of the permit application for the project is limited to the criteria set forth in Section 2-1-428 and to the procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook. The method for determining whether a given permit application will be classified as ministerial is set forth in Section 2-1-427.

Per Section 2-1-427, if the District determines that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook, the District's evaluation of the permit application is classified as ministerial and the engineering evaluation of the permit application by the District will be limited to the use of said specific procedures, fixed standards and objective measurements. For such projects, the District will merely apply the law to the facts as presented in the permit application, and the District's decision regarding whether to issue the permit will be based only on the criteria set forth in Section 2-1-428 and in the District's Permit Handbook and BACT/TBACT Workbook.

For this permit application, the District determined that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook Chapter 3.4 “Petroleum Refinery Fugitive Emissions”. Since the District classified this permit application as ministerial pursuant to Section 2-1-427, and as a result of its evaluation of the permit application, the District determined that all of the criteria for approval of ministerial permit applications pursuant to Section 2-1-428 were met, the issuance by the District of an Authority to Construct and Permit to Operate for the proposed project is a mandatory ministerial duty and is accordingly exempt from the CEQA requirement of Section 2-1-310.

In addition to the ministerial exemption determination above, the District has also determined that the CEQA categorical exemptions of Sections 2-1-312.7 and 2-1-312.11 of the District Rules and Regulations and the CEQA "Common Sense Exemption" apply.

CEQA Categorical Exemptions and CEQA "Common Sense Exemption":
Though the District concludes that the modifications/alterations that are part of this application are ministerial, it also concludes that, even if it were not ministerial, certain other exemptions from CEQA apply (see CEQA Guidelines § 15300.1). Section 2-1-312 of the District Rules and Regulations sets forth specific types of projects, which have been determined by the District to be categorically exempt from CEQA.

Per Section 2-1-312.7, permit applications for the replacement or reconstruction of existing sources or facilities, where the new source or facility will be located on the same site as the source or facility replaced and will have substantially the same purpose and capacity as the source or facility replaced, are exempt from the CEQA review.

Per Section 2-1-312.11, in addition to ministerial projects, permit applications for a new or modified source or sources or for process changes, which will satisfy the "No Net Emission Increase" provisions of District Regulation 2, Rule 2 and for which there is no possibility that the project may have any significant environmental effect in connection with any environmental media or resources other than air quality, are exempt from the CEQA review. The reason for this exemption should be apparent on its face: if a facility is given legal permission to emit more air pollutants from certain points while at the same time being disallowed permission for an equivalent amount of the same type of emissions from other points at the facility, then there is deemed to be no net effect on the air environment, and therefore no possibility of a significant effect under CEQA, provided no-air impacts are also examined and deemed to be of no possible significant consequence.

Also, per the CEQA Guidelines in Title 14, California Code of Regulations, Chapter 3, Article 5, Section 15061(b)(3), a project is exempt from CEQA if the activity is covered by the general rule that CEQA applies only to projects, which have the potential for causing a significant effect on the environment. This is commonly known as the "Common Sense Exemption". Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to CEQA. The "no net increase" exemption of 2-1-312.11 is essentially a specific, codified, instance of the Common Sense Exemption.

The new fugitive components that will be added as part of the proposed modifications to the NHT are exempt from Regulation 2-1-301 per Regulation 2-1-128.21. As a result, the 0.15 TPY increase in POC emissions summarized in Table 2 above will not be counted toward the cumulative increase in emissions at Shell. Therefore, the District determined that the project satisfies the "No Net Emission Increase" provisions of District Regulation 2, Rule 2. Shell has completed and submitted to the District CEQA Appendix H, Environmental Information Form, for the project.

The District has reviewed the CEQA Appendix H form. Shell responded to all the questions on the above form, with the exception of item 29, by stating either "No", or "Not Applicable". Shell responded to item 29 "Use or disposal of potentially hazardous materials, such as toxic substances, flammables or explosives" with a "Yes" and stated the following: "While the proposed Enhanced Naphtha Processing Project will not introduce any new hazardous materials into the refinery, the project will allow the refinery to increase throughput of petroleum naphtha (a flammable material) in the NHT by approximately 3,000 BPD, or about a 10 percent increase over current naphtha processing levels in those units. There will be a corresponding decrease of approximately 3,000 BPD of heavier product production (e.g., jet fuel, diesel fuel)."

In addition to the above form, Shell also submitted the following additional information in order for the District to determine the project's possible significant effects:

12. *Please provide a completed Appendix H, Environmental Information Form, which contains sufficient information for the District to complete the CEQA Initial Study of the project. For responses in the above form that are either marked "Yes" and/or "NA", please fully explain the relevant issue(s) in detail.*

    Shell has followed the guidelines in Appendix H of the BAAQMD Permit Handbook (Environmental Information Form), which is included in the preceding pages of this Appendix C.

13. *Please describe any new equipment, including pumps and piping that will be installed for this project. Will any new piping be installed aboveground?*

    The changes proposed for the Enhanced Naphtha Processing Project involve the installation of valves, flanges, and vessel internals (e.g., packing materials) in existing refinery process units. The new piping will be installed aboveground in existing pipe racks.

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14. To determine potential impacts to groundwater and surface water quality, please respond to the following:

q. Will this project result in an increase in the risk of a spill with potential for impacting surface water and groundwater? Please explain.

The project involves replacing existing pumps, valves, flanges, and piping with slightly larger pumps, valves, flanges, and piping. There is minimal potential for the Enhanced Naphtha Processing Project to increase the risk of a spill that would impact surface water or groundwater.

r. What spill prevention measures and monitoring are in place at Shell to limit the potential risk of a spill due to this project.

The proposed project involves replacing existing pumps, valves, flanges, and piping with slightly larger pumps, valves, flanges, and piping within existing refinery process units. These replacements are not expected to affect the probability or consequences of a spill compared to current operations.

Shell's existing program of operator training, prevention, mitigation, and response is based on prevention of environmental impacts, and will further reduce the risk of a spill. Shell has prepared and implemented a Storm Water Pollution Prevention Plan (SWPPP) and a Spill Prevention Control and Countermeasures (SPCC) plan to prevent water quality contamination. Storm drains are closed by default, and collected storm water is sent to the Refinery's effluent wastewater treatment plant.

s. To address runoff at the site, does Shell have a Storm Water Pollution Prevention Plan and Spill Prevention Control and Countermeasures Plan?

Shell has prepared the SWPPP and SPCC Plan, as required.

t. How frequently does Shell conduct groundwater monitoring and how often are the analytical results submitted to the Regional Water Quality Control Board?

Shell performs quarterly groundwater monitoring as required by Waste Discharge Requirements (WDR) Order 95-234, issued by the San Francisco Bay Regional Water Quality Control Board (SFBRWQCB). Results are submitted to the SFBRWQCB twice a year.

Additionally, Shell is required to perform a capture zone analysis on the facility. The WDR order requires that an ongoing hydraulic groundwater capture program be installed, operated, and maintained. Groundwater extraction systems are installed at the perimeter of the facility and serve to capture the groundwater before it leaves the site.

u. What is direction of the groundwater flow beneath the Shell refinery site?

The equipment to be changed is located in the East Valley groundwater basin of the facility. Groundwater flows from South to North at a velocity of approximately four feet per year.

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15. To determine potential impacts due to diesel-fueled trucks associated with the project, please respond to the following:

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a. How and from where will water be delivered to the project?

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The proposed project may slightly increase the water demand in the existing light oil processing (LOP) units described in this application due to increased throughput. Water will be supplied through the existing distribution piping.

b. Would the installation of the new equipment result in an increase in existing diesel-fueled truck traffic to and from the truck loading racks?

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No. Gasoline, diesel and jet fuel products are all shipped from the refinery by truck, pipeline, and ship. Although the proposed project may cause an increase in gasoline production of 3,000 BPD, there will be a corresponding reduction in diesel and jet fuel production. If increase in truck traffic were to occur as a result of the project due to gasoline shipments, a corresponding decrease in diesel and jet fuel shipments would also occur. Therefore, anticipated truck traffic to/from the truck loading racks is not expected to change. Further, incremental changes in gasoline shipments are typically accommodated using pipeline delivery rather than truck transportation.

c. For construction, how many diesel-fueled trucks will be used for mobilization, construction, and demobilization of the project?

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The mobilization, construction, and demobilization activities related to the Enhanced Naphtha Processing Project will require up to about four months. The projected construction requirements are provided in Table C-1.

Table C-1
Enhanced Naphtha Processing Project Construction Requirements

	Mobilization	**Construction**	**Demobilization**
Number of Diesel Trucks[1]	2	3	2
Number of Days[2]	30	120	15
Total Days of Diesel Operated Cranes and Equipment[2]		65	
Maximum Number of Construction Workers		20	
Route Taken for Equipment Truck Deliveries		Gate 75	

Notes:
1. Maximum trucks on site on any given construction day.
2. Construction days may not be consecutive.

d. What is the likely route that the diesel-fueled trucks will take from the nearest freeway to the Shell gate?

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The most likely route for delivery of construction materials to the Enhanced Naphtha Processing Project construction site will be via Highway 680 to Marina Vista Avenue. The diesel-fueled trucks will enter the refinery through Gate 75.

The District finds these assertions and arguments to be credible and concludes that this permit application is exempt from CEQA because it is ministerial, it is categorically exempt from CEQA, and the project qualifies for the "Common Sense Exemption" of Subsection (b)(3) of the State CEQA Guidelines.

Based on all of the information before the District and the District's review of the information submitted, the District has determined that there is no possibility that the project may have any significant environmental effect. The District has considered whether the modifications/alterations to process units that are part of this application are part of a larger project for CEQA purposes, and has concluded that it is not. Although other Shell refinery permitting applications have been acted on or are currently pending before the District, the modifications to the NHT is not necessarily linked to any of these. Specifically, completion of the modifications/alterations to process units that are part of this application is not necessary in order for Shell to proceed with other permit applications, nor are any changes proposed in this application a foreseeable consequence of other permit applications.
On a general level, the stated purpose of the modifications/alterations to process units that are part of this application involves the shifting of production of heavier hydrocarbon products to more economically desirable lighter hydrocarbon products at Shell. This purpose does not imply any necessary relationship to other projects, in the sense of being prerequisite to other projects or a foreseeable consequence of them.

Permit Conditions

As it *currently* exists part 1 of permit condition 18618 in Shell's Title V permit states the following:

General Throughput Conditions and other miscellaneous monitoring requirements for Title V:

1. The following throughput limits are based upon District records at the time of MFR permit issuance. Exceedance of those limits for which Regulation 2-1-234.4 was the identified basis are not a violation of the permit if the operator can, within 60 days, provide documentation demonstrating the throughput limit should be higher, established in accordance with 2-1-234.3, and the excess throughput complies with the new limit. Exceedance of those limits which have other permit conditions or application information as the basis are a violation of Regulation 2-1-307 immediately upon exceedance of the limit. (basis: Regulation 2-1-234.3, Regulation 2-1-307)

S-#	Description	Daily Limit	Annual Limit
1424	DH Naphtha Straightrun Hydrotreater (NHT)	28,500 bbl/day	9,599,500 bbl/yr

As previously discussed in the "Background" section above, the NHT is a modified source per Regulation 2-1-234.1. Therefore, references to the NHT in permit condition 18618 will be deleted. This is so because, permit condition 18618 contains place holder limits for sources that are part of Shell's Title V permit that haven't undergone NSR review. Since the proposed modifications to the NHT have undergone NSR review under this permit application (# 18062), allowing the throughputs at the NHT to be governed by permit condition 18618 would be incorrect. In light of the above and going forward, the NHT will be governed by a new permit condition (# 24162).

The *proposed* amendments to part 1 of permit condition 18618 are as follows:

General Throughput Conditions and other miscellaneous monitoring requirements for Title V:

1. The following throughput limits are based upon District records at the time of MFR permit issuance. Exceedance of those limits for which Regulation 2-1-234.4 was the identified basis are not a violation of the permit if the operator can, within 60 days, provide documentation demonstrating the throughput limit should be higher, established in accordance with 2-1-234.3, and the excess throughput complies with the new limit. Exceedance of those limits which have other permit conditions or application information as the basis are a violation of Regulation 2-1-307 immediately upon exceedance of the limit. (basis: Regulation 2-1-234.3, Regulation 2-1-307)

S-#	Description	Daily Limit	Annual Limit
1424	DH Naphtha Straightrun Hydrotreater (NHT)	28,500 bbl/day	9,599,500 bbl/yr

(PC 24162)

1. The owner/operator of S-1424 “DH Naphtha Straightrun Hydrotreater (NHT) shall ensure that the daily and annual throughput of naphtha range material at the above source does not exceed 31,500 barrels per day and 10,609,974 barrels per year, respectively.
(Basis: Regulation 2-1-302)

2. To demonstrate compliance with part 1 of this permit condition, the owner/operator of S-1424 shall maintain records of materials throughput at the above source on a daily basis. These records shall be summarized on a monthly basis, and may be in the form of computer-generated data, which is available to District personnel on short notice (rather than actual paper copies of throughput data). These records shall be kept on file for a minimum of 5 years from the date of entry.
(Basis: Cumulative Increase, Regulation 2-1-403)

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RECOMMENDATION

Waive the AC, and issue Shell a PO for the proposed modifications at the following source:

S-1424 DH Naphtha Straightrun Hydrotreater (NHT)
31,500 bbl/day; 10,609,974 bbl/yr

Modify permit condition 18618 as proposed; issue Shell a new permit condition (# 24162).

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11
Application: 19373

Background
Shell Oil Products US – Martinez Refinery (Shell) has submitted this application to administratively amend permit condition 18618 that governs the operation of the following existing sources:

S-1507 EMSR1 – CO Boiler #1; 232 MMBTU/hr
S-1509 EMSR1 – CO Boiler #2; 232 MMBTU/hr
S-1512 EMSR1 – CO Boiler #3; 232 MMBTU/hr

The daily firing rate for each of the above three CO boilers (COBs) is limited by part 1 of permit condition 18618 in Shell's Title V permit[72] to not exceed 5,568[73] MMBTU/CO boiler/day. The permit condition does not specify whether the limit is in terms of Lower Heating Value (LHV) or Higher Heating Value (HHV). Permit condition 18618 contains Title V throughput limits for grandfathered sources at Shell. Grandfathered sources are sources that were already in existence on/before 1979 when the District required them to obtain permits and have been physically unmodified since then. In addition to the above and per Regulation 2-1-234.3, a grandfathered source is one for which the District has never issued an Authority to Construct (AC) and its daily or annual emissions are not limited by any permit conditions.

Per information contained in the District's database, the COBs have been in operation at Shell since January 1, 1966 and have not been physically modified[74] since that time. Whereas it is true that the District never issued Shell an AC to install the COBs, it is also true that the combined daily emissions from the COBs are limited by permit conditions other than permit condition 18618. Specifically, the daily emissions of NOx, POC, SO2, PM, and CO from the three COBs are part of Shell's facility baseline profiles outlined in Tables II, III, IV, V, VI of permit condition 7618, respectively. Likewise, the combined daily NOx and emissions from the three COBs are limited to 5,452 lbs/day and 6,805 lbs/day by parts 85 and 90 of permit condition 12271, respectively. In light of the above, the COBs at Shell partially meet the qualification criteria i.e. were never issued an AC, for grandfathered sources under Regulation 2-1-234.3.

Why amend permit condition 18618?

Since its initial issuance on December 1, 2003 under Application 16467, the daily firing rate limit for the COBs in part 1 of permit condition 18618 in Shell's Title V permit were based data expressed in terms of the LHV of fuels combusted in them. Historically, facilities such as Shell (and possibly the other Bay Area refineries) internally track the firing rate of their combustion sources in LHV terms and report the firing rate for the subject sources to the District in terms of the HHV of fuels combusted in them. Doing so involves increasing the calculated LHV values by approximately10% to account for the differences between the LHV and HHV. The District usually considers that permitted firing rate limits be in HHV terms. Almost all permit conditions containing such limits pre-qualify either in

[72] All references to "Shell's Title V permit" in this evaluation refer to the Title V permit that was issued by the District to Shell on April 4, 2008.
[73] 5,568 MMBTU/day (LHV) = 232 MMBTU/hr (LHV) x 24 hr/day
[74] The following minor revisions were made to the COBs since 1966: (1) adding facilities to allow for Bio-Waste to be injected into the boiler's burner assemblies, and (2) addition of the Over Fire Air facilities to lower NOx emissions.

their preamble and/or someplace within the body of their permit condition the terms/units in which the firing rates for the subject sources are expressed. For example, part 23 of permit condition 12271 and part 1 of permit condition 16688 in Shell's Title V permit explicitly state that the firing rates for the sources subject to the above permit conditions are expressed in terms of HHV. Doing so alleviates any confusion when determining compliance for both the District and the facility (Shell in this case) as discussed below. However, Condition 18618 does not explicitly state either LHV or HHV.

Per discussions with Shell staff, the original Design Process Data Sheet developed by Alcorn - the manufacturer of the COBs, listed the hourly firing rate for the three COBs as 232 MMBTU/hr/COB (LHV). As is the case with sources that are part of permit conditions 12271 and 16688 and to be consistent, Shell should have ensured that the COB limits were converted from LHV to HHV and the units expressed in their initial Title V permit and subsequent revisions thereafter were in HHV terms. This oversight on the part of Shell for not ensuring that the daily firing rates for the COBs be expressed in HHV terms (instead of in terms of LHV) in their initial Title V permit and subsequent revisions thereafter resulted in a *supposed* exceedance of the existing LHV limit as discussed below.

The Supposed *Exceedance:*

As previously stated, though Shell tracks the firing rate of the COBs in LHV terms, compliance of the firing rate with permit limits is determined and reported to the District in terms of HHV. Because neither the preamble to, nor the body of permit condition 18618 had any such pre-qualifications as to how the permitted daily firing rate of the COBs were expressed, Shell staff mistakenly construed that the firing rate for the COBs in the above permit condition were expressed in terms of HHV. In other words, Shell staff mistakenly assumed that COB #2's (S-1509) firing rate of 5,568 MMBTU/day in Shell's Title V permit was expressed in HHV terms.

In August 2008, the firing rate (in HHV) of S-1509 ranged from 5,575 MMBTU/day up to 5,827 MMBTU/day. Shell staff believed that S-1509 had operated beyond its permitted rate limit resulting in an exceedance and hence submitted this permit application. Only recently did Shell realize that their firing rate limits in their Title V permit were incorrectly expressed since its initial issuance. Realistically, even if the calculated firing rate for COB #2 in HHV were to be expressed in terms of LHV, S-1509's firing rate in August 2008 would have ranged between 5,068[75] MMBTU/day up to 5,297[76] MMBTU/day – below their incorrectly listed Title V permit limit of 5,568 MMBTU/day. As previously stated, this **supposed** ***exceedance in August 2008 would not have occurred had the daily firing rates for COBs been expressed as 255[77] MMBTU/hr/COB HHV (6,120 MMBTU/day/COB HHV) instead of 232 MMBTU/hr/COB LHV (5,568 MMBTU/day/COB LHV) in Shell's Title V permit all along.***

Steps taken by Shell since the supposed *exceedance:*

Over the course of the six days in August 2008, the daily firing rate (in HHV) for S-1509 ranged from 5,575 MMBTU/day up to 5,827 MMBTU/day. Because the COBs combust a variety of fuels such as liquid waste, carbon monoxide, flexigas, and refinery make gas, the

[75] 5,068 MMBTU/day (LHV) = 5,575 MMBTU/day (HHV) / 1.10
[76] 5,297 MMBTU/day (LHV) = 5,827 MMBTU/day (HHV) / 1.10
[77] 255 MMBTU/day (HHV) = 232 MMBTU/hr (LHV) x 1.10

firing rate when combusting the above fuels could not be measured directly (were values), nor was the Utilities Board Operator's Instrumentation monitoring the operation of the COBs equipped with alarms to alert refinery staff of the impending exceedance. Shell staff discovered the supposed exceedance of the 5,568 MMBTU/day LHV daily limit when running the Title V compliance assurance reports in September 2008. As a result of the above incident and going forward, Shell modified the Utilities Board Operator's Instrumentation by incorporating the ability to calculate the firing rate for the COBs in both LHV and HHV with appropriate alarms that would notify refinery staff of compliance problems well in advance.

The solution:

In order to ensure there is no ambiguity to staff associated with either Shell and/or District in determining whether the COBs comply with their daily firing rate limits outlined in part 1 of permit condition 18618 and going forward, the existing firing rate limit in Shell's Title V permit for the COBs will be amended to express the limit in terms of both LHV and HHV of the fuels combusted in them. For example, the daily firing rate limit for S-1509 would henceforth be expressed as 5,568 MMBTU/day (LHV) and 6,125 MMBTU/day (HHV).

Can permit condition 18618 be amended?

The preamble to part 1 of permit condition 18618 states the following:
"The following throughput limits are based upon District records at the time of MFR issuance. Exceedance of those limits for which Regulation 2-1-234.4 3[78] was the identified basis are not a violation of the permit if the operator can, within 60 days, provide documentation demonstrating the throughput limit should be higher, established in accordance with 2-1-234.3, and the excess throughput complies with the new limit. Exceedance of those limits which have other permit conditions or application information as the basis are a violation of Regulation 2-1-307 immediately upon exceedance of the limit. (basis: Regulation 2-1-234.3, Regulation 2-1-307)"

The original Design Process Data Sheet developed by Alcorn - the manufacturer of the COBs, lists the hourly firing rate for the three COBs as 232 MMBTU/hr/COB (LHV). Typically the nominal nameplate design capacity for combustion equipment, such as the COBs, is conservatively low. However, the actual maximum capacity could be as high as +20% above the nominal capacity to account for engineering contingencies and to also ensure that the equipment can at least achieve/deliver at its nameplate capacity. This also explains why Regulation 2-1-234.3 allows the capacity of a source to be revised based on its actual operational data if it hasn't been physically modified.

Aside from the minor revisions made to the COBs discussed under footnote #3 (which are beyond the scope of this evaluation), and assuming none of the processes upstream/downstream of the COBs were de-bottlenecked in August 2008 when the supposed exceedance of the daily firing rate limit occurred at S-1509, it is it is safe to state that the COBs were not modified. Specifically, each of the three COBs has always had a maximum continuous steam production rate of 150,000 lbs/hour of 650 PSIG steam @ 750°F. Likewise, each of the three COBs has always had a peak steam production rate of 180,000 lbs/hr for a period of 1 hour in any 8-hour interval. The supposed exceedance of the S-1509's daily firing rate limit in August 2008 resulted in no changes to either its maximum continuous steam production rate and/or its peak steam production rate.

[78] The reference to Reg. 2-1-234.4 in the preamble to PC 18618 should be Reg. 2-1-234.3.

As allowed under the preamble to part 1 of permit condition 18618, the District will administratively amend the above permit condition to express the existing firing rate limit in Shell's Title V permit in terms of both the LHV and HHV of the fuels combusted in them. Amending permit condition 18618 in Shell's Title V permit as proposed will not result in any changes to the facility baseline profiles outlined in Tables II, III, IV, V, VI of permit condition 7618, nor would it result in any changes to the combined daily NOx (of 5,452 lbs/day) and SO2 (of 6,805 lbs/day) emissions from the three COBs outlined in parts 85 and 90 of permit condition 12271, respectively as discussed below.

Regulation 2-2-605.4:

Sources at the Shell operate under two separate emission bubbles called the "REFEMS" and "Clean Fuels Permit" bubbles. Emissions from sources operating under the "REFEMS" and "Clean Fuels Project (CFP)" bubbles are governed by permit conditions 7618 and 12271, respectively. Under Application 6904, the District adjusted the NOx emissions for sources operating under the above emission bubbles to reflect the NOx emission reductions required by Regulation 9, Rule 10 and issued Shell a Permit to Operate on January 2003. Specifically, the "Facility Baseline Profile – NOx Emissions (lbs/day)" under Table II in permit condition 7618 was reduced by 7,121 lbs/day, and the combined NOx emissions of 6,770 lbs/day from the three CO Boilers (S1507, 1509, and 1512) under part 85 of permit condition 12271 was reduced by 1,318 lbs/day to 5,452 lbs/day.

Under Application 18185, Shell voluntarily reduced the concentration of Total Reduced Sulfur (TRS) in fuels combusted at sources that were part of permit condition 12271 from 100 ppm to 70 ppm on an annual average basis. Doing so resulted in a 70 TPY reduction from CFP combustion sources. Rather than bank these emission reductions, Shell reclaimed the SO_2 offsets it provided to the District under the CFP by increasing the SO_2 emission limit for the CO boilers – combustion sources that were not part of the CFP. Specifically, the CFP SO_2 emissions cap of 209.7 TPY in part A of permit condition 12271 was reduced by 70 TPY to 139.7 TPY. In addition, part 90 of permit condition 12271 was amended from 6,422 lb/day/three CO boilers to 6,805 lb/day/three CO boilers[79], and part 91 of permit condition 12271 was amended from 2,141 lb/day/CO boiler to 2,262 lb/day/CO boiler[80].

Because the proposed amendments to permit condition 18618 will not result in any changes to the emission caps outlined in permit conditions 7618 and 12271, the NOx and SO2 offsets previously generated under Applications 6904 and 18185 will not be affected. However, it is Shell's responsibility to operate the COBs in a manner that ensures continued compliance with the emission limits outlined in the "REFEMS" and "Clean Fuels Permit" emissions bubbles. In light of the above, the proposed changes to part 1 of permit condition 18618 will not result in an emission increase per Regulation 2-2-605.4, which states:

"Fully Offset Source: For a source which has, contained in a permit condition, an emission cap or emission rate which has been fully offset by the facility (without using emission reductions from the Small Facility Banking Account), the baseline throughput and baseline emission rate shall be based on the levels allowed by the permit condition."

[79] (70 ton/yr x 2000 lb/ton) / (365 days/yr) = 383.56 lb/day;
6422 lb/day/three CO boilers + 383.56 lb/day ~ 6805 lb/day/three CO boilers

[80] (6805 lb/day/three CO boilers) / (3 CO boilers) ~ 2,262 lb/day/CO boiler

Since the proposed amendments to permit condition 18618 will not result in an increase in emissions at Shell, Air Toxics, BACT, Cumulative Increase, and Offsets are not triggered.

STATEMENT OF COMPLIANCE

The source-specific applicable requirements and the applicable limits and compliance monitoring requirements for the three COBs in Shell's Title V are summarized in Tables IV-BK and VII-BA, respectively. For the purposes of this evaluation (with respect to permit condition 18618) and in light of Shell's impending renewal of their Title V permit, the above tables will be modified in the revised/renewed permit as shown below:

Table IV - BK
Source-specific Applicable Requirements
S1507 - UTIL CO BOILER .1
S1509 - UTIL CO BOILER 2
S1512 - UTIL CO BOILER 3

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
BAAQMD Condition # 18618			
Part 1	Throughput limit (basis: Regulation 2-1-234.3)	N	
Part 2	Recordkeeping (basis: Regulation 2-1-234.3)	N	
Part 4	Fuel certification (basis: Regulation 2-6-409.2)	Y	
Part 9	Source Test for grain loading rate (basis: Regulation 2-6-409.2)	Y	

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Table VII – BA
Applicable Limits and Compliance Monitoring Requirements
S1507 – UTIL CO BOILER 1, S1509 – UTIL CO BOILER 2,
S1512 – UTIL CO BOILER 3

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
Through-put	BAAQMD Condition #18618, Part 1	N		Maximum Firing Rate: 5,568 MMBTU/day/COB (LHV) 2,032,320 MMBTU/yr/COB (LHV) 6,125 MMBTU/day/COB (HHV) 2,235,625 MMBTU/yr/COB (HHV)	BAAQMD Condition #18618, Part 2	P/A	Records

Because part 1 of permit condition 18618 is non-federally enforceable, the proposed changes to the above permit condition qualify as an administrative amendment to Shell's Title V permit per Regulation 2-6-201. In light of the above and under Application 19374 (NSR Application 19373's Title V counterpart), Shell's Title V permit will be administratively amended.

Per Section 2-1-311 of the District's rules and regulations, a permit application for a proposed new or modified source will be classified as ministerial and will accordingly be exempt from the CEQA requirement of Section 2-1-310 if the District's engineering evaluation and basis for approval of the permit application for the project is limited to the criteria set forth in Section 2-1-428 and to the procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook. The method for determining whether a given permit application will be classified as ministerial is set forth in Section 2-1-427.

Per Section 2-1-427, if the District determines that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook, the District's evaluation of the permit application is classified as ministerial and the engineering evaluation of the permit application by the District will be limited to the use of said specific procedures, fixed standards and objective measurements. For such projects, the District will merely apply the law to the facts as presented in the permit application, and the District's decision regarding whether to issue the permit will be based only on the criteria set forth in Section 2-1-428 and in the District's Permit Handbook and BACT/TBACT Workbook.

For this permit application, the District determined that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective

measurements set forth in the District's Permit Handbook Chapter 2.1 "Boilers, Steam Generators, and Process Heaters". Since the District classified this permit application as ministerial pursuant to Section 2-1-427, and as a result of its evaluation of the permit application, the District determined that all of the criteria for approval of ministerial permit applications pursuant to Section 2-1-428 were met, the issuance by the District of an Authority to Construct and Permit to Operate for the proposed project is a mandatory ministerial duty and is accordingly exempt from the CEQA requirement of Section 2-1-310.

In addition, since the proposed amendments (~ project) to permit condition 18618 will not result in a "net increase" in emissions at the refinery the project is exempt from CEQA per the following regulations:

Regulation 2-1-312.1 that states:

"Applications to modify permit conditions for existing or permitted sources or facilities that do not involve any increases in emissions or physical modifications."; and

Regulation 2-1-312.11.4 that states:

"Projects satisfying the "no net emission increase" provisions of District Regulation 2, Rule 2 for which there will be some increase in the emissions of any toxic air contaminant, but for which the District staff's health risk screening analysis shows that the project will not result in a cancer risk (as defined in Regulation 2-5-206) greater than 1.0 in a million (10-6) and will not result in a chronic hazard index (as defined in Regulation 2-5-208) greater than 0.20, and for which there will be no other significant environmental effect."; and

The "common sense" exemption outlined in CEQA Chapter 3, Article 5, Section 15061(b)(3).

Shell has submitted an Appendix H "Environmental Information Form" along with this application.

PSD is not applicable to this project because there are no emission increases.

PERMIT CONDITIONS

Part 1 of permit condition 18618 as it exists in Shell's Title V permit:

General Throughput Conditions and other miscellaneous monitoring requirements for Title V:

1. The following throughput limits are based upon District records at the time of MFR permit issuance. Exceedance of those limits for which Regulation 2-1-234.4 was the identified basis are not a violation of the permit if the operator can, within 60 days, provide documentation demonstrating the throughput limit should be higher, established in accordance with 2-1-234.3, and the excess throughput complies with the new limit. Exceedance of those limits which have other permit conditions or application information as the basis are a violation of Regulation 2-1-307 immediately upon exceedance of the limit. (basis: Regulation 2-1-234.3, Regulation 2-1-307)

S-#	Description	Daily Limit	Annual Limit
1507	UTIL CO Boiler 1	5568 MMBTU/day	365 x Daily Limit
1509	UTIL CO Boiler 2	5568 MMBTU/day	365 x Daily Limit
1512	UTIL CO Boiler 3	5568 MMBTU/day	365 x Daily Limit

Proposed amendments to part 1 of permit condition 18618:

General Throughput Conditions and other miscellaneous monitoring requirements for Title V:

1. The following throughput limits are based upon District records at the time of MFR permit issuance. Exceedance of those limits for which Regulation 2-1-234.4 3was the identified basis are not a violation of the permit if the operator can, within 60 days, provide documentation demonstrating the throughput limit should be higher, established in accordance with 2-1-234.3, and the excess throughput complies with the new limit. Exceedance of those limits which have other permit conditions or application information as the basis are a violation of Regulation 2-1-307 immediately upon exceedance of the limit. (basis: Regulation 2-1-234.3, Regulation 2-1-307)

S-#	**Description**	**Daily Limit**	**Annual Limit**
1507	UTIL CO Boiler 1	5,568 MMBTU/day (LHV) 6,125 MMBTU/day (HHV)	365 x Daily Limit
1509	UTIL CO Boiler 2	5,568 MMBTU/day (LHV) 6,125 MMBTU/day (HHV)	365 x Daily Limit
1512	UTIL CO Boiler 3	5,568 MMBTU/day (LHV) 6,125 MMBTU/day (HHV)	365 x Daily Limit

RECOMMENDATION

Modify part 1 of permit condition 18618 as proposed for the following equipment:

S-1507 EMSR1 – CO Boiler #1; 232 MMBTU/hr
S-1509 EMSR1 – CO Boiler #2; 232 MMBTU/hr
S-1512 EMSR1 – CO Boiler #3; 232 MMBTU/hr

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K. R. Bhagavan

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11
Application: 19465

Background

Shell Martinez Refinery (Shell) has submitted this application to obtain enforceable limits, in the form of a permit condition, for the following sources:

S-1490 DH F-43 GOHT Feed; 33 MMBTU/hr
S-1491 DH F-44 NHT Feed; 52 MMBTU/hr
S-1492 DH F-45 Primary Column Reboil; 104 MMBTU/hr
S-1493 DH F-46 Stabilizer Reboil; 55 MMBTU/hr
S-1494 DH F-47 Secondary Column Reboil; 46 MMBTU/hr
S-1495 DH F-49 CRU Preheat; 190 MMBTU/hr
S-1496 DH F-50 CRU; 225 MMBTU/hr
S-1497 DH F-51 CRU; 106 MMBTU/hr
S-1498 DH F-52 CRU Reboil; 39 MMBTU/hr
S-1499 DH F-53 CRU Regen; 31 MMBTU/hr

The above sources were retrofitted with ultra low NOx burners (ULNB) under Applications # 5258 (for S-1490 through S-1493) in May 2002, #14651 (for S-1494) in February 1995, and #13078 (for S-1495 through S-1499) in July 2005 to enhance compliance with Regulation 9 "Inorganic Gaseous Pollutants", Rule 10 "Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators and Process Heaters in Petroleum Refineries".

On March 21, 2001, Shell entered into a voluntary settlement with the U.S. Environmental Protection Agency (EPA) to resolve several environmental issues at refineries it owns and operates within the U.S. The refinery in Martinez, CA is one such refinery. A Consent Decree (CD) was lodged with the EPA that includes the requirement that Shell will complete a program to reduce overall NOx emissions from heaters and boilers at the select few refineries that are part of the CD. To obtain credit for projects conducted at the select few refineries that are part of the CD and which result in NOx reductions, Shell is required by the CD to apply for and receive enforceable permit limits from the local permitting authority based on the following CD excerpt:

The allowable emissions from any heater or boiler is defined in the CD as "($E_{allowable}$) = The requested portion of the permitted allowable pounds of NOx per million BTU for heater or boiler i /(2000 pounds per ton) x [(the lower of permitted or maximum heat input rate capacity in million BTU per hour for heater or boiler i) x (the lower of 8760 or permitted hours per year)."

As it currently exists, S-1486, S-1487, S-1488, S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, and S-1499 exhaust through Chimney #1 - a common exhaust stack, which is equipped with a NOx and O2 Continuous Emission Monitor (CEM). The use of one CEM to measure combined NOx emissions is allowed by the CD if all of the sources have been retrofitted with NOx controls. Sources S-1486, S-1487 and S-1488 have not been retrofitted with NOx controls. Therefore, the common Chimney #1 NOx CEM cannot be used to monitor compliance with the CD limits. In contrast, S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, and S-1499 have been retrofitted with NOx controls and exhaust into the west breeching of Chimney #1. The west breeching of Chimney #1 was recently equipped with NOx and O2 CEMS to measure the combined NOx emissions from the above sources to meet the CD monitoring requirements.

Shell has requested that the permitted allowable emission rate for S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, and S-1499 be limited to 0.033 lbs NOx/MMBTU. In light of the above, the combined lower of their permitted or maximum heat input rate capacity for the above sources is 881 MMBTU/hr. Therefore the $E_{allowable}$ for the above sources will be 127.34 TPY[81]. The allowable emissions derived above is inclusive of emissions associated with startups, shutdowns, upsets and malfunctions for the above sources, because the CD does not explicitly state that such emission types must be excluded when estimating the allowable emissions.

The District is the local permitting authority for the Martinez refinery. The NOx emission reductions from retrofitting the above heaters are also being used in part to meet the NOx reduction requirements from heaters and boilers in Shell's NOx Control Plan for Heaters and Boilers. Shell will demonstrate compliance with the allowable emissions derived in the preceding paragraph for S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, and S-1499 by continually monitoring the NOx emissions via the NOx CEM in the west breeching of Chimney #1 and fuel usage rates via fuel flow meters.

In addition to obtaining an enforceable limit via a permit condition for the ten heaters discussed in the preceding paragraphs, Shell has also requested the District to administratively amend permit condition #17532 (for S-1514) and #22119 (for S-1760) that govern the operation of the following sources:

S-1514 UTIL F-70 Boiler 4; 409 MMBTU/hr
S-1760 OPCEN F-102 FXU Steam Superheater; 139 MMBTU/hr

In 2003, Shell applied for and received an enforceable permit limit of 0.05 lb NOx/MMBTU (HHV) outlined in permit condition 17532 for S-1514 under Application 7694. Likewise in 2005, Shell applied for and received an enforceable permit limit of 0.05 lb NOx/MMBTU (HHV) outlined in permit condition 22119 for S-1760 under Application 11157.

Following are the textual descriptions of the above permit conditions as they currently exist in Shell's Title V permit:

Condition # 17532

1. Only gaseous fuel shall be burned in S-1514. (Basis: Reg. 1-520.1)
2. Startup Condition Deleted.
3. The owner/operator shall operate S1514 to not exceed 0.05 lb NOx/MMBTU (HHV) based on a rolling hourly 8760-hour average heat input. The annual average heat input rate used to calculate the allowable (potential to emit) NOx emissions shall be the source's maximum permitted daily heat input rate of 9816 MMBTU (HHV)/day expressed on a 24-hour basis as 409 MMBTU (HHV)/hr.
   [basis: Shell-EPA Consent Decree]

Condition # 22119

1. Only gaseous fuel shall be burned in S-1760.
   [Basis: Reg. 1-520.1]

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[81] (0.033 lbs NOx/MMBTU) x (ton/2000 lbs) x (881MMBTU/hr) x (8,760 hr/yr) = 127.34 TPY

2. The owner/operator shall operate S1760 to not exceed 0.05 lb NOx/MMBTU (HHV) based on a rolling hourly 8760-hour average heat input. The annual average heat input rate used to calculate the allowable (potential to emit) NOx emissions shall be the source's maximum permitted daily heat input rate of 3336 MMBTU (HHV)/day expressed on a 24-hour basis as 139 MMBTU (HHV)/hr.
[Basis: Shell-EPA Consent Decree]

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In order to provide additional NOx reductions towards their CD commitment, Shell has requested that the existing permit limit of 0.05 lb/MMBTU (HHV) for S-1514 and S-1760 be reduced by 10% and 34%, respectively. Specifically, the existing permit limit for S-1514 will be reduced from 0.05 lb/MMBTU (HHV) to 0.045 lb/MMBTU (HHV), and the existing permit limit for S-1760 will be reduced from 0.05 lb/MMBTU (HHV) to 0.033 lb/MMBTU (HHV).

As it currently exists, part 2 of permit conditions #17532 and #22119 require a calculation of annual potential to emit based on a maximum average heat input. This potential to emit is used to calculate a maximum allowable annual NOx limit. Henceforth, rather than express this limit in the form of a calculation the above permit conditions will be amended to express them as the maximum allowable annual NOx limit instead.

As an example, consider S-1514. The proposed permitted allowable emission rate for the above source is 0.045 lbs NOx/MMBTU, and the lower of its permitted or maximum heat input rate capacity is 409 MMBTU/hr. Therefore, $E_{allowable}$ for S-1514 is 80.61 TPY[82]. In similar fashion, the $E_{allowable}$ for S-1760 is 20.09 TPY. The allowable emissions derived above is inclusive of emissions associated with startups, shutdowns, upsets and malfunctions for sources S-1514 and S-1760, because the CD does not explicitly state that such emission types must be excluded when estimating the allowable emissions.

Following are the revised textual descriptions of the permit conditions #17532 and #22119:

Condition # 17532

1. Only gaseous fuel shall be burned in S-1514. (Basis: Reg. 1-520.1)
2. Startup Condition Deleted.
3. The owner/operator shall operate S1514 to not exceed 0.045 lb NOx/MMBTU (HHV) based on a rolling hourly 8760-hour average heat input. Compliance with the NOx emission rate (in lb NOx/MMBTU) shall be determined using data gathered by NOx CEMS and fuel flow meters.
   (Basis: Shell-EPA Consent Decree)
4. The owner/operator shall ensure that the allowable NOx emissions from S1514 do not exceed 80.61 tons per year. The allowable NOx emissions shall include emissions associated with startups, shutdowns, upsets and malfunctions.
   (Basis: Shell-EPA Consent Decree)

Condition # 22119

1. Only gaseous fuel shall be burned in S-1760.
   [Basis: Reg. 1-520.1]
2. The owner/operator shall operate S1760 to not exceed 0.033 lb NOx/MMBTU (HHV) based on a rolling hourly 8760-hour average heat input. Compliance with the NOx

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[82] (0.045 lbs NOx/MMBTU) x (ton/2000 lbs) x (409 MMBTU/hr) x (8,760 hr/yr) = 80.61 TPY

emission rate (in lb NOx/MMBTU) shall be determined using data gathered by NOx CEMS and fuel flow meters. [Basis: Shell-EPA Consent Decree]

3. The owner/operator shall ensure that the allowable NOx emissions from S1760 do not exceed 20.09 tons per year. The allowable NOx emissions shall include emissions associated with startups, shutdowns, upsets and malfunctions.
[Basis: Shell-EPA Consent Decree]

On December 1, 2003, the District issued Shell a Title V operating permit i.e. initial permit. The proposed changes to Shell's Title V permit stemming from incorporating the new permit condition required by the CD for S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, and S-1499 and the amendments to permit conditions #17532 and #22119 qualifies as a minor permit revision i.e. a revision to an existing Title V permit that is neither an administrative amendment as defined in Section 2-6-201, nor a significant permit revision as defined in Section 2-6-226. Minor revisions to an existing Title V permit are subject to a 45-day US EPA review, but are not subject to a public notice. The initial permit is in the process of being renewed. The new permit condition for the ten heaters and the proposed amendments to permit conditions #17532 and #22119 will be incorporated into the renewed permit before it is issued.

Emissions Summary

The issuance of an enforceable limit in the form of a new permit condition for S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, and S-1499 as required by the CD, and the proposed amendments to permit conditions #17532 and #22119 will not increase or change emissions at the refinery.

Statement Of Compliance

Sources S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, and S-1499, S-1514 and S-1760 were retrofitted with Ultra Low NOx Burners to enhance Shell's compliance with Regulation 9, Rule 10. In addition, emissions from the above sources will be continuously monitored with NOx and O_2 CEMS. Therefore, the above sources are expected to comply with the above rule.

The project is categorically exempt from the District's CEQA regulation, per Section 2-1-312.11.1 because the issuance of an enforceable limit to S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, and S-1499 in the form of a new permit condition as required by the CD will not result in an emissions increase. In addition, the proposed reductions to the emissions limits for S-1514 and S-1760 will also not result in an emissions increase. Shell has submitted Appendix H "Environmental Information Form".

The project is over 1,000 feet from the nearest school and is therefore not subject to the public notification requirements of Reg. 2-1-412.

BACT, PSD, NSPS, and NESHAPS are not triggered.

Offsets are not required.

Permit Condition:

(PC 24263)

For S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, and S-1499:

1. Only gaseous fuel shall be burned in S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, and S-1499. [Basis: Regulation 2-1-301]
2. The owner/operator shall operate S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, and S-1499 to not exceed 0.033 lb NOx/MMBTU (HHV) based on a rolling hourly 8,760-hour average heat input.
   [Basis: Shell-EPA Consent Decree]
3. The owner/operator shall ensure that the allowable NOx emissions from S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, and S-1499 do not exceed 127.34 tons per year. The allowable NOx emissions shall include emissions associated with startups, shutdowns, upsets and malfunctions.
   [Basis: Shell-EPA Consent Decree]

Recommendation:

Issue Shell an enforceable limit in the form of a new permit condition #24263 for sources S-1490, S-1491, S-1492, S-1493, S-1494, S-1495, S-1496, S-1497, S-1498, and S-1499 as required by the CD. Amend permit conditions #17532 and #22119 as proposed. Incorporate the changes that are part of this application into Shell's Title V renewal permit.

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Evaluation Report
A/N 20070
G# 7114 (Plant 11, Source 1598)
Shell Refinery, Martinez

Background

Shell has applied for an A/C to replace the Phase II vapor recovery on the existing GDF at the Martinez refinery with an EVR certified Phase II system. No other work is proposed under this application.

Shell currently operates one 12K tank and 2 single product nozzles with EBW EVR 2-point Phase I and balance Phase II vapor recovery equipment. This project is limited to replacing the hanging hardware with VR-203 certified equivalents and installing the Veeder Root Vapor Polisher and other components of the VST EVR Phase II system without ISD.

Proposed Phase II equipment consists of the VST EVR Phase II system with the Veeder-Root Vapor Polisher pursuant to CARB Executive Order VR-203. ISD controls have not been proposed.

Emissions

No change in permitted throughput has been requested.

As the EVR Phase II equipment is certified to slightly more stringent standards than the existing balance Phase II vapor recovery equipment, there should be no increase in emissions per unit throughput.

The net emission increase under this A/N will be zero.

Statement of Compliance

As there will be no net emissions increase from this project, this application is not subject to the BACT and offset requirements of Regulation 2, Rule 2.

The proposed VST EVR Phase II equipment is certified under VR-203. Plans submitted with this application verify that the installation will satisfy the requirements of this Executive order:

- Each dispenser will each be equipped with VST-EVR-NB nozzles (one per side) and VST hoses.
- The site has a V-R TLS 350 console and will be equipped with the proper software and controls for operation of the VST EVR Phase II system with the V-R Vapor Polisher
- A Vapor Pressure Sensor will be installed in the dispenser nearest the tanks.
- This site is not equipped with vapor pots or condensate traps. This site has not modified their underground piping since April 1, 2003 and thus is not subject the piping size requirements of VR-203
- The outlet of the V-R Vapor Polisher will be 12’ above grade, and the vent pipes will be adequately supported

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Shell is currently conditions to 940,000 gal/yr under cond #14098. They have agreed to accept a condition limiting throughput to less than 600,000 gal/yr and are thus not subject to ISD requirements.

Use of CARB certified equipment satisfies all requirements of District Regulation 8, Rule 7.

Permit Conditions

Authority to Construct Conditions:

COND# 24297 --

1. The VST EVR Phase II Vapor Recovery System with the Veeder-Root Vapor Polisher, including all associated underground plumbing, shall be installed, operated, and maintained in accordance with the most recent revision of the California Air Resources Board (CARB) Executive Order (E.O.). VR-203. Section 41954(f) of the California Health and Safety Code prohibits the sale, offering for sale, or installation of any vapor control system unless the system has been certified by the state board.

2. Only CARB-certified EVR Phase I vapor recovery systems shall be used in conjunction with the VST EVR Phase II Vapor Recovery System.

3. The owner/operator of the facility shall maintain records in accordance with the following requirements. Records shall be maintained on site and made available for inspection for a period of 24 months from the date the record is made.
   a. Monthly throughput of gasoline pumped, summarized on an annual basis
   b. A record of all testing and maintenance as required by E.O. VR-203, Exhibit 2. The records shall include the maintenance or test date, repair date to correct test failure, maintenance or test performed, affiliation, telephone number, name and Certified Technician Identification Number of individual conducting maintenance or test.

4. All applicable components shall be maintained to be leak free and vapor tight. Leak Free, as per BAAQMD (District) Regulation 8-7-203, is a liquid leak of no greater than three drops per minute. Vapor Tight is as defined in District Manual of Procedures, Volume IV, ST-30.

5. Start-up notification: applicant must contact the

assigned Permit Engineer, listed in the correspondence section of this letter, by phone, by fax [(415) 749-4949], or in writing at least three days before the initial operation of the equipment is to take place. Operation includes any start-up of the source for testing or other purposes. Operation of equipment without notification being submitted to the District, may result in enforcement action. Please do not send start-up notifications to the Air Pollution Control Officer.

6. The following performance tests shall be successfully conducted at least ten (10) days, but no more than thirty (30) days after start-up. For the purpose of compliance with this Condition, all tests shall be conducted after back-filling, paving, and installation of all required Phase I and Phase II components.
  a. Static Pressure Performance Test using CARB Test Procedure TP-201.3 (3/17/99) in accordance with E.O. VR-203, Ex. 4. If the tank size is 500 gallons or less, the test shall be performed on an empty tank.
  b. Dynamic Back Pressure Test using CARB Test Procedure TP-201.4 (7/3/02) in accordance with the condition listed in item 1 of the Vapor Collection Section of E.O. VR-203, Exhibit 2. The dynamic back pressure shall not exceed 0.35" WC @ 60 CFH and 0.62" WC @ 80 CFH.
  c. Liquid Removal Test using E.O. VR-203, Exhibit 5.
  d. Vapor Pressure Sensor Verification Test using E.O. VR-203, Exhibit 8
  e. Nozzle Bag Test on all nozzles in accordance with E.O. VR-203, Exhibit 10.
  f. Veeder-Root Vapor Polisher Operability Test in accordance with E.O. VR-204, Exhibit 11.
  g. Veeder-Root Vapor Polisher Emissions Test in accordance with E.O. VR-204, Exhibit 12.

7. The VST EVR Phase II system with the Veeder-Root Vapor Polisher shall be capable of demonstrating on-going compliance with the vapor integrity requirements of CARB Executive Order E.O. VR-203. The owner or operator shall conduct and pass the following tests at least once in each consecutive 12-month period following successful completion of start-up testing. Tests shall be conducted and evaluated using the above referenced test methods and standards.
  a. Static Pressure Performance Test - TP-201.3
  b. Dynamic Back Pressure Test - TP-201.4
  c. Liquid Removal Test - E.O. VR-203, Exhibit 5

d. Vapor Pressure Sensor Verification Test - E.O. VR-203, Exhibit 8
e. Veeder-Root Vapor Polisher Operability Test in accordance with E.O. VR-204, Exhibit 11.
f. Veeder-Root Vapor Polisher Emissions Test in accordance with E.O. VR-204, Exhibit 12.

8. The applicant shall notify Source Test by email at gdfnotice@baaqmd.gov or by FAX at (510) 758-3087, at least 48 hours prior to any testing required for permitting. Test results for all performance tests shall be submitted in a District-approved format within thirty days of testing. Start-up tests results submitted to the District must include the application number and the GDF number. (For annual test results submitted to the District, enter "Annual" in lieu of the application number.) Test results may be submitted by email (gdfresults@baaqmd.gov), FAX (510) 758-3087) or mail (BAAQMD Source Test Section, Attention Hiroshi Doi, 939 Ellis Street, San Francisco CA 94109).

9. The maximum length of the coaxial hose assembly, including breakaway, swivels, and whip hoses, shall be fifteen (15) feet..

10. The dispensing rate shall not exceed ten (10.0) gallons per minute (gpm), nor be less than six (6.0) gpm with the trigger at the highest setting. Compliance with this condition shall be verified using the applicable provisions of E.O. VR-203, Ex. 5. Flow limiters may not be used.

11. A Vapor Pressure Sensor shall be installed in the dispenser closest to the underground tanks.

12. The TLS console controlling the Veeder-Root Vapor Polisher shall be equipped with a printer and have an open RS232 port that is accessible to District staff during operating hours.

13. Except when necessary for testing and maintenance, the Veeder-Root Vapor Polisher shall be on and in automatic vapor processor mode with the inlet valve in the open position per E.O. VR-203, Ex. 2. The handle shall not be removed for any reason.

14. The outlet of the Veeder-Root Vapor Polisher shall be at least 12 feet above grade.

15. The station shall maintain OSHA-approved access to the Veeder-Root Vapor Polisher. This access should be provided immediately upon request by District personnel

16. The VST EVR Phase II Vapor Recovery System shall be maintained and operated in accordance with E.O. VR-203 and the System Operating Manual approved by CARB.

17. Security tags shall be installed and maintained on the Veeder-Root Vapor Polisher. A Veeder-Root Vapor Polisher Operability Test and a Veeder-Root Vapor Polisher Emissions Test shall be performed after the replacement of any damaged or missing tags using the above referenced test methods and subject to the above notification and reporting requirements.

18. The headspace of all underground tanks connected to VST EVR Phase II Vapor Recovery System shall be connected by a manifold below grade at the tanks and/or a manifold between the vent lines.

19. For stations installed or performing a major modification of underground vapor piping after April 1, 2003, all vapor recovery piping shall be a minimum of 2" from the vent stack or dispensers to the first manifold and a minimum of 3" in diameter from the manifold to the underground tanks, with the headspace of all tanks connected by a below-grade manifold. The following piping shall slope down towards the lowest octane tank with a minimum slope of 1/8" per linear foot:

a) Any manifold piping connecting the storage tank headspaces.

b) All vapor recovery piping between the dispenser and storage tank.

c) Vent piping from the base of the vent pipe to the storage tank(s).

A major modification is considered a project that adds to, replaces, or removes more than 50% of the underground vapor piping.

20. Condensate traps or knock-out pots are prohibited.

21. Each storage tank vent pipe shall be equipped with a CARB certified pressure/vacuum relief valve as required by the applicable Phase I E.O.. Vents pipes may be manifolded

to reduce the number of relief valves needed. No relief valve shall be installed on the Veeder-Root Vapor Polisher outlet.

22. The Veeder-Root EVR system and TLS console may only be installed and serviced by contractors that have completed the Veeder-Root training program. Installation and start-up shall be in accordance with VR-203 and the Veeder Root installation manual.

Permit to Operate Conditions

COND# 7878 --------------------------------------

Pursuant to BAAQMD Toxic Section policy, this facility's annual throughput shall not exceed 600,000 gallons in any consecutive 12 month period.

COND# 21593 --------------------------------------

1. The EBW EVR Phase I Vapor Recovery System, including all associated plumbing and components, shall be operated and maintained in accordance with the most recent version of California Air Resources Board (CARB) Executive Order VR-104. Section 41954(f) of the California Health and Safety Code prohibits the sale, offering for sale, or installation of any vapor control system unless the system has been certified by the state board.

2. The owner or operator shall conduct and pass a Rotatable Adaptor Torque Test (CARB Test Procedure TP201.1B) and either a Drop Tube/Drain Valve Assembly Leak Test (TP201.1C) or, if operating drop tube overfill prevention devices ("flapper valves"), a Drop Tube Overfill Prevention Device and Spill Container Drain Valve Leak Test (TP201.1D) at least once in each 36-month period. Measured leak rates of each component shall not exceed the levels specified in VR-104.

The applicant shall notify Source Test by email at gdfnotice@baaqmd.gov or by FAX at (510) 758-3087, at least 48 hours prior to any testing required for permitting. Test results for all performance tests shall be submitted within fifteen (15) days of testing. Start-up tests results submitted to the District must include the application number and the GDF number. (For annual test results submitted to the District, enter "Annual" in lieu of the application number.) Test results may be submitted by email (gdfresults@baaqmd.gov), FAX (510) 758-3087) or mail (BAAQMD Source Test Section, Attention Hiroshi Doi, 939 Ellis Street, San Francisco CA 94109).

COND# 24298 --

1. The VST EVR Phase II Vapor Recovery System with the Veeder-Root Vapor Polisher without ISD, including all associated underground plumbing, shall be installed, operated, and maintained in accordance with the most recent revision of the California Air Resources Board (CARB) Executive Order (E.O.). VR-203. Section 41954(f) of the California Health and Safety Code prohibits the sale, offering for sale, or installation of any vapor control system unless the system has been certified by the state board.

2. The owner/operator of the facility shall maintain records in accordance with the following requirements. Records shall be maintained on site and made available for inspection for a period of 24 months from the date the record is made.
   a. Monthly throughput of gasoline pumped, summarized on an annual basis

3. All applicable components shall be maintained to be leak free and vapor tight. Leak Free, as per BAAQMD (District) Regulation 8-7-203, is a liquid leak of no greater than three drops per minute. Vapor Tight, as per District Regulation 8-7-206, is a leak of less than 100 percent of the lower explosive limit on a combustible gas detector measured at a distance of 1 inch from the source or absence of a leak as determined by the District Manual of Procedures, Volume IV, ST-30 or CARB Method TP-201.3.

4. The VST EVR Phase II system with the Veeder-Root Vapor Polisher without ISD shall be capable of demonstrating on-going compliance with the vapor integrity requirements of CARB Executive Order E.O. VR-203. The owner or operator shall conduct and pass the following tests at least once in each consecutive 12-month period following successful completion of start-up testing. Tests shall be conducted and evaluated using the below referenced test methods and standards.
   a. Static Pressure Performance Test - TP-201.3

b. Dynamic Back Pressure Test - TP-201.4 (7/3/02) in accordance with the condition listed in item 1 of the Vapor Collection Section of E.O. VR-203, Exhibit 2. The dynamic back pressure shall not exceed 0.35" WC @ 60 CFH and 0.62" WC @ 80 CFH

c. Liquid Removal Test - E.O. VR-203, Exhibit 5, Option 1 (Only test hoses containing more than 25 ml liquid)

d. Vapor Pressure Sensor Verification Test - E.O. VR-203, Exhibit 8,

e. Veeder-Root Vapor Polisher Operability Test. E.O. VR-203, Exhibit 11

f. Veeder-Root Vapor Polisher Emissions Test - E.O. VR-203, Exhibit 12

5. The applicant shall notify Source Test by email at gdfnotice@baaqmd.gov or by FAX at (510) 758-3087, at least 48 hours prior to any testing required for permitting. Test results for all performance tests shall be submitted in a District-approved format within thirty days of testing. Start-up tests results submitted to the District must include the application number and the GDF number. (For annual test results submitted to the District, enter "Annual" in lieu of the application number.) Test results may be submitted by email (gdfresults@baaqmd.gov), FAX (510) 758-3087) or mail (BAAQMD Source Test Section, 939 Ellis Street, San Francisco CA 94109).

6. The maximum length of the coaxial hose assembly, including breakaway, swivels, and whip hoses, shall be fifteen (15) feet..

7. The dispensing rate shall not exceed ten (10.0) gallons per minute (gpm), nor be less than six (6.0) gpm with the nozzle trigger at the highest setting. Compliance with this condition shall be verified using the applicable provisions of E.O. VR-203, Ex. 5. Flow limiters may not be used.

8. The TLS console controlling the Veeder-Root Vapor Polisher shall be equipped with a printer and have an open RS232 port that is accessible to District staff during operating hours.

9. Except when necessary for testing and maintenance, the Veeder-Root Vapor Polisher shall be on and in automatic vapor processor mode with the inlet valve in the open position per E.O. VR-203, Ex. 2. The handle shall not be

removed for any reason.

10. The station shall maintain OSHA-approved access to the Veeder-Root Vapor Polisher. This access should be provided immediately upon request by District personnel

11. Security tags shall be installed and maintained on the Veeder-Root Vapor Polisher. A Veeder-Root Vapor Polisher Operability Test and a Veeder-Root Vapor Polisher Emissions Test shall be performed after the replacement of any damaged or missing tags using the above referenced test methods and subject to the above notification and reporting requirements.

12. Each storage tank vent pipe shall be equipped with a CARB certified pressure/vacuum relief valve as required by the applicable Phase I E.O.. Vents pipes may be manifolded to reduce the number of relief valves needed. No relief valve shall be installed on the Veeder-Root Vapor Polisher outlet.

Title V Permit Revisions

This plant has a Title V permit. This project will require a minor revision of the Title V permit.

Proposed revisions to the Title V permit are attached.

Recommendation

All fees have been paid. Recommend that an A/C be issued for the above project.

By ______________________________ date ____________________

Scott Owen
Supervising AQ Engineer

Table IV – BO
Source-specific Applicable Requirements
S1598 – MAINT GASOLINE DISPENSING FACILITY

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
BAAQMD Regulation 8, Rule 7	**Organic Compounds - Gasoline Dispensing Facilities (11/6/02)**		
8-7-113	Tank Gauging and Inspection Exemption	Y	
8-7-301	Phase I Requirements	Y	
8-7-301.1	Requirement for CARB Phase I System	Y	
8-7-301.2	Installation of Phase I Equipment per CARB Requirements	Y	
8-7-301.3	Submerged Fill Pipes	Y	
8-7-301.5	Maintenance of Phase I Equipment per Manufacturers Guidelines or CARB Executive Order	Y	
8-7-301.6	Leak-Free, Vapor-Tight	Y	
8-7-301.7	Poppetted Drybreaks	Y	
8-7-301.8	No Coaxial Phase 1 Systems on New and Modified Tanks	Y	
8-7-301.9	CARB-Certified Anti-Rotational Coupler or Swivel Adapter	Y	
8-7-301.10	System Vapor Recovery Rate	Y	
8-7-301.11	CARB-Certified Spill Box	Y	
8-7-301.12	Drain Valve Permanently Plugged	Y	
8-7-301.13	Vapor Tightness and Testing	Y	
8-7-302	Phase II Requirements	Y	
8-7-302.1	Requirement for CARB Certified Phase II System	Y	
8-7-302.2	Maintenance of Phase II System per CARB Requirements	Y	
8-7-302.3	Maintenance of All Equipment as Specified by Manufacturer	Y	
8-7-302.4	Repair of Defective Parts Within 7 Days	Y	
8-7-302.5	Leak-Free, Vapor-Tight	Y	
8-7-302.6	Insertion Interlocks	Y	
8-7-302.7	Built-In Vapor Check Valve	Y	
8-7-302.8	Minimum Liquid Removal Rate	Y	
8-7-302.9	Coaxial Hose	Y	
8-7-302.10	Galvanized Piping or Flexible Tubing	Y	
8-7-302.12	Liquid Retainment Limit	Y	
8-7-302.13	Spitting Limit	Y	
8-7-302.14	Back Pressure for Vapor Balance		
8-7-303	Topping Off	Y	
8-7-304	Certification Requirements	Y	
8-7-306	Prohibition of Use	Y	
8-7-307	Posting of Operating Instructions	Y	

Table IV – BO
Source-specific Applicable Requirements
S1598 – MAINT GASOLINE DISPENSING FACILITY

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
8-7-308	Operating Practices	Y	
8-7-309	Contingent Vapor Recovery Requirements	Y	
8-7-313	Requirements for New or Modified Phase II Installations	Y	
8-7-315	Pressure Vacuum Valve Requirement, Underground Storage Tank	Y	
8-7-401	Permit Requirements, New and Modified Installations	Y	
8-7-406	Testing Requirements, New and Modified Installations	Y	
8-7-407	Periodic Testing	Y	
8-7-408	Test Notification	Y	
8-7-501	Burden of Proof	Y	
8-7-502	Right of Access	Y	
8-7-503	Record Keeping Requirements	Y	
8-7-503.1	Gasoline Dispensed Records	Y	
8-7-503.2	Dispensing Facility Maintenance Records	Y	
8-7-503.3	Dispensing Records Retention	Y	
BAAQMD Condition # 7878			
Part 1	Annual gasoline throughput limit [basis: Cumulative Increase, Toxics]	N	
Part 2	Recordkeeping [basis: Toxics, Cumulative Increase, Toxics]	N	

Table VII – BD
Applicable Limits and Compliance Monitoring Requirements
S1598 – MAINT GASOLINE DISPENSING FACILITY

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
HAP	BAAQMD Condition # 7878, Part 1	N		Annual gasoline throughput shall not exceed 600,000 gallons in any 12-month period	BAAQMD Condition #7878,	P/M	Records
POC	8-7-301.6	Y		All Phase I vapor recovery equipment, except for components with an allowable leak rate, shall be maintained to be leak-free, vapor tight	8-7-301.13 8-7-602	P/A	Tightness Test

Table VII – BD
Applicable Limits and Compliance Monitoring Requirements
S1598 – MAINT GASOLINE DISPENSING FACILITY

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
POC	8-7-302.5	Y		All Phase II vapor recovery equipment, except for components with an allowable leak rate, shall be maintained to be leak-free, vapor tight	8-7-301.13 8-7-602	P/A	Tightness Test
POC	Cond #24298 pt. 4	Y		Back Pressure for Vapor Balance, per Executive Order VR-203 shall not exceed 0.35" WC @ 60 CFH and 0.62" WC @ 80 CFH measured using CARB TP201.4 (7/3/02)	8-7-302.14 8-7-601	P/A	Back-pressure Test
POC	Cond #24298 pt. 4	Y		Liquid Removal Test per CARB E.O. VR-203, Exhibit 5, Option 1	CARB E.O VR-203	P/A	Liquid Removal Test
POC	Cond #24298 pt. 4	Y		Vapor Pressure Sensor Verification Test per E.O. VR-203, Exhibit 8,	CARB E.O VR-203	P/A	Vapor Pressure Sensor Verification
POC	Cond #24298 pt. 4	Y		Veeder-Root Vapor Polisher Operability Test. E.O. VR-203, Exhibit 11	CARB E.O VR-203	P/A	Vapor Pressure Operability Test
POC	Cond #24298 pt. 4	Y		Veeder-Root Vapor Polisher Emissions Test - E.O. VR-203, Exhibit 12	CARB E.O VR-203	P/A	Vapor Polisher Emissions Test

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11

Application: 20868

Background

Shell Oil Products US – Martinez Refinery (Shell) has submitted this application to obtain a Permit to Operate (PO) to replace two Stratco® Contactor Reactors (Reactors) at the following source:

S-1430 CP Alkylation Plant (ALKY)
14,000 bbl/day alkylate produced

The ALKY unit is made up of four simultaneously operating Reactors (Reactor #'s 1 through 4), dedicated acid settlers for each of the four Reactors, 2 columns, 3 chillers, 2 coalescers, heat exchangers, pumps, piping, various vessels, and related refinery equipment. Shell has proposed to replace Reactors #2 and #3 under this application, which is similar to the Reactors #1 and #4 replacement projects that were reviewed by the District under Application 7770 in 2003 (for Reactor #1) and Application 16726 in 2008 (for Reactor #4), respectively. As was the case with the predecessors to Reactors #1 and #4, the existing Reactors #2 and #3 have reached the end of their useful life and need to be replaced. In comparison to the reactors they will replace, the new Reactors #2 and #3 will have a different metallurgy, larger capacity (13,000 gallons versus 11,000 gallons), and a smaller tube diameter (3/4" versus 1") for increased surface area.

The alkylation reaction combines isobutane with light olefins in the presence of a strong acid catalyst within the Reactor to form a low vapor pressure, high octane-blending component (alkylate). Each one of Shell's four Reactors is a horizontal pressure vessel containing an inner circulation tube, a tube bundle to remove the heat of the reaction, and a mixing impeller. The hydrocarbon feed and sulfuric acid enter the Reactor via separate nozzles on the suction side of the impeller inside the circulation tube. As the feeds pass across the impeller, an emulsion of hydrocarbon and acid is formed. The emulsion in the Reactor is continuously circulated at very high rates around the tube bundle to convert the olefins to alkylate. A portion of the acid emulsion in the Reactor is withdrawn from the discharge side of the impeller and flows to an acid settler, where the hydrocarbon phase (reactor effluent) is separated from the acid emulsion. The acid, being the heavier of the two phases, settles to the lower portion of the settler vessel. The acid leaving the settler vessel is recycled back to the suction side of the impeller in the form of an emulsion, which is richer in acid than the emulsion entering the settler. When the acid loses its strength, the spent acid is shipped offsite to an acid reprocessing facility.

The purpose of the tube bundle is to remove the heat of reaction and minimize temperature differences between any two points in the reaction zone. This reduces the possibility of localized hot spots that could potentially cause side reactions which could degrade the alkylate product and increase the chances of corrosion within the Reactor vessel. The intense mixing in the Reactor also provides uniform distribution of the hydrocarbons in the acid emulsion, which prevents localized areas of non-optimum isobutane to olefin ratios and acid to olefin ratios, both of which promote olefin polymerization reactions. In the absence of the intense mixing in the Reactor described above, higher reaction temperatures would dramatically favor the side polymerization reactions which would dilute the acid and require more fresh acid to be added to get the same alkylate quality. Therefore, the better the mixing and greater the cooling surface area, the less catalyst (acid) is needed to get the best quality product.

Shell achieved all of the above benefits when it replaced Reactors #1 and #4. Specifically, after increasing the reactor volume and tube bundle surface area at a constant feed rate, the overall temperature within Reactors #1 and #4 was lowered, acid consumption was reduced, and alkylate quality was improved (higher octane). In other words, the overall lower temperature and fewer hot spots from the larger reactor volume combined with the increased tube bundle surface area caused less acid to be wasted on side reactions, and therefore decreased acid consumption.

Regulation 2-1-234.1 states the following:
"2-1-234 Modified Source: Any existing source that undergoes a physical change, change in method of operation, increase in throughput or production, or addition and that results or may result in any of the following:
234.1 An increase in either the daily or annual emission level of any regulated air pollutant, or an increase in the production rate or capacity that is used to estimate the emission level, that exceeds emission or production levels approved by the District in any authority to construct."

Part 1 of permit condition 18618 in Shell's Title V permit[83] limits alkylate produced at the ALKY unit to 14,000 bbl/day. Shell's proposal to replace Reactors #2 and #3 under this application will not result in an increase in alkylate production beyond the above limit, nor would it de-bottleneck any units upstream/downstream of the ALKY. Therefore, per Regulation 2-1-234.1 the ALKY unit is not considered a modified source.

Based on information contained in Shell's Flare Minimization Plan (FMP) which was approved by the District in July 2007 and subsequent annual FMP updates, the ALKY unit is serviced by the LOP Flare (S-1471). It is highly unlikely that the proposed replacement of Reactors #2 and #3 at S-1430 would result in flaring beyond existing levels at S-1471.

There will be a small increase in emissions from fugitive components. This increase will be considered to be an exempt modification in accordance with the exemption in BAAQMD Regulation 2-1-128.21.

Emissions Calculations

Process units such as the ALKY are closed processes, implying that the only sources of emissions from such units are from fugitive leaks. No pumps, compressors, or pressure relief valves will be replaced as a result of the proposed project. Valves and flanges will be replaced as needed. An increase in the number of valves and flanges at Reactors #2 and #3 is not anticipated to increase. However, it is conservatively assumed that there would be an increase of up to 80 new valves and 80 new flanges in "light liquid" service. Table 1 summarizes leak rates for the above fugitive components, which are similar to those that were used by the District under Application 1821[84].

[83] All references to "Shell's Title V permit" in this evaluation refer to the Title V permit that was issued by the District to Shell on May 17, 2007.
[84] The District issued Shell an AC and PO for Application 1821 on January 2002 and August 2002, respectively.

Table 1

Note:

Type/service	Number of components[1]	Emission factor (Lb/hr/ component)	POC[85], lb/hr	POC, lb/day	POC, lb/yr	POC, TPY
Valves/Gas/Light Liquid	80	0.00016[2]	0.0128	0.3072	112.128	0.056
Flanges/All[3]	80	0.00026[2]	0.0208	0.4992	182.208	0.091
Totals	**160**		**0.0336**	**0.8064**	**294.336**	**0.147**

11) Component counts estimated by Shell.

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12) Correlation equations used to derive the emission factors discussed below were excerpted from Table IV-3a (page 20) of the "California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities", February 1999. The following correlation equation "2.27E-6*(SV)^0.747" was used in concert with a Screening Value (SV) of 100 ppmv to derive the emission factor for valves as shown below:
    = 2.27E-6*(100)^0.747
    = (7.1E-5 kg/hr/source) x (2.205 lb/kg)
    = 1.6E-4 lb/hr/valve
    The following correlation equation "4.53E-6*(SV)^0.706" was used in concert with a Screening Value (SV) of 100 ppmv to derive the emission factor for flanges as shown below:
    = 4.53E-6*(100)^0.706
    = (1.2E-4 kg/hr/source) x (2.205 lb/kg)
    = 2.6E-4 lb/hr/flange
    Please note that the SV of 100 ppmv used in the above equations is based on the maximum leak rate allowed by Regulation 8 "Organic Compounds", Rule 18 "Equipment Leaks".
    Though a flanged valve requires at least two flanges i.e. valves leak at a higher rate than flanges, it can be seen from the leak rates outlined in Table 1 that the leak rates for flanges is greater than those for flanged valves. In contrast, socket-welded valves don't require flanges. For the purposes of this evaluation it is assumed that the 80 new valves that will consist of 40 flanged valves and 40 socket-welded valves.
13) Flange counts include connectors.

It can be seen from Table 1 above that the proposed modifications/alterations to process units that are part of this application would result in an increase of less than a pound (0.8064 lbs/day) of fugitive POC emissions per day.

[85] POC – Precursor Organic Compounds

Toxic Risk Screen Analysis

Toxic Air Contaminant (TAC) emissions from fugitive components summarized in Table 2 below were estimated using organic gas speciation profiles listed under Profile ID 316 "Refinery – pipes, valves & flanges – composite" in CARB's spreadsheet entitled "ORGPROF.xls" for those compounds for which the District has established TAC Trigger Levels (TTLs) in Table 2-5-1 in Regulation 2, Rule 5 "New Source Review of Toxic Air Contaminants". A copy of the above spreadsheet can be found from the following URL: http://www.arb.ca.gov/ei/speciate/dnldopt.htm#specprof

Table 2

TAC	Organic Fraction	TAC Emissions			
		Lbs/hr	Lbs/day	Lbs/yr	TPY
Propylene	0.001	0.000034	0.00082	0.30	0.0002
n-hexane	0.034	0.0011	0.0264	9.636	0.005
Isomers of xylene	0.002	0.000067	0.002	0.73	0.0004
Benzene	0.001	0.000034	0.00082	0.30	0.0002
Toluene	0.005	0.0002	0.005	1.83	0.0009

Note:

For example, n-hexane emissions summarized in Table 2 above were estimated as follows: From Table 1, the daily POC emissions from the 160 new fugitive components is equal to 0.0336 lb/hr. The organic fraction of n-hexane in CARB's "ORGPROF.xls" spreadsheet is 0.034. Therefore, the hourly n-hexane emissions are equal to 0.0336 x 0.034 = 0.0011 lbs/hr, and the daily & annual n-hexane emissions are 0.0264 lbs/day (0.0011 x 24) & 9.636 lbs/yr (0.0264 x 365), respectively.

Table 3 below summarizes the Acute and Chronic TTL's for TAC's summarized in Table 2, and compares the emissions summarized in the above table to the TTL's outlined in Table 2-5-1 in Regulation 2, Rule 5 to verify if a Toxic Health Risk Screening Analysis (HRSA) is warranted.

Table 3

TAC	Acute TTL (lbs/hr)	Emissions (lbs/hr)	Exceeds Acute TTL?	Chronic TTL (lbs/yr)	Emissions (lbs/yr)	Exceeds Chronic TTL?
Propylene	NA	0.000034	NA	125,000	0.30	No
n-hexane	NA	0.0011	NA	270,000	9.636	No
Isomers of xylene	49	0.000067	No	27,000	0.73	No
Benzene	2.9	0.000034	No	6.4	0.30	No
Toluene	82	0.0002	No	12,000	1.83	No

It can be seen from Table 3 above, that this application does not warrant a Toxic HRSA.

Regulation 2-1-128.21 Exemption

Regulation 2-1-128.21 states the following:

"2-1-128 Exemption, Miscellaneous Equipment: The following equipment is exempt from the requirements of Sections 2-1-301 and 302, provided that the source does not require permitting pursuant to Section 2-1-319. 128.21 Modification, replacement, or addition of fugitive components (e.g. valves, flanges, pumps, compressors, relief valves, process drains) at existing permitted process units at petroleum refineries, chemical plants, bulk terminals or bulk plants, provided that the cumulative emissions from all additional components installed at a given process unit during any consecutive twelve month period do not exceed 10 lb/day, and that the components meet applicable requirements of Regulation 8 rules."

It can be seen from emission calculations summarized in Table 1 above that the cumulative emissions from the 160 new fugitive components that will be installed at the ALKY unit as part of this application is below 10 lb/day i.e. 0.8064 lb/day. In addition, the new fugitive components, summarized in Table 1 will meet the requirements of Regulation 8 "Organic Compounds", Rule 18 "Equipment Leaks" and will be incorporated into Shell's Leak Detection and Repair (LDAR) program.

The proposed alteration to the ALKY unit that is part of this application also meets the requirements outlined in Regulation's 2-1-316 through 319 as follows:

- ***Regulation 2-1-316:***
  The hazardous air pollutant (HAP) emissions from fugitive components in Table 2 above will neither result in the emission of 2.5 TPY or more of a single HAP emissions, or 6.5 TPY or more of a combination of HAPs.
- ***Regulation 2-1-317:***
  The ALKY unit is not a source of public nuisance.
- ***Regulation 2-1-318:***
  It can be seen from Table's 2 and 3 above that the ALKY unit doesn't contain any of the compounds listed in Sections 318.1 through 318.8 of the above regulation.
- ***Regulation 2-1-319:***
  It can be seen from Table 1 above that the "post-control" POC emissions from the 160 new fugitive components is below 5 TPY (0.147 TPY), and all the requirements contained in Regulation 2-1-316 through 2-1-318 are satisfied.

For the purposes of Regulation's 2-1-316 through 319, the emissions from the changes in fugitive components have been considered to be the source, and not the entire process unit. The emissions from the fugitive components at the entire process unit have not been determined at this time.

Therefore, the District concludes that the additional fugitive components summarized in Table 1 above qualify for the exemption under Regulation 2-1-128.21.

BACT

Per Regulation 2, Rule 2, Section 301, BACT is only triggered if emissions from a new source or an increase in emissions from a modified source has the potential to emit 10 lbs or more per highest day of emissions. Replacement of Reactors #2 and #3 at the ALKY unit does not constitute a modification of the above process unit (please refer to the Reg. 2-1-234.1 discussion in the "Background" section), and the fugitive components summarized in

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Table 1 above are exempt per Regulation 2-1-128.21. Therefore, BACT is not triggered for the increase in emissions from fugitive components that are part of this application.

Again, this is because the "source" for the purposes of the 2-1-128.21 exemption is considered to be the changes in the components. If the process unit were considered to the "source," the process unit would have been subject to BACT because it likely emits more than 10 lb POC/day before the modification.

Cumulative Increase & Offsets

Shell is an existing facility. Since the increase in POC emissions stemming from the additional fugitive components summarized in Table 1 above are exempt under Regulation 2-1-128.21, the proposed project to replace ALKY Reactors #2 and #3 will not result in a cumulative increase in criteria pollutant emissions. Therefore, offsets are also not warranted.

Statement Of Compliance

The fugitive components summarized in Table 1 above will be subject to Sections 301, 302, 304, 306, and 307 in Regulation 8 "Organic Compounds", Rule 18 "Equipment Leaks". Sections 301, 302, and 304 require, among other things, that organic compound leaks, not exceed 100 ppm for general components, valves, and connections. Section 8-5-306 limits the percentages of non-repairable equipment allowed. Section 8-5-307 requires that leaking equipment not be used unless the leak discovered by the operator, is minimized within 24 hours and repaired within 7 days.

The four existing Reactors at the ALKY unit are not equipped with Atmospheric Pressure Relief Devices (APRDs), nor would the replacement of Reactors #2 and #3, which is the subject of this evaluation, result in the addition of any new APRDs. For the purposes of Regulation 8 "Organic Compounds", Rule 28 "Episodic Releases from Pressure Relief Devices at Petroleum Refineries and Chemical Plants", it should be noted that three columns downstream of the four Reactors are equipped with APRDs. Specifically, the Deisobutanizer (Column #: C-111; APRD #s: SVM-34 & SVM-37), the Depropanizer (Column #: C-112; APRD #: SVJ-143), and the C4/C5 Splitter (Column #: 129; APRD #: SVH-288). The replacement of Reactors #2 and #3 will not impact the relief scenarios at the above columns, because the flows to the columns will remain unchanged and there will be no increase in the amount of alkylate produced[86] at the ALKY unit. Please refer to a copy of a letter dated July 28, 2006 which is attached with this evaluation from Shell to Mr. Kelly Wee, Director of Compliance and Enforcement Division which summarizes information on PRDs at pressure related systems at process units & non-process units at the refinery for purposes of Regulation 8, Rule 28.

Regulation 11 "Hazardous Pollutants", Rule 7 "Benzene" limits the emission of benzene from sources (such as pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, flanges and other product accumulator vessels, and control devices) intended to operate in benzene service. Regulation 11-7-207 defines "In Benzene service" to be any equipment which either contains or contacts a fluid (liquid or gas) that is at least 10 percent benzene by weight. The proposed project will not involve process streams, which will either contain or contact a fluid that is at least 10 percent

[86] Part 1 of PC 18618 in Shell's Title V permit limits alkylate produced at S-1430 to 14,000 bbl/day.

benzene by weight. Therefore, Regulation 11, Rule 7 does not apply to the ALKY Reactors #2 and #3 replacement project

The increase in the number of fugitive components associated with Shell's "MTBE Removal Project", which was reviewed by the District under Application 1821[87], made the ALKY unit subject to the requirements of 40 CFR Part 60, Subpart GGG "Equipment Leaks of VOC in Petroleum Refineries" (NSPS GGG) on November 19, 2002. Though Table's IV-AL & AN in Shell's Title V permit don't explicitly list NSPS GGG as the applicable requirements for the ALKY unit, it is implied that the requirements of the above rule summarized in Table IV-DP apply to the above process unit at all times. In light of the above applicability determination, the two new Reactors and the 160 fugitive components summarized in Table 1 above are subject to and are expected to comply with the requirements of NSPS GGG.

Please note that Table IV-DP contains references to 40 CFR Part 60 Subpart VV "Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry" (NSPS VV) only because NSPS GGG references NSPS VV. The US EPA intent was to subject a facility (Shell in this case) to either NSPS GGG or NSPS VV and not both of the above rules. In other words, the NSPS GGG requirements applied to refinery process units, and chemicals plants were expected to comply with the requirements in NSPS VV[88].

As it currently exists in Shell's Title V permit (refer to Table's IV-AL & AN), the ALKY unit is not subject to any National Emissions Standards for Hazardous Air Pollutants (NESHAP) in 40 CFR Part 61, because the above rule regulates sources of specific pollutants. The proposed ALKY Reactor replacement will not result in emissions of any new pollutants that are subject to the NESHAPs. Therefore, the ALKY unit is not subject to 40 CFR Part 61.

Maximum Achievable Control Technology (MACT) standards in 40 CFR Part 63 is applicable to toxic air emissions emanating from specific source categories at facilities, which are major sources of HAPs. The MACT standards that potentially are applicable to the ALKY unit include 40 CFR Part 63, Subpart A "General Requirements", and 40 CFR Part 63, Subpart CC "National Emissions Standards for Hazardous Air Pollutants from Petroleum Refineries" (MACT CC). Though Table's IV-AL & AN in Shell's Title V permit don't explicitly list MACT CC as the applicable requirements for the ALKY unit, it is implied that the requirements of the above rule summarized in Table IV-DS apply to various refinery operations (such as the ALKY unit) including equipment leaks at all times. As previously discussed in the preceding paragraphs, though NSPS VV is not directly applicable to petroleum refineries in the Bay Area that don't produce MTBE, Table IV-DS contains references to sections from the above rule only because MACT CC references NSPS VV.

In light of the above, the fugitive components similar to those summarized in Table 1 above, which will be added to the ALKY unit, must comply with NSPS VV if they will be used in organic HAP (OHAP) service. "In organic hazardous air pollutant service" is defined in MACT CC as follows: *"means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP's as determined according to the provisions of § 63.180(d) of subpart H of this part and table*

[87] The District issued Shell an AC and PO under AN 1821 on January 16, 2002 and August 1, 2002, respectively.
[88] Refineries that produce MTBE are subject to NSPS VV. Because refineries in the Bay Area don't produce MTBE, NSPS VV is not directly applicable to Shell.

of this subpart. The provisions of § 63.180(d) of subpart H also specify how to determine that a piece of equipment is not in organic HAP service."

Of the TAC's summarized in Table's 2 & 3 above, benzene (0.1%), hexane (3.4%), toluene (0.5%), and the mixed isomers of xylene (0.2%) appear in Table 1 of MACT CC. Since the total percent by weight of the above OHAP's is below 5% i.e. 4.2%, the new fugitive components that will be added as part of the proposed ALKY Reactor replacement are not subject to MACT CC. However, the requirements of MACT CC in Table IV-DS would apply to the new fugitive components even if they contain/contact fluids containing less than 5% by wt. This is so because when MACT CC went into effect in 1998, Shell decided to eliminate the guesswork/un-certainty surrounding whether a certain OHAP stream(s) was subject to the MACT CC or not. Given that the District's Regulation 8, Rule 18 is at least as stringent if not more stringent than MACT CC, Shell decided to subject their process units and associated components to the MACT CC requirements at all times.

PSD is not applicable to this project because there is no cumulative increase in emissions at the plant, since the increase in emissions associated with the new fugitive components that will be added as part of the proposed ALKY Reactor replacement project are exempt from Regulation 2-1-301 per Regulation 2-1-128.21.

The California Environmental Quality Act (CEQA):

Per Section 2-1-311 of the District Rules and Regulations, a permit application for a proposed new or modified source will be classified as ministerial and will accordingly be exempt from the CEQA requirement of Section 2-1-310 if the District's engineering evaluation and basis for approval of the permit application for the project is limited to the criteria set forth in Section 2-1-428 and to the procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook. The method for determining whether a given permit application will be classified as ministerial is set forth in Section 2-1-427.

Per Section 2-1-427, if the District determines that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook, the District's evaluation of the permit application is classified as ministerial and the engineering evaluation of the permit application by the District will be limited to the use of said specific procedures, fixed standards and objective measurements. For such projects, the District will merely apply the law to the facts as presented in the permit application, and the District's decision regarding whether to issue the permit will be based only on the criteria set forth in Section 2-1-428 and in the District's Permit Handbook and BACT/TBACT Workbook.

For this permit application, the District determined that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook Chapter 3.4 "Petroleum Refinery Fugitive Emissions". Since the District classified this permit application as ministerial pursuant to Section 2-1-427, and as a result of its evaluation of the permit application, the District determined that all of the criteria for approval of ministerial permit applications pursuant to Section 2-1-428 were met, the issuance by the District of an Authority to Construct and Permit to Operate for the proposed project is a mandatory ministerial duty and is accordingly exempt from the CEQA requirement of Section 2-1-310.

In addition to the ministerial exemption determination above, the District has also determined that the CEQA categorical exemptions of Sections 2-1-312.7 and 2-1-312.11 of the District Rules and Regulations and the CEQA "Common Sense Exemption" apply.

CEQA Categorical Exemptions and CEQA "Common Sense Exemption":
Though the District concludes that the modifications/alterations that are part of this application are ministerial, it also concludes that, even if it were not ministerial, certain other exemptions from CEQA apply (see CEQA Guidelines § 15300.1). Section 2-1-312 of the District Rules and Regulations sets forth specific types of projects, which have been determined by the District to be categorically exempt from CEQA.

Per Section 2-1-312.7, permit applications for the replacement or reconstruction of existing sources or facilities, where the new source or facility will be located on the same site as the source or facility replaced and will have substantially the same purpose and capacity as the source or facility replaced, are exempt from the CEQA review.

Per Section 2-1-312.11, in addition to ministerial projects, permit applications for a new or modified source or sources or for process changes, which will satisfy the "No Net Emission Increase" provisions of District Regulation 2, Rule 2 and for which there is no possibility that the project may have any significant environmental effect in connection with any environmental media or resources other than air quality, are exempt from the CEQA review. The reason for this exemption should be apparent on its face: if a facility is given legal permission to emit more air pollutants from certain points while at the same time being disallowed permission for an equivalent amount of the same type of emissions from other points at the facility, then there is deemed to be no net effect on the air environment, and therefore no possibility of a significant effect under CEQA, provided no-air impacts are also examined and deemed to be of no possible significant consequence.

Also, per the CEQA Guidelines in Title 14, California Code of Regulations, Chapter 3, Article 5, Section 15061(b)(3), a project is exempt from CEQA if the activity is covered by the general rule that CEQA applies only to projects, which have the potential for causing a significant effect on the environment. This is commonly known as the "Common Sense Exemption". Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to CEQA. The "no net increase" exemption of 2-1-312.11 is essentially a specific, codified, instance of the Common Sense Exemption.

The new fugitive components that will be added as part of the proposed ALKY Reactor replacement project are exempt from Regulation 2-1-301 per Regulation 2-1-128.21. As a result, the 0.147 TPY increase in POC emissions summarized in Table 1 above will not be counted toward the cumulative increase in emissions at Shell. Therefore, the District determined that the project satisfies the "No Net Emission Increase" provisions of District Regulation 2, Rule 2. Shell has completed and submitted to the District CEQA Appendix H, Environmental Information Form, for the project.

The District has reviewed the CEQA Appendix H form. Shell did not provide a "Yes" response to any of the questions in the above form. Shell submitted the following additional information to enable the District to determine the project's possible significant effects:

16. *Please describe any new equipment, including pumps and piping that will be installed for this project. Will any new piping be installed aboveground? How often would any project-related aboveground piping and exposed buried piping be inspected for leaks and spills?*
Each new Alkylation reactor will replace an existing reactor of approximately the same size. The new reactors will have a different metallurgy, a slightly larger capacity (13,000 gallons versus the existing 11,000 gallons), and smaller tube diameter (3/4" versus the existing 1") for increased surface area. The new reactors will be built in the same location as the existing reactors, with substantially the same purpose and capacity. All piping will be above ground. Prior to usage, the piping will be inspected and pressure tested in order to verify adequate integrity of the system. The associated piping components will also be entered into the facility-wide leak detection and repair program and maintained per BAAQMD Regulation 8-18.

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17. *To determine potential impacts to groundwater and surface water quality, please respond to the following:*

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v. *Will this project result in an increase in the risk of a spill with potential for impacting surface water and groundwater? Please explain.*
There is minimal potential for the Alkylation Project to increase the risk of a spill that would impact surface water or groundwater due to Shell's program of operator training, prevention, mitigation and response. The system is designed to prevent leakage and spillage. Shell's response program is based on prevention of environmental impacts.

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w. *What spill prevention measures and monitoring are in place at Shell to limit the potential risk of a spill due to this project.*
Spills are prevented through the training, daily inspections and maintenance programs at Shell. Shell has an approved Spill Prevention, Control, and Countermeasure (SPCC) Plan and Storm Water Pollution Prevention Plan (SWPPP), which are available upon request.

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x. *To address runoff at the site, does Shell have a Storm Water Pollution Prevention Plan and Spill Prevention Control and Countermeasures Plan?*
Shell has an approved SWPPP and SPCC Plan, as required, which are available onsite for inspection during normal business. The SPCC plan will not be updated to account for the two new Alkylation reactors.

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y. *How frequently does Shell conduct groundwater monitoring and how often are the analytical results submitted to the Regional Water Quality Control Board?*
Shell performs quarterly groundwater monitoring as required by Waste Discharge Requirements (WDR) Order 95-234, issued by the San Francisco Bay Regional Water Quality Control Board (SFBRWQCB). Results are submitted to the SFBRWQCB twice a year. A recent copy is available upon request.

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Additionally, Shell is required to perform a capture zone analysis on the facility. The WDR order requires that an ongoing hydraulic groundwater capture program be installed, operated, and maintained. Groundwater extraction systems are installed at the perimeter of the facility and serve to capture the groundwater before it leaves the site. The Alkylation Reactors

No. 2 and 3 will be located in the East Valley groundwater basin. A copy of the most recent annual capture zone report is available upon request.

z. *What is direction of the groundwater flow beneath the Shell refinery site?*
Groundwater flows from South to North at a velocity of approximately four feet per year.

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18. *To determine potential impacts due to diesel-fueled trucks associated with the project, please respond to the following:*

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a. *How and from where will materials be delivered to the new reactor?*

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Materials are delivered to the Alkylation reactors via existing piping. No diesel-fueled trucks are used to deliver materials to the new reactors.

b. *If diesel-fueled trucks are used to deliver materials, what is the average storage capacity of a typical delivery truck, and how many delivery trucks will be making deliveries to the new reactor on any given day (worst case)?*

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Materials are delivered to the Alkylation reactors via existing piping. No diesel-fueled trucks are used to deliver materials to the new reactors.

c. *Would the installation of the new reactor result in an increase in existing diesel-fueled truck traffic to and from the truck loading racks?*
No, this project will not impact existing diesel-fueled truck traffic.

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d. *For construction, how many diesel-fueled trucks will be used for mobilization, construction, and demobilization of the project?*
Construction, mobilization, and demobilization of the project will require up to 7 total diesel-fueled truck round trips. The following diesel-fueled truck round trips are expected:

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i. **Delivery of the new reactors – 2 round trip**
ii. **Removing old reactors – 2 round trip**
iii. **Shipments of pipes and fittings – 1-2 round trips**
iv. **Shipments of structural materials – 1-2 round trips**
v. **Shipments of instruments – 1 round trip**

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e. *What is the likely route that the diesel-fueled trucks will take from the nearest freeway to the Shell gate?*
All trucks will exit 680 at Pacheco Boulevard and come to the receiving yard through the P3 gate.

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The District finds these assertions and arguments to be credible. Thus, the District concludes that the permit application is exempt from CEQA because it is ministerial, it is categorically exempt from CEQA, and the project qualifies for the "Common Sense Exemption" of Subsection (b)(3) of the State CEQA Guidelines.

Based on all of the information before the District and the District's review of the information submitted, the District has determined that there is no possibility that the project may have any significant environmental effect.

The District has considered whether the proposed ALKY Reactor replacement project is part of a larger project for CEQA purposes, and has concluded that it is not. On a general level, the stated purpose of the proposed ALKY Reactor replacement project is that the existing Reactors #2 and #3 have reached the end of their useful life and need to be replaced. This purpose does not imply any necessary relationship to other projects, in the sense of being prerequisite to other projects or a foreseeable consequence of them.

Permit Conditions

Part 1 of permit condition 18618 in Shell's Title V permit limits alkylate produced at the ALKY unit to 14,000 bbl/day. Shell's proposal to replace Reactors #2 and #3 under this application will not result in an increase in alkylates beyond the afore-referenced permitted limit. Therefore, no changes to permit condition 18618 are warranted at this time.

Recommendation

Waive the AC and issue Shell a PO to perform the following alterations:

- Replace two existing 11,000 gallon Reactors #2 and #3 with two new 13,000 gallon reactors.
- Install 80 new flanges and 80 new valves.

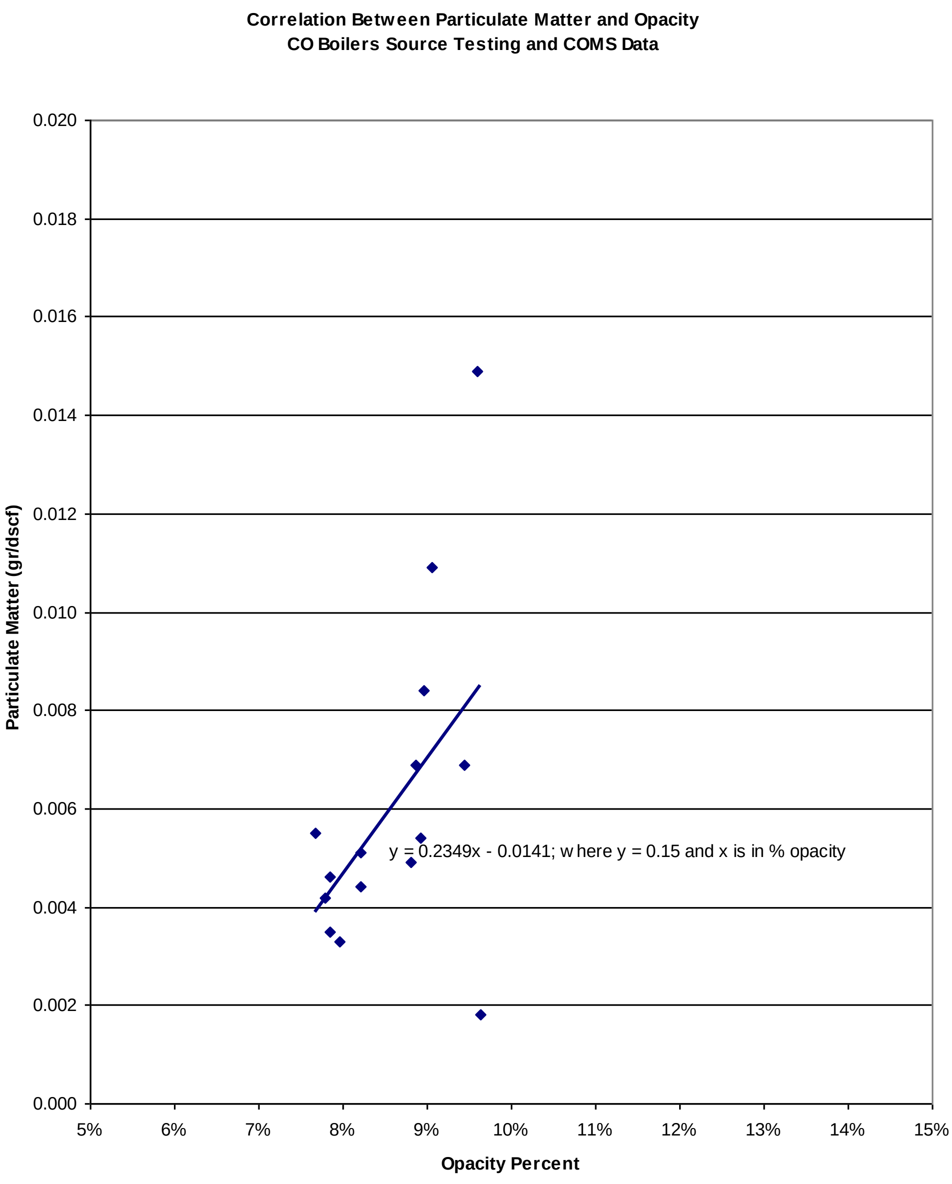
At the following source:

S-1430 CP Alkylation Plant (ALKY)
14,000 bbl/day alkylate produced

K. R. Bhagavan

APPENDIX C

CORRELATION BETWEEN PM AND OPACITY FOR CO BOILERS


Correlation Between Particulate Matter and Opacity
CO Boilers Source Testing and COMS Data
Particulate Matter (gr/dscf)
0.020
0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
5%
6%
7%
8%
9%
10%
11%
12%
13%
14%
15%
Opacity Percent
y = 0.2349x - 0.0141; w here y = 0.15 and x is in % opacity

APPENDIX D
CAM ANALYSIS

Source #	Source Description	Pollutant	Abated By	Abatement Description	Federally Enforceable Emissions Limit or Standard 40 CFR 64.2(a)(1)	Basis of Limit 40 CFR 64.2(a)(1)	Basis of Limit Proposed after Nov. 15 1990? (Y/N) Exemption 40 CFR 64.2(b)(1)(i)	Title V Permit Specifies a Continuous Compliance Determination Method? (Y/N) Exemption 40 CFR 64.2(b)(1)(vi)	Unit Uses a Control Device to Achieve Compliance with Limit? (Y/N) 40 CFR 64.2(a)(2)	Pre-Control PTE < MST? (Y/N) 40 CFR 64.2(a)(3)	Subject to CAM?	CAM Exemption	Comment
1426	CP Catalytic Cracking Unit (CCU)	FP	A12, A13, A14	ESP	0.15 grain per dscf	6-1-310	N	Y (COM)	Y	Not Necessary to Calculate	N	41 CFR 64.2(b)(1)(i)	Opacity is considered to be a surrogate for free particles.
1426	CP Catalytic Cracking Unit (CCU)	CO	S1507, S1509, S1512	CO boilers	CO emissions shall not exceed 500 ppmv	NSPS Subpart J 60.105(a)(2), 60.105(c)	N	Y CO CEMs	Y	Not Necessary to Calculate	N	41 CFR 64.2(b)(1)(vi)	Exempt
1426	CP Catalytic Cracking Unit (CCU)	CO			CO emissions shall not exceed 500 ppmv	NSPS Subpart J 60.103(a)	N	Y CO CEMs	Y	Not Necessary to Calculate	N	42 CFR 64.2(b)(1)(vi)	Exempt
1426	CP Catalytic Cracking Unit (CCU)	CO			CO emissions shall not exceed 500 ppmv	NSPS Subpart J 60.103(a)	N	Y CO CEMs	Y	Not Necessary to Calculate	N	43 CFR 64.2(b)(1)(vi)	Exempt
1431	CP Sulfur Plant 1 (SRU1)	S02	A52	SCOTNo. 1	250 ppmv SO2 dry, at 0% oxygen	9-1-307 and NSPS Subpart J 60.104 (a)(2)(i)	N	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Exempt
1431	CP Sulfur Plant 1 (SRU1)	S02	A52	SCOTNo. 1	250 ppmv SO2 dry, at 0% oxygen	MACT Subpart UUU 63.1568(a)(1)(i)	Y- proposed 9/11/1998	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
1431	CP Sulfur Plant 1 (SRU1)	S02	A1501	F-56 Backup Thermal Oxidizer for Sulfur Plants 1 and 2	250 ppmv SO2 dry, at 0% oxygen	9-1-307 and NSPS Subpart J 60.104 (a)(2)(i)	N	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Exempt
1431	CP Sulfur Plant 1 (SRU1)	S02	A1501	F-56 Backup Thermal Oxidizer for Sulfur Plants 1 and 2	250 ppmv SO2 dry, at 0% oxygen	MACT Subpart UUU 63.1568(a)(1)(i)	Y- proposed 9/11/1998	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt

Source #	Source Description	Pollutant	Abated By	Abatement Description	Federally Enforceable Emissions Limit or Standard 40 CFR 64.2(a)(1)	Basis of Limit 40 CFR 64.2(a)(1)	Basis of Limit Proposed after Nov. 15 1990? (Y/N) Exemption 40 CFR 64.2(b)(1)(i)	Title V Permit Specifies a Continuous Compliance Determination Method? (Y/N) Exemption 40 CFR 64.2(b)(1)(vi)	Unit Uses a Control Device to Achieve Compliance with Limit? (Y/N) 40 CFR 64.2(a)(2)	Pre-Control PTE < MST? (Y/N) 40 CFR 64.2(a)(3)	Subject to CAM?	CAM Exemption	Comment
1431	CP Sulfur Plant 1 (SRU1)	S02	A1517	F-77 Primary Thermal Oxidizer for Sulfur Plants 1 and 2	250 ppmv SO2 dry, at 0% oxygen	9-1-307 and NSPS Subpart J 60.104 (a)(2)(i)	N	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Exempt
1431	CP Sulfur Plant 1 (SRU1)	S02	A1517	F-77 Primary Thermal Oxidizer for Sulfur Plants 1 and 2	250 ppmv SO2 dry, at 0% oxygen	MACT Subpart UUU 63.1568(a)(1)(i)	Y- proposed 9/11/1998	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
1432	CP Sulfur Plant 2 (SRU2)	SO_2	A1431	SCOT No. 2	250 ppmv SO2 dry, at 0% oxygen	9-1-307 and NSPS Subpart J 60.104 (a)(2)(i)	N	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Exempt
1432	CP Sulfur Plant 2 (SRU2)	SO_2	A1431	SCOT No. 2	250 ppmv SO2 dry, at 0% oxygen	MACT Subpart UUU 63.1568(a)(1)(i)	Y- proposed 9/11/1998	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
1432	CP Sulfur Plant 2 (SRU2)	S02	A1501	F-56 Backup Thermal Oxidizer for Sulfur Plants 1 and 2	250 ppmv SO2 dry, at 0% oxygen	9-1-307 and NSPS Subpart J 60.104 (a)(2)(i)	N	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Exempt

Source #	Source Description	Pollutant	Abated By	Abatement Description	Federally Enforceable Emissions Limit or Standard 40 CFR 64.2(a)(1)	Basis of Limit 40 CFR 64.2(a)(1)	Basis of Limit Proposed after Nov. 15 1990? (Y/N) Exemption 40 CFR 64.2(b)(1)(i)	Title V Permit Specifies a Continuous Compliance Determination Method? (Y/N) Exemption 40 CFR 64.2(b)(1)(vi)	Unit Uses a Control Device to Achieve Compliance with Limit? (Y/N) 40 CFR 64.2(a)(2)	Pre-Control PTE < MST? (Y/N) 40 CFR 64.2(a)(3)	Subject to CAM?	CAM Exemption	Comment
1432	CP Sulfur Plant 2 (SRU2)	S02	A1501	F-56 Backup Thermal Oxidizer for Sulfur Plants 1 and 2	250 ppmv SO2 dry, at 0% oxygen	MACT Subpart UUU 63.1568(a)(1)(i)	Y- proposed 9/11/1998	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
1432	CP Sulfur Plant 2 (SRU2)	S02	A1517	F-77 Primary Thermal Oxidizer for Sulfur Plants 1 and 2	250 ppmv SO2 dry, at 0% oxygen	9-1-307 and NSPS Subpart J 60.104 (a)(2)(i)	N	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Exempt
1432	CP Sulfur Plant 2 (SRU2)	S02	A1517	F-77 Primary Thermal Oxidizer for Sulfur Plants 1 and 2	250 ppmv SO2 dry, at 0% oxygen	MACT Subpart UUU 63.1568(a)(1)(i)	Y- proposed 9/11/1998	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
1507	UTIL CO Boiler 1	PM	A12	Electrostatic Precipitator 1	0.15 grain/dscf	6-1-310	N	Y COMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Opacity is a surrogate for PM

Source #	Source Description	Pollutant	Abated By	Abatement Description	Federally Enforceable Emissions Limit or Standard 40 CFR 64.2(a)(1)	Basis of Limit 40 CFR 64.2(a)(1)	Basis of Limit Proposed after Nov. 15 1990? (Y/N) Exemption 40 CFR 64.2(b)(1)(i)	Title V Permit Specifies a Continuous Compliance Determination Method? (Y/N) Exemption 40 CFR 64.2(b)(1)(vi)	Unit Uses a Control Device to Achieve Compliance with Limit? (Y/N) 40 CFR 64.2(a)(2)	Pre-Control PTE < MST? (Y/N) 40 CFR 64.2(a)(3)	Subject to CAM?	CAM Exemption	Comment
1509	UTIL CO Boiler 2	PM	A13	Electrostatic Precipitator 2	0.15 grain/dscf	6-1-310	N	Y COMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Opacity is a surrogate for PM
1512	UTIL CO Boiler 3	PM	A14	Electrostatic Precipitator 3	0.15 grain/dscf	6-1-310	N	Y COMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Opacity is a surrogate for PM
1578	Sulfur Pit for Sulfur Plant 1	SO2	A1501	F-56 Backup Thermal Oxidizer for Sulfur Plants 1 and 2	250 ppmv SO2 dry, at 0% oxygen	NSPS Subpart J 60.104(a)(2)	N	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Exempt
1578	Sulfur Pit for Sulfur Plant 1	SO2	A1517	F-77 Primary Thermal Oxidizer for Sulfur Plants 1 and 2	250 ppmv SO2 dry, at 0% oxygen	NSPS Subpart J 60.104(a)(2)	N	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Exempt
1579	Sulfur Pit for Sulfur Plant 2	SO2	A1501	F-56 Backup Thermal Oxidizer for Sulfur Plants 1 and 2	250 ppmv SO2 dry, at 0% oxygen	NSPS Subpart J 60.104(a)(2)	N	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Exempt

Source #	Source Description	Pollutant	Abated By	Abatement Description	Federally Enforceable Emissions Limit or Standard 40 CFR 64.2(a)(1)	Basis of Limit 40 CFR 64.2(a)(1)	Basis of Limit Proposed after Nov. 15 1990? (Y/N) Exemption 40 CFR 64.2(b)(1)(i)	Title V Permit Specifies a Continuous Compliance Determination Method? (Y/N) Exemption 40 CFR 64.2(b)(1)(vi)	Unit Uses a Control Device to Achieve Compliance with Limit? (Y/N) 40 CFR 64.2(a)(2)	Pre-Control PTE < MST? (Y/N) 40 CFR 64.2(a)(3)	Subject to CAM?	CAM Exemption	Comment
1579	Sulfur Pit for Sulfur Plant 2	S02	A1517	F-77 Primary Thermal Oxidizer for Sulfur Plants 1 and 2	250 ppmv SO2 dry, at 0% oxygen	NSPS Subpart J 60.104(a)(2)	N	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Exempt
1765	OPCEN Sulfur Plant 3 (SRU3)	SO2	A76	SCOT No. 3	250 ppmv SO2 dry, at 0% oxygen	Regulation 9-1-307 NSPS Subpart J 40 CFR 60.104(a)(2) NESHAPS 40 CFR 63 Subpart UUU	Y Subpart UUU was proposed 9/11/98	Y SO2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
1765	OPCEN Sulfur Plant 3 (SRU3)	S02	A2023	Thermal oxidizer for SRU3	250 ppmv SO2 dry, at 0% oxygen	9-1-307 and NSPS Subpart J 60.104 (a)(2)(i)	N	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Exempt
1765	OPCEN Sulfur Plant 3 (SRU3)	S02			250 ppmv SO2 dry, at 0% oxygen	MACT Subpart UUU 63.1568(a)(1)(i)	Y- proposed 9/11/1998	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
1765	OPCEN Sulfur Plant 3 (SRU3)	SO2	A-4181	Thermal Oxidizer for Sulfur Plant 4 and sulfur pit in Sulfur Plt 3	≤ 250 ppmvd SO2 at 0% oxygen, 12-hour rolling average	9-1-307 and NSPS Subpart J 60.104 (a)(2)(i)	N	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Exempt
1765	OPCEN Sulfur Plant 3 (SRU3)	SO2	A-4181	Thermal Oxidizer for Sulfur Plant 4 and sulfur pit in Sulfur Plt 3	≤ 250 ppmvd SO2 at 0% oxygen, 12-hour rolling average	MACT Subpart UUU 63.1568(a)(1)(i)	Y- proposed 9/11/1998	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
1803	OPCEN Coke Corral	PM	A1803	Water Spray Sprinklers for OPCEN Coke Corral	4.10 $P^{0.67}$ lb/hr particulate, where P is process weight rate in ton/hr	Regulation 6-1-311	N	N	N	Not Necessary to Calculate	N	N	Water spray is not within the CAM control device definition because it does not destroy or remove air pollutant(s).

Source #	Source Description	Pollutant	Abated By	Abatement Description	Federally Enforceable Emissions Limit or Standard 40 CFR 64.2(a)(1)	Basis of Limit 40 CFR 64.2(a)(1)	Basis of Limit Proposed after Nov. 15 1990? (Y/N) Exemption 40 CFR 64.2(b)(1)(i)	Title V Permit Specifies a Continuous Compliance Determination Method? (Y/N) Exemption 40 CFR 64.2(b)(1)(vi)	Unit Uses a Control Device to Achieve Compliance with Limit? (Y/N) 40 CFR 64.2(a)(2)	Pre-Control PTE < MST? (Y/N) 40 CFR 64.2(a)(3)	Subject to CAM?	CAM Exemption	Comment
1805	Tank 12038	VOC	A1805	Carbon Adsorption (2 Canisters)	Change out with unspent carbon upon breakthrough defined as detection at its outlet of 50 ppm VOC, measured as methane and Abatement efficiency of at least 95% by weight	Condition # 4298 Parts 5 and 6 and 40CFR61.354	Y - proposed 1/7/1993	N	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(i)	Exempt
2001	LOG Marine Loading Berth 1	VOC	A100	Thermal Oxidizer for Marine Vapor Recovery System	Destruction efficiency > 95 weight%	Regulation 8-44-301 & Condtion 4288 Part 6	N	Y Temperature CPMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Exempt
2002	LOG Marine Loading Berth 2	VOC	A100	Thermal Oxidizer for Marine Vapor Recovery System	Destruction efficiency > 95 weight%	Regulation 8-44-301 & Condtion 4288 Part 6	N	Y Temperature CPMS	Y	Not Necessary to Calculate	N	41 CFR 64.2(b)(1)(vi)	Exempt
2003	LOG Marine Loading Berth 3	VOC	A100	Thermal Oxidizer for Marine Vapor Recovery System	Destruction efficiency > 95 weight%	Regulation 8-44-301 & Condtion 4288 Part 6	N	Y Temperature CPMS	Y	Not Necessary to Calculate	N	42 CFR 64.2(b)(1)(vi)	Exempt
2004	LOG Marine Loading Berth 4	VOC	A100	Thermal Oxidizer for Marine Vapor Recovery System	Destruction efficiency > 95 weight%	Regulation 8-44-301 & Condtion 4288 Part 6	N	Y Temperature CPMS	Y	Not Necessary to Calculate	N	43 CFR 64.2(b)(1)(vi)	Exempt
4002	DC F-13425-A DCU	NOx	A4002	SCR No. 1 for Delayed Coking Unit	NOx ≤ 10 ppmv, dry @ 3% O2, averaged over 3 hr	Condition # 12271 Part 35	Y proposed 1995	Y NOx CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4003	DC F-13425-B DCU	NOx	A4003	SCR No. 2 for Delayed Coking Unit	NOx ≤ 10 ppmv, dry @ 3% O2, averaged over 3 hr	Condition # 12271 Part 35	Y proposed 1995	Y NOx CEMS	Y	Not Necessary to Calculate	N	41 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4031	DC F-14012 HGHT Reboil	NOx	A4141	SCR for HGHT Heaters	NOx ≤10 ppmv, dry @ 3% O2, averaged over 3 hr	Condition # 12271 Part 35	Y proposed 1995	Y NOx CEMS	Y	Not Necessary to Calculate	N	41 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4141	DC F-14011 HGHT Feed	NOx	A4141	SCR for HGHT Heaters	NOx ≤10 ppmv, dry @ 3% O2, averaged over 3 hr	Condition # 12271 Part 35	Y proposed 1995	Y NOx CEMS	Y	Not Necessary to Calculate	N	41 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4161	DC H-101 HP3 Steam Methane Reformer	NOx	A4161	SCR for Hydrogen Plant 3 Steam Methane Reformer	NOx ≤ 10ppmv, dry @ 3% O2, averaged over 3 hr	Condition # 12271 Part 29	Y proposed 1995	Y NOx CEMS	Y	Not Necessary to Calculate	N	41 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4180	OPCEN Sulfur Plant 4 (SRU4)	SO2	A4181	Thermal Oxidizer for Sulfur Plant 4	Conversion Efficiency > 95 weight%	Condition # 12271 Part 68	Y proposed 1997	Y SO2 CEMS	Y	Not Necessary to Calculate	N	42 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4180	OPCEN Sulfur Plant 4 (SRU4)	SO2	A-4181	Thermal Oxidizer for Sulfur Plant 4 and sulfur pit in Sulfur Pit 3	≤ 250 ppmvd SO2 at 0% oxygen, 12-hour rolling average	9-1-307 and NSPS Subpart J 60.104 (a)(2)(i)	N	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Exempt
4180	OPCEN Sulfur Plant 4 (SRU4)	SO2	A-4181	Thermal Oxidizer for Sulfur Plant 4 and sulfur pit in Sulfur Pit 3	≤ 250 ppmvd SO2 at 0% oxygen, 12-hour rolling average	MACT Subpart UUU 63.1568(a)(1)(i)	Y- proposed 9/11/1998	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4180	OPCEN Sulfur Plant 4 (SRU4)	VOC	S4201	DC Clean Fuels Flare	Hydrocarbon destruction efficiency of 98.5%	Condition 12271 Part 57, 60 and 61	Y proposed 1995	N		Not Necessary to Calculate	N	Basis of limit is after 1990	

Source #	Source Description	Pollutant	Abated By	Abatement Description	Federally Enforceable Emissions Limit or Standard 40 CFR 64.2(a)(1)	Basis of Limit 40 CFR 64.2(a)(1)	Basis of Limit Proposed after Nov. 15 1990? (Y/N) Exemption 40 CFR 64.2(b)(1)(i)	Title V Permit Specifies a Continuous Compliance Determination Method? (Y/N) Exemption 40 CFR 64.2(b)(1)(vi)	Unit Uses a Control Device to Achieve Compliance with Limit? (Y/N) 40 CFR 64.2(a)(2)	Pre-Control PTE < MST? (Y/N) 40 CFR 64.2(a)(3)	Subject to CAM?	CAM Exemption	Comment
4190	UTIL Boiler 6 Gas Turbine 1	NOx	A4190	SCR No. 1 for Boiler 6	NOx ≤ 5 ppmv, dry @ 15% O2, averaged over 3 hr	Condition # 12271 Part 24c	Y proposed 1995	Y NOx CEMS	Y	Not Necessary to Calculate	N	41 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4190	UTIL Boiler 6 Gas Turbine 1	NOx	A4191	Catalytic Oxidation No. 1 for Boiler 6	NOx ≤ 5 ppmv, dry @ 15% O2, averaged over 3 hr	Condition # 12271 Part 24c	Y proposed 1995	Y NOx CEMS	Y	Not Necessary to Calculate	N	41 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4191	UTIL Boiler 6 Supplemental Steam Generator 1	NOx	A4190	SCR No. 1 for Boiler 6	NOx ≤ 5 ppmv, dry @ 15% O2, averaged over 3 hr	Condition # 12271 Part 24c	Y proposed 1995	Y NOx CEMS	Y	Not Necessary to Calculate	N	41 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4191	UTIL Boiler 6 Supplemental Steam Generator 1	NOx	A4191	Catalytic Oxidation No. 1 for Boiler 6	NOx ≤ 5 ppmv, dry @ 15% O2, averaged over 3 hr	Condition # 12271 Part 24c	Y proposed 1995	Y NOx CEMS	Y	Not Necessary to Calculate	N	41 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4192	UTIL Boiler 6 Gas Turbine 2	NOx	A4192	SCR No. 2 for Boiler 6	NOx ≤ 5 ppmv, dry @ 15% O2, averaged over 3 hr	Condition # 12271 Part 24c	Y proposed 1995	Y NOx CEMS	Y	Not Necessary to Calculate	N	41 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4192	UTIL Boiler 6 Gas Turbine 2	NOx	A4193	Catalytic Oxidation No. 2 for Boiler 6	NOx ≤5 ppmv, dry @ 15% O2, averaged over 3 hr	Condition # 12271 Part 24c	Y proposed 1995	Y NOx CEMS	Y	Not Necessary to Calculate	N	41 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4193	UTIL Boiler 6 Supplemental Steam Generator 2	NOx	A4192	SCR No. 2 for Boiler 6	NOx ≤ 5 ppmv, dry @ 15% O2, averaged over 3 hr	Condition # 12271 Part 24c	Y proposed 1995	Y NOx CEMS	Y	Not Necessary to Calculate	N	41 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4193	UTIL Boiler 6 Supplemental Steam Generator 2	NOx	A4193	Catalytic Oxidation No. 2 for Boiler 6	NOx ≤5 ppmv, dry @ 15% O2, averaged over 3 hr	Condition # 12271 Part 24c	Y proposed 1995	Y NOx CEMS	Y	Not Necessary to Calculate	N	41 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4211	DC V-13222 ISOM Maintenance Drop Out Vessel	VOC	S4201	DC Clean Fuels Flare	Hydrocarbon destruction efficiency of 98.5%	Condition 12271 Part 57, 60 and 61	Y proposed 1995	N		Not Necessary to Calculate	N	Basis of limit is after 1990	
4347	OPCEN Pit for Sulfur Plant 4	SO2	A4181	Thermal Oxidizer for Sulfur Plant 4	Conversion Efficiency > 95 weight%	Condition # 12271 Part 68	Y proposed 1997	Y SO2 CEMS	Y	Not Necessary to Calculate	N	42 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Exempt
4347	OPCEN Pit for Sulfur Plant 4	SO2	A-4181	Thermal Oxidizer for Sulfur Plant 4 and sulfur pit in Sulfur Pit 3	≤ 250 ppmvd SO2 at 0% oxygen, 12-hour rolling average	NSPS Subpart J 60.104(a)(2)	N	Y SO_2 CEMS	Y	Not Necessary to Calculate	N	40 CFR 64.2(b)(1)(vi)	Exempt

Note: This list only includes pollutants that are abated by a control device to meet a federally enforceable emission standard.
PTE = Potential to Emit
MST = Major Source Threshold
CEMS = Continuous Emissions Monitoring System
CPMS = Continuous Parametric Monitoring System
NA = Not Applicable
BAAQMD = Bay Area Air Quality Management District.
Per 40 CFR 64, a control device does not include passive control measures that act to prevent pollutants from forming, such as the use of seals, lids, or roofs to prevent the release of pollutants, use of low-polluting fuel or feedstocks, or the use of combustion or other process design features or characteristics. This includes low NOx burner technology.
Inherent process equipment means equipment that is necessary for the proper or safe functioning of the process, or material recovery equipment that the owner or operator documents is installed and operated primarily for purposes other than compliance with air pollution regulations.
All asphalt storage tanks are subject to Regulation 6-1-311, the weight process rate limitation. However, the tanks do not use emission control devices to achieve this limit. The emissions are already low.

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APPENDIX E

GLOSSARY

ACT
Federal Clean Air Act

APCO
Air Pollution Control Officer

ARB
Air Resources Board

BAAQMD
Bay Area Air Quality Management District

BACT
Best Available Control Technology

Basis
The underlying authority which allows the District to impose requirements.

CAA
The federal Clean Air Act

CAAQS
California Ambient Air Quality Standards

CAM
Compliance Assurance Monitoring per 40 CFR Part 64

CAPCOA
California Air Pollution Control Officers Association

CEM
Continuous Emission Monitor

CEQA
California Environmental Quality Act

CFR
The Code of Federal Regulations. 40 CFR contains the implementing regulations for federal environmental statutes such as the Clean Air Act. Parts 50-99 of 40 CFR contain the requirements for air pollution programs.

CO
Carbon Monoxide

Cumulative Increase
The sum of permitted emissions from each new or modified source since a specified date pursuant to BAAQMD Rule 2-1-403, Permit Conditions (as amended by the District Board on 7/17/91) and SIP Rule 2-1-403, Permit Conditions (as approved by EPA on 6/23/95). Cumulative increase is used to determine whether threshold-based requirements are triggered.

District
The Bay Area Air Quality Management District

EPA
The federal Environmental Protection Agency.

Excluded
Not subject to any District regulations.

Federally Enforceable, FE
All limitations and conditions which are enforceable by the Administrator of the EPA including those requirements developed pursuant to 40 CFR Part 51, subpart I (NSR), Part 52.21 (PSD), Part 60 (NSPS), Part 61 (NESHAPs), Part 63 (MACT), and Part 72 (Permits Regulation, Acid Rain), including limitations and conditions contained in operating permits issued under an EPA-approved program that has been incorporated into the SIP.

FP
Filterable Particulate as measured by BAAQMD Method ST-15, Particulate.

HAP
Hazardous Air Pollutant. Any pollutant listed pursuant to Section 112(b) of the Act. Also refers to the program mandated by Title I, Section 112, of the Act and implemented by 40 CFR Part 63.

Major Facility
A facility with potential emissions of: (1) at least 100 tons per year of regulated air pollutants, (2) at least 10 tons per year of any single hazardous air pollutant, and/or (3) at least 25 tons per year of any combination of hazardous air pollutants, or such lesser quantity of hazardous air pollutants as determined by the EPA administrator.

MFR
Major Facility Review. The District's term for the federal operating permit program mandated by Title V of the Federal Clean Air Act and implemented by District Regulation 2, Rule 6.

MOP
The District's Manual of Procedures.

NAAQS
National Ambient Air Quality Standards

NESHAPS
National Emission Standards for Hazardous Air Pollutants. See in 40 CFR Parts 61 and 63.

NMHC
Non-methane Hydrocarbons (Same as NMOC)

NMOC
Non-methane Organic Compounds (Same as NMHC)

NOx
Oxides of nitrogen.
NSPS

Standards of Performance for New Stationary Sources. Federal standards for emissions from new stationary sources. Mandated by Title I, Section 111 of the Federal Clean Air Act, and implemented by 40 CFR Part 60 and District Regulation 10.

NSR
New Source Review. A federal program for pre-construction review and permitting of new and modified sources of pollutants for which criteria have been established in accordance with Section 108 of the Federal Clean Air Act. Mandated by Title I of the Federal Clean Air Act and implemented by 40 CFR Parts 51 and 52 and District Regulation 2, Rule 2. (Note: There are additional NSR requirements mandated by the California Clean Air Act.)

Offset Requirement
A New Source Review requirement to provide federally enforceable emission offsets for the emissions from a new or modified source. Applies to emissions of POC, NOx, PM10, and SO2.

Phase II Acid Rain Facility
A facility that generates electricity for sale through fossil-fuel combustion and is not exempted by 40 CFR 72 from Titles IV and V of the Clean Air Act.

POC
Precursor Organic Compounds

PM
Particulate Matter

PM10
Particulate matter with aerodynamic equivalent diameter of less than or equal to 10 microns

PSD
Prevention of Significant Deterioration. A federal program for permitting new and modified sources of those air pollutants for which the District is classified "attainment" of the National Air Ambient Quality Standards. Mandated by Title I of the Act and implemented by both 40 CFR Part 52 and District Regulation 2, Rule 2.

PTE
Potential to Emit as defined by BAAQMD Regulation 2-6-218

SIP
State Implementation Plan. State and District programs and regulations approved by EPA and developed in order to attain the National Air Ambient Quality Standards. Mandated by Title I of the Act.

SO2
Sulfur dioxide

THC
Total Hydrocarbons (NMHC + Methane)

Title V
Title V of the federal Clean Air Act. Requires a federally enforceable operating permit program for major and certain other facilities.

TOC
Total Organic Compounds (NMOC + Methane, Same as THC)

TPH
Total Petroleum Hydrocarbons

TRMP
Toxic Risk Management Plan

TSP
Total Suspended Particulate

VOC
Volatile Organic Compounds

Units of Measure:

Bhp	=	brake-horsepower
btu	=	British Thermal Unit
cu. ft.	=	cubic foot
cfm	=	cubic feet per minute
dscf	=	dry standard cubic foot
dscfm	=	dry standard cubic foot per minute
g	=	gram
gal	=	gallon
gpm	=	gallons per minute
gr	=	grain
hp	=	horsepower
hr	=	hour
lb	=	pound
in	=	inch
max	=	maximum
m2	=	square meter
min	=	minute
mm	=	million
MMbtu	=	million btu
MMcf	=	million cubic feet
ppmv	=	parts per million, by volume
ppmw	=	parts per million, by weight
psia	=	pounds per square inch, absolute
psig	=	pounds per square inch, gauge
scfm	=	standard cubic feet per minute
tpy	=	tons per year
yr	=	year