

Bay Area Air Quality Management District

939 Ellis Street
San Francisco, CA 94109
(415) 771-6000

**Permit Evaluation
and
Statement of Basis
for
MAJOR FACILITY REVIEW PERMIT
Reopening – Revision 2**

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

November 2006

Application 12430

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

TABLE OF CONTENTS

A.	Background.....	3
B.	Facility Description	4
C.	Permit Content.....	4
I.	Standard Conditions	4
II.	Equipment	34
III.	Generally Applicable Requirements	34
IV.	Source-Specific Applicable Requirements	34
V.	Schedule of Compliance	36
VI.	Permit Conditions	37
VII.	Applicable Limits and Compliance Monitoring Requirements	39
VIII.	Test Methods	40
IX.	Permit Shields	40
D.	Alternate Operating Scenarios:.....	41
E.	Compliance Status:	41
	APPENDIX A	42
	APPENDIX B.....	48
	APPENDIX C.....	49

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 Volume 40 of the Code of Federal Regulations (CFR), and as incorporated in 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, of 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.

The District issued the initial Title V permit to this facility on December 1, 2003 (Initial Permit).

Revision 1: On December 16, 2004, the District ~~issued the modified~~ and issued the ~~and~~ permit to amend flare and Regulation 9, Rule 10 requirements, add new permitted sources, and correct typographical and other inadvertent errors. The reopening of the Initial Permit is generally referred to as Revision 1 and the modified permit as the (~~Revision 1 Permit~~).

Revision 2: By letter dated October 8, 2004, EPA objected to the Revision 1 Permit and required that it be reopened. EPA submitted comments and identified a number of issues to be resolved for ~~actions to the~~ District's five-refinery Title V permits, including Shell's initial ~~P~~ permit. (Note that EPA commented on the five refineries' permits in this letter, but that not all comments concern this facility.) A copy of the October letter is attached as Appendix B. This reopening is generally referred to as "Revision 2." The District has revised the Revision 1 Permit to address those issues applicable to the Shell Permit and to update the Permit as well (Revision 2 Permit).

~~All changes to the Revision 2 Permit will be clearly shown in "strikeout/underline" format. When the permit is finalized, the "strikeout/underline" format will be removed.~~

~~The Revision 2 Permit statement of basis discusses the changes made by this limited reopening. The statement of basis~~ It also provides additional analysis supporting applicability determinations made previously by the District. In some instances, the additional analyses did not result in a

permit change. In those instances, the District is not reopening the permit, and the particular analyses ~~are~~ provided for information only.

This Revision 2 Permit statement of basis does not address factual and legal bases for permit requirements and conditions that are not the subject of the limited reopening. These matters are addressed in the comprehensive statements of basis that accompany the Initial Permit and the Revision 1 Permit. Those statements of basis are available upon request.

All changes to the Revision 2 Permit will be clearly shown in "strikeout/underline" format. When the permit is finalized, the "strikeout/underline" format will be removed.

B. Facility Description

The facility description can be found in the Statement of Basis that was prepared for the Revision 1 Permit ~~reopened permit that was issued December 16, 2004.~~ The Revision 1 Permit is available upon request.

C. Permit Content

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

I. Standard Conditions

The following language was added as Standard Condition I.B.12: "The permit holder is responsible for compliance, and certification of compliance, with all conditions of the permit, regardless whether it acts through employees, agents, contractors, or subcontractors. (Regulation 2-6-307)." The purpose is to ensure that all activities at the facility comply with all applicable requirements.

The District has deleted Miscellaneous Conditions I.J.5 through I.J.9 in the permit. The Conditions referred to determinations that the District had intended to make by February 15, 2000 concerning the applicability of certain regulations to the Facility's processes and equipment. The District has made the determinations, which are set forth below in the section entitled "Complex Applicability Determinations," and modified the permit as appropriate.

Complex Applicability Determinations:

Applicability of NSPS Subpart J to thermal oxidizers

The District is ~~proposing to re~~ revising the permit to indicate the applicability of NSPS Subpart J at certain thermal oxidizers. NSPS Subpart J requirements will be added to Table IV – CF for LOG Marine Loading Berths 1, 2, 3 and 4 consisting of sources S2001, S2002, S2003, and S2004 which are abated by A100 Thermal Oxidizer for Marine Vapor Recovery. Table VII – BR for LOG Marine Loading Berths 1, 2, 3 and 4 consisting of sources S2001, S2002, S2003, and S2004 which are abated by A100 Thermal Oxidizer for Marine Vapor Recovery contains monitoring for Subpart J.

This Revision 2 Permit ~~today's proposal~~ is responsive to EPA's comments relative to the Bay Area refinery permits that a thermal oxidizer located at refinery is a "fuel gas combustion device" within the meaning of § 60.101(g) and therefore subject to Subpart J, provided other

applicability criteria are met. EPA's comments are based on the definition of "fuel gas" found at § 60.101(d), which defines "fuel gas" as "any gas which is generated at a petroleum refinery and which is combusted." EPA made this comment on earlier versions of the refinery Title V permits, but did not include the issue in its list of reopening issues either on October 8, 2004, or March 15, 2005. One purpose of this proposal is to determine whether EPA still holds to this view. The following discussion presents the District's understanding of the arguments favoring applicability, and also notes countervailing arguments that have been put forth by the refineries.

NSPS Subpart J applies to a "fuel gas combustion device ... which commences construction or modification after June 11, 1973." (40 CFR § 60.100(b).) Any device subject to Subpart J shall not "[b]urn ... any fuel gas that contains hydrogen sulfide (H₂S) in excess of 230 mg/dscm." (40 CFR § 105(a)(1).) Subpart J defines fuel gas as "any gas which is generated at a petroleum refinery and which is combusted." (40 CFR § 60.101(d).)

The question that has arisen at some Bay Area refineries is whether a thermal oxidizer at a waste water treatment unit or a gas loading rack is a "fuel gas combustion device." It has been argued that although ~~these thermal oxidizers~~ abatement device at a waste water treatment unit or a gas loading rack are ~~s~~ are combusting gas generated at a refinery, the combusted gases are typically not sufficiently rich in hydrocarbons to support combustion and so are not "fuel gas," both in the common sense of that term and the intended meaning of that term as used in NSPS J. Secondly, it has been argued that only gases generated at "petroleum refinery processing units" should be considered as "fuel gas," and that this would preclude applicability to wastewater treatment systems and gas loading racks. Finally, it has been argued that certain gases combusted at thermal oxidizers are not subject to the hydrogen sulfide standard of NSPS J because they are not compatible with amine treatment.

The District views these arguments as being for the most part analytically distinct. Accordingly, they are addressed in order below.

Does "Fuel Gas" Refer Only to Gases That Can Support Combustion?

As noted above, NSPS J defines "fuel gas" as "any gas which is generated at a petroleum refinery and which is combusted." Aside from the exemption of specific gas streams, the scope of this definition appears comprehensive. A textual argument might be made that the reference to "gas" in the phrase "gas which is generated," should be read as synonymous with "fuel gas." In other words, that "fuel gas" should be afforded its common-sense meaning as gas capable of supporting combustion, rather than the broader literal meaning given to it by the section 101(d) definition. This interpretation runs counter to the common practice for reading definitions, i.e., by importing meaning from the defined phrase into the definition itself.

"Fuel gas" was defined in the initial promulgation of NSPS J. In the proposed rule, "fuel gas" meant, in relevant part, "process gas and/or natural gas or any other gaseous mixture which will support combustion." 38 FR 15408 (June 11, 1973). In the final rule, "fuel gas" was defined as "any gas which is generated by a petroleum refinery process unit and which is combusted." 39 FR 9315 (March 8, 1974). Thus the phrase "gaseous mixture which will support combustion" was replaced by the phrase "[gas] which is combusted." This raises the question whether any change in meaning from proposal to final was intended.

The preamble to the final rule discusses a different change regarding fuel gas combustion (exemption of process upset gases), noting that it “do[es] not represent any change in the Agency’s original intent.” *Id.*, at 9310. From the fact that changes to the “fuel gas” definition are not mentioned, it might be inferred that no changes in meaning were intended (i.e., since discussion was devoted to changes that did not alter intent, one would presume any changes that did would have merited discussion). However, the comparison of proposed to final rule combined with the supposition that no change in intent occurred merely begs the question of which version better represents EPA’s true intent.

The stronger presumption, however, is that a change in rule language intends a change in meaning. The change in language clearly has a broadening effect: a gas that, standing alone, will not support combustion will nevertheless combust if introduced into a sufficiently robust environment. EPA could quite reasonably have decided that basing applicability of a standard on the capacity of a gas stream to support combustion places too much weight on a variable facet of operations. In this plausible scenario, the final rule language could be viewed as simply a more accurate statement of EPA’s original intent.

Other federal standards contain definitions of “fuel gas” that clearly limit the phrase to gases that can support combustion. See, e.g., NSPS VV, SOCOMI HON. However, these are distinct standards established for purposes other than control of SO₂ emissions. Inferences drawn from comparing definitions of “fuel gas” are ambiguous at best. These more specific definitions would seem to cut against, rather than support, arguments made by the refineries. That EPA can, when it chooses, define “fuel gas” to exclude gases not supporting combustion could lead one to infer that the literal meaning of section 60.101(d) is also the intended meaning.

Is “Fuel Gas” Limited to Gas Generated at Petroleum Processing Units?

As initially promulgated, “fuel gas” was defined as “gas generated at a petroleum refinery process unit.” In the 1973 proposed rule, this phrase appeared in the definition of “process gas” but not in the definition of “fuel gas.” It was added into the definition of “fuel gas” in the final rule, without explanation. A “refinery process unit” is, and has been, defined in section 101(f) as “any segment of a petroleum refinery in which a specific processing operation is conducted.”

There is little if anything to illuminate the intended meaning of “process,” which in this provision is used to define itself. There is arguably a common usage that refers only to operations that act upon petroleum and transform it towards some end product. Background documents for the 1974 rule explain that “[r]efinery processes, such as distillation and fluid catalytic cracking, produce substantial quantities of ‘process gas....’” The same document states that “[f]uel gas is produced in a refinery from a wide variety of processes including: crude oil separation, catalytic cracking, hydrocracking, coking, and reforming.” However, there is no indication in these background documents that the phrase “refinery process units” was intended to be so limited.

“Process” could also be used in a broader sense to include waste water treatment plants, hydrogen plants, and other ancillary process that do not involve petroleum. In any case, EPA subsequently amended the definition of fuel gas to refer to any gas “generated at a refinery.” Though no explanation was offered for the change, the plain language of the rule as revised would appear to foreclose whatever inferences could have been based on the earlier formulation.

It might be argued that interpreting “process” to include any refinery operation deprives the definition of purpose. However, this broader interpretation of “process” does distinguish gas generated onsite from gas imported to the refinery (e.g., pipeline natural gas). Subsequent revision to the standard clarifying the exemption of pipeline gas is consistent with the idea that the reference to “refinery process unit” in the initial definition of “fuel gas” was intended to serve this same purpose.

Does “Fuel Gas” Refer Only to Gas Streams Subject to Amine Treatment?

There are clear indications in the regulatory history of NSPS J that the intent of the rule was to apply only to gases subject to amine treatment. Background documents to the initial proposal discuss amine treatment as the cost effective available control. In 1979, the rule was revised to answer two specific questions: were Thermofor catalytic cracking units treated the same as fluid catalytic cracking units under the regulation (answer: yes); and were auxiliary fuels burned along with gases generated by exempt units subject to the standards (answer: yes). The preamble to this direct-final rulemaking states that the hydrogen sulfide standard of NSPS J is “based on amine treating of refinery fuel gas.” 44 FR 13481 (March 12, 1979). The definition of “fuel gas” was accordingly changed to exclude gases generated at catalytic cracking units, because these gases are chemically unsuitable for amine treatment.

This raises the question of whether other gas streams not susceptible to amine treatment should be considered exempt from the hydrogen sulfide standard of NSPS J. The idea finds considerable support in the original background documents and the 1979 preamble discussion. The 1979 preamble notes that “amine treating can be used, and in most major refineries normally is used, to remove hydrogen sulfide from . . . refinery fuel gas streams.” *Id.* There is thus an inference that the intent of the standard was to apply only to fuels found in refinery fuel gas systems, or capable of being collected and used in fuel gas systems, because these systems are typically coextensive with the gas streams that are processed by an amine treater at a refinery.

However, there is no reference in the text of the rule itself to amine treatment compatibility as a criterion of applicability. Under the terms of the rule, gas generated at refinery is either “fuel gas,” and therefore subject, or not. Rather than create an explicit exemption based on amine treatment compatibility, EPA chose to specifically exclude those gas streams it knew to require different treatment. The argument for limiting applicability based on amine treatment compatibility therefore finds no foothold in the text of the rule. Presumably, other sources could be expected to comply with the standard using a different control technique (e.g., caustic scrubbing); or normally produce gases of sufficiently low sulfur content as to be inherently compliant.

Proposal to Incorporation of NSPS Subpart J

This discussion begins by noting that the arguments that have been raised against applying the hydrogen sulfide standard of NSPS J to thermal oxidizers are analytically distinct. Though mostly true, it may be that certain arguments shade into others. For instance, the argument that only gases compatible with amine treatment were intended to be subject to the standard, which in turn tends to implicate only gases commonly in the fuel gas system, lends some further weight to the textual argument that “fuel gas,” as defined in section 101(d), should be accorded its common sense meaning, as opposed to its literal meaning. Further weight is added by a seeming emphasis, evidenced throughout the regulatory history, on gases generated at units that process

petroleum as the subject of controls, which units in turn tend to be the primary source of fuel gas used to support combustion at refinery heaters and boilers.

However, the potential for tying together these different strands of evidence has never been taken up by EPA. EPA has never (to the District's knowledge) analyzed the technical feasibility, benefits, and costs of alternative controls and their application to gas streams not compatible with amine treatment, and although the practical consequences of application of NSPS J to the thermal oxidizers in question are not clear, EPA has established a consistent record of interpreting NSPS J to apply broadly and according to its literal terms. See, e.g., December 2, 1999, letter from J. Rasnic, EPA, to P. Guillemette, Koch Refining Co.. The District assumes that EPA's longstanding interpretation would receive substantial deference from a reviewing court. Incremental changes to regulatory language over time, though sometimes unexplained, have tended to support these broader readings. The District speculates that the broader interpretation finds its policy justification in the desire to close potential loopholes -- that is, to remove any incentive to route treatable gas streams away from treatment. Though this may not be consistent with how some understand the original intent of the rule, it is nevertheless a legitimate and rational regulatory goal that finds ample support in the plain language of the rule. ~~The District notes that, to its knowledge, EPA has never analyzed the technical feasibility, benefits, and costs of alternative controls and their application to gas streams not compatible with amine treatment. As a result, the practical consequences of application of NSPS J to the thermal oxidizers in question are not clear.~~ The District notes that EPA did not comment on the District's proposal to apply this interpretation.

~~The District is therefore proposes incorporating into the Title V permit of the NSPS J as applicable to e to certain thermal oxidizers, and solicits comment on this proposal. If today's proposal is finalized, the District will consider the appropriateness of imposing a schedule of compliance for units not in compliance. The District therefore also seeks comment regarding appropriate terms for a schedule of compliance.~~

MACT Subpart CC applicability for Flares

Subpart CC applies to, among other things, miscellaneous process vents from petroleum refining process units (40 CFR 63.640(c)(1)). "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 Sec. 63.640(a) (40 CFR 63.641). Miscellaneous process vents do not include gaseous streams routed to a fuel gas system nor do they include episodic or nonroutine releases (40 CFR 63.641).

Subpart CC also contains a more general exemption from testing, monitoring, recordkeeping, and reporting requirements for refinery fuel gas systems or emission points routed to refinery fuel gas systems (40 CFR 63.640(d)(5)).

Subpart CC defines "emission point" to mean an individual miscellaneous process vent, storage vessel, wastewater stream, or equipment leak associated with a petroleum refining process unit (40 CFR 63.641). "Fuel gas system" means the offsite and onsite piping and control system that gathers gaseous streams generated by refinery operations, may blend them with sources of gas, if

available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside of the refinery (40 CFR 63.641). "Combustion device" means an individual unit of equipment such as a flare, incinerator, process heater, or boiler used for the combustion of organic hazardous air pollutant vapors (40 CFR 63.641).

The definition of "fuel gas system" clearly indicates that a system begins at the emission point. Once the gas is in the collection system, the fuel gas exemptions apply, even if the collected gases are subsequently routed to a flare. EPA, in its October 8, 2004 letter, disagreed with that interpretation. EPA's rationale appears to be that the fuel gas system begins at the fuel gas compressor (and presumably any piping leading directly to the compressor). However, EPA's interpretation renders the part of the definition of "fuel gas system" that includes gathering streams a nullity. Moreover, the definition indicates with equal clarity that a "fuel gas system" remains such even when the gas is routed to a combustion device, which, as noted above, is defined to include flares.

An alternative rationale exists in that gases vented to the flares in question are not within the definition of "miscellaneous process vents." At all of the affected refineries, process gas collected by the gas recovery system are routed to flares only under two circumstances: (1) situations in which, due to process upset or equipment malfunctions, the gas pressure in the flare header rises to a level that breaks the water seal leading to the flare; or (2) situations in which, during process startups, shutdowns, or process upsets, the quality of the gas falls to a level such that it cannot be introduced into the fuel gas system. Episodic or nonroutine releases such as those associated with startup, shutdown, malfunction, maintenance, depressuring [sic], and catalyst transfer operations are, by definition, not miscellaneous process vents, and are not subject to Subpart CC.

Regulation 8-2 and Hydrogen Plant Vents

The Revision 1 Permit (~~issued on December 16, 2004~~) addressed EPA's comments on hydrogen plant vents.

Cooling Water Tower Monitoring

~~The District has determined that the best modern practice for operation of refinery heat exchangers is frequent monitoring for potential heat exchanger leaks. The District has reviewed the current practice of Bay Area refineries, and has determined that daily visual inspection, plus water sampling and analysis for indicators of hydrocarbon leaks once per shift, is the best modern practice. A cooling tower that is maintained using best modern practices is exempt from Regulation 8-2.~~

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 employs maintenance and operating practices that qualify as BMPs. Therefore, CWTs owned and operated by Shell at the facility are exempt from Regulation 8, Rule 2.

The facility has the burden of keeping records necessary to demonstrate that it qualifies for the exemption. The District has determined that Shell is using best modern practices to monitor cooling tower water for indications of heat exchanger leaks. Therefore, Regulation 8-2 will be removed from the source-specific applicable requirement tables for sources S1457, S1778, and S4210. Please refer to Tables IV-AS & CY, and Table VII-AJ.

NSPS QQQ Requirements for Oil-Water Separators

Shell's slop oil tanks are subject to Subpart Kb (see Table IV G.1.6). Therefore, the slop oil tanks are not subject to Subpart QQQ. per 40 CFR Section 60.692-3(d) of Subpart QQQ states that Section 60.692-3(d):

~~60.692-3(d)~~ “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.”

Shell has two process water tanks (S-4350 and S-4356) and two wastewater treatment tanks (S-12490 and S-12491) that meet the definition of oil-water separator. S-4350 and S-4356 are subject to NSPS Subpart Kb (see Table IV-DG). S-12490 and S-12491 are also subject to NSPS Subpart Kb (see Table IV-AC). Therefore, pursuant to 40 CFR 60.692-3(d), NSPS QQQ does not apply to any of these sources.

NESHAP Subpart FF Requirements for Biotreaters

EPA’s comments were addressed in ~~the permit~~ the Revision 1 Permit issued December 16, 2004.

Shell’s facility contains two biotreaters designated ETP-1 (S-1467) and ETP-2 (S-5117). The District modified the Initial Permit (~~issued December 1, 2003~~) in accordance with the permit holder’s written request, dated June 6, 2004, to incorporate five changes that were required as a result of the de-listing of the ETP-1 biotreater from the Benzene-Waste NESHAPS criteria.

ETP-1 Biotreater:

As specified in the Revision I Permit, the Shell wastewater treatment train designated “ETP-1” ~~is~~ not required to be managed in accordance with the control requirements specified by 40 CFR 61 Subpart FF (or the wastewater provisions of 40 CFR 63 Subpart CC). The permit holder had selected the “6BQ” compliance option under 40 CFR Subpart FF. The Revision 1 Permit Statement of Basis described the operation of 6BQ inaccurately. The corrected description is set forth below, shown in underline/strikeout format:

“Under 40 CFR 61 Subpart FF and the wastewater provisions of 40 CFR 63 Subpart CC, facilities have several available compliance options. The compliance option selected for the Shell Martinez Refinery, known as “6BQ,” requires that most aqueous benzene containing waste be managed in controlled systems in accordance with the standards listed in 40 CFR 61 Subpart FF (an aqueous stream is one containing 10% or greater water on an annual average basis). All non-aqueous benzene waste streams must be managed and controlled in accordance with 40 CFR 61.342 (c)(1).

“The selected compliance option provides a six (6) mega-gram per year (Mg/yr) ‘allotment’ for aqueous waste streams that are not managed in ~~controlled systems~~ **enhanced biodegradation units**. To comply with the 6BQ compliance option, Shell has segregated the ‘larger’ benzene containing streams, including those managed in controlled systems. The remaining benzene containing aqueous waste streams, including those managed in ETP-1, are managed in uncontrolled systems. ~~and Both~~ **are** subject to a facility-wide requirement to annually document that ~~these all~~ streams **not routed to enhanced biodegradation units** contain less than six Mg/yr of benzene. This facility-wide requirement is cited in Table IV-DV for citation 61.342(e)(2). Although Shell currently manages ETP-1 in accordance with the control provisions of 40 CFR 61 Subpart FF, the regulations allow Shell to manage ETP-1 as an uncontrolled system under the “6BQ” compliance option. Therefore, in the Title V permit, these operations are being de-listed from the standards listed in 40 CFR 61 Subpart FF and the wastewater provisions of 40 CFR 63 Subpart CC.”

ETP-2 Biotreater:

The ETP-2 biotreater is subject to some requirements under Subpart FF.

- 1) 61.355(k)(4) says that those wastes entering an enhanced biodegradation unit as defined by 61.348(b)(2)(ii)(B) shall not be included in the benzene quantity determination if (k)(4)(i) and (k)(4)(ii) are met.
- 2) The benzene to the biotreater must be less than 10 ppm on a flow-weighted annual average basis (40 CFR 61.355(k)(4)(i)]. Note also that those waste management units upstream of the biotreater must also be controlled [40 CFR 61.355(k)(4)(ii)]. This would include the DNFs, tanks, etc - which are controlled.

The description of the applicability of 6BQ contained in Table IV-DV of the Revision 1 Permit is also incorrect. ~~The following change will be made to the permit in Revision 2 Permit contains the following language.~~

61.342(e)(2) ~~Uncontrolled~~ Aqueous wastes (with a flow-weighted annual average water content of 10% or more by volume) shall be limited to 6 Mg/yr. **Waste routed to enhanced biodegradation units is not included in this total.**

NESHAP Subpart FF for non-aqueous waste streams

Shell has indicated that there are no non-aqueous benzene waste streams at the ~~facility~~ refinery. Therefore, 61.342(e)(1) ~~has~~ will not be added as a source specific applicable requirement in the permit. However, the above citation will be included in Table IV-DV "Facility" in the event non-aqueous streams are added, handled and treated at the facility during the term of this permit.

ESP Monitoring

(response to EPA Letter October 8, 2004, Attachment 2)

The District ~~has~~ 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~~ will added to the proposed permit ~~Pa~~ permit ~~C~~ condition requiring ~~(# 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 ~~ing~~ 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.

~~Permit condition # 22165 has been added 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~~

Compliance with Regulation 9-1-313.2

The District ~~is proposed to~~ ~~ing deletion of~~ Title V permit conditions in the five Bay Area refinery permits related to monitoring for compliance with District Rule 9-1-313.2. District Rule 9-1-313 allows three options for compliance; ~~but is complied with~~ at all five Bay Area refineries

~~comply pursuant to through Section 313.2, which requires operation of a sulfur removal and recovery system that achieves 95% reduction of H₂S from refinery fuel gas. Conditions were established in the 2003 issuance of these permits to periodically verify that a 95% reduction is being achieved. Though details vary amongst the five refineries, all permits require some form of compliance demonstration, generally involving inlet-outlet source testing. The refineries have 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 is now proposing deletion of the conditions.~~

The monitoring in all five refinery permits was established pursuant to Section 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 2-6 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 9-1-313.2, the District ~~determined now believes~~ that compliance with Section 9-1-313.2 is sufficiently assured without the addition of Title V monitoring and has deleted the requirement.

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 District Rule 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. District Rule 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 ~~District Rule~~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.

District Rule 9-1-313 was adopted in 1990, at a time when all but one Bay Area gasoline-producing refinery were already operating 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 District Rule 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 District Rule 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. Most relevant to today's proposal, 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 District Rule 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 District Rule 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 District Rule 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 today 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 District Rule 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, District Rule 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.

~~The District solicits comment on this proposal and on possible alternative approaches to verifying compliance with the 95% reduction goal of section 313.2. The District knows of no examples in which monitoring for such a standard has been successfully implemented in other jurisdictions. Finally, the District notes that it is considering revision of 9-1-313 that would shift the focus from reduction efficiency to a standard that is both more pertinent to air quality protection and more verifiable.~~

EPA comments previously not addressed by the District:

EPA Comment:

Add NSPS Subpart J for thermal oxidizers and I.C. engines that burn fuel gas.

District's Response:

The following table lists thermal oxidizers at Shell that are also contained in "Table II B - Abatement Devices" of the permit:

Thermal Oxidizer I.D.	Thermal Oxidizer Description
A100	Thermal Oxidizer for Marine Vapor Recovery
A1501	Backup Thermal Oxidizer for Sulfur Plants 1 & 2
A1517	Primary Thermal Oxidizer for Sulfur Plants 1 & 2
A1518	Catalytic Oxidizer for SCOT No. 3
A4181	Thermal Oxidizer for Sulfur Plant 4

A100: Thermal Oxidizer for Marine Vapor Recovery

NSPS Subpart J applies to any combustion device built or modified after June 11, 1973 that burns fuel gas. Any gas generated at the refinery is a fuel gas. A100 is a combustion device that burns vent gases from marine terminal loading, and was constructed on July 1992. It is therefore subject to NSPS J. The company utilizes alternative monitoring approved by EPA in accordance with 40 CFR sec. 60.13(i).

The Revision 2 Permit ~~District will~~ incorporates the requirements of 40 CFR sec. 60.104(a)(1) into Shell's Title V permit by amending permit condition 4288, which governs the operation of sources S2001 through S2004, to include parts 12 through 14. In addition, the requirements will be incorporated into Tables IV-CF and VII-BR.

A1501, A1517, A1518 and A4181: Oxidizers operating at Shell's Sulfur Plants

These oxidizers are not subject to 40 CFR 60.104(a)(1) for fuel gas combustion in NSPS Subpart J. Instead, the above oxidizers are subject to 40 CFR 60.104(a)(2), which addresses discharge of any gases into the atmosphere from Claus sulfur recovery plants. Shell operates four Claus sulfur recovery plants - S1431 (abated by A1501 or A1517), S1432 (abated by A1501 or A1517), S1765 (abated by A1518), and S4180 (abated by A4181). It should be noted that 40 CFR 60.104(a)(2) is already listed as an applicable requirement for the above sources in Tables IV-AQ and VII-AH.

Table II-B currently lists 60.104(a)(2) for A4181 and does not list the requirement for A1501, A1517 and A1518. For consistency, the Revision 2 Permit ~~includes~~ ~~District will add~~ 40 CFR sec. 60.104(a)(2) for A1501, A1517 and A1518 in Table II-B.

I.C. Engines Combusting Fuel Gas:

Shell does not operate any internal combustion (I.C.) engines that burn fuel gas.

EPA Comment:

EPA requested ~~that~~ the District ~~to~~ examine flares S1470 and S4201 for federal enforceability of efficiency requirements and include monitoring requirements. Please refer to item 1 in an e-mail from the EPA to the District dated 9/30/04.

District's Response:

S1470 – LOG LPG Loading Flare:

Flare S1470 is a control device that is routinely used to control emissions from the liquefied petroleum gas (LPG) Loading Rack (S4338). Source S4338, is a non-gasoline organic liquid loading rack used for loading propane, and is potentially subject to Regulation 8, Rule 6 “Organic Liquid Bulk Terminals and Bulk Plants.” However, S4338 is exempt from the requirements of the above rule per Section 117.

The exemption provided in Section 110.3 of Regulation 8, Rule 1 applies to those sources that are either subject to Regulation 8, Rule 2 “Miscellaneous Operations” or Regulation 8, Rule 4 “General Solvent and Surface Coating Operations.” ~~Neither of those regulations which applies to S1470. This is because~~ Section 201 in Regulation 8, Rule 2 defines a miscellaneous operation as “any operation other than those limited by the other Rules of this Regulation 8 and the Rules of Regulation 10.” ~~Because since S1470 is used to abate~~ emissions from a source that is subject to the requirements in Regulation 8, Rule 6, the operation of S1470 is not a “miscellaneous operation” and therefore, Regulation 8, Rule 2 does not apply. Accordingly, the District deleted ~~In light of the above, Sections 110 and 110.3 of Regulation 8, Rule 1 in Table IV-AW will be deleted from the Revision 2 Permit Shell's permit.~~

Table IV-AW lists NSPS Subpart A requirements applicable to S1470 and references 40 CFR sec. 60.11, “Compliance with standards and maintenance requirements,” among other requirements. Section 60.11(d) pertains to the use of good air pollution control practices at S1470 to ensure emissions from the flare are minimized. In addition, Table VII-AN lists the control device requirements for flares such as S1470 contained in Section 60.18 (c) through (f). Compliance with the above sections is monitored by inspection of the records of the heat content and maximum tip velocity at the flare. No change has been made ~~to the permit. will be made.~~

Event-based visible emissions checks will ~~will~~ ensure compliance with Regulation 6 “Particulate Matter and Visible Emissions” standards contained in Tables IV-AW and VII-AN.

~~Since it is not practically enforceable, Part 74 of a federally-enforceable permit condition 12271 which explicitly required the overall capture and destruction efficiency of 98.5% by weight for S1470 while abating organic compound emissions from S4338. The District has to be 98.5% by weight has been deleted~~ Part 74 because it is not practically enforceable.

Based on these facts, the District ~~has~~ determined that Shell's permit contains adequate federally enforceable efficiency and monitoring requirements.

S4201 –DC Clean Fuels Flare:

S4201 ~~is used to control~~ emissions resulting from process upsets from DC Clean Fuels sources:

- S4211, DC V-13222 ISOM Maintenance Drop Out Vessel

- S4212, DC V-13441 ISOM Maintenance Drop Out Vessel
- S4080, DC Isomerization Unit (ISOM)
- S4140, DC Heavy Cracked Gasoline Hydrotreater (HGHT)
- S4160, DC Hydrogen Plant 3 (HP3)
- S4180, OPCEN Sulfur Plant 4 (SRU4)
- S4001, DC Delayed Coking Unit (DCU)
- S4020, DC Distillate Hydrotreater (DHT)
- S4050, DC Catalytic Gas Depentanizer (CGDP)

The District's Regulation 8 "Organic Compounds" does not contain specific rules that address emissions resulting from process upsets at the above sources/processes. Therefore, source S4201 is potentially subject to Regulation 8, Rule 2 "Miscellaneous Operations." However, Section 110.3 in Regulation 8, Rule 1 "General Provisions" exempts sources such as S4201 from the provisions of Regulation 8 "Organic Compounds" if it can be determined that 90% of the organic carbon contained in the organic compound emissions routed to the flare is oxidized to carbon dioxide. The District has determined that this flare meets the 90% destruction efficiency requirements. Therefore, Table IV-CX lists Sections 110 and 110.3 of Regulation 8, Rule 1 as applicable requirements.

Table IV-CX lists NSPS Subpart A requirements as applicable to S4201 and references 40 CFR 60.11, "Compliance with standards and maintenance requirements," among other requirements. Section 60.11(d) pertains to the use of good air pollution control practices at S4201 to ensure emissions from the flare are minimized. In addition, Tables IV-CX and VII-CI list the non-federally enforceable requirements contained in Regulation 12, Rule 11 "Miscellaneous Standards of Performance: Flare Monitoring at Petroleum Refineries." Compliance with the requirements to continuously monitor the flow rate and the composition of the gases flared is verified by inspection.

Event-based visible emissions checks ensures compliance with Regulation 6 "Particulate Matter and Visible Emissions" standards contained in Tables IV-CX and VII-CI.

Tables A.1 and A.2 in Part A under "General Permit Conditions" of permit condition 12271 explicitly limit the monthly and annual emissions from sources, including S4201, that were part of Shell's Clean Fuels Project. Compliance with the limits outlined in the above tables ~~will be~~ are verified by inspection. In addition, part 61 of permit condition 12271 explicitly requires S4201 to have a hydrocarbon destruction efficiency of 98.5% by weight.

Part 12 of permit condition 18618 explicitly limits the quantity of vent gas combusted at S4201, ~~and Shell is required by p~~ Part 13 of the permit condition requires the facility to maintain records outlining the quantity of vent gas combusted at S4201 on an hourly basis.

In light of the above discussion, it is evident that Shell's permit contains adequate federally enforceable efficiency and monitoring requirements.

Corrections made to other flare tables:

There are nine flares at Shell, of which four serve as control devices (A101, A102, A103, and S1470), and the remaining five are used to control emissions resulting from process upsets (S1471, S1472, S1771, S1772 and S4201).

As previously discussed under S1470, the exemption provided in Section 110.3 of Regulation 8, Rule 1 applies to those sources that are either subject to Regulation 8, Rule 2, “Miscellaneous Operations,” or Regulation 8, Rule 4, “General Solvent and Surface Coating Operations.” The “pencil flares” at Shell (A101, A102, and A103) serve as alternate emissions control devices for several storage tanks subject to Regulation 8, Rule 5, “Storage of Organic Liquids,” when the vapor recovery system is down. ~~Because~~^{Since} the pencil flares are used only to abate emissions from sources that are subject to the requirements in Regulation 8, Rule 5, the operation of the pencil flares is not a “miscellaneous operation” and therefore, Regulation 8, Rule 2 does not apply. In light of the above, Sections 110 and 110.3 of Regulation 8, Rule ~~have been 1,~~ ~~will be~~ deleted from Tables IV-AXa and AXb in the Revision 2 Shell’s pPermit. ~~Further~~^{In addition,} Sections 306, 328.1.2, 502, 603.1 and 603.2 of Regulation 8, Rule 5, ~~have~~ ^{will be} added to Tables IV-AXa and AXb. ~~The above tables, and testing & monitoring provisions contained in Sections 502, 603.1, and 603.2~~ ^{havewill be} added to Table VII-AOa.

As previously discussed under S4201, the District’s Regulation 8, “Organic Compounds,” does not contain specific rules that address emissions resulting from process upsets at sources/processes abated by flares S1471, S1472, S1771, and S1772. Therefore, the above flares are potentially subject to Regulation 8, Rule ~~2-2,~~ “Miscellaneous Operations.” However, Section 110.3 in Regulation 8, Rule 1 “General Provisions” exempts sources such as S1471, S1472, S1771, and S1772 from the provisions of Regulation 8, “Organic Compounds,” if it can be determined that 90% of the organic carbon contained in the organic compound emissions routed to the flares are oxidized to carbon dioxide. In light of the above, Tables IV-AXc, BW, and BX list Sections 110 and 110.3 of Regulation 8, Rule 1 as applicable requirements.

~~Lastly,~~ part 12 of permit condition 18618 explicitly limits the quantity of vent gas combusted at S1471, S1472, S1771, and S1772. ~~and Shell is required by p~~Part 13 of the permit condition requires the facility to maintain records outlining the quantity of vent gas combusted at the above flares on an hourly basis.

EPA Comment:

Source S2007 (Dissolved Nitrogen Flootation Unit) and S2008 (Dissolved Nitrogen Flootation Unit) are not included in the list of uncontrolled sources handling aqueous benzene waste streams. Therefore, the units should be subject to 40 CFR 61.354(d). EPA requested that -the District ~~to~~ revise the permit to specify how Shell would ~~it~~ comply with 40 CFR Section 61 FF 61.354(d) for S2007 and S2008. Please refer to item 3 (comment 123) in an e-mail from ~~the~~ EPA to the District dated 8/2/04.

District’s Response:

~~Per~~ 40 CFR 61, Subpart FF (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 ~~is~~ required to manage and treat both aqueous and non-aqueous waste streams in accordance with the requirements of ~~in~~ 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). Shell has elected to manage and treat ~~its~~~~their~~ facility waste in accordance with the requirements of per Section 61.342(e). 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~~.

As previously discussed under “NESHAP Subpart FF for non-aqueous waste streams,” there are no non-aqueous benzene waste streams at the facility at the present time. However, Section 61.342(e)(1) ~~is~~~~will be~~ included as an applicable requirement in Table IV-DV in the event the facility commences to manage and treat non-aqueous benzene waste streams during the term of this permit.

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).

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 must be counted toward the 6 Mg/yr limit at the point the waste is generated. For example, if ~~a~~ ~~a~~ benzene-containing wastes ~~is~~~~are~~ sent to an ETP-1 sewer during a maintenance activity (e.g. pump maintenance), the benzene in the benzene-containing waste ~~it~~ must be 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 must be operated in compliance with the appropriate control standards outlined in Sections 61.343 through 61.348. Therefore, the DNFs at ETP-2 must be controlled and the facility must 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 ~~Since~~ the carbon adsorption system that abates the DNFs at ETP-2 does not regenerate the carbon bed directly on site in the control device (carbon canisters), the facility ~~Shell~~ ~~must~~ ~~is~~ ~~required~~ ~~to~~ monitor the 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, Likewise, 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 abating the DNF's at ETP-1 and no changes ~~have~~will ~~been~~ made to the permit.

EPA Comment:

EPA requested the District to review Shell's cogeneration unit emissions increases for NSR applicability. Please refer to item 1 in Attachment 4 of EPA's October 8, 2004 letter.

District's Response:

The facility's cogeneration (cogen) units are made up of the following sources: S4190 (Turbine 1), S4191 (HRSG¹), S4192 (Turbine 2), and 4193 (HRSG).

The above sources were reviewed as part of Shell's Clean Fuels Project Permit (NSR Application: 8407) and were issued an Authority to Construct (ATC) and Permit to Operate (PTO) by the District in December 1993 and August 1996, respectively. The following table summarizes emissions that were previously estimated under NSR Application 8407:

Source #	Firing Rate (MMBTU/hr)	NOx (TPY)	POC (TPY)	CO (TPY)	PM/PM10 (TPY)	SO2 (TPY)
4190	470	35	32.94	32.94	10.29	33.95
4191	56	4.17	3.92	3.92	1.23	4.05
4192	470	35	32.94	32.94	10.29	33.95
4193	56	4.17	3.92	3.92	1.23	4.05
Total		78.34	73.72	73.72	23.04	76

The design capacity of the cogen units were listed incorrectly in the PTO issued under NSR Application 8407 and in the Initial Title V Permit and in previously-issued permits issued prior to December 16, 2004. Specifically, the above documents listed the maximum hourly firing rates of the turbines S4190 & S4192 as 470 MMBTU/hr/turbine, and the HRSGs S4191 & S4193 as 222 MMBTU/hr/HRSG. In contrast, the Bechtel Cogeneration Data Book has always listed the maximum hourly firing rates of the turbines S4190 & S4192 as 548 MMBTU/hr/turbine, and the HRSGs S4191 & S4193 as 258 MMBTU/hr/HRSG. The permit holder has affirmed that it has not modified the cogen units since their installation.

The permit holder disputed the design's maximum capacity of the cogen units in its "Draft Title V Permit Review Submittal," dated August 14, 2001, and in its "Comments on Draft Title V Permit," dated September 22, 2003. Thereafter, the permit holder appealed the cogen units' limits set forth in the Initial Permit (~~issued December 1, 2003~~). Following the District's review of the permit holder's further submissions, the District corrected the throughput limits in the Revision 1 Permit (~~issued December 16, 2004~~).

In summary: the capacities listed in the District's permits to operate and the Initial Title V permits were based on nominal firing rates contained in Shell's initial application for an Authority to Construct. However, Shell installed cogen unit's turbines and HRSGs with ~~The equipment that was~~

¹ "HRSG" refers to → Heat Recovery Steam Generators.

~~installed, however, has a higher capacities~~ than listed in the application. The facility equipment has not ~~been modified~~ the equipment since ~~their installation~~ construction. The equipment's operation, for NSR applicability purpose, is limited by the permit condition limiting emissions. NSR is triggered by an emissions increase, and none has occurred. Therefore, NSR does not apply.

Table 1 summarizes Authorities to Construct and Permits to Operate recently issued to Shell. Information provided in the table identifies those portions of Shell’s Title V permit that have been impacted as result of the District’s NSR actions.

Table 1

Application #	Application Summary	Summary of Changes made to Shell’s Title V permit in Rev. 2
3930	<p><u>Abatement of sulfur pit emissions from Sulfur Recovery Unit (SRU):</u> In accordance with a Consent Decree with the US EPA, emissions from an existing sulfur pit at SRU3 that was previously unabated, is currently routed to thermal oxidizer (A1518) located at SRU 3.</p> <p>Please refer to a copy of the engineering evaluation in Appendix C.</p>	<p>Table II-A: 1. Assigned source number S1766 to sulfur pit located at SRU 3.</p> <p>Table II-B: 1. Under the column titled “Source(s) controlled” added S1766 to the row corresponding to A1518.</p>
4106	<p><u>Removal of Stretford Plant (A75), Installation of Flexsorb Unit (A751), and Modifications to Sulfur Plant 3 (S1765):</u> Shell replaced an existing Stretford Unit (A-75) with an Exxon Mobil Flexsorb[®] Gas Treatment System/Flexsorb[®] System (A-751). The Stretford Unit used to treat Flexigas[®] (FXG) fuel produced at the Flexicoker[®] (S-1759). Both A-75 and A-751 are sulfur dioxide (SO₂) control devices because they are used to reduce hydrogen sulfide (H₂S) in FXG fuel before it is combusted and oxidized to SO₂ in refinery heaters and other combustion devices.</p> <p>Please refer to a copy of the engineering evaluation in Appendix C.</p>	<p>Changes to permit discussed under Application 9699.</p>
4192	<p><u>Modification of Hydrogen Plant #3/HP-3 (S4160):</u> Shell modified HP-3 by adding a condensate stripper system. The intent of this modification was to enhance the quality of steam produced at HP-3 by improving the removal of dissolved CO₂ and other gases, thereby reducing corrosion in the steam system. In addition, the modification also reduced the water carryover into the Steam</p>	<p>Section VI: 1. Modified part 33 of permit condition 12271 as proposed.</p>

Application #	Application Summary	Summary of Changes made to Shell's Title V permit in Rev. 2
	<p>Methane Reformer/SMR (S4161) thereby reducing damage to furnace refractory caused by water impinging on refractory tiles.</p> <p>Please refer to a copy of the engineering evaluation in Appendix C.</p>	
4688	<p><u>Loss of Exemption (LOE) I.C. Engine:</u> Modify permit condition 19097 to include S-5140 permitted under Application 7568.</p> <p>Please refer to a copy of the engineering evaluation in Appendix C.</p>	<p><u>Section VI:</u> 1. Modified part 1 of permit condition 19097 to include S-5140.</p>
4695	<p><u>Abatement of sulfur pit emissions from Sulfur Recovery Unit (SRU):</u> In accordance with a Consent Decree with the US EPA, emissions from existing sulfur pits that were previously unabated, are now routed to thermal oxidizers (A1501 or A1517) located at either SRU 1 (S1431) or SRU 2 (S1432), respectively.</p> <p>Please refer to a copy of the engineering evaluation in Appendix C.</p>	<p><u>Table II-A:</u> 1. Assigned source numbers S1578 and S1579 to <u>the</u> sulfur pits <u>that are located</u> at SRU 1 and SRU 2, respectively.</p> <p><u>Table II-B:</u> 1. Under the column titled "Source(s) controlled" added S1578 and S1579 to rows corresponding to A1501 and A1517.</p>
6745	<p>Installation of Low-NOx burners at S1760 FXU Steam Superheater: Burners at S1760 were replaced with ultra low-NOx burners. In accordance with startup conditions, Shell submitted source test results to verify the validity of the limits outlined in NOx box permit condition 18265.</p> <p>Please refer to a copy of the engineering evaluation in Appendix C.</p>	<p><u>Section VI:</u> 1. Corrected typographical error in part 5.A. "NOx Box ranges" of permit condition 18265. Specifically, changed the emission factor for S1760 from 0.5 lb/MMBTU to 0.05 lbs/MMBTU.</p>
9504	<p>Modification of Crude Unit (S1420): Shell discontinued production of a specialty lube oil that was used to be produced from San Joaquin Valley (SJV) crude oil, among other products,</p>	<p><u>Table's II-A & II-B:</u> 1. Deleted references to S1411.</p> <p><u>Table's IV-B & AL:</u> 1. Deleted references to S1411.</p>

Application #	Application Summary	Summary of Changes made to Shell's Title V permit in Rev. 2
	<p>at the Lubes Distillation Unit (S1411). Shell modified S1420 by rerouting to it the SJV crude that was previously sent to S1411 to S1420, and shut down S1411. The modification of S1420 resulted in an increase of throughput at S1420 from 160,000 bbl/day (~ 52,925,000 bbl/yr) to 178,800 bbl/day (~ 59,568,000 bbl/yr). In addition, 34 valves and 112 flanges were added to S1420 to permit S1420 to be charged at a rate of 178,800 bbl/day.</p> <p>Please refer to a copy of the engineering evaluation in Appendix C.</p>	<p><u>Section VI:</u></p> <ol style="list-style-type: none"> Deleted S1411 from part 1 of permit condition 18618. Changed daily throughput listed under S1420 in part 1 of permit condition 18618 from 160,000 bb/day to 178,800 bbl/day. Changed annual throughput listed under S1420 in part 1 of permit condition 18618 from 52,925,000 bbl/yr to 59,568,000 bbl/yr. <p><u>Table's VII-A & AE:</u></p> <ol style="list-style-type: none"> Deleted reference to S1411.
<p>9699</p>	<p><u>Title V Permit Revision:</u> Minor revision of Shell's Title V permit to incorporate changes that were part of Application 4106, discussed above.</p> <p>Please refer to a copy of the engineering evaluation in Appendix C.</p>	<p><u>Table II-B:</u> Deleted A-75; Added A-751.</p> <p><u>Tables IV-AR & VII-AI (for S1765):</u> Incorporated applicable requirements contained in the new permit condition 19748.</p> <p><u>Tables IV-BQ & VII-BF (for S1759):</u> Incorporated applicable requirements contained in the amended parts (E.2.a through E.2.d) of permit condition 7618 in Table IV-BQ, and parts E.2.a and E.2.d are referenced in Table VII-BF.</p> <p>▸</p> <p><u>Tables IV-BW & VII-BI (for S1771):</u> Incorporated applicable requirements contained in the amended parts (E.2.a through E.2.d) of permit condition 7618 in Table IV-BW, and parts E.2.b,</p>

Application #	Application Summary	Summary of Changes made to Shell's Title V permit in Rev. 2
		<p>E.2.c, and E.2.d are referenced in Table VII-BI.</p> <p>-</p> <p>Section VI:</p> <ol style="list-style-type: none"> Deleted references to A75 in part 1 of permit condition 4041. Deleted A75 from part E.2 of permit condition 7618. Amended existing permit condition 7618 (parts E.2.a through E.2.d) to include startup and shutdown conditions for S1759. Reduced the SO2 REFEMS cap in Table IV-B of permit condition 7618 by 80 lbs/day. Modified part 1 "Daily Limit" of permit condition 18618 per Reg. 2-1-234.3 for S1765 from 73 equivalent long tons /day to 150 equivalent long tons /day. Added a new permit condition 19748 for S1765 to ensure SRU modifications will comply with the expected reductions in SO2 and H2S.
10053	<p>Flexicoker Coke Transloading Operation (S6061): <u>Installation of operation that provides loading for a</u>Approximately 450 tons of coke will be loaded from hopper trucks that are equipped with self-contained particulate control filters into five rail cars within Shell using existing rail car tracks.</p> <p>Please refer to a copy of the engineering evaluation in Appendix C.</p>	<p>Table II-A:</p> <ol style="list-style-type: none"> Included new source S6061. <p>Tables IV-DX & VII-CZ:</p> <ol style="list-style-type: none"> Created a new table to include S6061 and pertinent applicable requirements. <p>Section VI:</p> <ol style="list-style-type: none"> Added new permit condition 21671.
11157 & 11158	<p>Title V Permit Revision: In accordance with a Consent Decree with the US EPA, Shell replaced burners at S1760 under Application 6745, discussed above, to reduce</p>	<p>Section VI:</p> <ol style="list-style-type: none"> Created a new permit condition 22119.

Application #	Application Summary	Summary of Changes made to Shell's Title V permit in Rev. 2
	<p>overall NOx emissions at the plant. In order for the US EPA to grant Shell credits for projects that result in NOx reductions at the refinery, the Consent Decree requires Shell to apply for and receive enforceable permit limits from the District. Application 11157 pertains to the District's issuance of an enforceable permit condition to Shell, and Application 11158 entails incorporating the permit condition issued under Application 11157 into Shell's Title V permit.</p> <p>Please refer to a copy of the engineering evaluation in Appendix C.</p>	
11159	<p><u>Title V Permit Revision:</u> Administrative Amendment to delete 85 sources (including sources 106, 107, 459, 788, 1405, 1452, 1459, 1531, 1532, 1535, 1536, 1538, 1562, 1563, 1565, 1566, 1567, 1568, 1571, 1572, 1573, 1574, and 1575).</p> <p>Please refer to a copy of the engineering evaluation in Appendix C.</p>	<p><u>Table II-A:</u> 1. Deleted sources 858, 860, 861, 1004, 1023, 1050, 1409, 1415, 1478, 1479, 1539, 1540, and 2009.</p> <p><u>Table II-B:</u> 1. Deleted sources 860, 861, 1004, 1409, 1539, and 1540.</p> <p><u>Table II-C:</u> 1. Deleted sources 30, 31, 32, 35, 36, 38, 56, 84, 90, 109, 259, 260, 261, 262, 343, 344, 368, 398, 422, 423, 424, 426, 427, 428, 514, 523, 524, 525, 526, 786, 787, 804, 822, 837, 877, 880, 926, 927, 942, 957, 958, 993, 1000, 1001, 1009, 1013, 1024, 1026, 1071, 1185, and 1564.</p> <p><u>Tables IV-R, IV-S, VII-P, VII-Q, IX-B-2 and Permit condition 4977:</u> 1. Deleted references to source 858 in Tables IV-R and VII-P. 2. Deleted tables IV-S, Permit condition 4977, and Table VII-Q</p>

Application #	Application Summary	Summary of Changes made to Shell's Title V permit in Rev. 2
		<p>since they pertain to source 858.</p> <p><u>Tables IV-B, VII-A, and Permit condition 18618:</u></p> <p>1. Deleted references to sources 860, 861, and 1004 in the above tables and part 1 of permit condition 18618.</p> <p><u>Tables IV-R, IV-X, VII-P, VII-S, IX-B-2, and Permit condition 7133:</u></p> <p>1. Deleted references to sources 1023 and 1050 in Tables IV-R and VII-P.</p> <p>2. Deleted tables IV-X, Permit condition 7133, and Table VII-S since they pertain to sources 1023 and 1050.</p> <p><u>Tables IV-B, IV-AL, VII-A, and VII-AE:</u></p> <p>1. Deleted references to source 1409 and 1415 in the above tables.</p> <p><u>Tables IV-AZ, VII-AQ, and Permit conditions 7618, 16688, 18265, and 18618:</u></p> <p>1. Deleted references to sources 1478 and 1479 in the above tables.</p> <p>2. Deleted references to sources 1478 and 1479 in permit condition 7618, 16688 (part 1), 18265 (parts 1, 5, 12, 18, and 19), 18618 (part 6).</p> <p><u>Tables IV-Hb, and VII-G:</u></p> <p>1. Deleted references to source 1539 in the above tables.</p> <p><u>Tables IV-BN, and VII-BC:</u></p> <p>1. Deleted the above tables since they pertain to source 1540.</p>

Application #	Application Summary	Summary of Changes made to Shell's Title V permit in Rev. 2
		<p><u>Tables IV-AT, IV-CI, VII-AK, VII-BT, and Permit condition 5077:</u></p> <p>1. Deleted references to source 2009 in Tables IV-R, VII-P, and permit condition 5077 (parts 10 through 12).</p> <p>2. Deleted tables IV-CI and VII-BT since they pertain to source 2009.</p> <p><u>Table IV-DW:</u></p> <p>1. Deleted sources 30, 31, 32, 35, 36, 38, 56, 84, 90, 109, 259, 260, 261, 262, 343, 344, 368, 398, 422, 423, 424, 426, 427, 428, 514, 523, 524, 525, 526, 786, 787, 804, 822, 837, 877, 880, 926, 927, 942, 957, 958, 993, 1000, 1001, 1009, 1013, 1024, 1026, 1071, 1185, and 1564.</p>
11613 & 11614	<p><u>Alterations to FCCU Catalyst Regenerator:</u></p> <p>Shell was issued a Permit to Operate under the District's Accelerated Permitting Program to perform alterations at source S-1426. Sources upstream and downstream of S-1426 will not be de-bottlenecked, and Shell will comply with the limits outlined in part 1 of permit condition 18618. Please refer to a copy of the engineering evaluation in Appendix C.</p>	No changes made to the permit
Compliance with Regulation 9-1-313.2		<p>The District hasis proposing deletion of Title V permit conditions in the five Bay Area refinery permits related to monitoring for compliance with 9-1-313.2. 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</p>

Application #	Application Summary	Summary of Changes made to Shell's Title V permit in Rev. 2
		<p>system that achieves 95% reduction of H2S from refinery fuel gas. Conditions were established in the 2003 issuance of these permits to periodically verify that a 95% reduction is being achieved. Though details vary amongst the five refineries, all permits require some form of compliance demonstration, generally involving inlet-outlet source testing. The refineries have 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 is now proposing deletion of the conditions.</p>

Table 2 summarizes Authorities to Construct and Permits to Operate issued to Shell after April 2005. Information provided in the Table 2 identifies those portions of Shell's Title V permit that have been impacted as result of the District's NSR actions.

Table 2

<u>Application #</u>	<u>Application Summary</u>	<u>Summary of Changes made to Shell's Draft Rev. 2 Title V permit that was issued for public comment on April 13, 2005</u>
12473	<p><u>Gasoline Dispensing Facility # 7114:</u> <u>The District authorized Shell to replace the existing Phase I vapor recovery equipment on their gasoline service station (S-1598) with an EVR-certified system.</u></p>	<p><u>Table IV-BO:</u> <u>1. Corrected the description for Regulation 8-7-302.12 from "Liquid Retainment Limit" to "Liquid Retention Limit".</u> <u>2. Inserted future effective date of 1/1/09 for Regulations 8-7-302.12 and 8-7-302.13.</u> <u>3. Added parts 1 and 2 of permit</u></p>

<u>Application #</u>	<u>Application Summary</u>	<u>Summary of Changes made to Shell's Draft Rev. 2 Title V permit that was issued for public comment on April 13, 2005</u>
		<p>condition 21593 as applicable requirements for S-1598.</p> <p>Section VI: 1. Added a new permit condition (# 21593) to govern the operation of S-1598.</p> <p>Table VII-BD: 1. Revised the "Monitoring Type" description for column entries corresponding to Regulations 8-7-301.13 and 8-7-602 from "Tightness Test" to "Static Pressure Performance Test, ST-30". 2. Revised the "Monitoring Type" description for column entries corresponding to Regulations 8-7-302.14 and 8-7-601 from "Back Pressure Test" to "Dynamic Back Pressure Test (ST-27). 3. Added a row entry for the new applicable requirement associated with part 2 of the new permit condition (# 21593).</p>
<p><u>12731 & 12732</u></p>	<p><u>Dimersol re-rate project:</u> <u>The District authorized Shell to perform certain modifications/alterations at sources S-1427, S-1430, and S-1764, and approved the company's proposal to change the catalyst formulation at CCU (S-1426), which would result in an increase in C3/C4 production in lieu of heavier CCU products i.e. gas oils, etc. The expected increase in C3 yield would result in an increase in dimate processing capacity of the DIMER unit (S-1764) from 3,200 bbl/day to 4,000 bbl/day.</u> Please refer to a copy of the engineering</p>	<p>Section VI: 1. Modified part 1 "Daily Limit" of permit condition 18618 per Reg. 2-1-234.3 for S1764 from 3,200 bbl/day to 4,000 bbl/day.</p>

<u>Application #</u>	<u>Application Summary</u>	<u>Summary of Changes made to Shell's Draft Rev. 2 Title V permit that was issued for public comment on April 13, 2005</u>
	evaluation in Appendix C.	
13078	<p><u>Ultra Low NOx Burners (ULNBs) Retrofit:</u> The District authorized Shell to replace burners at the following sources located at their Catalytic Reformer Unit and Saturates Gas Plant: S-1495 through S-1500, and S-1762.</p>	No changes were made to the Revision 2 P-permit.
13085 & 13086	<p><u>Modification of the Total Reduced Sulfur (TRS) Limit for two Delayed Coker Unit (DCU) Heaters:</u> The District modified permit condition 12271 that governs the operation of sources that were part of Shell's Clean Fuels Project (CFP), which were permitted under application # 8407. Specifically, the District modified part 18 of permit condition 12271 as it relates to the operation of two DCU heaters (S-4002 and S-4003).</p>	<p><u>Table IV-CP:</u> 1. Replaced the reference to part 18 in permit condition 12271 to part 18.a.</p> <p><u>Section VI:</u> 1. Modified permit condition 12271 by splitting up part 18 of the permit condition into two separate subparts i.e. parts 18 and 18.a. Specifically, the modified part 18 is intended to govern all CFP sources except for the two DCU heaters (S-4002 and S-4003), and the new part 18.a. is solely intended to govern the two DCU heaters.</p> <p><u>Table VII-BY:</u> 1. For a row corresponding to the SO2 Limit, changed the reference to part 18 of permit condition 12271 to part 18.a. 2. Changed the TRS limit from 70 ppm to 100 ppm expressed as H₂S, 12-month average.</p>
13410	<p><u>Ultra Low NOx Burners (ULNBs) Retrofit:</u> The District authorized Shell to replace burners at the following sources S-1510 and S-1511.</p>	No changes were made to the Revision 2 P-permit.
14224	<p><u>Ethanol Tank:</u> The District authorized Shell to</p>	1. Deleted S-129 from Table's II-

<u>Application #</u>	<u>Application Summary</u>	<u>Summary of Changes made to Shell's Draft Rev. 2 Title V permit that was issued for public comment on April 13, 2005</u>
	demolish an existing 15,000 bbl floating roof tank (S-129) that was used to store gasoline, and erect a new 15,000 bbl internal floating roof tank (S-6062) at S-129's existing location.	<p><u>A, IV-B, IV-Ja, VII-A, VII-H, and IX.B-1. Deleted references to S-129 from part 1 of permit condition 18618 in Section VI.</u></p> <p><u>2. Added S-6062 to Table's II-A, IV-R, VII-P, and IX.B-2 in Shell's Title V permit. Added permit condition 23003 in Section VI.</u></p>

In a letter dated June 21, 2005 to the District, Shell indicated that sources S-1412, S-1476, and S-1477, have been retired from service. The District modified the Title V permit administratively to delete references to the ~~refore,~~ references to the ~~above~~ sources ~~have been deleted~~ from the following sections in ~~Shell's Title V~~ the permit administratively:

- S-1412: Table's II-A, IV-AL, and VII-AE.
- S-1476: Table's II-A, IV-AY, AZ, & CS, permit condition's 7618, 16688, 18265, & 18618, and VII-AP.
- S-1477: Table's II-A, IV-AY, AZ, & CS, permit condition's 7618, 16688, 18265, & 18618, and VII-AP.

In a letter dated July 20, 2006 to the District, Shell indicated that sources S-1416, S-1484, S-4170, and S-4171, have been retired from service. The District modified the Title V permit administratively to delete ~~refore,~~ references to those ~~above~~ sources ~~have been deleted~~ from the following sections in ~~Shell's Title V~~ the permit administratively:

- S-1416: Table's II-A & B, IV-B & AL, permit condition 18618, and VII-A & AE.
- S-1484: Table's II-A, IV-AZ, & AZa, permit condition's 7618, 16688, 18265, & 18618, and VII-AQ & AQa.
- S-4170: Table's II-A & B, IV-B, AL, & CR, permit condition's 12271 & 18618, and VII-A, AE, & CA.
- S-4171: Table's II-A, IV-CS & CSa, permit condition's 12271, 16688, 18265, & 18618, and VII-CB. In addition to the above, Table VII-CC that contained the monitoring requirements for S-4171 has been deleted from Shell's Title V permit.

II. Equipment

Section II of the permit, "Equipment," was modified as follows:

- Sulfur pits at SRU1, SRU2, and SRU3 have been assigned source numbers S1578, S1579, and S1766, respectively.
- The abatement device table has been modified to reflect that emissions from sources S1578 and S1579 are abated by A1501 and A1517. In similar fashion, the table has been modified to indicate that emissions from S1766 are abated by A1518.
- Deleted references to S1411.
- Deleted references to A75 and added A751.
- Added a new source S6061.
- Added 60.104(a)(2) as an applicable requirement for A1501, A1517, and A1518.
- A determination was made that the 98.5% overall capture and destruction efficiency for S1470 in part 74 of permit condition 12271 is not practically enforceable. Therefore, the above requirement was deleted in Table II B.
- Deleted sources 858, 860, 861, 1004, 1023, 1050, 1409, 1415, 1478, 1479, 1539, 1540, and 2009 in Table II-A.
- Deleted sources 860, 861, 1004, 1409, 1539, and 1540 in Table II-B.
- Deleted sources 30, 31, 32, 35, 36, 38, 56, 84, 90, 109, 259, 260, 261, 262, 343, 344, 368, 398, 422, 423, 424, 426, 427, 428, 514, 523, 524, 525, 526, 786, 787, 804, 822, 837, 877, 880, 926, 927, 942, 957, 958, 993, 1000, 1001, 1009, 1013, 1024, 1026, 1071, 1185, and 1564 in Table II-C.
- Deleted abatement devices A2 (abating sources S860, S861, and S1004), A11 (abating S1411), and A27 (abating sources S1409 and S1539) from Table II-B, because all the above sources were retired from service. All sources, except ~~for~~ source S1411, were deleted under Application 11159; ~~and~~ source S1411 was deleted under Application 9504.
- Deleted sources 129, 1412, 1416, 1476, 1477, 1484, 4170, and 4171 from Table II-A. In addition, added S6062 to Table II-A and deleted S1416 from Table II-B.

III. Generally Applicable Requirements

No change has been made to this section.

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) listed following the corresponding District Rules. SIP rules are District rules that have been approved by EPA into 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 portions of the SIP rule are cited separately after the District rule. The SIP portions will be federally

enforceable; the non-SIP versions will not be federally enforceable, unless EPA has approved them 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's or EPA's 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.

- Deleted references to S1411 in Tables IV-B and AL.
- Incorporated applicable requirements that are part of a new permit condition 19748 for S1765 in Table IV-AR.
- Incorporated applicable requirements contained in the amended parts (E.2.a through E.2.d) of permit condition 7618 in Table IV-BQ.
- Incorporated applicable requirements contained in the amended parts (E.2.a through E.2.d) of permit condition 7618 in Table IV-BW.
- Created a new table IV-DX for S6061 and the pertinent applicable requirements.
- Added the parts 12 through 14 of permit condition 4288 that pertain to Shell's Alternate Monitoring Plan for A100 in Table IV-CF.
- Deleted Sections 110 and 110.3 of Regulation 8, Rule 1 in Table IV-AW for S1470.
- Deleted Sections 110 and 110.3 of Regulation 8, Rule 1 in Table's IV-AXa (for A101 & A102) and AXb (for A103).
- Added Sections 306, 328.1.2, and 502 of Regulation 8, Rule 5 in Table's IV-AXa (for A101 & A102) and AXb (for A103).
- Deleted Regulation 8, Rule 2 applicable requirements in Tables IV-AS and CY for cooling water towers S1457, S1778, and S4210.
- Changed the textual description of citation 61.342(e)(2) in Table IV-DV.
- A determination was made that the 98.5% overall capture and destruction efficiency for S1470 in part 74 of permit condition 12271 is not practically enforceable. Therefore, the above requirement was deleted from Table IV-AW.
- Deleted references to source 858 in Table IV-R. ~~Likewise, d~~ Deleted table IV-S ~~because since~~ it pertains to source 858.
- Deleted references to sources 860, 861, and 1004 in ~~T~~table IV-B.
- Deleted references to sources 1023 and 1050 in Table IV-R. ~~D~~ Likewise, ~~de~~leted table IV-X ~~because since~~ it pertains to sources 1023 and 1050.
- Deleted references to sources 1409 and 1415 in ~~T~~tables IV-B and AL.
- Deleted references to sources 1478 and 1479 in Table IV-AZ.
- Deleted references to source 1539 in Table IV-AHb.
- Deleted Table IV-BN since it pertains to source 1540.

- Deleted references to source 2009 in Table IV-AT. ~~DLikewise, deleted T~~table IV-CI because since it pertains to source 2009.
- Deleted references to sources 30, 31, 32, 35, 36, 38, 56, 84, 90, 109, 259, 260, 261, 262, 343, 344, 368, 398, 422, 423, 424, 426, 427, 428, 514, 523, 524, 525, 526, 786, 787, 804, 822, 837, 877, 880, 926, 927, 942, 957, 958, 993, 1000, 1001, 1009, 1013, 1024, 1026, 1071, 1185, and 1564 in Table IV-DW.
- Changed the effective dates for Section 63.1574(f)(1) in Tables IV-AOa, AP, AQa, and AQb from 5/11/05 to 9/8/05.
- Changed the effective dates for Section 63.1574(f)(2) in Tables IV-AOa, AP, AQa, and AQb from 5/11/05 to 4/11/05.
- Although part 1 of permit condition 18265 lists S1800 as being equipped with CEMS, Table IV-BZ incorrectly references parts 1 through 7, 9 through 15, and 17 through 21, of the above permit condition. Therefore, Table IV-BZ has been revised to correctly reference parts 1, 2, 8, 10, 11, 13, 14, 15, 17, 20, and 21. In addition, part 16 of permit condition 18265 that pertains to S1800 has been added to Table IV-BZ.
- Parts 1 through 5 of permit condition 22165 governing ESPs A12, A13, and A14 abating CO Boilers S1507, S1509, and S1512, respectively, have been incorporated as non-federally enforceable applicable requirements in Table IV-BK.
- Source S1760 is equipped with CEMS. Therefore, reference to the source has been deleted from Table IV-AZ. A new Table IV-AZb for S1760 has been added to the permit.
- Corrected the description for Regulation 8-7-302.12 from “Liquid Retainment Limit” to “Liquid Retention Limit” in Table IV-BO (for S-1598). In addition, inserted a future effective date of 1/1/09 for Regulations 8-7-302.12 and 8-7-302.13, and added parts 1 and 2 of permit condition 21593 as applicable requirements.
- Replaced the reference to part 18 in permit condition 12271 to part 18.a in Table IV-CP (for S-4002 and S-4003).
- Deleted references to source 129 from Tables IV-B and Ja, and added reference to source 6062 in Table IV-R.
- Deleted references to S1412 from Table IV-AL; deleted references to S1476 and S1477 from Tables IV-AY, AZ, & CS.
- Deleted references to S1416 from Tables IV-B & AL; deleted references to S1484 from Tables IV-AZ, & AZa; deleted references to S4170 from Tables IV-B, AL, & CR; deleted references to S4171 from Tables IV-CS & Csa.

V. Schedule of Compliance

No change has been made to this section.

VI. Permit Conditions

The District has issued this Revision 2 Permit as a result of ~~As part of the Revision 1 Title V~~ Permit reopening, several administrative permit amendments, and for clarification and enforceability of certain permit conditions. For example, as a result of the Revision 1 Permit reopening, the District is ~~proposing changes made to several~~ has modified permit conditions pertaining to flares and Regulation 9-10 requirements, ~~and, as appropriate, revised conditions for clarity and enforceability.~~ The Title V permit is being updated to accurately reflect these applicable requirements. ~~All changes to existing permit conditions are clearly shown in “strike out/underline” format in the proposed permit. When the permit is issued, all “strikeout” language will be deleted; all “underline” language will be retained,~~ subject Flame

- Modified part 33 of permit condition 12271.
- Modified part 1 of permit condition 19097.
- Corrected a typographical error in part 5.A. for S1760 in permit condition 18265.
- Deleted S1411 from part 1 of permit condition 18618.
- Changed daily throughput listed under S1420 in part 1 of permit condition 18618 from 160,000 bbl/day to 178,800 bbl/day.
- Changed annual throughput listed under S1420 in part 1 of permit condition 18618 from 52,925,000 bbl/yr to 59,568,000 bbl/yr.
- Deleted references to A75 in part 1 of permit condition 4041.
- Deleted A75 from part E.2 of permit condition 7618.
- Amended existing permit condition 7618 (parts E.2.a through E.2.d) to include startup and shutdown conditions for S1759.
- Reduced the SO₂ REFEMS cap in Table IV-B of permit condition 7618 by 80 lbs/day.
- Modified part 1 “Daily Limit” of permit condition 18618 per Reg. 2-1-234.3 for S1765 from 73 equivalent long tons /day to 150 equivalent long tons /day.
- Added a new permit condition 19748 for S1765.
- Added a new permit condition 21671.
- Added a new permit condition 22119.
- Added parts 12 through 14 to permit condition 4288 in light of Shell’s Alternate Monitoring Plan for A100.
- A determination was made that the 98.5% overall capture and destruction efficiency for S1470 is not practically enforceable. Therefore, the above requirement was deleted from part 74 of permit condition 12271.
- Deleted permit condition 4977 since it pertains to source 858.
- Deleted references to sources 860, 861, and 1004 in part 1 of permit condition 18618.
- Deleted permit condition 7133 since it pertains to sources 1023 and 1050.
- Deleted references to sources 1409 and 1415 in tables Table IV-B and AL.
- Deleted references to sources 1478 and 1479 in permit condition 7618, 16688 (part 1), 18265 (parts 1, 5, 12, 18, and 19), 18618 (parts 1 and 6).
- Deleted references to source 2009 in permit condition 5077 (parts 10 through 12).
- Deleted part 115 of permit condition 12271 and part 10 of permit condition 18618, pertaining to Regulation 9-1-313.2.
- Permit condition 18265, Part 1 lists which of those sources are equipped with CEMS. The following sources governed by permit condition 18265 are not equipped with

CEMS:

S1476, S1477, S1480, S1481, S1483, S1484, S1506, S4021, and S4171.

The following sources governed by permit condition 18265 are equipped with CEMS: 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

- Added a new permit condition 21593 for S1598.
- Modified part 1 “Daily Limit” of permit condition 18618 per Reg. 2-1-234.3 for S1764 from 3,200 bbl/day to 4,000 bbl/day.
- Modified permit condition 12271 by splitting up part 18 of the permit condition into two separate subparts i.e. parts 18 and 18.a. Specifically, the modified part 18 is intended to govern all sources that were permitted under the Clean Fuels Project application except for the two DCU heaters (S-4002 and S-4003), and the new part 18.a. is solely intended to govern the two DCU heaters.
- Deleted references to S129 from part 1 of permit condition 18618; added a new permit condition 23003 for S6062.
- Deleted references to S1476 and S1477 in permit condition’s 7618, 16688, 18265, & 18618.
- Deleted references to S1416 in permit condition 18618; deleted references to S1484 in permit condition’s 7618, 16688, 18265, & 18618; deleted references to S4170 in permit condition’s 12271 & 18618; deleted references to S4171 in permit condition’s 12271, 16688, 18265, & 18618.

For sources that are equipped with CEMS, Parts 1, 2, 8, 10, 11, 13, 14, 15, 17, 20, and 21 are applicable requirements and are listed in Tables IV-BA, BC, BD, BG, BL, BZ, and CU. For sources that are not equipped with CEMS, Parts 1 through 7, 9 through 15, and 17 through 21 are applicable requirements and are listed in Tables IV-AY, AZ, and CS.

Note that S1800 is equipped with CEMS. The permit has incorrectly listed parts 1 through 7, 9 through 15, and 17 through 21 as the applicable requirements in Table IV-BZ. Therefore, this Revision 2 permit revises Table IV-BZ to list the correct applicable requirements (Parts 1, 2, 8, 10, 11, 13, 14, 15, 17, 20, and 21). This Revision 2 permit also adds to Table IV-BZ part 16 of permit condition 18265 as an applicable requirement of S1800.

Sources S1508 and S1760 are equipped with CEMS. The permit also incorrectly listed parts 12, 18, and 19 of permit condition 18265 as applicable requirements of S1508. This revision deletes S1508 from parts 12, 18 and 19. Table IV-BA was correct and not revised. Similarly, this revision deletes S1760 from parts 1, 5, 12, 18, and 19 of permit condition 18265. This Revision 2 permit also deletes S1760 from Table IV-AZ and VII-AQ and adds two new Tables IV-AZb and VII-AQb for S1760.

This Revision 2 permit replaces in the Tables the future effective date for a number of these applicable requirements from 12/01/04 to January 1, 2005. The permit also adds the future effective date of January 1, 2005 for permit condition 18265, part 11. In addition, part 11 has been amended to explicitly list sources that are equipped with CEMS.

- Permit condition 22165 consisting of parts 1 through 5 governing ESPs A12, A13, and A14 abating CO Boilers S1507, S1509, and S1512, respectively, was added to the permit.

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, the frequency of monitoring, and the 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.

- Deleted references to S1411 in Tables VII-A and AE.
- Incorporated applicable requirements that are part of a new permit condition 19748 for S1765 in Table VII-AI.
- Incorporated applicable requirements contained in the amended parts (E.2.a through E.2.d) of permit condition 7618 in Table VII-BF.
- Incorporated applicable requirements contained in the amended parts (E.2.a through E.2.d) of permit condition 7618 in Table VII-BI.
- Created a new table IV-DX for S6061 and the pertinent applicable requirements.
- Added the parts 12 through 14 of permit condition 4288 that pertain to Shell's Alternate Monitoring Plan for A100 in Table VII-BR.
- Added Sections 502, 603.1, and 603.2 of Regulation 8, Rule 5 in Table VII-AOa (for A101, A102 & A103).
- Deleted Regulation 8, Rule 2 applicable requirements in Table VII-AJ for cooling water towers S1457, S1778, and S4210.
- A determination was made that the 98.5% overall capture and destruction efficiency for S1470 in part 74 of permit condition 12271 is not practically enforceable. Therefore, the above requirement was deleted from Table's VII-AN and VII-CS.
- Deleted references to source 858 in Table VII-P. Likewise, deleted table VII-Q since it pertains to source 858.
- Deleted references to sources 860, 861, and 1004 in table VII-A.
- Deleted references to sources 1023 and 1050 in Table VII-P. Likewise, deleted table VII-S since it pertains to sources 1023 and 1050.
- Deleted references to sources 1409 and 1415 in tables VII-A and AE.
- Deleted references to sources 1478 and 1479 in Table VII-AQ.
- Deleted references to source 1539 in Table VII-G.
- Deleted Table VII-BC since it pertains to source 1540.
- Deleted references to source 2009 in Table VII-P. Likewise, deleted table VII-BT since it pertains to source 2009.
- Deleted references to sources 30, 31, 32, 35, 36, 38, 56, 84, 90, 109, 259, 260, 261, 262, 343, 344, 368, 398, 422, 423, 424, 426, 427, 428, 514, 523, 524, 525, 526, 786, 787, 804, 822, 837, 877, 880, 926, 927, 942, 957, 958, 993, 1000, 1001, 1009, 1013, 1024, 1026, 1071, 1185, and 1564 in Table IV-DW.
- Changed references to Regulation 8-10-501 and 502 in Table's VII-AE, AG, CK, and CL to reflect the above sections are SIP approved.
- Deleted references to Regulation 9-1-313.2 in Tables VII-AH, CF, and CY.
- Source S1760 is equipped with CEMS. Therefore, reference to the source has been deleted from Table VII-AQ. A new Table VII-AQb for S1760 has been added to the permit.

- Part 1 of permit condition 22165 governing ESPs A12, A13, and A14 abating CO Boilers S1507, S1509, and S1512, respectively, has been incorporated as non-federally enforceable continuous monitoring requirement in Table VII-BA.
- In Table VII-BD (for S1598), revised the “Monitoring Type” description for column entries corresponding to Regulations 8-7-301.13 and 8-7-602 from “Tightness Test” to “Static Pressure Performance Test, ST-30”. In addition, revised the “Monitoring Type” description for column entries corresponding to Regulations 8-7-302.14 and 8-7-601 from “Back Pressure Test” to “Dynamic Back Pressure Test (ST-27). Lastly, added a row entry for the new applicable requirement associated with part 2 of the new permit condition (# 21593).
- In Table VII-BY (for S4002 & S4003), changed the reference to the SO2 limit outlined in permit condition 12271 from part 18 to part 18.a. In addition, changed the TRS limit from 70 ppm to 100 ppm expressed as H₂S, 12-month average.
- Deleted references to S129 in Table’s VII-A and H; added references to S6062 in Table VII-P.
- Deleted references to S1412 in Table VII-AE; deleted references to S1476 & S1477 in Table VII-P.
- Deleted references to S1416 in Table’s VII-A & AE; deleted references to S1484 in Table’s VII-AQ & AQA; deleted references to S4170 in Table’s VII-A, AE, & CA; deleted references to S4171 in Table VII-CB. In addition, deleted Table VII-CC that contained the monitoring requirements for S-4171.

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.

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

Changes to the permit in this revision:

None.

IX. Permit Shields

Changes made to this section of the permit generally reflect the changes to other parts of the permit that have previously been discussed.

- Due to the changes noted in Table IV and VII for S1772, S1772 should also be added to Permit Shield IX A-12 to indicate that it is not subject to Subpart J.

Based on comments received by EPA, the following table has been developed to further explain the reasoning behind the permit shields requested by the facility:

A correction has been made in the reason cited for shielding S1470 from the requirements of Regulation 12, Rule 11, “Miscellaneous Standards of Performance: Flare Monitoring at

Petroleum Refineries,” in Section IX “Permit Shield.” Specifically, a paragraph in Table IX-A-2 states the following:

“Miscellaneous Standards of Performance – Flare Monitoring at Petroleum Refineries (Per BAAQMD Regulation 12-11-110, the provisions of BAAQMD Regulation 12, Rule 11 do not apply to flares or thermal oxidizers used to control emissions exclusively from organic liquid storage vessels subject to BAAQMD Regulation 8, Rule 5 or exclusively from loading racks subject to BAAQMD Regulation 8 Rules 6, 33, or 39. Flares S1470, A101, A102, and A103 serve organic liquid storage vessels subject to BAAQMD Regulation 8, Rule 5 and are therefore exempt from BAAQMD Regulation 12, Rule 11.)”

While it is true that S1470 is used to control emissions from S4338, a LPG loading rack that is potentially subject to, but is exempt from, the requirements in Regulation 8, Rule 6, the second sentence in the above paragraph incorrectly states that S1470 abates organic compound emissions from storage vessels subject to Regulation 8, Rule 5. In light of the above, the reference to S1470 will be deleted from the second sentence of the above paragraph in Table IX-A-2.

Deleted references to sources 858, 1023, and 1050 in Table IX-B-2.

D. Alternate Operating Scenarios:

No alternate operating scenario has been requested for this facility.

E. Compliance Status:

Changes to the permit in this revision:

The facility is not currently in violation of any requirement. Moreover, the District has updated its review of recent violations and has not found a pattern of violations that would warrant imposition of a compliance schedule.

H:\pub_data\titleV\permit\sob\A0011soba-1.doc

APPENDIX A
GLOSSARY

ACT

Federal Clean Air Act

APCO

Air Pollution Control Officer: Head of Bay Area Air Quality Management District

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

CAPCOA

California Air Pollution Control Officers Association

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

CCR-2

Canadian Chemical Reclaimer heater.

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). Used to determine whether threshold-based requirements are triggered.

District

The Bay Area Air Quality Management District

dscf

Dry Standard Cubic Feet

DNF

Dissolved Nitrogen Flotation.

EPA

The federal Environmental Protection Agency.

ETP

Effluent Treatment Plant.

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.

FCC

Fluid Catalytic Cracker

FP

Filterable Particulate as measured by BAAQMD Method ST-15, Particulate.

Furfural Raff/Furfural Extr

These sources are heaters that contain furnaces within them. The heater is the overall unit and the combustion box is the furnace.

GDF

Gasoline Dispensing Facility

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.

H2SO4

Sulfuric Acid

ISOM

Isomerization plant.

Long ton

2200 pounds

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.

MDEA

Methyl Diethanolamine

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.

MSDS

Material Safety Data Sheet

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)

NO_x

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, NO_x, 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.

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:

bbl	=	barrel
bhp	=	brake-horsepower
btu	=	British Thermal Unit
cfm	=	cubic feet per minute

g	=	grams
gal	=	gallon
gpm	=	gallons per minute
hp	=	horsepower
hr	=	hour
lb	=	pound
in	=	inches
max	=	maximum
m ²	=	square meter
m	=	thousand
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
yr	=	year

APPENDIX B

October 8, 2004 EPA Letter

APPENDIX C
ENGINEERING EVALUATIONS

**ENGINEERING EVALUATION
MARTINEZ REFINING COMPANY
PLANT NO. 11
APPLICATION NO. 3930**

BACKGROUND

This application is to vent the existing sulfur pit at Sulfur Recovery Unit No. 3 (SRU 3; S-1765) to the existing SCOT 3 catalytic oxidizer (A-1518). Martinez Refining Company (MRC) is required to abate the sulfur pit in accordance with their Consent Decree with EPA.

The sulfur pit is currently included as part of SRU 3. As part of this application, the sulfur pit at SRU 3 will be assigned its own source number. This is consistent with the SRU 4 at MRC, and with other refineries which have separate permits for sulfur pits. Although the sulfur pit will be assigned a new source number, it is not a new or modified source, as defined in Regulation 2, Rule 1.

The equipment involved with this application is:

S-1766 SRU 3 SULFUR PIT (existing); Alteration to add abatement by A-1518, F-109 Catalytic Oxidizer, SCOT 3

As a result of this project, H₂S and other sulfur compounds that are currently emitted to atmosphere will be oxidized at A-1518 to form SO₂. This will cause an increase in SO₂ emissions at the exhaust stack of A-1518. Because the additional SO₂ is a direct result of abating another source, it is considered to be a secondary pollutant. In accordance with Reg. 2-2-112, these secondary emissions are exempt from BACT requirements.

EMISSIONS SUMMARY

The additional SO₂ emissions from the exhaust of A-1518 are not quantified in this evaluation, for the following reasons.

This project does not result in an increase of the permitted level of SO₂ emissions from MRC. This is because SRU 3 is included in the emission cap that was established under permit application number 26786. This permit resulted in emission profiles (caps) for all criteria pollutants, including SO₂. These emission caps are included in Condition ID# 7618. Since SRU 3 is included under the SO₂ emission cap, and because the sulfur pit was originally permitted as part of SRU 3, the sulfur pit is also included in the SO₂ emission cap. Therefore, any additional SO₂ generated by abating the sulfur pit at SRU 3 must also be included in the SO₂ emission cap. MRC is not requesting to increase the SO₂ emission cap as part of this application. Under the cap, any SO₂ increase at the catalytic oxidizer must be “offset” by a corresponding decrease at another source under the cap.

Note that there will be a “localized” increase in SO₂ from A-1518. Normally, the District would calculate the localized increase for a source that was subject to a group emission limit (cap). The localized increase would be necessary to determine whether or not BACT is triggered. In this case, however, BACT is not required because secondary pollutants are exempt from BACT under Reg. 2-1-112. Therefore, it is not necessary to calculate the localized increase.

STATEMENT OF COMPLIANCE

As a result of this project, S-1766, SRU 3 Sulfur Pit, will comply with the Consent Decree between MRC and EPA. In addition, the SCOT 3 Catalytic Oxidizer will continue to comply with Reg. 9-1-307, which limits SO2 emissions to 250 ppm.

The project is categorically exempt from CEQA, per Reg. 2-1-312.2, because it is for the addition of abatement equipment.

The project is over 1000 feet from the nearest school and therefore not subject to the public notification requirements of Reg. 2-1-412.

A Toxic Risk Screening Analysis is not required, because there are no toxic emission increases. TBACT does not apply.

BACT, PSD, and offsets do not apply.

Per the Consent Decree between Equilon and EPA, this source will comply with NSPS, Subpart J. By abating the sulfur pit emissions with the catalytic oxidizer (A-1518), SO2 emissions from the sulfur pit will be included with other SO2 emissions from SRU 3. These emissions are monitored for compliance with the 250 ppm NSPS limit (40 CFR 60.104(a)(2)).

PERMIT CONDITIONS

As discussed above, S-1766 will be subject to the existing Condition ID# 7618. Data Bank records will be update to link ID# 7618 to S-1766.

RECOMMENDATION

Issue a Conditional Authority to Construct for the following:

S-1766 SRU 3 SULFUR PIT (existing); Alteration to add abatement by A-1518, F-109 Catalytic Oxidizer, SCOT 3

EXEMPTIONS

By: _____
Supervising Air Quality Engineer

January 24, 2002

EVALUATION REPORT

Company Martinez Refining Co.
Application # 4106
Plant # 11

1. Background:

Equilon Enterprises, LLC, Martinez Refining Company (MRC) is proposing to replace an existing Stretford Unit (A-75) with an Exxon Mobil Flexsorb[®] Gas Treatment System (Flexsorb[®] System) (A-751). The Stretford Unit is currently used to treat Flexigas[®] (FXG) fuel produced at the Flexicoker[®] (S-1759). The existing Stretford Unit (A-75) and replacement Flexsorb[®] System (A-751) are sulfur dioxide (SO₂) control devices because they are used to reduce hydrogen sulfide (H₂S) in FXG fuel before it is combusted and oxidized to SO₂ in refinery heaters and other combustion devices.

Flexsorb[®] System

The Flexsorb[®] System uses an amine scrubbing technology that selectively removes H₂S from process gas streams. Removal of H₂S in FXG fuel with the new Flexsorb[®] System will be at least as effective as the existing Stretford Unit. However, an improved H₂S removal efficiency is expected with the Flexsorb[®] System and will result in reduced SO₂ emissions from refinery combustion devices that burn FXG fuel. This project will not involve modifications or changes in throughput at the upstream system Flexicoker[®] (S-1759) or downstream combustion devices. FXG fuel production will not be effected by the proposed project.

The Flexsorb[®] System equipment can be characterized in three sections: 1) FXG Treating Column, 2) Dilute Amine Processing and 3) Fresh Amine Handling

The Flexsorb[®] System utilizes conventional amine gas treating equipment (absorber column). The amine is continuously regenerated in a steam reboiled regenerator/stripper column. The system also includes pumps, a feed/effluent heat exchanger, filters, amine storage tanks, amine and additive loading and unloading, and auxiliary facilities.

FXG Treating Column

The existing sour FXG fuel stream generated by the Flexicoker[®] is a low-Btu fuel that will be treated by the new Flexsorb[®] System before being used to fuel a number of refinery heaters. The only changes to this gas handling system will be to disconnect the Stretford Unit (A-75) and add the necessary piping, valves, and fittings to connect the Flexsorb[®] System in its place. The total number of new valves and other components will not increase by more than 50. Further, the FXG fuel consists primarily of nitrogen and carbon dioxide (CO₂) (totaling approximately 70 volume percent), combustible quantities of carbon monoxide, hydrogen, H₂S, and methane (totaling approximately 25 volume percent), and water. This gas stream is essentially free of precursor organic compounds (POCs). As a result, fugitive organic emissions are expected to be negligible.

Dilute Amine Processing

As the amine solution circulates in the absorber (approximately 35 percent solution in water) it removes H₂S from the FXG fuel stream. The solvent passes through filters and heat exchange equipment, and into the amine regenerator/H₂S stripper column. The H₂S is stripped from the amine solution, cooled, and sent to a sulfur recovery unit. The amine solution is returned to the absorber after small quantities of makeup amine solution are added, as necessary. It is expected that the steam to be used to heat the regenerator will come from the waste steam at MRC. No additional capacity from existing steam plants will be required. The proprietary amine used in the Flexsorb[®] System is a high molecular weight, high boiling point material as a 35 percent by weight mixture in water. As a result, the emissions of POC from the amine are expected to be negligible.

Fresh Amine Handling

Undiluted makeup amine will be received periodically by truck. The trucks will offload directly to the Flexsorb[®] System surge tank. Fugitive emissions from the valves, pump seal (if any), and connectors will be negligible, because there will be less than 20 new fugitive components in heavy liquid service.

Sulfur Recovery Unit No. 3 (SRU-3)

In addition to treating the FXG fuel, the existing Stretford Unit produces elemental sulfur. However, H₂S removed by the Flexsorb[®] System will be contained in an acid gas that must be conveyed to an existing Claus sulfur recovery plant for recovery of elemental sulfur. Installation of the Flexsorb[®] System will require modifications to Sulfur Recovery Unit No. 3 (SRU-3) (S-1765). With this project, the conventional Claus design of SRU-3 will be modified to an Oxy-Claus design. Oxygen will be used in place of some or all of the air in the primary combustion stage of SRU-3. Use of oxygen instead of air will reduce diluent gases (nitrogen) that restrict the total gas throughput and recovery of sulfur.

The modifications proposed by this project include changeout of the existing Claus unit burner to a BOC oxygen burner or equivalent. Other ancillary components of SRU-3 (such as pumps and heat exchangers) may be added or modified. Under similar operating conditions, the Oxy-Claus unit will generate smaller effluent gas volumes with higher pollutant concentrations than a conventional Claus unit. However, even with higher throughput, the Oxy-Claus unit will generate lower mass emissions because of improved sulfur recovery.

Minor changes will also be required for the Shell Claus Offgas Treating Unit No. 3 (SCOT-3) (A-76). The SCOT-3 recycles unrecovered sulfur back to SRU-3. A small quantity of unrecovered H₂S from SCOT-3 is converted to SO₂ by passing it through a catalytic oxidizer before venting it to the atmosphere. Overall, the Claus SRU/SCOT combination will remove in excess of 99.9 percent of the sulfur.

No changes will be required for the catalytic oxidizer (A-1518) used to control emissions from SCOT-3. The catalytic oxidizer is a source of secondary air emissions because refinery fuel gas is combusted in the heater section of the catalytic oxidizer. The quantity of refinery fuel gas combusted in this heater will not increase due to the proposed conversion of SRU-3 to an Oxy-Claus unit. A fuel increase is not needed because the mass of H₂S and volume of absorber vent gas sent to the catalytic oxidizer will decrease with an Oxy-Claus unit. There may actually be a slight fuel savings at the heater which will reduce emissions of combustion products, such as CO, nitrogen oxides (NO_x) POC,

non-precursor organic compounds (NPOC) and particulate matter less than 10 microns (PM10). Additionally, the reduced nitrogen levels with an Oxy-Claus are expected to decrease formation of NOx during combustion.

Other Emission Sources Associated with Project

Other emission sources associated with the SRU-3 include the existing methyl diethanolamine (MDEA) storage tanks. However, these tanks will not be modified with the proposed project.

Air emissions associated with the periodic, infrequent change-out of catalyst are considered negligible. Spent catalyst will be sent offsite for reprocessing and/or disposed of in accordance with state and federal regulations. Primary emissions from the unit will exit in the catalytic oxidizer stack. No additional fugitive emissions are anticipated over current levels.

In order to provide H₂S control and sulfur recovery during scheduled and forced outages of SRU-3, MRC also intends to connect Flexsorb[®] System acid gas with SRU-4 so it can be utilized as a backup to SRU-3. For added backup capability and to minimize any potential for acid gas flaring, a second header will be installed to convey DEA acid gas to SRU-1 (S-1431) and SRU-2 (S-1432). However, SRU-1 (S-1431) and SRU-2 (S-1432) do not require any modification the sources to handle any flexigas that may be sent to it for backup treatment nor do they require any change to their proposed Title V throughput limits.

Liquid storage tank(s) for oxygen, a vaporizer and connections to SRU-3 will be required. These facilities are exempt from air permitting under Regulation 2-1-123.2

2. Emission Calculations:

Emissions that will result from replacement of the existing Stretford Unit with the Flexsorb[®] System including necessary modifications to SRU-3 are estimated as follows:

Flexsorb[®] System Emissions

Part E.2 of Condition # 7618 currently limits the H₂S concentration of the treated flexigas (after the Stretford Unit, A-75) to 35 ppmv or 80 ppmv when processing more than 50% San Joaquin Valley crude. The composition of the flexigas produced during portions of the startup and shutdown of the Flexicoker (S-1759) is not compatible with the Flexsorb System (S-1765). As a result, flexigas must bypass the Flexsorb System (S-1765) to avoid contamination and deactivation of the Flexsorb solution. During startup and shutdown, the composition of flexigas prohibits its use in refinery heaters. As a result, flexigas must be routed to the flexigas flare (S-1771), which is the current procedure during startup and shutdown of the Flexicoker (S-1759). The increased emission from flexigas flaring will be minimized because the turnarounds of the Flexicoker (S-1759) are scheduled approximately once every three years for unit maintenance. Additionally, flexigas production during startup and shutdown of the Flexicoker (S-1759) is considerably below normal production levels. These periods of untreated flexigas during startup and shutdown events at the Flexicoker unit are estimated to last approximately no more than 48 to 96 hours, respectively. As a result, the facility has requested amendments to Permit Condition 7618, Part E.2. to reflect startup and shutdown limitations.. They shall also continue to comply with the NSPS limit of 163 ppmv (on a 3-hour average).

Removal of H₂S from FXG fuel with the proposed Flexsorb[®] System will be at least as efficient as with the existing Stretford Unit. The proposed control device replacement

with a Flexsorb[®] System will not increase throughput or emissions upstream at the Flexicoker[®] or downstream at combustion devices. The proposed Major Facility Review Title V throughput limits for the Flexicoker[®] will not be exceeded as a result of this project. Hence, there is no resulting emissions increase expected from the replacement of the Stretford unit (A-75) with the Flexsorb[®] System (A-751).

SRU-3 Emissions

The proposed Oxy-Claus unit will have a sulfur conversion rate significantly improved over a conventional Claus unit (S-1765). This will enable MRC to increase the total Claus throughput while achieving a net reduction in the mass of SO₂ emissions. The Flexsorb[®] System acid gas will be combined with diethanolamine (DEA) acid gas in SRU-3. The new Oxy-Claus SRU-3/SCOT-3 combination will remove well in excess of 99.9 percent of the sulfur in the acid gas feed. The existing catalytic oxidizer achieves a 95 percent weight conversion of H₂S to SO₂. Use of an Oxy-Claus unit will result in increased stack gas emission concentrations, but reduced mass emissions when compared to a conventional Claus unit. The increased concentrations are caused by the significantly reduced nitrogen diluent. Reduced mass emissions, even with increased throughput, are caused by the increased sulfur recovery capabilities with the new Oxy-Claus SRU-3/SCOT-3 combination.

Section 60.104(a)(2)(I) of 40 CFR 60 Subpart J (Standards of Performance for Petroleum Refineries) limit SO₂ emissions from Claus sulfur recovery plants to 250 ppmv at 0% excess air. The facility shall continue to meet this NSPS standard after the proposed alteration of S-1765.

SRU-3 is currently permitted within the West Of Rockies (WOR) Refinery Emissions (REFEMs) emissions cap defined by Condition No. 7618. SRU-3 has been fully offset. To establish a baseline for SRU-3 per Regulation 2-2-605.4, the District determined that the baseline throughput and baseline emission rate are based on the levels allowed by the permit condition. MRC is not proposing to change the current maximum permitted baseline emission rate. Therefore, there is no increase or decrease in maximum permitted emission limits for SRU-3.

SRU-3 currently has a maximum permitted throughput limit for inclusion in MRC's Major Facility Review Permit Title V of 73 long tons equivalent sulfur load per day. With the proposed project, maximum permitted throughput will increase to 150 long tons equivalent sulfur load per day. No changes in proposed Major Facility Review Title V throughput limits are requested for the other three sulfur plants at the Martinez facility.

The increased sulfur load at SRU-3 will not increase emissions because the Oxy-Claus unit will be significantly more efficient in converting reduced sulfur to elemental sulfur. Table 1 below indicates that the difference between pre-project potential emissions at the current permitted throughput and post-project potential emissions is a net reduction in H₂S and SO₂ emissions.

TABLE 1

Category	Potential Emissions, tons per year	
	SO ₂	H ₂ S
Post-project	28 (250ppm, 3.6MMscf/day)	0.77 (13.2 ppm, 3.6 MMscf/day)
Pre-project	34 (250 ppm, 4.41 MMscf/day)	0.95 (13.2 ppm H ₂ S, 4.41 MMscf/day)
Cumulative Change	(6)	(0.18)

Although the emissions are SO₂ are estimated to be reduced, the facility has requested that they be limited to their pre-project emissions (34 tons per year).

Catalytic Oxidizer

The catalytic oxidizer is a source of secondary air emissions because refinery fuel gas is combusted in the heater section of the catalytic oxidizer. The quantity of refinery fuel gas combusted in this heater will not increase due to the proposed conversion of SRU-3 to an Oxy-Claus unit. A fuel increase is not needed because the mass of H₂S and volume of absorber vent gas sent to the catalytic oxidizer will decrease with an Oxy-Claus unit. There may actually be a slight fuel savings at the heater, which will reduce emissions of combustion emissions including CO, NO_x, POC, NPOC and PM10. Additionally, the reduced nitrogen levels with an Oxy-Claus will result in a decreased formation of NO_x during combustion. These emission reductions are not quantified.

Fugitive Emissions

FXG Treating Column

FXG fuel contains little or no POC compounds. Therefore, fugitive leaks of FXG fuel through valves and other components are not expected to result in POC emissions. The increase of fugitive POC emissions, if any, will be negligible because the number of valves and other components in FXG service are approximately the same for both the new Flexsorb[®] System and the Stretford Unit. (The Delta increase in components will be less than 50.)

Dilute Amine Processing

The proprietary amine used in the Flexsorb[®] System is a high molecular weight, high boiling point material in a 35 percent by weight mixture in water. As a result, the emissions of POC from the unit are expected to be negligible.

Fresh Amine Handling

Undiluted makeup amine will be received periodically by truck. The trucks will offload directly to the Flexsorb[®] System surge tank. Fugitive emissions increases from the valves, pump seal (if any), and connectors will be negligible, because There will be less than 20 new fugitive components in heavy liquid service.

No Change in Other Emission Sources Associated with Project

There will be no change in emissions from other emission sources associated with the SRU-3 because:

- The existing methyl diethanolamine (MDEA) storage tanks will not be modified with the proposed project.
- Air emissions associated with the periodic, infrequent change-out of catalyst are considered negligible. Spent catalyst will be sent offsite for reprocessing and/or disposed of in accordance with state and federal regulations. Primary emissions from the unit will exit in the catalytic oxidizer stack. No additional fugitive emissions are anticipated over current levels.
- In order to provide H₂S control and sulfur recovery during scheduled and forced outages of SRU-3, MRC also intends to connect Flexsorb[®] System acid gas with SRU-4 so it can be utilized as a backup to SRU-3. For added backup capability and to minimize any potential for acid gas flaring, a second header will be installed to convey DEA acid gas to SRU-1 (S-1431) and SRU-2 (S-1432).

Toxics

The only toxic compound emissions calculated for this project are H₂S from SRU-3. There will be a decrease in H₂S emitted from SRU-3. The total potential H₂S emissions from modified SRU-3 are 1,540 pounds per year, which is below the Regulation 2-1-316 screening risk assessment trigger level of 8,100 pounds H₂S per year. Therefore, no screening risk assessment and no further action is required. The project complies with the District's Risk Management policy.

3. Statement of Compliance:

The proposed project does not have any impact on the quantity of FXG fuel produced by MRC, nor does it have any impact on the quantity of FXG fuel burned in the refinery's combustion devices. The Flexicoker[®] (S1759), which produces FXG fuel, and refinery combustion devices will not be modified, as defined in Regulation 2-1-234, and their operations will be unaffected by the proposed project. The existing Stretford Unit (A75)

does not restrict the quantity of FXG fuel production and the new Flexisorb[®] System (A751) will not allow for increased Flexicoker[®] throughput. Part E.2 of Condition # 7618 which currently limits the H₂S concentration of the treated flexigas to 35 ppmv or 80 ppmv when processing more than 50% San Joaquin Valley crude will continue to limit the H₂S concentration in the Flexisorb treated flexigas. The composition of the flexigas produced during portions of the startup and shutdown of the Flexicoker (S-1759) is not compatible with the Flexisorb System (S-1765). As a result, flexigas must bypass the Flexisorb System (S-1765) to avoid contamination and deactivation of the Flexisorb solution. During startup and shutdown, the composition of flexigas prohibits its use in refinery heaters. As a result, flexigas must be routed to the flexigas flare (S-1771), which is the current procedure during startup and shutdown of the Flexicoker (S-1759). The increased emission from flexigas flaring will be minimized because the turnarounds of the Flexicoker (S-1759) are scheduled approximately once every three years for unit maintenance. Additionally, flexigas production during startup and shutdown of the Flexicoker (S-1759) is considerably below normal production levels. These periods of untreated flexigas during startup and shutdown events at the Flexicoker unit are estimated to last approximately no more than 48 to 96 hours, respectively. As a result, the facility has requested amendments to Permit Condition 7618, Part E.2. to reflect startup and shutdown limitations.

The proposed Major Facility Review Title V throughput limits for the Flexicoker[®] will not be exceeded as a result of this project. SRU-3 (S-1765) will be modified, as defined in Regulation 2-1-234. Although there will be no emissions increase, there will be an increase in production rate that is above levels currently proposed in the draft major facility review permit. The equivalent sulfur load will increase above the annual throughput capacity of 73 long tons. The new annual throughput capacity will be 150 long tons equivalent sulfur load. Permit conditions will be added for SRU-3 in conformance with District policy and in accordance with Regulation 2-1-234.

No other sources will be modified or require throughput limits to be defined or modified because of this project.

Best Available Control Technology (BACT/TBACT)

Regulation 2-2-301.1 requires that BACT be used to control emissions from any new source with the potential to emit 10 pounds per day or more of NO_x, SO₂, POC, NPOC, PM₁₀ or CO. For a modified source that has been fully offset in a previous permitting action, BACT is required if the new maximum permitted emissions are greater than the previous maximum permitted emissions and the new maximum permitted emissions are 10 pounds per day or more.

Flexisorb[®] System. Since the new Flexisorb[®] System will not increase emissions from any emission unit, and is likely to decrease emissions, BACT is not required to be installed on any of the FXG fuel gas combustion devices.

SRU-3. Source S-1765 was fully offset in its original permit issuance in Application No. 7618 under the WOR (REFEMs cap). When SRU-3 (S-1765) was permitted, an emissions cap ("REFEMs cap") was developed for a number of sources, including S-1765. According to information obtained in the permitting files for Application # 7618, the originally permitted sulfur dioxide (SO₂) emissions level for SRU-3 was 48.5 tons per year (266 pounds/day). However, both the NSPS for petroleum refineries (Subpart J) and Regulation 9-1 limit plant emissions to 250 ppm of SO₂ corrected to 0 percent oxygen. Based on a search of Reasonable Available Control Technology (RACT) levels in other

California air districts, the 250 ppmv SO₂ limit was determined to be the most stringent RACT level. At the 250 ppmv SO₂ RACT emissions level, SRU-3 can potentially emit 34 tons per year prior to the proposed modification. This emissions level is based on a throughput of 73 long tons equivalent sulfur loads per day, which is the throughput indicated in the permitting files for this source. Based on the proposed modification to SRU-3 (conversion to an oxy-Claus unit), SRU-3 will have potential emissions of 28 tons per year of SO₂ emissions. Although the emissions are SO₂ are estimated to be reduced, the facility has requested that they be limited to their pre-project emissions (34 tons per year). The proposed modification to SRU-3 while using oxygen at full capacity does not trigger BACT. SRU-3 is not subject to BACT because potential emissions from the new Oxy-Claus unit are less than the current potential emissions from the conventional Claus unit.

Other Emissions Sources Associated with this Project. No other sources associated with this project will be modified as defined in Regulation 2-1-234 and/or trigger BACT as required in Regulation 2-2-301, including:

- Existing methyl diethanolamine (MDEA) storage tanks.
- Fugitive emissions from new valves and system components.
- Header to convey Flexsorb[®] System acid gas to SRU-4.
- Second header will be installed to convey DEA acid gas to SRU-1 (S-1431) and SRU-2 (S-1432).
 - Liquid storage tank(s) for oxygen, a vaporizer and connections to SRU-3.

New Source Performance Standards (NSPS)

New Source Performance Standard (NSPS) for Petroleum Refineries (Subpart J), 40 CFR 60.104(a)(1), requires that the H₂S concentration of FXG fuel is limited to 0.10 grains per dscf (163 ppm) on a 3-hour average. However, there is an exemption during periods of startup and shutdowns in the NSPS. Additionally, 40 CFR 60.105(a)(4) requires that an analyzer be installed to continuously monitor and record H₂S concentrations in the FXG fuel. MRC currently complies with these requirements and will be required to comply after installation of the Flexsorb[®] System.

NSPS, Subpart J, 40 CFR 60.104(a)(2)(i), requires that SO₂ emissions from SRU-3 are limited to 250 ppmvd at 0 percent oxygen on a 12-hour average. Additionally, 40 CFR 60.105(a)(5) requires that emissions monitors be installed to continuously monitor record SO₂ and oxygen concentrations. MRC currently complies with these requirements and will be required to comply after the modification of SRU-3.

Offsets

SO₂ emission offsets must be provided if a new or modified source at a Major Facility will result in a cumulative increase (minus any contemporaneous emission reduction credits) in excess of 1.0 ton per year since April 5, 1991, per Regulation 2-2-303. The proposed modification to SRU-3 while using oxygen at full capacity does not trigger emission offsets because the pre-project RACT adjusted permitted level (34 TPY of SO₂) is greater than the potential emissions after the proposed modification (28 TPY of SO₂). Because Shell still wants to keep the SRU-3 (S-1765) within the REFEMS emission cap,

the cap will be adjusted by subtracting 14.6 tons per year of SO₂, the amount of the RACT adjustment (48.5 TPY – 34 TPY of SO₂).

Prevention of Significant Determination (PSD)

The project is exempt from PSD requirements since the project emissions will not exceed any of the thresholds listed in Regulation 2-2-304 through 2-2-306.

California Environmental Quality ACT (CEQA)

The project is categorically exempt from CEQA review per Regulation 2-1-312.11. The project satisfies the “No Net Emission Increase” provisions of Regulation 2, Rule 2 and the project has no potential for causing a significant adverse environmental impact in connection with any of the environmental media or resources listed in Section II of Appendix I of the State CEQA Guidelines.

Public Notice for Schools

Because MRC is not located within 1,000 feet of any school, the public notification requirements of Regulation 2-1-412 are not triggered.

4. Conditions

I recommend that Condition No. 7618, Part E2 be amended to reflect startup and shutdown of the FXU:

C. FUEL CONDITIONS

1. Except during periods of startup and shutdown, while the refinery is processing more than 50 % San Joaquin Valley (SJV) crudes, the H₂S concentration of Flexigas shall not exceed 80 ppmv on a daily average, nor 60 ppmv on an annual average. At all other times, except during periods of startup and shutdown, the owner/operator shall not operate the H₂S concentration of the Flexigas to exceed 35 ppmv. If the owner/operator can demonstrate that the Stretford Unit cannot achieve the 35 ppmv H₂S concentration on the Flexigas while processing less than 50% SJV crudes, the owner/operator may apply to the APCO for re-evaluation and possible revision of this permit condition.
 - a. For the purpose of this condition, startup and shutdown of the Flexicoker (S1759) operation shall not exceed 48 hours and 96 hours, respectively.
 - b. Flaring of untreated flexigas at the at the OPC1_FXG Flare (S1771) during startup of the Flexicoker (S1759) shall not exceed 48 hours. SO₂ emissions during startup at the the OPC1_FXG Flare (S1771) from untreated flexigas burning will not exceed 5 tons per startup. Startup is defined as the period of time between the initiation of feed to the Flexicoker (S1759) and when the Flexorb Unit (A-751) is online and flexigas composition has stabilized at H₂S levels sufficient to meet Condition No. 7618 Part E.2.
 - c. Flaring of untreated flexigas at the OPC1_FXG Flare (S1771) during shutdown of the Flexicoker (S1759) shall not exceed 96 hours. SO₂ emissions during shutdown at the the OPC1_FXG Flare (S1771) from untreated flexigas burning shall not exceed 8 tons per shutdown. Shutdown is defined as the period of time

between the cessation of normal operation of the Flexsorb Unit (A-751) and when flexigas production at the Flexicoker (S1759) ends.

- d. The owner/operator must calculate SO₂ emissions for each start-up and shutdown of the Flexicoker (S1759). These startup and shutdown SO₂ emissions are to be included in their SO₂ cap specified in Table IV of this condition.

In addition, I recommend the following change to the REFEMS emission cap:

Condition Modifications Log:

Table IV – SO₂ Baseline reduced by 110.2 lb/day per Flexsorb Project (June 2002)

**TABLE IV.
SHELL BASELINE PROFILE -- SOX EMISSIONS (LB/DAY)**

SO₂ baseline reduced 1398 lb/day per Cond. ID# 12271. (AN 1362, Feb. 2002)

SO₂ baseline reduced by 110.2 lb/day for Flexsorb project (June 2002)

No. of days	Pounds per day	
1	23023	22912.8
2	23011	22900.8
3	22804.6	22694.4
4	22737.4	22627.2
5	22658.2	22548.0
6	22487.8	22377.6
7	22221.4	22111.2
8	22199.8	22089.6
9	22125.4	22015.2
10	22111	22000.8
11	22065.4	21955.2
12	21854.2	21744.0
13	21851.8	21741.6
14	21763	21652.8
15	21686.2	21576.0
16	21556.6	21446.4
17	21472.6	21362.4
18	21451	21340.8
19	21424.6	21314.4
20	21074.2	20964.0
21	21021.4	20911.2
22	20995	20884.8
23	20867.8	20757.6
24	20858.2	20748.0

25	20723.8	20613.6
26	20644.6	20534.4
27	20577.4	20467.2
28	20570.2	20460.0
29	20512.6	20402.4
30	20510.2	20400.0
31	20491	20380.8
32	20474.2	20364.0
33	20452.6	20342.4
34	20402.2	20292.0
35	20327.8	20217.6
36	20063.8	19953.6
37	20027.8	19917.6
38	19586.2	19476.0
39	19571.8	19461.6
40	19569.4	19459.2
41	19418.2	19308.0
42	19367.8	19257.6
43	19137.4	19027.2
44	19127.8	19017.6
45	19123	19012.8
46	19019.8	18909.6
47	19017.4	18907.2
48	18995.8	18885.6
49	18902.2	18792.0
50	18897.4	18787.2
51	18890.2	18780.0
52	18839.8	18729.6
53	18681.4	18571.2
54	18616.6	18506.4
55	18523	18412.8
56	18455.8	18345.6
57	18391	18280.8
58	18208.6	18098.4
59	18201.4	18091.2
60	18155.8	18045.6
61	18136.6	18026.4
62	18119.8	18009.6
63	18055	17944.8
64	18045.4	17935.2
65	18028.6	17918.4
66	18023.8	17913.6
67	18011.8	17901.6
68	17987.8	17877.6
69	17843.8	17733.6
70	17800.6	17690.4
71	17793.4	17683.2

72	17791	17680.8
73	17788.6	17678.4
74	17762.2	17652.0
75	17661.4	17551.2
76	17647	17536.8
77	17560.6	17450.4
78	17524.6	17414.4
79	17493.4	17383.2
80	17443	17332.8
81	17387.8	17277.6
82	17385.4	17275.2
83	17371	17260.8
84	17313.4	17203.2
85	17311	17200.8
86 to 87	17301.4	17191.2
88	17294.2	17184.0
89	17291.8	17181.6
90	17267.8	17157.6
91	17265.4	17155.2
92	17215	17104.8
93	17176.6	17066.4
94	17145.4	17035.2
95	17128.6	17018.4
96	17126.2	17016.0
97	17104.6	16994.4
98	17090.2	16980.0
99	17080.6	16970.4
100	17054.2	16944.0
101	17042.2	16932.0
102	17032.6	16922.4
103	17023	16912.8
104	17020.6	16910.4
105	16979.8	16869.6
106	16946.2	16836.0
107	16939	16828.8
108	16929.4	16819.2
109	16927	16816.8
110	16883.8	16773.6
111	16871.8	16761.6
112	16869.4	16759.2
113	16845.4	16735.2
114	16831	16720.8
115	16814.2	16704.0
116	16797.4	16687.2
117	16792.6	16682.4
118	16790.2	16680.0
119	16775.8	16665.6

120	16749.4	16639.2
121	16713.4	16603.2
122	16711	16600.8
123	16699	16588.8
124	16689.4	16579.2
125	16672.6	16562.4
126	16667.8	16557.6
127	16651	16540.8
128	16648.6	16538.4
129	16643.8	16533.6
130	16615	16504.8
131	16607.8	16497.6
132	16595.8	16485.6
133	16579	16468.8
134	16567	16456.8
135	16552.6	16442.4
136	16538.2	16428.0
137	16502.2	16392.0
138	16497.4	16387.2
139 to 140	16480.6	16370.4
141	16468.6	16358.4
142	16449.4	16339.2
143	16444.6	16334.4
144	16442.2	16332.0
145	16437.4	16327.2
146	16432.6	16322.4
147	16430.2	16320.0
148	16375	16264.8
149	16312.6	16202.4
150	16298.2	16188.0
151	16271.8	16161.6
152 to 153	16267	16156.8
154	16264.6	16154.4
155	16255	16144.8
156	16252.6	16142.4
157	16243	16132.8
158	16221.4	16111.2
159 to 160	16219	16108.8
161	16214.2	16104.0
162	16185.4	16075.2
163	16163.8	16053.6
164	16147	16036.8
165	16142.2	16032.0
166	16135	16024.8
167	16132.6	16022.4
168	16123	16012.8
169	16115.8	16005.6

170	16051	15940.8
171	16043.8	15933.6
172	16034.2	15924.0
173	16007.8	15897.6
174	15993.4	15883.2
175	15983.8	15873.6
176	15976.6	15866.4
177	15971.8	15861.6
178	15945.4	15835.2
179	15940.6	15830.4
180	15926.2	15816.0
181	15919	15808.8
182 to 183	15902.2	15792.0
184	15895	15784.8
185	15861.4	15751.2
186	15854.2	15744.0
187	15820.6	15710.4
188 to 189	15796.6	15686.4
190	15782.2	15672.0
191	15775	15664.8
192	15765.4	15655.2
193 to 194	15763	15652.8
195	15743.8	15633.6
196 to 197	15736.6	15626.4
198 to 199	15717.4	15607.2
200	15695.8	15585.6
201	15655	15544.8
202	15635.8	15525.6
203	15609.4	15499.2
204	15547	15436.8
205 to 207	15527.8	15417.6
208	15518.2	15408.0
209	15513.4	15403.2
210	15506.2	15396.0
211	15503.8	15393.6
212	15501.4	15391.2
213	15496.6	15386.4
214	15494.2	15384.0
215	15489.4	15379.2
216	15484.6	15374.4
217	15482.2	15372.0
218	15479.8	15369.6
219	15477.4	15367.2
220 to 221	15475	15364.8
222	15472.6	15362.4
223	15467.8	15357.6
224	15448.6	15338.4

225	15446.2	15336.0
226	15441.4	15331.2
227 to 229	15439	15328.8
230	15434.2	15324.0
231	15429.4	15319.2
232	15422.2	15312.0
233 to 234	15419.8	15309.6
235	15417.4	15307.2
236	15410.2	15300.0
237	15403	15292.8
238	15395.8	15285.6
239	15393.4	15283.2
240	15388.6	15278.4
241	15386.2	15276.0
242	15367	15256.8
243	15364.6	15254.4
244	15362.2	15252.0
245	15359.8	15249.6
246	15357.4	15247.2
247	15355	15244.8
248 to 250	15352.6	15242.4
251 to 252	15350.2	15240.0
253 to 254	15345.4	15235.2
255	15343	15232.8
256 to 257	15340.6	15230.4
258	15333.4	15223.2
259	15314.2	15204.0
260	15311.8	15201.6
261	15307	15196.8
262	15304.6	15194.4
263	15302.2	15192.0
264	15299.8	15189.6
265	15275.8	15165.6
266	15273.4	15163.2
267 to 268	15268.6	15158.4
269 to 270	15266.2	15156.0
271	15261.4	15151.2
272	15256.6	15146.4
273	15254.2	15144.0
274	15251.8	15141.6
275	15213.4	15103.2
276	15199	15088.8
277	15124.6	15014.4
278	15081.4	14971.2
279	15047.8	14937.6
280	15045.4	14935.2
281	15035.8	14925.6

282	14971	14860.8
283 to 287	14961.4	14851.2
288 to 294	14949.4	14839.2
295	14702.2	14592.0
296	14690.2	14580.0
297 to 307	14680.6	14570.4
308 to 325	14668.6	14558.4
326 to 365	14659	14548.8

I recommend that Condition No. 18618, Part 1 be modified as follows (basis: Regulation 2-1-234.3. Only S-1765 's throughput limits are requested for change from proposed.):

S#	Description	Hourly or Daily Limit	Annual Limit
S-1431	EMSR4 Sulfur Plant 1	1431+1432 <331 ton/day (equivalent sulfur load)	365 x Daily Limit
S-1432	EMSR4 Sulfur Plant 2	1431+1432<331 ton/day (equivalent sulfur load)	365 X Daily Limit
S-1765	OPC5_Sulfur Recovery Plant#3	150 ton/day (equivalent sulfur load)	365 X Daily Limit
S-4180	OPC-9 Sulfur Recovery Plant #4	140 long tons/day	365 X Daily Limit
S-1759	OPC1_Flexicoker	48,300 bbl/day	365 X Daily Limit

I recommend the following conditions be added for S-1765:

- 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)**
- 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)**

5. **Authority to Construct:**

I recommend that the Authority to Construct be issued to MRC for the following:

**Replace abatement device (Stretford Unit):
A-751 Exxon Mobil Flexsorb[®] Gas Treatment System**

**Modify emissions unit:
S-1765 Sulfur Recovery Unit No. 3 (SRU-3)**

**Increase Throughput to:
S-1765 Sulfur Recovery Unit No. 3 (SRU-3)**

6. **Exemptions:**

Oxygen brought onto the site for use in the new Oxy-Claus unit will be placed in an oxygen storage vessel. The vessel will meet the requirements Regulation 2-1-319 and is exempt from permitting under Regulation 2-1-123.2.

M.K. Carol Lee
Senior Air Quality Engineer

Date

**ENGINEERING EVALUATION
SHELL OIL PRODUCTS
PLANT NO. 11
APPLICATION NO. 4695**

BACKGROUND

This is an “alteration” application to abate the existing sulfur pits at Sulfur Recovery Units (SRU) 1 and 2. Each sulfur pit will be abated by either of the existing SRU 1 or SRU 2 thermal oxidizers. Shell is required to abate the sulfur pits in accordance with their Consent Decree with EPA. This application is similar to application number 3930, under which the sulfur pit at SRU 3 was abated.

These sulfur pits are currently included as part of SRU 1 and 2. As part of this application, each sulfur pit will be assigned its own source number. This is consistent with the SRU 4 at Shell, and with other refineries that have separate permits for sulfur pits. Although the sulfur pits will be assigned new source numbers, they are not new or modified sources, as defined in Regulation 2, Rule 1.

The equipment involved with this application is:

S-1578 SRU 1 SULFUR PIT (existing); Alteration to add abatement by A-1501, SRU 1 Thermal Oxidizer, or A-1517, SRU 2 Thermal Oxidizer

S-1579 SRU 2 SULFUR PIT (existing); Alteration to add abatement by A-1501, SRU 1 Thermal Oxidizer, or A-1517, SRU 2 Thermal Oxidizer

As a result of this project, H₂S and other sulfur compounds that are currently emitted to atmosphere will be oxidized at A-1501 and A-1517 to form SO₂. This will cause an increase in SO₂ emissions at the exhaust stacks of A-1501 and A-1517. Because the additional SO₂ is a direct result of abating another source, it is considered to be a secondary pollutant. In accordance with Reg. 2-2-112, these secondary emissions are exempt from BACT requirements.

EMISSIONS SUMMARY

The additional SO₂ emissions from the exhaust of A-1501 and A-1517 are not quantified in this evaluation, for the following reasons.

This project does not result in an increase of the permitted level of SO₂ emissions from Shell. This is because SRU 1 and SRU 2 are included in the emission cap that was established under permit application number 26786. This permit resulted in emission profiles (caps) for all criteria pollutants, including SO₂. These emission caps are included in Condition ID# 7618. Since SRU 1 and SRU 2 are included under the SO₂ emission cap, and because these sulfur pits were originally permitted as part of SRU 1 and SRU 2, these sulfur pits are also included in the SO₂ emission cap. Therefore, any additional SO₂ generated by abating the sulfur pit at SRU 1 and SRU 2 must also be included in the SO₂ emission cap. Shell is not requesting to increase the SO₂ emission cap as part of this application. Under the cap, any SO₂ increase at the thermal oxidizers must be “offset” by a corresponding decrease at another source under the cap.

Note that there will be a “localized” increase in SO₂ from A-1501 and A-1517. Normally, the District would calculate the localized increase for a source that was subject to a group emission limit (cap). The localized increase would be necessary to determine whether or not BACT is triggered. In this case, however, BACT is not required because secondary pollutants are exempt from BACT under Reg. 2-1-112. Therefore, it is not necessary to calculate the localized increase.

STATEMENT OF COMPLIANCE

As a result of this project, S-1578 and S-1579, SRU 1 and 2 Sulfur Pits, will comply with the Consent Decree between Shell and EPA. In addition, the Thermal Oxidizers (A-1501 and A-1517) will continue to comply with Reg. 9-1-307, which limits SO₂ emissions to 250 ppm.

The project is categorically exempt from CEQA, per Reg. 2-1-312.2, because it is for the addition of abatement equipment.

The project is over 1000 feet from the nearest school and therefore not subject to the public notification requirements of Reg. 2-1-412.

A Toxic Risk Screening Analysis is not required, because there are no toxic emission increases. TBACT does not apply.

BACT, PSD, and offsets do not apply.

Per the Consent Decree between Shell (previously Equilon) and EPA, this source will comply with NSPS, Subpart J. By abating the sulfur pit emissions, SO₂ emissions from the sulfur pit will be included with other SO₂ emissions from SRU 1 and SRU 2. These emissions are monitored for compliance with the 250 ppm NSPS limit (40 CFR 60.104(a)(2)).

PERMIT CONDITIONS

As discussed above, S-1766 will be subject to the existing Condition ID# 7618. Data Bank records will be updated to link ID# 7618 to S-1578 and S-1579.

RECOMMENDATION

Issue a Conditional Authority to Construct for the following:

S-1578 SRU 1 SULFUR PIT (existing); Alteration to add abatement by A-1501, SRU 1 Thermal Oxidizer, or A-1517, SRU 2 Thermal Oxidizer

S-1579 SRU 2 SULFUR PIT (existing); Alteration to add abatement by A-1501, SRU 1 Thermal Oxidizer, or A-1517, SRU 2 Thermal Oxidizer

EXEMPTIONS

None.

By: _____
Supervising Air Quality Engineer

July 31, 2002

**ENGINEERING EVALUATION
SHELL REFINERY
PLANT NO. 11
APPLICATION NO. 6745**

BACKGROUND

This application is to replace the burners in S-1760 with Low-NOx burners. By definition (Reg. 2-1-233.1), burner replacement is an alteration.

This application includes the following source:

S-1760 **FXU STEAM SUPERHEATER, F-102;** Alteration to Replace Burners with Callidus LE Low-NOx Burners, 139 MM BTU/hr

EMISSIONS SUMMARY

There are no emission increases associated with this alteration. The maximum firing rate of the furnace will not increase above the existing maximum firing rate of 139 MM BTU/hr, as limited by Condition ID# 16688.

The cumulative increase for this application is ZERO for all pollutants.

STATEMENT OF COMPLIANCE

The proposed project will enhance compliance with Regulation 9, Rule 10, by reducing NOx emission from this source.

The project is considered to be ministerial under the District's CEQA regulation 2-1-311 and therefore is not subject to CEQA review. The engineering review for this project requires only the application of standard permit conditions and standard emissions factors and therefore is not discretionary as defined by CEQA. Permit Handbook Chapter 2.4)

The project is over 1000 feet from the nearest school and therefore not subject to the public notification requirements of Reg. 2-1-412.

A Toxic Risk Screening Analysis is not required because there are no emission increases for this application. TBACT does not apply.

Best Available Control Technology: In accordance with Regulation 2, Rule 2, Section 301, BACT is triggered for any new or modified source with the potential to emit 10 pounds or more per highest day of POC, NPOC, NOx, CO, SO₂ or PM₁₀. Since there are no emission increases, BACT is not triggered.

Offsets: Offsets must be provided for any new or modified source at a facility that emits more than 15 tons/yr of POC or NOx. The District may provide offsets from the Small Facility Banking Account for a facility with emissions between 15 and 50 tons/yr of POC or NOx, provided that facility has no available offsets, and all existing sources of POC and/or NOx are equipped with Best Available Retrofit Control Technology (BARCT). Based on the emission calculations above, offsets are not required for this application.

PSD, NSPS, and NESHAPS do not apply.

PERMIT CONDITIONS

S-1760 is currently subject to Cond. ID# 16688, which limits the maximum firing rate to 139 MM BTU/hr, and to Cond. ID3 18265, which is the IERC Alternative Compliance Plan that includes a NOx emission factor and minimum and maximum O2 and firing rate limits for S-1760.

The following condition will be imposed under this application to require source testing to ensure compliance with the IERC ACP emission factor and O2 and firing rate limits.

1. Within 60 days of startup of S-1760 following the installation of Low-NOx burners, the owner/operator shall conduct District-approved source testing to confirm that the NOx emission factor, minimum and maximum O2, and minimum and maximum firing rates (4-corner box) that are contained in Condition ID# 18265 are still valid. The owner/operator shall submit a test report to the District's Source Test Manager within 30 days following the completion of the testing. [Basis: Reg. 9-10-502]
2. The NOx emission factor, minimum and maximum O2, and/or minimum and maximum firing rates (4-corner box) for S-1760 that are contained in Condition ID# 18265 may be adjusted administratively, based on the source testing conducted under Item 1. [Basis: Reg. 9-10-502]

RECOMMENDATION

Issue a Conditional Authority to Construct for the alteration to S-1760 described in the Background section of this report.

EXEMPTIONS

None.

By: _____
Supervising Air Quality Engineer

January 9, 2003

EVALUATION REPORT

Company Shell Martinez Refinery
Application # 9504
Plant # 11

1. Background:

Shell has permits for two crude distillation units – S-1411, Lubes Distillation Unit (LDU), and S-1420, Crude Unit (CU). The CU is the primary crude unit, with a throughput limit of 160,000 barrels per day. The LDU is a much smaller crude unit, with a throughput limit of 18,800 barrels per day.

Until recently, the LDU received San Joaquin Valley (SJV) crude oil via pipeline. One of the cuts from the LDU was used to produce a specialty lubricating oil, and the majority of the LDU cuts were combined with the products of the main CU to be further processed into gasoline, diesel, jet fuel, etc. Shell no longer wishes to produce this specialty lube oil, and has shut down the LDU. This application is to re-route the SJV crude that was previously sent to the LDU to the CU, and to increase the throughput limit of the CU from 160,000 to 178,800 barrels per day. The permit for the LDU will be surrendered, so there will be no overall increase in crude capacity at the refinery.

System hydraulics between the charge pumps and the crude column currently prevent the CU (S-1420) from being charged at a rate of 178.8 MBD. The proposed project primarily involves piping and valves changes that will reduce pressure drops across the piping, heat exchangers, and the desalters. There will be no modification to existing furnaces that serve the CU (S-1420). However, there is the potential for increased utilization of the furnaces within their currently permitted capacities. Processed units downstream of the CU (S-1420) will not be modified. Total throughput of crude tankage throughout the refinery will not increase above currently permitted limits. Similarly, storage of distillation products will not be affected by the proposed project.

Shell has indicated that the increase in crude throughput at the CU will not increase the amount of crude oil delivered to the refinery via marine vessel. Shell does not have the physical capacity to receive all of the current 160,000 bbl/day of crude over the wharf. This project does not provide the ability to increase crude tenders over the wharf past the wharf's current capacity. To increase the current wharf capacity would require a physical modification.

Shell plans to begin construction on the project by August 2, 2004, complete construction and begin operation at the new capacity by October 1, 2004.

2. Emission Calculations:

There will be an increase of its throughput limit from 160 to 178.8 MBD or 52,925,000 to 59,600,000 barrels (bbl) per year of crude. However, there is no overall increase in crude expected into the facility itself. There is only the rerouting of crude from the Lube Plant (S-1411), which has shutdown, to the CU (S-1420).

Combustion emissions will not increase because all process heaters have existing permit conditions limiting fuel usage, and Shell is not increasing these limits.

Processing units, like the CU (S-1420) have no discrete emission points. Instead, emissions are quantified for fugitive components that are part of the processing unit. Fugitive sources of organic emissions include valves, flanges, connectors, pumps, pressure relief valves (PRVs) and other devices, which may leak organic gases or liquids.

Emissions that will result from the addition of fugitive components to existing process units are estimated as follows:

Fugitive Emissions

Fugitive emissions (leaks from mechanical components) were calculated from component counts, emission factors, and stream compositions. A total POC emission rate was calculated by multiplying the net component count increase by the POC emission factors. POC emission factors for valves, pumps, and compressors in light liquid or gas service are based on factors used by the District in the Engineering Evaluation Report for the SHELL Clean Fuels Project (Application No. 8407).

Component	Service	Emission Factor (lb/hr/component)	Source
Valve	Gas/Light Liquid	0.0000231	a
Valve	Heavy Liquid	0.00008	b
Pump	Light Liquid	0.000704	a
Pump	Heavy Liquid	0.00613	b
Compressor	Gas	0.000205	a
Flange	All	0.00017	b
Pressure Relief Valve	All	0.0	c

- (a) Developed from Martinez Refining Company 1999 Inspection and Monitoring data and CAPCOA Revised 1995 EPA Correlation Equations
- (b) BAAQMD Engineering Evaluation Report, permit application #8407, November 4, 1993
- (c) All new PRVs will be vented to control

Type/Service	Number of Components	Emission factor, lb/hr/component	POC lb/hr	POC lb/day
Valves/All	34	0.0000231	0.00079	0.019
Pump seals/All	0	0	0	0
Pressure Relief Devices	0	0	0	0
Connectors/All	0	0	0	0
Flanges/All	112	0.00017	0.019	0.46
Open-ended lines/All	0	0	0	0
Others/All	0	0	0	0
Totals	146		0.020	0.48

POC = 0.48 lb/day(365 day/yr) = 174 lbs/yr = 0.087 TPY

Hence, the cumulative increase for this project is for the emission increase resulting from the fugitive components increase.

Toxics

The following summarizes the increase of toxics resulting from tank and fugitive component modifications:

Toxic	Maximum Concentration (%)	Increase Emission (lb/yr)	Toxic Trigger Level (lb/yr)
Benzene	0.29	0.50	6.7
Hexane	3.82	6.65	8.3E+04
Naphthalene	0.03	0.052	2.7E+02
PAH	0.00056	0.00097	4.4E-02
Toluene	0.71	1.24	3.9E+04
Xylene	0.57	1.0	5.8E+04

Comparing the toxics emissions to Regulation 2-1-316 screening risk assessment trigger levels reveal that the estimated toxics emissions are below the screening trigger levels. As a result, a risk screening is not required.

3. Statement of Compliance:

In accordance with Regulation 2-1-128.21:

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.

the addition of fugitive components at the CU (S-1420) at petroleum refineries, which do not result in cumulative emissions that exceed 10 lb/day, are exempt from permitting requirements. Because the estimated cumulative increase of the additional fugitive components is 0.48 lb/day and do not require permitting pursuant to Section 2-1-319, the addition of fugitive components to the CU (S-1420) is exempt from permitting requirements.

Regulation 8-18 applies to equipment leaks at most refinery equipment, except for leaks at devices, which are regulated by other rules (tank appurtenances, relief devices vented to control systems and leaks at devices which handle low vapor pressure initial boiling points greater than 302 degrees F). This regulation includes leak criteria, repair requirements for leaks and monitoring requirements. New fugitive devices associated with this project will largely be subject to this rule and will be incorporated into the maintenance and inspection program for fugitive devices and are assumed to be in compliance pending inspection.

Subpart CC applies to various refinery operations including miscellaneous process vents and equipment leaks. Existing fugitive components, miscellaneous process units and storage vessels in the CU are subject to 40 CFR 63 Subpart CC and subsequently subject to 40 CFR 63 Subpart VV. Compliance with these requirements is addressed in detail in the Title V permit for this facility. The new valves and flanges to be added as a result of this project will also meet the

requirements of 40 CFR 63 Subpart CC and will be incorporated into the refinery LDAR program. For equipment leaks, compliance with the standards of this MACT is assured by compliance with the more strict requirements of District Regulation 8-18.

As for the increase of throughput limit for the CU (S-1420), there is no increase of emissions from the process unit itself. However, due to the increase of emissions resulting from the increase of fugitive components at the CU (S-1420), the CU (S-1420) is a modified source, per Regulation 2-1-234.2:

2-1-234 Modified Source: Any existing source which undergoes a physical change, change in the method of operation of, increase in throughput or production, or addition which results or may result in any of the following:

234.2 An increase of either the daily or annual emission level of any regulated air pollutant, or the production rate or capacity that is used to estimate the emission level, above levels contained in a permit condition in any current permit to operate or major facility review permit.

Best Available Control Technology

Because the increase of fugitive emissions is less than 10 pounds per day, it does not trigger BACT requirements.

Offsets

Offsets are required for any cumulative increase at this Major Facility:

POC = 0.087 TPY(1.15) = 0.1 TPY

However, per Regulation 2-2-421, these offsets are deferred until 30 days prior to Permit to Operate renewal and prior to issuance of any Permit to Operate, whatever comes first.

Prevention of Significant Determination (PSD)

The project is exempt from PSD requirements since the project emissions will not exceed any of the thresholds listed in Regulation 2-2-304 through 2-2-306.

California Environmental Quality ACT (CEQA)

The CEQA related information requirements pursuant to Regulation 2-1-426 are satisfied by the inclusion of the District's Environmental Information Form Appendix H. This form has been completed by SHELL and indicates that there will be no significant environmental effect in connection with any environmental media or resource other than air quality, which will be offset with banking credits. The increase in throughput at S-1420 is exempt from CEQA requirements per Regulation 2-1-312.11.

Public Notice for Schools

Because SHELL is not located within 1,000 feet of any school, the public notification requirements of Regulation 2-1-412 are not triggered.

4. Conditions

I recommend that Condition # 18618 Parts 1 be amended as follows:

--	--	--	--

1420	DH Crude Unit (CU)	178,800 bbl/day	59,568,000 bbl/yr
------	--------------------	-----------------	-------------------

5. Authority to Construct:

I recommend that the Authority to Construct be issued to SHELL for the following:

S-1420 DH Crude Unit: Increase Throughput to 178,800 bbl/day and 59,568,000 bbl/year [Addition of 34 Valves and 112 Flanges]

6. Exemptions:

None.

12/80-ER1

By M.K. Carol Lee _____
Senior Air Quality Engineer

Date _____

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11
Application: 9699

BACKGROUND

Shell Oil Products US – Martinez Refinery (Shell) has submitted this application to incorporate changes approved in Application Number (AN) 4106 into Shell’s existing Title V permit. This application (AN 9699) qualifies as a minor permit revision. AN 4106 is described below.

The District issued Shell an Authority to Construct (AC) on July 24, 2002 to perform the following modifications at the OPCEN² Sulfur Plant 3 (SRU³) under AN 4106:

- Modify S-1765, which used to be a conventional Claus unit, to an Oxy-Claus unit; and
- Replace a Stretford Unit (A-75) with an Exxon Mobil Flexsorb[®] Gas Treatment System (A-751); and
- Perform minor modifications on the SCOT Unit No. 3 (A-76).

Supporting information submitted by Shell with AN 4106 indicated that the above changes would result in a substantial increase in the amount of elemental sulfur recovered at S-1765 i.e. from 73 long tons per day to 150 long tons per day, and would therefore reduce plant wide emissions of hydrogen sulfide (H₂S) and sulfur dioxide (SO₂). Specifically, H₂S laden Flexigas fuel (FXG) from the Flexicoker (S-1759) is routed to A-751, which selectively removes H₂S from FXG fuel. The FXG fuel is then combusted and the sulfur compounds in the fuel are oxidized to SO₂ in the various refinery heaters and other combustion devices. The acid gas containing H₂S removed at A-751 is sent to S-1765 and A-76 where approximately 99.9% of the reduced sulfur is converted to elemental sulfur. Residual H₂S gas remaining after treatment at S-1765 and A-76 is oxidized to SO₂ at catalytic oxidizer A-1518.

In a letter dated March 11, 2004, Shell notified the District that it started-up the modified S-1765 and the new A-751 on March 20, 2004, and April 20, 2004, respectively. The District issued Shell a Permit to Operate (PO) on August 6, 2004. Please refer to the “Background” section of the engineering evaluation report for AN 4106.

EMISSIONS CALCULATION

Table 1 in the “Emission Calculations” section of the engineering evaluation report for AN 4106 summarizes the pre-project and post-project emissions associated with AN 4106. It can be seen from Table 1, that the modifications to SRU 3 in AN 4106 resulted in a reduction in SO₂ and H₂S emissions by 6 TPY and 0.18 TPY, respectively.

² OPCEN - Operations Central

³ SRU- Sulfur Recovery Unit

TOXIC RISK SCREEN ANALYSIS (RSA)

It can be seen from the discussion on “Toxics” in the “Emission Calculations” section of the engineering evaluation report for AN 4106, that the post-project H₂S emissions of 0.77 TPY (1,540 lbs/yr) from S-1765 is below the Table 2-1-316 toxic air contaminant trigger level of 8,100 lbs/yr. Therefore, a Toxic RSA was not warranted when AN 4106 was evaluated.

CUMULATIVE INCREASE

As previously discussed in the above “Emission Calculation” section, changes that are part of AN 4106 resulted in a reduction in SO₂ and H₂S emissions by 6 TPY and 0.18 TPY, respectively. Therefore, there was no increase in emissions at Shell associated with AN 4106.

BACT

Per Regulation 2-2-301.1, BACT is applicable only when modification to an existing source results in an increase in emissions. As previously discussed, modifications to S-1765 result in a decrease in emissions of SO₂ and H₂S emissions. Therefore, BACT is not triggered. Please refer to the “Best Available Control Technology (BACT/TBACT)” discussion under the “Statement of Compliance” section of the engineering evaluation report for AN 4106.

OFFSETS

Per Regulation 2-2-303, an increase in emissions for a given pollutant, SO₂ in this case, from a new or modified source needs to be offset only if the cumulative increase in emissions for that pollutant minus any contemporaneous emission reduction credits provided by a facility for that pollutant since April 5, 1991 exceeds 1 TPY. The modification to S-1765 while using oxygen at full capacity permitted in AN 4106 does not trigger emission offsets because the *pre-project* RACT adjusted permitted level (33.9 TPY of SO₂)⁴ is greater than the *post-project* emissions (27.7 TPY of SO₂)⁵.

Source S-1765 was fully offset when it was permitted under AN 26786 in 1984. The refinery baseline/emissions cap (referred to as “REFEMS cap”) was developed for a number of sources, including S-1765 under AN 26786. The SO₂ emissions used in constructing the REFEMS cap assumed an emissions contribution of 266 lbs/day (48.55 TPY) from the sulfur plant. Both, the New Source Performance Standard (NSPS) for petroleum refineries (40 CFR 60, Subpart J), and Regulation 9, Rule 1 “Inorganic Gaseous Pollutants – Sulfur Dioxide” limit sulfur plant emissions to 250 ppm of SO₂ corrected to 0 percent oxygen. For lack of a more stringent standard, the above limit was determined to be the most stringent RACT level when modifications to S-1765 were evaluated under AN 4106.

Please refer to the “Best Available Control Technology (BACT/TBACT)” and “Offsets” discussion under the “Statement of Compliance” section of the engineering evaluation report for AN 4106 in Attachment 1.

⁴ (250 scf SO₂/MMscf gas) x (4.41 MMscf gas/day) x (lb-mole/380 scf) x (64 lb SO₂/lb-mole) x (1 ton/2000 lbs) x (365 days/yr) = 33.88 ~ 33.9 TPY. Please note all emissions exhaust (*with air*) from the stack of A-1518 and include the following feed streams (DEA acid gas, and sulfur storage pit vents). Based on a throughput of 73 equivalent long tons sulfur load per day.

⁵ (250 scf SO₂/MMscf gas) x (3.60 MMscf gas/day) x (lb-mole/380 scf) x (64 lb SO₂/lb-mole) x (1 ton/2000 lbs) x (365 days/yr) = 27.66 ~ 27.7 TPY. Please note all emissions exhaust (*air free*) from the stack of A-1518 and include the following feed streams (Flexsorb[®] system acid gas, DEA acid gas, and sulfur storage pit vents). Based on a throughput of 150 equivalent long tons sulfur load per day.

STATEMENT OF COMPLIANCE

On December 1, 2003, the District issued Shell a Title V operating permit. This permit application to incorporate changes to Shell's existing Title V operating permit stemming from AN 4106, 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, since the modifications to SRU 3 did not result in an increase in emissions beyond permitted levels. The minor revision to Shell's existing Title V permit is subject to a 45-day US EPA review, but is not subject to a public notice.

To ensure that modifications to SRU 3 would comply with the expected reductions in SO₂ and H₂S emissions a new permit condition 19748 was included under AN 4106. Specifically, parts 1 and 2 of permit condition 19748 limit the SO₂ and H₂S concentrations at the exhaust stack of A-1518 to 250 ppmvd and 13.2 ppmvd, respectively, measured at 0% oxygen and averaged over a 24-hr period. A source test conducted by Air Science Technologies on behalf of Shell at the exhaust stack of A-1518 in May 2004, as required by part 6 of permit condition 19748, determined the SO₂ and H₂S concentrations measured at 0% oxygen to be 101.4 ppm and 0.009 ppm, respectively. Emissions of the above pollutants are continuously monitored by Continuous Emission Monitors (CEMs). In light of the above, it is likely that S-1765 will comply with the applicable standards and monitoring requirements for SO₂ and H₂S contained in Regulation 9-1, NSPS J, and the National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (MACT UUU) which becomes effective in April 2005.

Modifications to S-1765 are exempt from a California Environmental Quality Act (CEQA) review per Section 312.11.1 in Regulation 2, Rule 1, which states "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." Also, per Title 14, Article 18, Section 15281 of the Act, CEQA does not apply to the issuance, modification, amendment, or renewal of any permit by an air pollution control district or air quality management district pursuant to Title V, as defined in Section 39053.3 of the Health and Safety Code, or pursuant to an air district Title V program established under Sections 42301.10, 42301.11, and 42301.12 of the Health and Safety Code, unless the issuance, modification, amendment, or renewal authorizes a physical or operational change to a source or facility. Source S-1765 is not located within 1,000 feet of the nearest public school and hence the project to permit the source is not subject to the public notification requirements contained in Regulation 2-1-412.

Modifications to S-1765 do not trigger additional PSD, NSPS and/or NESHAP requirements than those already existing in Shell's existing Title V permit.

Please refer to the "Statement of Compliance" section of the engineering evaluation report for AN 4106 in Attachment 1.

PROPOSED CHANGES TO THE TITLE V PERMIT

References to A-75 in Table II-B have been deleted from Shell’s permit. A new row has been inserted in Table II-B to reflect the installation of the new Flexsorb® system. References to A-75 in permit condition 7618, part E.2 have been deleted. Please refer to the underline/strikeout version of permit condition 7618 in the “Changes to Permit Conditions” section below.

Table II B – Abatement Devices

Abatement Device	Description	Source(s) Controlled	Applicable Requirement	Operating Parameters	Limit or Efficiency
A75	Stretford Unit	S1759	Condition # 7618 Part E2	None	H2S limits in Flexigas
A751	Flexsorb® system	S1759	Condition # 7618 Part E2	None	H2S limits in Flexigas

The composition of the flexigas produced during portions of the startup and shutdown at S-1759 is not compatible with A-751 and hence prohibits its use in refinery heaters. In light of the above, the flexigas bypasses A-751, to avoid contamination and deactivation of the Flexsorb® solution, and is routed to S-1771 instead. Shell estimated the periods of untreated flexigas produced during startup and shutdown events at S-1759 to not last more than 48 hours and 96 hours, respectively. The company estimated the SO₂ emissions rates during startup and shutdown to be 0.1042 ton/hr (5 tons/startup)⁶ and 0.0833 ton/hr (8 tons/shutdown)⁷, respectively. In light of the above, part E.2 of the permit condition 7618 was amended to reflect the startup and shutdown limitations. The new startup and shutdown limits (i.e. duration of each event and mass emissions per event) that are part of the amended part E of permit condition 7618 have been incorporated into Tables IV-BQ & VII-BF, Tables IV-BXa & VII-BI as follows:

**Table IV - BQ
Source-specific Applicable Requirements
S1759 – OPCENFLEXICOKER (FXU)**

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
	See Table IV – AL & AM for additional requirements.		
BAAQMD Condition # 7618			
Part E.2.a.	<u>Duration of startups and shutdowns</u>	<u>Y</u>	
Part E.2.d.	<u>Quantification of SO2 emissions during startups and shutdowns</u>	<u>Y</u>	

⁶ (0.1042 ton/hr) x (48 hrs/event) = 5 tons per startup

⁷ (0.0833 ton/hr) x (96 hrs/event) = 8 tons per shutdown

**Table VII – BF
Applicable Limits and Compliance Monitoring Requirements
S1759 – OPCEN FLEXICOKE (FXU)**

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
See Table VII – AE & AF for additional requirements.							
<u>Duration of startups and shutdowns</u>	<u>BAAQMD Condition # 7618, Part E.2.a.</u>	<u>Y</u>		<u>Duration of startup < 48 hours/event;</u> <u>Duration of shutdown < 96 hours/event</u>	<u>BAAQMD Condition #7618, Parts E.2.d. and G</u>	<u>P/E</u>	<u>Records</u>

**Table IV - BXa
Source-specific Applicable Requirements
S1771 – OPCEN Flexigas Flare**

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
BAAQMD Condition # 7618			
Part E.2.b.	<u>Limit on the duration and mass emissions when flaring untreated flexigas during startups</u>	<u>Y</u>	
Part E.2.c.	<u>Limit on the duration and mass emissions when flaring untreated flexigas during shutdowns</u>	<u>Y</u>	

**Table VII – BI
Applicable Limits and Compliance Monitoring Requirements
S1771 – OPCEN FLEXIGAS FLARE**

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
<u>Duration and SO2 mass emissions when flaring untreated flexigas during startups</u>	<u>BAAQMD Condition # 7618, Part E.2.b.</u>	<u>Y</u>		<u>Duration of startup < 48 hours/event; SO2 emissions < 5 tons/event</u>	<u>BAAQMD Condition #7618, Parts E.2.d. and G</u>	<u>P/E</u>	<u>Records</u>
<u>Duration and SO2 mass emissions when flaring untreated flexigas during shutdowns</u>	<u>BAAQMD Condition # 7618, Part E.2.c.</u>	<u>Y</u>		<u>Duration of shutdown < 96 hours/event; SO2 emissions < 8 tons/event</u>	<u>BAAQMD Condition #7618, Parts E.2.d. and G</u>	<u>P/E</u>	<u>Records</u>

CHANGES TO PERMIT CONDITIONS

Permit Condition #: **7618**

The following is the text of the amended part E.2 of permit condition:

”2. ~~While the refinery is processing more than~~Except during periods of startup and shutdown,

while the refinery is processing more than 50 % San Joaquin Valley (SJV) crudes, the H2S concentration of Flexigas shall not exceed 80 ppmv on a daily average, nor 60 ppmv on an annual average. At all other times, except during periods of startup and shutdown, the H2S concentration of the Flexigas shall not exceed 35 ppmv. If the owner/operator can demonstrate that the ~~Stretford Unit~~ Flexisorb[®] Unit cannot achieve the 35 ppmv H2S concentration on the Flexigas while processing less than 50% SJV crudes, the owner/operator may apply to the APCO for re-evaluation and possible revision of this permit condition.

- a. For the purpose of this condition, startup and shutdown of the Flexicoker (S1759) operation shall not exceed 48 hours and 96 hours, respectively.
- b. Flaring of untreated flexigas at the OPC1 FXG Flare (S1771) during startup of the Flexicoker (S1759) shall not exceed 48 hours. SO2 emissions during startup at the OPC1 FXG Flare (S1771) from untreated flexigas burning will not exceed 5 tons per startup. Startup is defined as the period of time between the initiation of feed to the Flexicoker (S1759) and when the Flexisorb Unit (A-751) is online and flexigas composition has stabilized at H2S levels sufficient to meet Condition No. 7618 Part E.2.
- c. Flaring of untreated flexigas at the OPC1 FXG Flare (S1771) during shutdown of the Flexicoker (S1759) shall not exceed 96 hours. SO2 emissions during shutdown at the OPC1 FXG Flare (S1771) from untreated flexigas burning shall not exceed 8 tons per shutdown. Shutdown is defined as the period of time between the cessation of normal operation of the Flexisorb Unit (A-751) and when flexigas production at the Flexicoker (S1759) ends.
- d. The owner/operator must calculate SO2 emissions for each start-up and shutdown of the Flexicoker (S1759). These startup and shutdown SO2 emissions are to be included in their SO2 cap specified in Table IV of this condition.”

As previously discussed in the “Offsets” section of this evaluation, the post-project SO₂ emissions (27.7 TPY) from S-1765 is less than the pre-project RACT adjusted permitted level (33.9 TPY). In light of the above, the District adjusted the REFEMS cap contained in Table IV of the permit condition by the amount of RACT adjustment by subtracting the pre-project permitted emissions from sulfur plant (48.5 TPY), from the pre-project RACT adjustment (33.9 TPY). In other words, the SO₂ emissions baseline was reduced by 80 lbs/day⁸.

⁸ (48.5 – 33.9) tons/yr x (2000 lbs/ton) / (365 days/yr) = 80 lbs/day

The following is the text of Table IV *before* amending the permit condition:
"TABLE IV.

FACILITY BASELINE PROFILE-SOX EMISSIONS
(LB/DAY)

S02 baseline reduced 1398 lb/day per Condition ID# 12271.
(AN 1362, Feb. 2002)

No. of Days	Pounds per Day
1	23023
2	23011
3	22804.6
4	22737.4
5	22658.2
6	22487.8
7	22221.4
8	22199.8
9	22125.4
10	22111
11	22065.4
12	21854.2
13	21851.8
14	21763
15	21686.2
16	21556.6
17	21472.6
18	21451
19	21424.6
20	21074.2
21	21021.4
22	20995
23	20867.8
24	20858.2
25	20723.8
26	20644.6
27	20577.4
28	20570.2
29	20512.6
30	20510.2
31	20491
32	20474.2
33	20452.6
34	20402.2
35	20327.8
36	20063.8
37	20027.8
38	19586.2
39	19571.8
40	19569.4
41	19418.2
42	19367.8
43	19137.4
44	19127.8
45	19123
46	19019.8

47	19017.4
48	18995.8
49	18902.2
50	18897.4
51	18890.2
52	18839.8
53	18681.4
54	18616.6
55	18523
56	18455.8
57	18391
58	18208.6
59	18201.4
60	18155.8
61	18136.6
62	18119.8
63	18055
64	18045.4
65	18028.6
66	18023.8
67	18011.8
68	17987.8
69	17843.8
70	17800.6
71	17793.4
72	17791
73	17788.6
74	17762.2
75	17661.4
76	17647
77	17560.6
78	17524.6
79	17493.4
80	17443
81	17387.8
82	17385.4
83	17371
84	17313.4
85	17311
86 to 87	17301.4
88	17294.2
89	17291.8
90	17267.8
91	17265.4
92	17215
93	17176.6
94	17145.4
95	17128.6
96	17126.2
97	17104.6
98	17090.2
99	17080.6
100	17054.2
101	17042.2
102	17032.6

103	17023
104	17020.6
105	16979.8
106	16946.2
107	16939
108	16929.4
109	16927
110	16883.8
111	16871.8
112	16869.4
113	16845.4
114	16831
115	16814.2
116	16797.4
117	16792.6
118	16790.2
119	16775.8
120	16749.4
121	16713.4
122	16711
123	16699
124	16689.4
125	16672.6
126	16667.8
127	16651
128	16648.6
129	16643.8
130	16615
131	16607.8
132	16595.8
133	16579
134	16567
135	16552.6
136	16538.2
137	16502.2
138	16497.4
139 to 140	16480.6
141	16468.6
142	16449.4
143	16444.6
144	16442.2
145	16437.4
146	16432.6
147	16430.2
148	16375
149	16312.6
150	16298.2
151	16271.8
152 to 153	16267
154	16264.6
155	16255
156	16252.6
157	16243
158	16221.4
159 to 160	16219

161	16214.2
162	16185.4
163	16163.8
164	16147
165	16142.2
166	16135
167	16132.6
168	16123
169	16115.8
170	16051
171	16043.8
172	16034.2
173	16007.8
174	15993.4
175	15983.8
176	15976.6
177	15971.8
178	15945.4
179	15940.6
180	15926.2
181	15919
182 to 183	15902.2
184	15895
185	15861.4
186	15854.2
187	15820.6
188 to 189	15796.6
190	15782.2
191	15775
192	15765.4
193 to 194	15763
195	15743.8
196 to 197	15736.6
198 to 199	15717.4
200	15695.8
201	15655
202	15635.8
203	15609.4
204	15547
205 to 207	15527.8
208	15518.2
209	15513.4
210	15506.2
211	15503.8
212	15501.4
213	15496.6
214	15494.2
215	15489.4
216	15484.6
217	15482.2
218	15479.8
219	15477.4
220 to 221	15475
222	15472.6
223	15467.8

224	15448.6
225	15446.2
226	15441.4
227 to 229	15439
230	15434.2
231	15429.4
232	15422.2
233 to 234	15419.8
235	15417.4
236	15410.2
237	15403
238	15395.8
239	15393.4
240	15388.6
241	15386.2
242	15367
243	15364.6
244	15362.2
245	15359.8
246	15357.4
247	15355
248 to 250	15352.6
251 to 252	15350.2
253 to 254	15345.4
255	15343
256 to 257	15340.6
258	15333.4
259	15314.2
260	15311.8
261	15307
262	15304.6
263	15302.2
264	15299.8
265	15275.8
266	15273.4
267 to 268	15268.6
269 to 270	15266.2
271	15261.4
272	15256.6
273	15254.2
274	15251.8
275	15213.4
276	15199
277	15124.6
278	15081.4
279	15047.8
280	15045.4
281	15035.8
282	14971
283 to 287	14961.4
288 to 294	14949.4
295	14702.2
296	14690.2
297 to 307	14680.6
308 to 325	14668.6

326 to 365 14659”

The following is a text of Table IV *after* amending the permit condition:
"TABLE IV.

FACILITY BASELINE PROFILE-SOX EMISSIONS
(LB/DAY)

S02 baseline reduced 1398 lb/day per Condition ID# 12271.
(AN 1362, Feb. 2002)

S02 baseline reduced by 80 lb/day for Flexsorb project
(AN 4106, June 2002)

Note: the 110.2 lb/day reduction was a calculation error. The
14.6 Ton/yr reduction for the Flexsorb Project is equal to 80.0
lb/day.

No. of days	Pound per day
1	22943
2	22931
3	22724.6
4	22657.4
5	22578.2
6	22407.8
7	22141.4
8	22119.8
9	22045.4
10	22031
11	21985.4
12	21774.2
13	21771.8
14	21683
15	21606.2
16	21476.6
17	21392.6
18	21371
19	21344.6
20	20994.2
21	20941.4
22	20915
23	20787.8
24	20778.2
25	20643.8
26	20564.6
27	20497.4
28	20490.2
29	20432.6
30	20430.2
31	20411
32	20394.2
33	20372.6
34	20322.2
35	20247.8
36	19983.8
37	19947.8
38	19506.2
39	19491.8
40	19489.4
41	19338.2

42	19287.8
43	19057.4
44	19047.8
45	19043
46	18939.8
47	18937.4
48	18915.8
49	18822.2
50	18817.4
51	18810.2
52	18759.8
53	18601.4
54	18536.6
55	18443
56	18375.8
57	18311
58	18128.6
59	18121.4
60	18075.8
61	18056.6
62	18039.8
63	17975
64	17965.4
65	17948.6
66	17943.8
67	17931.8
68	17907.8
69	17763.8
70	17720.6
71	17713.4
72	17711
73	17708.6
74	17682.2
75	17581.4
76	17567
77	17480.6
78	17444.6
79	17413.4
80	17363
81	17307.8
82	17305.4
83	17291
84	17233.4
85	17231
86 to 87	17221.4
88	17214.2
89	17211.8
90	17187.8
91	17185.4
92	17135
93	17096.6
94	17065.4
95	17048.6
96	17046.2
97	17024.6

98	17010.2
99	17000.6
100	16974.2
101	16962.2
102	16952.6
103	16943
104	16940.6
105	16899.8
106	16866.2
107	16859
108	16849.4
109	16847
110	16803.8
111	16791.8
112	16789.4
113	16765.4
114	16751
115	16734.2
116	16717.4
117	16712.6
118	16710.2
119	16695.8
120	16669.4
121	16633.4
122	16631
123	16619
124	16609.4
125	16592.6
126	16587.8
127	16571
128	16568.6
129	16563.8
130	16535
131	16527.8
132	16515.8
133	16499
134	16487
135	16472.6
136	16458.2
137	16422.2
138	16417.4
139 to 140	16400.6
141	16388.6
142	16369.4
143	16364.6
144	16362.2
145	16357.4
146	16352.6
147	16350.2
148	16295
149	16232.6
150	16218.2
151	16191.8
152 to 153	16187
154	16184.6

155	16175
156	16172.6
157	16163
158	16141.4
159 to 160	16139
161	16134.2
162	16105.4
163	16083.8
164	16067
165	16062.2
166	16055
167	16052.6
168	16043
169	16035.8
170	15971
171	15963.8
172	15954.2
173	15927.8
174	15913.4
175	15903.8
176	15896.6
177	15891.8
178	15865.4
179	15860.6
180	15846.2
181	15839
182 to 183	15822.2
184	15815
185	15781.4
186	15774.2
187	15740.6
188 to 189	15716.6
190	15702.2
191	15695
192	15685.4
193 to 194	15683
195	15663.8
196 to 197	15656.6
198 to 199	15637.4
200	15615.8
201	15575
202	15555.8
203	15529.4
204	15467
205 to 207	15447.8
208	15438.2
209	15433.4
210	15426.2
211	15423.8
212	15421.4
213	15416.6
214	15414.2
215	15409.4
216	15404.6
217	15402.2

218	15399.8
219	15397.4
220 to 221	15395
222	15392.6
223	15387.8
224	15368.6
225	15366.2
226	15361.4
227 to 229	15359
230	15354.2
231	15349.4
232	15342.2
233 to 234	15339.8
235	15337.4
236	15330.2
237	15323
238	15315.8
239	15313.4
240	15308.6
241	15306.2
242	15287
243	15284.6
244	15282.2
245	15279.8
246	15277.4
247	15275
248 to 250	15272.6
251 to 252	15270.2
253 to 254	15265.4
255	15263
256 to 257	15260.6
258	15253.4
259	15234.2
260	15231.8
261	15227
262	15224.6
263	15222.2
264	15219.8
265	15195.8
266	15193.4
267 to 268	15188.6
269 to 270	15186.2
271	15181.4
272	15176.6
273	15174.2
274	15171.8
275	15133.4
276	15119
277	15044.6
278	15001.4
279	14967.8
280	14965.4
281	14955.8
282	14891
283 to 287	14881.4

288 to 294	14869.4
295	14622.2
296	14610.2
297 to 307	14600.6
308 to 325	14588.6
326 to 365	14579

Permit Condition #: **18618**

The pre- Flexsorb[®] project SO₂ emissions level was based on a throughput of 73 equivalent long tons sulfur load per day. The post - Flexsorb[®] project SO₂ emissions level is based on a throughput of 150 equivalent long tons sulfur load per day. Therefore, the throughput limit for S-1765 outlined in part 1 of the permit condition was revised as follows:

Pre-Project

S#	Description	Hourly or Daily Limit	Annual Limit
S-1765	OPCEN Sulfur Plant 3 (SRU3)	73 equivalent long ton/day	365 X Daily Limit

Post-Project

S#	Description	Hourly or Daily Limit	Annual Limit
S-1765	OPCEN Sulfur Plant 3 (SRU3)	150 equivalent long ton/day	365 X Daily Limit

Permit Condition #: 19748

This permit condition is a new permit condition that was included under AN 4106 to ensure that modifications to SRU 3 would comply with the expected reductions in SO₂ and H₂S emissions.

Following is the text of the above permit condition:

- “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)
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)”

In order to incorporate the emission limits and monitoring outlined in the above permit condition, Tables IV-AR and VII-AI in Shell’s existing Title V permit will be modified as follows:

Table IV - AR
Source-specific Applicable Requirements
S1765– OPCEN SULFUR PLANT 3 (SRU3)

Applicable Requirement	Regulation Title or Description of Requirement	Federally Enforceable (Y/N)	Future Effective Date
	See Table IV – AQ for additional requirements.		
BAAQMD Condition # 19748			
Part 1	Catalytic oxidizer operating requirements (basis: Cumulative Increase; NSPS)	Y	
Part 2	Concentration of H2S in catalytic oxidizer exhaust (basis: Cumulative Increase)	Y	
Part 3	Annual SO2 mass emission limit for the catalytic oxidizer (basis: Cumulative Increase)	Y	
Part 4	Operating requirements in the event of SRU3, SCOT3, and catalytic oxidizer shutdown (basis: Cumulative Increase)	Y	
Part 5	SO2 CEM requirement at catalytic oxidizer (basis: Cumulative Increase)	Y	
Part 6	Annual source test requirement at catalytic oxidizer (basis: Cumulative Increase)	Y	

**Table VII – AI
Applicable Limits and Compliance Monitoring Requirements
S1765 – OPCEN SULFUR PLANT T3 (SRU3)**

Type of Limit	Citation of Limit	FE Y/N	Future Effective Date	Limit	Monitoring Requirement Citation	Monitoring Frequency (P/C/N)	Monitoring Type
See Table VII – AH for additional requirements.							
SO2	BAAQMD Condition #19748 Parts 1, 3			Concentration < 250 ppmvd at 0% oxygen, averaged over 24 hours; Annual emissions < 34 TPY	BAAQMD Condition #19748 Part 5	C	CEM
H2S	BAAQMD Condition #19748 Part 2			Concentration < 13.2 ppmvd at 0% oxygen, averaged over 24 hours	BAAQMD Condition #19748 Part 6	P/A	Annual Source Test
NOx, SO ₂ , CO and PM	BAAQMD Condition #7618, Part A	Y		Daily emission increases over baseline profile shall be offset by reductions below profile at a ratio of at least 2.0:1	BAAQMD Condition #7618, Part B, F and G	P/D	Calculation, reporting and records

RECOMMENDATION

Issue a minor Title V revision to Shell by incorporating all the changes discussed in this evaluation as part of Revision 1 (Rev. 1) changes to Shell’s existing Title V permit.

K. R. Bhagavan
AQE II

Date

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11
Application: 10053

BACKGROUND

Shell Oil Products US – Martinez Refinery (Shell) has submitted this permit application under the District’s Accelerated Permitting Program (APP) to obtain a Permit to Operate (PO) for the following source:

S-6061 FXU⁹ Transloading; 450 tons/day

As it currently exists, bed coke from the Flexicoker Unit (S-1759) stored at the Flexicoker Bed Coke Silos (S-1767 and S-1768) is loaded into hopper trucks and transported to a bulk rail terminal outside Shell where the coke is pneumatically loaded via hoses into rail cars. Shell has submitted this permit application with the intent of loading approximately 450 tons of coke from hopper trucks that are equipped with self-contained particulate control filters into five rail cars within Shell using existing rail car tracks.

On December 1, 2003, the District issued Shell a Title V operating permit. The following tables in Shell’s existing Title V will be modified/added to reflect the presence of S-6061:

- Table II A – Permitted Sources
- Add Table’s IV-DX and VII-DX – containing Regulation 6 standards
- Section VI - Create a new permit condition (# 21671) and include references to the new permit condition in Tables IV-DX and VII-DX, as applicable.

In light of the above, this permit application to grant Shell a PO to install S-6061 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. The proposed minor revisions are subject to a 45-day US EPA review, but are not subject to a public notice.

EMISSIONS CALCULATION

This application to permit S-6061 will result in an increase in Particulate Matter (PM₁₀) emissions at Shell. Results from a particle size analysis conducted by Shell for coke at S-1759, indicated the average particle size for coke is approximately equal to 122.5 microns (μ). The analysis showed that 99% of the volume of particles analyzed, were approximately 135 μ in size, and that the smallest particle size was 26 μ. Please refer to Attachment 1.

Since the average particle size of cement is smaller than that of coke, the transloading operations at S-6061, can be approximated to the controlled pneumatic unloading of cement to elevated storage silos. In light of the above, an emission factor of 0.00099 lbs Total PM per ton of coke unloaded outlined in Table 11.12-2 “Emission Factors for Concrete Batching,” October 2001, will be used to estimate the increase in PM₁₀ emissions at Shell. Please refer to Attachment 2.

⁹ Flexicoker Unit (FXU)

The daily PM₁₀ emissions using the AP-42 emission factor is
 = (0.00099 lbs PM₁₀/ ton of coke unloaded) x (450 tons of coke unloaded/day)
 = 0.45 lbs PM₁₀/day; 164 lbs/yr (0.08 TPY)

TOXIC RISK SCREEN ANALYSIS (RSA)

Table 1 summarizes the Toxic Air Contaminants (TAC) found in the Flexicoker coke and compares the resultant TAC emissions to the District TAC Trigger Levels (TTLs) found in Table 2-1-316 in Regulation 2, Rule 1.

**Table 1:
Toxic Air Contaminant Emissions From S-6061**

TAC	Composition in FXU Coke ¹⁰ (ppm w)	TAC Emissions ¹¹ (lbs/yr)	District TTLs (lbs/yr)
Arsenic	13	0.002	0.025
Bromine	30	0.005	330
Chlorine	5.6	0.001	1,400
Manganese	13	0.002	77
Nickel	3,290	0.54	0.73
Selenium	26	0.004	97
Zinc	50	0.008	6,800

It can be seen from Table 1 above that the TAC emissions associated with S-6061 are under the District's TTLs. Therefore, a Toxic RSA is not required.

CUMULATIVE INCREASE

The increase in PM₁₀ emissions at Shell associated with the operation of S-6061 is summarized in Table 2.

**Table 2:
Cumulative Increase in Emissions**

Emissions (TPY)	Current ¹² (TPY)	New (TPY)	Total (TPY)
PM ₁₀	1.341	0.08	1.421

Therefore, the cumulative increase in PM₁₀ emissions at Shell is 1.421 TPY.

¹⁰ Concentrations of Nickel and Chlorine are routinely measured. Please refer to Attachment 4. Concentrations of the remaining TACs are not routinely measured and the concentrations summarized in Table 1 are based on information previously submitted by Shell with their Clean Fuels Permit (AN 8407, Appendix B-4) in 1993. Please refer to Attachment 4-A.

¹¹ For example, consider Arsenic.
 = (0.45 lbs PM₁₀/day) x (13/1,000,000) x (365 days/yr) = 0.002 lbs arsenic/yr.

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.

BACT

The operation of S-6061 will result in an increase in daily PM₁₀ emissions of 0.45 lbs/day. Since this increase in PM₁₀ emissions is below the BACT trigger level of 10 lbs/day, BACT is not triggered.

OFFSETS

Information on PM₁₀ emissions at Plant 11 in the District’s database is presented in Table 3. The increase in PM₁₀ emissions associated with this application is 0.08 TPY.

Table 3:
Emission Offsets

Emissions (TPY)	Current¹³ (TPY)	New (TPY)	Total (TPY)	Offset Trigger (TPY)
PM ₁₀	404.59	0.08	404.67	> 1

Per Regulation 2-2-303 an increase in emissions for a given pollutant from a new or modified source needs to be offset only if the cumulative increase in emissions for that pollutant minus any contemporaneous emission reduction credits provided by a facility for that pollutant since April 5, 1991 exceeds 1 TPY. It can be seen from Table 2 in the preceding section that the cumulative increase in PM₁₀ emissions is above 1 TPY. Therefore, Shell will have to provide the District emission offsets for 1.421 tons.

STATEMENT OF COMPLIANCE

Source S-6061 is potentially subject to and will most definitely comply with Sections 301, 305, 310, and 311 in Regulation 6 “Particulate Matter and Visible Emissions” for the following reasons. The hopper trucks that will be used to transport the coke to railcars within the refinery are equipped with self-contained particulate control filters. Specifically, the trucks are equipped with standard filter canisters containing 500 individual filter tubes and capable of handling up to 1,600 CFM. Each filter tube is rated at 5 μ. In light of the above, it is highly unlikely that the post-control PM₁₀ exhaust stream exiting the hopper trucks at a rate of 0.00099 lbs/ton of coke unloaded after passing through the array of filter tubes, will contain particulate matter entrained in it in quantities high enough to cause an exceedance of the Ringlemann No. 1 opacity limitation in Section 6-301 and/or result in visible particles that will fall on real property not owned by Shell as outlined in Section 6-305.

Please refer to Attachment 3.

Section 6-310 limits particulate matter emissions to 0.15 gr/dscf. As previously discussed in the preceding paragraph, the filter tubes within each hopper truck are capable of handling 1,600 CFM and the post-control PM₁₀ exhaust emissions, previously estimated in the “Emission Calculation” section, was estimated to be equal to 0.45 lbs/day. The above emission rate translates to approximately 0.001 gr/dscf¹⁴. We can therefore conclude that the post-control PM₁₀ exhaust from S-6061 complies with the outlet grain-loading rate in Section 6-310.

Section 6-311 limits the emission rate of general particulate operations by the following equation:

$$E \text{ (lbs/hr)} = 0.026 * P^{0.67}, \text{ where “P” is the actual process rate in lbs/hr.}$$

¹³ Db → q2 → p → all

¹⁴ (0.45 lbs/day) x (7,000 grains/lb) / (1440 minutes/day) x (1600 ft³/min) = 0.001 grains/ ft³

As previously discussed in the “Emission Calculation” section, 450 tons (900,000 lbs/day) of coke will be unloaded from the hopper trucks to the rail cars on any given day. The value of “P” therefore is equal to 37,500 lbs/hr¹⁵. The allowable particulate matter emission rates per Section 6-311 for the above process rate is 40 lbs/hr. The post-control particulate matter emission rate from S-6061 is 0.02 lbs/hr¹⁶. We can therefore conclude that the particulate matter emissions from S-6061 comply with the limit in Section 6-311.

Shell has submitted a completed Appendix H “Environmental Information Form” with this application. This application to permit S-6061 is ministerial and requires the application of standard permit conditions and standard emission factors in accordance with Permit Handbook Chapter 11 (Section 5 – Concrete Batch Plants). Therefore, this application is not subject to a CEQA review.

Source S-6061 is not located within 1,000 feet of the nearest public school and hence the project to permit the source is not subject to the public notification requirements contained in Regulation 2-1-412.

The operation of S-6061 will not trigger additional PSD, NSPS and/or NESHAP requirements than those already existing in Shell’s existing Title V permit.

MONITORING ANALYSIS:

As previously discussed in the “Emission Calculation” section and the preceding “Statement of Compliance” section, at a daily PM₁₀ emission rate of less than 1 lb associated with S-6061, it is highly unlikely that the refinery will have difficulty complying with Sections 301, 305, 310, and 311 in Regulation 6. In light of the above, no additional monitoring is recommended.

PERMIT CONDITIONS

PC 21671

1. The owner/operator shall ensure that the hopper trucks that are used to transload flexicoker bed coke from silos S-1767 and S-1768 into rail cars within the refinery are equipped with self-contained particulate control filters which will ensure compliance with the Ringelmann 1 standard in Regulation 6, Section 301. (Basis: Regulation 6-301)
2. The owner/operator shall ensure the transloading of flexicoker bed coke from hopper trucks into rail cars within the refinery does not exceed 164,250 tons in any consecutive twelve-month period. (Basis: Cumulative Increase)
3. The owner/operator shall maintain daily records of the amount of flexicoker bed coke transloaded from the hopper trucks into the rail cars. The owner/operator shall retain the records on site for five years from the date of entry, and shall make the records available to District staff for inspection upon request. (Basis: Regulation 2-6-501)

RECOMMENDATION

In order for an application to qualify under the District’s APP, it is imperative that the uncontrolled emissions from the source under review be below 10 lbs/highest day and that the source not emit any TACs outlined in Table 2-1-316. The emission calculations presented in this evaluation assume the PM₁₀ emissions associated with the transloading of coke from the hopper trucks to the railcars within Shell are controlled and that TACs will be emitted from S-6061. In light of the above, this application does not qualify under the District’s APP.

¹⁵ (900,000 lbs/day) / (24 hrs/day) = 37,500 lbs/hr

¹⁶ (37,500 lbs/hr x 0.00099 lbs/ton) / (2000 lbs/ton) = 0.018 ~ 0.02 lbs/hr

Waive the AC and issue Shell a PO for the following equipment:

S-6061 FXU Transloading; 450 tons/day

K. R. Bhagavan
AQE II

Date

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11
Application: 11157 & 11158

Background

On March 21 I 2001, Shell Oil Products entered into a voluntary settlement with the Environmental Protection Agency (EPA) to resolve environmental issues. 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 its refineries. To obtain credit for projects that result in NOx reductions, the CD requires Shell to apply for and receive enforceable permit limits based on the following CD excerpt:

The allowable emissions from any heater or boiler is defined 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)]."

Shell retrofitted S1760 (F-102) with ultra low NOx burners under Authority to Construct # 6745 to comply with Regulation 9-10. The NOx emission reductions from this heater retrofit 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. To satisfy the CD's permitting requirement, Shell has submitted this permit application in order to obtain an enforceable permit condition for S1760 from the District.

Emissions Summary

There is no increase or change of emissions associated with this application.

Statement Of Compliance

Source S1760 complies with the requirements in Reg. 9-10. The project is categorically exempt from the District's CEQA regulation, per Section 2-1-312.11.1 because there is no emissions increase. The project is over 1000 feet from the nearest school and 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: (# 22119)

For S1760

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 0.05 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) NO_x 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]

Recommendation:

Since the above maximum daily and hourly firing rates were previously incorporated into Shell's Title V permit (part 1 of permit condition 16688), I recommend incorporating the above permit condition into Shell's Title V permit.

K.R. Bhagavan

Date

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11
Application: 11159

Background

Shell requested that the following sources that have been removed (demolished) at the refinery be deleted from their Title V permit:

Sources 30, 31, 32, 35, 36, 38, 56, 84, 90, 106, 107, 109, 259, 260, 261, 262, 343, 344, 368, 398, 422, 423, 424, 426, 427, 428, 459, 514, 523, 524, 525, 526, 786, 787, 788, 804, 822, 837, 858, 860, 861, 877, 880, 926, 927, 942, 957, 958, 993, 1000, 1001, 1004, 1009, 1013, 1023, 1024, 1026, 1050, 1071, 1185, 1405, 1409, 1415, 1452, 1459, 1478, 1479, 1531, 1532, 1535, 1536, 1538, 1539, 1540, 1562, 1563, 1564, 1565, 1566, 1567, 1568, 1571, 1572, 1573, 1574, 1575, and 2009

Emissions Summary

There is no increase or change of emissions associated with this application.

Statement Of Compliance

The deletion of the above sources from Shell’s Title V permit qualifies as an Administrative Amendment as defined in Regulation 2, Rule 6, Section 201. The project is over 1000 feet from the nearest school and 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:

Not Applicable

Recommendation:

I recommend the following changes be made to Shell’s Title V permit:

Table II-A:

Delete sources 858, 860, 861, 1004, 1023, 1050, 1409, 1415, 1478, 1479, 1539, 1540, and 2009.

Table II-B:

Delete sources 860, 861, 1004, 1409, 1539, and 1540.

Table II-C:

Delete sources 30, 31, 32, 35, 36, 38, 56, 84, 90, 109, 259, 260, 261, 262, 343, 344, 368, 398, 422, 423, 424, 426, 427, 428, 514, 523, 524, 525, 526, 786, 787, 804, 822, 837, 877, 880, 926, 927, 942, 957, 958, 993, 1000, 1001, 1009, 1013, 1024, 1026, 1071, 1185, and 1564.

Tables IV-R, IV-S, VII-P, VII-Q, IX-B-2 and Permit condition 4977:

1. Delete references to source 858 in Tables IV-R and VII-P.

2. Delete tables IV-S, Permit condition 4977, and Table VII-Q since they pertain to source 858.

Tables IV-B, VII-A, and Permit condition 18618:

Delete references to sources 860, 861, and 1004 in the above tables and part 1 of permit condition 18618.

Tables IV-R, IV-X, VII-P, VII-S, IX-B-2, and Permit condition 7133:

1. Delete references to sources 1023 and 1050 in Tables IV-R and VII-P.
2. Delete tables IV-X, Permit condition 7133, and Table VII-S since they pertain to sources 1023 and 1050.

Tables IV-B, IV-AL, VII-A, and VII-AE:

Delete references to source 1409 and 1415 in the above tables.

Tables IV-AZ, VII-AQ, and Permit conditions 7618, 16688, 18265, and 18618:

1. Delete references to sources 1478 and 1479 in the above tables.
2. Delete references to sources 1478 and 1479 in permit condition 7618, 16688 (part 1), 18265 (parts 1, 5, 12, 18, and 19), 18618 (parts 1 and 6).

Tables IV-Hb, and VII-G:

Delete references to source 1539 in the above tables.

Tables IV-BN, and VII-BC:

Delete the above tables since they pertain to source 1540.

Tables IV-AT, IV-CI, VII-AK, VII-BT, and Permit condition 5077:

1. Delete references to source 2009 in Tables IV-R, VII-P, and permit condition 5077 (parts 10 through 12).
2. Delete tables IV-CI and VII-BT since they pertain to source 2009.

Table IV-DW:

Delete sources 30, 31, 32, 35, 36, 38, 56, 84, 90, 109, 259, 260, 261, 262, 343, 344, 368, 398, 422, 423, 424, 426, 427, 428, 514, 523, 524, 525, 526, 786, 787, 804, 822, 837, 877, 880, 926, 927, 942, 957, 958, 993, 1000, 1001, 1009, 1013, 1024, 1026, 1071, 1185, and 1564.

K.R. Bhagavan

Date

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11
Application: 11613 & 11614

Background

Shell submitted the above application to perform the following alterations at the Fluidized Catalytic Cracking Unit (FCCU) catalyst regenerator (V-593) at the FCCU – source S-1426 under the District’s Accelerated Permitting Program:

- a. Replace an air grid in V-593 with a new air grid during the January 2006 Turnaround; and
- b. Make temporary underflow and overflow piping changes in February 2005 at the 3rd stage (V-596) and the 4th stage separator’s (V-597), respectively; and
- c. Eliminate quench water injection into the flue gas during normal operations between V-593 and V-596 during the January 2006 Turnaround.
- d. Make permanent changes to the flue gas piping and V-596 to accommodate the increase in flue gas temperature and flue gas volume resulting from eliminating the quench water injection during the January 2006 Turnaround.
- e. Add steam quench to the underflow from V-596 to reduce the temperature of the flue gas entering V-597 during the January 2006 Turnaround.
- f. Make permanent underflow changes at V-596 and V-597 to accommodate the increase in flue gas volume resulting from eliminating the quench water injection during the January 2006 Turnaround.
- g. Replace the existing cyclone at V-597 with a newer and larger unit that can handle the increased underflow volume exiting V-597 during the January 2006 Turnaround.
- h. Install two critical flow nozzles in parallel with upstream and downstream block valves at underflow lines exiting V-597 leading to the CO Boilers (S-1507, S-1509, and S-1512) during the January 2006 Turnaround.
- i. Install a new catalyst fines hopper dedicated to V-597 during the January 2006 Turnaround, thereby utilizing the existing Spent Catalyst Storage Hopper (V-592) as a backup.
- j. Remove the mechanical stop on a large blast-off valve at Compressor (J-123).

The net effect of the above changes will result in an increased reliability of the FCCU Expander (T-149), decreased catalyst attrition rates in the Catalyst Regenerator, increased underflow of flue gas from the 4th stage separator to the CO Boilers, decrease in particulate matter emissions from transfer operations involving catalyst fines and spent catalyst at the 4th stage separator, and increased horsepower savings at the Compressor.

Emissions Summary

The proposed changes to the FCCU catalyst regenerator will not result in a modification of S-1426 as defined in Regulation 2-1-234.2, because the FCCU and the associated upstream and downstream units will continue to operate within their currently permitted throughput capacity and permitted emission limits. Therefore, no change is expected in the pre-project and post-project emission levels. In addition, Shell will comply with the daily feed throughput limit of 79,500 bbl/day for S-1426, and the daily CO Boiler fuel combustion limits of 5,568 MMBTU/day/CO Boiler for sources S-1507, S-1509, and S-1512 as required under part 1 of permit condition 18618. It is safe to conclude that the alterations to S-1426 will not result in the de-bottlenecking of either the upstream sources (S-1420, S-1428, and S-4020), or the downstream sources (S-1449, S-1429, and S-4140) at Shell.

Statement Of Compliance

Source S-1426 is subject to 40 CFR 60 Subparts A and J, among several other requirements, that are summarized in Table IV-AP of Shell’s Title V permit. Alterations to S-1426 will not result in any changes to Table IV-AP. The project is categorically exempt from the District’s CEQA regulation, per Section 2-1-312.11.1 because there will be no emission increase. Shell has submitted Appendix H “Environmental Information Form.” The project is over 1000 feet from the nearest school and 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:

None

Recommendation:

Alterations to S-1426 will not result in any changes to Shell’s Title V permit. Waive the Authority to Construct and issue Shell a Permit to Operate.

K.R. Bhagavan

Date

Evaluation Report
A/N 12473
G# 7114 (Plant 11, Source 1598)
Shell Oil Refinery, 3485 Pacheco Blvd, Martinez

Background

Service Station Systems, on behalf of Shell Oil, has applied for an A/C to replace the Phase I vapor recovery on the Shell Oil Refinery's existing underground gasoline tank with EVR certified Phase I equipment. No other work is proposed under this application.

Shell currently operates a 12,000 gallon underground gasoline tank with two EW A4005 gasoline nozzle equipped with two-point Phase I and balance Phase II vapor recovery equipment. This equipment is permitted as Source 1598 at Plant 11 and is subject to condition #14098, which limits annual gasoline throughput to 940,000 gallons per year.

Proposed Phase I equipment consists of EBW EVR Phase I per CARB Executive Order VR-103A. All other equipment will remain unchanged.

Emissions

No change in permitted throughput has been requested.

As the EVR Phase I equipment is certified at 98% efficiency (vs. 95% for conventional Phase I) 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 exempt from the BACT and offset requirements of Regulation 2, Rule 2.

The proposed EBW EVR Phase I equipment is certified under G-VR-103A, while the existing Phase II equipment is certified under G-70-17AD and 52AM. Use of CARB certified equipment satisfies all requirements of District Regulation 8, Rule 7.

Permit Conditions

Permit to Operate Conditions

COND# 14098 -----

Pursuant to BAAQMD Toxic Section Policy, this facility's annual gasoline throughput shall not exceed 940,000 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 overflow prevention devices ("flapper valves"), a Drop Tube Overflow 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-102. Results shall be submitted to BAAQMD within 15 days of the test date in a District-approved format.

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. The equipment has been installed. Per the ST-log, Shell passed all three required tests (ST-30, drop tube test, and the torque test) on April 27, 2005. Recommend that an A/C be waived and a P/O issued for the above project.

Scott Owen
Supervising AQ Engineer

Table IV – BO
Source-specific Applicable Requirements
S1598 – MAINT GASOLINE DISPENSING FACILITY

<u>Applicable Requirement</u>	<u>Regulation Title or Description of Requirement</u>	<u>Federally Enforceable (Y/N)</u>	<u>Future Effective Date</u>
<u>BAAQMD Regulation 8, Rule 7</u>	<u>Organic Compounds - Gasoline Dispensing Facilities (3/24/03)</u>		
<u>8-7-113</u>	<u>Tank Gauging and Inspection Exemption</u>	<u>Y</u>	
<u>8-7-301</u>	<u>Phase I Requirements</u>	<u>Y</u>	
<u>8-7-301.1</u>	<u>Requirement for CARB Phase I System</u>	<u>Y</u>	
<u>8-7-301.2</u>	<u>Installation of Phase I Equipment per CARB Requirements</u>	<u>Y</u>	
<u>8-7-301.3</u>	<u>Submerged Fill Pipes</u>	<u>Y</u>	
<u>8-7-301.5</u>	<u>Maintenance of Phase I Equipment per Manufacturers Guidelines or CARB Executive Order</u>	<u>Y</u>	
<u>8-7-301.6</u>	<u>Leak-Free, Vapor-Tight</u>	<u>Y</u>	
<u>8-7-301.7</u>	<u>Poppeted Drybreaks</u>	<u>Y</u>	
<u>8-7-301.8</u>	<u>No Coaxial Phase I Systems on New and Modified Tanks</u>	<u>Y</u>	
<u>8-7-301.9</u>	<u>CARB-Certified Anti-Rotational Coupler or Swivel Adapter</u>	<u>Y</u>	
<u>8-7-301.10</u>	<u>System Vapor Recovery Rate</u>	<u>Y</u>	
<u>8-7-301.11</u>	<u>CARB-Certified Spill Box</u>	<u>Y</u>	
<u>8-7-301.12</u>	<u>Drain Valve Permanently Plugged</u>	<u>Y</u>	
<u>8-7-301.13</u>	<u>Vapor Tightness and Testing</u>	<u>Y</u>	
<u>8-7-302</u>	<u>Phase II Requirements</u>	<u>Y</u>	
<u>8-7-302.1</u>	<u>Requirement for CARB Certified Phase II System</u>	<u>Y</u>	
<u>8-7-302.2</u>	<u>Maintenance of Phase II System per CARB Requirements</u>	<u>Y</u>	
<u>8-7-302.3</u>	<u>Maintenance of All Equipment as Specified by Manufacturer</u>	<u>Y</u>	
<u>8-7-302.4</u>	<u>Repair of Defective Parts Within 7 Days</u>	<u>Y</u>	
<u>8-7-302.5</u>	<u>Leak-Free, Vapor-Tight</u>	<u>Y</u>	
<u>8-7-302.6</u>	<u>Insertion Interlocks</u>	<u>Y</u>	
<u>8-7-302.7</u>	<u>Built-In Vapor Check Valve</u>	<u>Y</u>	
<u>8-7-302.8</u>	<u>Minimum Liquid Removal Rate</u>	<u>Y</u>	
<u>8-7-302.9</u>	<u>Coaxial Hose</u>	<u>Y</u>	
<u>8-7-302.10</u>	<u>Galvanized Piping or Flexible Tubing</u>	<u>Y</u>	
<u>8-7-302.12</u>	<u>Liquid Retention-Retention Limit</u>	<u>Y</u>	<u>1/1/09</u>
<u>8-7-302.13</u>	<u>Spitting Limit</u>	<u>Y</u>	<u>1/1/09</u>
<u>8-7-302.14</u>	<u>Back Pressure for Vapor Balance</u>	<u>Y</u>	
<u>8-7-303</u>	<u>Topping Off</u>	<u>Y</u>	
<u>8-7-304</u>	<u>Certification Requirements</u>	<u>Y</u>	
<u>8-7-306</u>	<u>Prohibition of Use</u>	<u>Y</u>	
<u>8-7-307</u>	<u>Posting of Operating Instructions</u>	<u>Y</u>	

Table IV – BO
Source-specific Applicable Requirements
S1598 – MAINT GASOLINE DISPENSING FACILITY

<u>Applicable Requirement</u>	<u>Regulation Title or Description of Requirement</u>	<u>Federally Enforceable (Y/N)</u>	<u>Future Effective Date</u>
8-7-308	<u>Operating Practices</u>	<u>Y</u>	
8-7-309	<u>Contingent Vapor Recovery Requirements</u>	<u>Y</u>	
8-7-311	<u>Exempt Tank Requirements</u>	<u>Y</u>	
8-7-313	<u>Requirements for New or Modified Phase II Installations</u>	<u>Y</u>	
8-7-315	<u>Pressure Vacuum Valve Requirement, Underground Storage Tank</u>	<u>Y</u>	
8-7-401	<u>Permit Requirements, New and Modified Installations</u>	<u>Y</u>	
8-7-406	<u>Testing Requirements, New and Modified Installations</u>	<u>Y</u>	
8-7-407	<u>Periodic Testing</u>	<u>Y</u>	
8-7-408	<u>Test Notification</u>	<u>Y</u>	
8-7-501	<u>Burden of Proof</u>	<u>Y</u>	
8-7-502	<u>Right of Access</u>	<u>Y</u>	
8-7-503	<u>Record Keeping Requirements</u>	<u>Y</u>	
8-7-503.1	<u>Gasoline Dispensed Records</u>	<u>Y</u>	
8-7-503.2	<u>Dispensing Facility Maintenance Records</u>	<u>Y</u>	
8-7-503.3	<u>Dispensing Records Retention</u>	<u>Y</u>	
<u>BAAQMD Condition # 14098</u>			
Part 1	<u>Annual gasoline throughput limit [basis: Cumulative Increase, Toxics]</u>	<u>N</u>	
Part 2	<u>Recordkeeping [basis: Toxics, Cumulative Increase, Toxics]</u>	<u>N</u>	
<u>BAAQMD Condition #21593 Part 1</u>	<u>Phase I equipment installed and maintained per CARB Executive Order (Basis: District Regulation 8-7-301.2)</u>	<u>Y</u>	
<u>BAAQMD Condition #21593 Part 2</u>	<u>Triennial drop tube/drain valve and static adaptor torque test requirements (Basis: District Regulation 8-7-301.2)</u>	<u>Y</u>	

Table VII – BD
Applicable Limits and Compliance Monitoring Requirements
S1598 – MAINT GASOLINE DISPENSING FACILITY

<u>Type of Limit</u>	<u>Citation of Limit</u>	<u>F E Y / N</u>	<u>Future Effective Date</u>	<u>Limit</u>	<u>Monitoring Requirement Citation</u>	<u>Monitoring Frequency (P/C/N)</u>	<u>Monitoring Type</u>
HAP	BAAQMD Condition #14098, Part 1	N		Annual gasoline throughput shall not exceed 940,000 gallons in any 12-month period	BAAQMD Condition #14098, Part 2 and Condition #18618, Part 2	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 Static Pressure Performance Test, ST-30
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 Static Pressure Performance Test, ST-30
POC	8-7-302.14	Y		Back Pressure for Vapor Balance, per applicable Executive Order or less than or equal to 0.15, 0.45, and 0.95 inches of water when measured at nitrogen flow rates of 20, 60, and 100 CFH respectively	8-7-302.14 8-7-601	P/A	Dynamic Back-pressure Test (ST-27)
POC	BAAQMD Condition # 21593 Part 2	Y		Drop tube/drain valve leak rate not to exceed 0.17 CFH @ 2" H ₂ O; minimum 360° rotation with maximum 108 pound-inch torque	BAAQMD 8-7-503.2 and BAAQMD Condition # 20666 Part 2	P/3A	Drop tube/drain valve leak test (CARB TP 201.1C or 201.1D) and torque test (CARB TP 201.1B)

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11
Application: 12731 & 12732

Background

Shell Oil Products US – Martinez Refinery (Shell) has submitted this application to receive the District’s authorization to perform certain modifications/alterations at the following existing sources:

S-1427 CP Catalytic Gas Plant (CGP)

S-1430 CP Alkylation Plant (ALKY)

S-1764 OPCEN Dimersol Plant (DIMER)

Shell is proposing to change the catalyst formulation of the existing aluminosilicate catalyst that it uses at S-1426 “CP Catalytic Cracking Unit (CCU)”. The company estimates the above change will result in an increase in C3/C4¹⁷ production in lieu of heavier CCU products i.e. gas oils, etc. The new catalyst formulation will have a slightly different crystalline structure in comparison to its existing counterpart. Shell proposes to replace approximately 7% of the existing catalyst with the new formulation, and contends that the new catalyst will retain the same general characteristics of the existing catalyst. The expected increase in C3 yield will result in an increase in dimate processing capacity of the DIMER unit from 3,200 bbl/day to 4,000 bbl/day.

Polymerization is a process utilized for the conversion of propane/propylene and/or butane/butylene feeds from other refinery operations into a low molecular weight, high-octane, polymer product, referred to as dimate. Refineries typically use either the Phosphoric Acid polymerization process, or the Dimersol process, which Shell employs. The Dimersol process is used to dimerize (~ double) light olefins such as ethylene, propylene, and butylenes into dimate.

Shell has proposed to make the following changes at the CGP, ALKY, and DIMER units to accommodate the increase in C3/C4 production:

Please refer to Figure 1 in Attachment A.

- a. Retrofit the overhead pumps at the CGP (source S-1427) to increase the delivery of C3/C4 hydrocarbons to the C3/C4 treaters (source S-1434), and replace 5 trays in the debutanizer column (C127) at the CGP; and
- b. Add a parallel cooler at the DIMER (source S-1764) to reduce the frequency of CCU (source S-1426) slowdowns when the DIMER is not able to fully process all C3 hydrocarbons produced at the CCU. Shell expects the addition of the parallel cooler will reduce flaring at the refinery during DIMER shutdowns, and reduce the amount of C3 hydrocarbons sent to the ALKY (source S-1430); and
- c. Alterations to the ALKY unit will involve modifications to the water and caustic systems, addition of demister plates and stilling baffles, and enlargement of the outlet nozzle of the ALKY product separator.

¹⁷ C3 – Propane; C4 - Butane

Shell has indicated that the change in catalyst formulation at the CCU will not result in any changes to either the catalyst addition rate and/or the coke burn rate at S-1426 from existing levels. The increase in C3/C4 production from the CCU's main fractionator will also result in the following changes at Shell:

d. Decrease in gas oils sent from S-1426 to the Hydrocracking Unit (source S-1449); and

e. Decrease in throughput from the CGP (source S-1427) to the Catalytic Gas Plant Depentanizer (source S-4050); and

f. Increase in throughput from the C3/C4 treaters (source S-1434) to the Dimersol C3/C4 Splitter (source S-1770); and

g. Increase in throughput of C3 and C4 hydrocarbons sent from S-1770 to the DIMER (source S-1764) and ALKY (source S-1430) units, respectively; and

h. Decrease in ALKY feed imported to the refinery by rail.

De-bottlenecking Analysis

Please refer to Figure 1 in Attachment A.

Sources upstream of the DIMER unit – source S-1764:

The use of the new catalyst formulation at the CCU – source S-1426 will result in a shift in production of heavier hydrocarbon products such as gas oils sent to the HCU – S-1449, in favor of desirable lighter products such as C3/C4 sent to the CGP – source S-1427.

The above changes will not increase the CCU's hydrocarbon processing capacity and will not result in modifications to permit condition 7618, which contains the REFEMS emissions cap for sources such as the CCU, and its furnaces, which were fully offset in previous NSR permitting actions.

The C3/C4 material generated at the CCU is sent to the RA Column (C125) at the CGP – source S-1427. There will be an increase in the utilization to this vessel (C125). Material from C125 will then be sent to the Debut Column (C127) which will also have an increase in utilization. Material from C127 will then be sent to either the Splitter – source S-1770 or the CGDP – source S-4050. There will be an increase in the utilization of the Splitter, and a corresponding decrease in the utilization of the CGDP. However, the above increases will not exceed any Title V throughput limits. Material from the Splitter will then be routed to either the DIMER unit – source S-1764 or the ALKY unit – source S-1430. As previously discussed in the “Background” section, an actual increase in dimate produced at the DIMER unit will result in a change to the Title V throughput limit i.e. from 3,200 bbl/day to 4,000 bbl/day. There will be no change to either the actual and/or the Title V throughput limit at the ALKY unit – source S-1430.

Sources downstream of the DIMER unit – source S-1764:

The proposed modifications/alterations to process units that are part of this application will not change the overall throughput through tankage at Shell, since the proposed increase in dimate production will be offset by decreases in heavier products. Dimate from the DIMER unit – source S-1764 will be sent to dimate storage tank – source S-14 prior to gasoline blending. There will no changes made to the Title V throughput limit for S-14. Likewise, alkylate from the ALKY unit – source S-1430 will be sent to alkylate storage tanks – sources S-1757, S-1758, and S-4334. There will no changes made to the Title V throughput limits for S-1757, S-1758, and S-4334.

Other units:

The proposed modifications/alterations to process units that are part of this application will result in the increased utilization of some steam producing units at Shell. However, none of the affected steam producing 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 steam producing units, and they will continue to comply with their respective emission limits.

There will be a reduction in flaring at the Light Oil Processing (LOP) flares as a result of adding a parallel cooler at the DIMER unit - source S-1764, since there will be a drop in the frequency of CCU - source S-1426 slowdowns when the DIMER unit is not able to fully process all C3 hydrocarbons produced at the CCU. Specifically, the reductions will occur at source S-1772 - the OPCEN Hydrocarbon Flare. The proposed modifications/alterations to process units that are part of this application will not result in any changes to the Title V throughput limit for the above flare.

Regulation 2-1-234.1

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.

As it currently exists, part 1 of permit condition 18618 limits the amount of dimate produced at the DIMER unit to 3,200 bbl/day. The proposed modifications/alterations to process units that are part of this application will result in an increase in the amount of dimate produced at the DIMER unit from 3,200 bbl/day to 4,000 bbl/day. Therefore, per Regulation 2-1-234.1 the DIMER unit is considered a modified source.

It can be seen from “De-bottlenecking Analysis” discussion above that unlike the DIMER unit, the CGP – source S-1427, and the ALKY – source S-1430, will undergo alterations i.e. they will not be modified.

Emissions Calculations

Process units are closed processes, implying the only sources of emissions from such units are from fugitive leaks. The proposed modifications/alterations to process units that are part of this application will result in the addition of new/retrofitted fugitive components i.e. valves, pumps, flanges, etc. Shell conservatively estimated 66 new valves, 2 new pumps (~ upgrades/retrofits), and 117 new flanges in “light liquid” service will be installed at the affected process units. Table 1 summarizes leak rates for the above fugitive components, which are similar to those that were used by the District under Application 1821¹⁸.

Table 1

Type/service	Number of components ¹	Emission factor (lb/hr/component) ²	POC ¹⁹ , lb/hr	POC, lb/day	POC, lb/yr	POC, tpy
<u>Valves/Gas/Light Liquid</u>	<u>66</u>	<u>0.000231</u>	<u>0.0015</u>	<u>0.036</u>	<u>13.14</u>	<u>0.0066</u>
<u>Pump seals/Gas/Light Liquid</u>	<u>2</u>	<u>0.000704</u>	<u>0.0014</u>	<u>0.0336</u>	<u>12.26</u>	<u>0.0061</u>
<u>Flanges/All³</u>	<u>117</u>	<u>0.00017</u>	<u>0.0199</u>	<u>0.4776</u>	<u>174.32</u>	<u>0.0872</u>
<u>Totals</u>	<u>185</u>		<u>0.0228</u>	<u>0.5472</u>	<u>199.72</u>	<u>0.0999</u>

- 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.

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 of fugitive POC emissions per day.

Toxic Risk Screen Analysis

Since this application was received after July 1, 2005, it is subject to Regulation 2, Rule 5 “New Source Review of Toxic Air Contaminants”.

Information on the speciation of the affected process streams that are part of the proposed project contained in a database maintained by Shell for the purposes of SARA Title III Toxic Inventory reporting indicates the presence of 1,3-butadiene and hydrogen sulfide (H₂S). Specifically, 1,3-butadiene (at a maximum concentration 0.40%) is present in various concentrations in process streams prior to and following dimerization at source S-1764 - the DIMER²⁰. In contrast, H₂S (at a maximum concentration of 4.70%) is only present in the untreated process streams prior to the C104 and C105 C3/C4 Treater

¹⁸ An AC and PO were issued to Shell under Application 1821 in January 2002 and August 2002, respectively.

¹⁹ POC – Precursor Organic Compounds

²⁰ 1,3-butadiene emissions = 0.40% of 199.72 lb POC/yr (from Table 1) = 0.80 lb 1,3-butadiene/yr

located at source S-1434, where it is substantially removed. Process streams downstream of S-1434 are presumed to not contain any H₂S.

Therefore, H₂S emissions quantified in Table 2 below conservatively assume the contribution of the above TAC will be from upgrades/retrofits to the two overhead pumps at the debutanizer – C127 at source S-1427, and the two flanges that will be added per overhead pump²¹. Please also refer to a summary of the proposed modifications/alterations in the “Background” section above, and Figure 1 in Attachment A.

Table 2

<u>Chemical</u>	<u>Post-Project TAC Emissions (lb/hour)²²</u>	<u>Table 2-5-1 Acute Trigger Level (lb/hour)</u>	<u>Post-Project TAC Emissions (lb/year)</u>	<u>Table 2-5-1 Chronic Trigger Level (lb/year)</u>	<u>Do the Post-Project TAC Emissions Exceed Table 2-5-1 Acute/Chronic Trigger Levels?</u>
<u>1,3-butadiene</u>	<u>0.000091</u>	<u>NA</u>	<u>0.80</u>	<u>1.1</u>	<u>No</u>
<u>Hydrogen sulfide</u>	<u>0.000098</u>	<u>0.093</u>	<u>0.86</u>	<u>390</u>	<u>No</u>

It can be seen from Table 2 above that the proposed modifications/alterations to process units that are part of this application don't trigger a Toxic RSA.

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 all additional components installed at process units that are part of this application is below 10 lb/day i.e. 0.5472 lb/day. The additional fugitive components, summarized in Table 1 will meet the requirements of Regulation 8, Rule 18

²¹ Using leak rates summarized in Table 1 to estimate H₂S emissions:
= (2 pumps x 0.000704 lb POC/hr/pump) + (4 flanges x 0.00017 lb POC/hr/flange)
= 0.002088 lb POC/hr ~ 0.05 lb POC/day
H₂S = 4.70% of 0.05 lb POC/day = 0.00235 lb H₂S/day ~ 0.86 lb H₂S/year

²² To get hourly TAC emissions, divide the annual emissions (in lbs/year) by 8,760 hours/yr

“Equipment Leaks” and will be incorporated into Shell’s Leak Detection and Repair (LDAR) program.

The modifications/alterations to process units that are part of this application 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 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:
None of the process units that are part of this application are public nuisance sources.
- Regulation 2-1-318:
It can be seen from Table 2 above that the amount of H₂S i.e. 0.86 TPY, which will result from modifications/alterations to process units that are part of this application is below the 10 TPY H₂S trigger outlined in Regulation 2-1-318.8.
- Regulation 2-1-319:
The “post-control” emissions of any regulated air pollutant from process units that are part of this application is below 5 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 addition of the fugitive components summarized in Table 1 above qualifies for the exemption under Regulation 2-1-128.21.

BACT

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.

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 August 12, 1994, and the BACT 2 level for the pumps (500 ppm expressed as methane) outlined in BACT Guidance Document #137.1 dated June 30, 1995.

Offsets & Cumulative Increase

The alterations/modifications to the CGP – source S-1427, the ALKY – source S-1430, and the DIMER – source S-1764 summarized in Table 1 above will result in an increase of 0.10 TPY of POC emissions. In order to offset the above emission increase, Shell will have to surrender to the District 0.12 TPY of Emission Reduction Credits (ERC) at an offset ratio of 1.15:1²³.

Statement Of Compliance

There will be no change made to the applicable requirements contained in Shell’s Title V permit under Tables IV-B, AL, and AN as it relates to the DIMER unit. However, the “Daily Limit” outlined in part 1 of permit condition 18618 will be amended from 3,200 bbl/day to 4,000 bbl/day.

The fugitive components summarized in Table 1 above will be subject to Sections 301, 302, 303, 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. In similar fashion, Section 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.

With the exception of the two pumps that will be retrofitted at the CCU – source S-1426, the remaining 183 fugitive components (66 valves + 117 flanges) that will be added to the DIMER unit – source S-1764 are potentially subject to the requirements of 40 CFR Part 60, Subpart GGG “Equipment Leaks of VOC in Petroleum Refineries”, and 40 CFR Part 60 Subpart VV “Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry”.

As it currently exists in Shell’s Title V permit, the DIMER unit is not subject to the requirements of 40 CFR Part 60, Subpart GGG (NSPS GGG). Per Section 60.590(c) in the above rule, addition or replacement of equipment (i.e. fugitive components in Shell’s case) for the purpose of process improvement, which is accomplished without a capital expenditure shall not by itself be considered a modification. The addition of the 183 fugitive components at the DIMER unit is not a capital expenditure as defined in 40 CFR 60, Subpart VV (NSPS VV). Capital expenditure calculation procedures outlined in NSPS VV are used, since the capital expenditure calculation procedure outlined in the rule references NSPS GGG, and NSPS GGG neither contains a definition or the calculation procedure for capital expenditure. Therefore, neither the DIMER unit, nor the 183 fugitive components that will be added to it are subject to NSPS GGG. In contrast, since the CGP – source S-1427 is considered to be a part of the CCU – source S-1426,

²³ Per Regulation 2-2-302.

which is subject to NSPS GGG. Therefore, the two pumps that will be upgraded at the CGP are subject to both NSPS GGG and NSPS VV.

As it currently exists in Shell's Title V permit, the DIMER unit – source S-1764 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 modifications to the DIMER unit that are part of this application will not result in the emissions of any new pollutants. Therefore, the DIMER unit is not subject to 40 CFR Part 61.

The Maximum Achievable Control Technology (MACT) standards in 40 CFR Part 63 apply 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 DIMER unit – source S-1764 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”.

40 CFR Part 63, Subpart CC (MACT CC) applies to various refinery operations including miscellaneous process vents and equipment leaks. The fugitive components similar to those that will be added to the DIMER unit, must comply with NSPS VV if they will be used 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.”

It can be seen from Table 2 above that the only organic HAP contained in the process streams associated with modifications to the DIMER unit is 1,3-butadiene (at a maximum concentration of 0.40%). Table 1 in MACT CC does not list hydrogen sulfide, which is included in Table 2 above, as an organic HAP. Therefore, neither the DIMER unit, not the fugitive components that will be added to it as part of this application are subject to MACT CC.

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: 136.1; dated August 12, 1994 & 137.1 dated June 30, 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 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 modifications/alterations to process units that are part of this application are exempt from Regulation 2-1-301 per Regulation 2-1-128.21. As a result, the 0.10 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 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 either "No", or "Not Applicable". Shell clarified to the District that their rationale in responding "Yes" to item 29 was to shed light on the fact that there will be an increase in dimate production (from 3,200 bbl/day to 4,000 bbl/day) which is a flammable material.

In addition to the above form, Shell has also submitted additional information in order for the District to determine the project's possible significant effects. To address specific CEQA related questions posed by the District, Shell responded as follows in their September 29, 2005 letter:

- a) Does the Dimersol Rerate Project qualify for a CEQA statutory exemption (see, e.g. Article 18, commencing with Section 15260)? If so, please indicate which statutory exemption and how the project qualifies.

Yes. The project qualifies for a CEQA statutory exemption based on BAAQMD Regulation 2-1-427 and 2-1-428. The project is ministerial. Section 15268 provides a statutory exemption for ministerial projects.

b) Is the Dimersol Rerate Project exempt from CEQA pursuant to a categorical exemption (see Article 19, commencing with Section 15300) and the application of that categorical exemption is not barred by one of the exceptions set forth in Section 15300.2? Please explain.

Yes. In accordance with BAAQMD 2-1-312.11, this project is categorically exempt from CEQA review because the project satisfies the "No Net Emissions Increase" provisions of BAAQMD Regulation 2-2; and there is no possibility that the project may result in significant adverse environmental impacts in connection with any of the environmental media or resources listed in the State CEQA Guidelines. The project satisfies the "No Net Emissions Increase" provisions since the project is exempt from ATC requirements, having emissions less than any threshold which would require an ATC, thereby exempting the project from the requirement to obtain emission offsets under the NSR rule. In compliance with the BAAQMD Regulation 2-1-312, Shell includes Dimersol Project permit application sufficient CEA-related information to demonstrate that the project qualifies for this exemption.

The proposed modifications to the Martinez Refinery are shown such that a rating of "no impact" on the environment can be assigned. The Dimersol Project is categorically exempt from the provisions of CEQA, under the State CEQA Guidelines (Section 15301 – Existing Facility and Section 15302 – Replacement or Reconstruction). This exemption applies because the Dimersol Project consists of minor, internal alterations to an existing processing unit. Minor alterations primarily involve piping and valve changes, pump modifications, and addition of a heat exchanger.

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 the information contained in the Appendix H form submitted and Shell's September 29, 2005 letter 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 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 DIMER unit 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. In reaching this conclusion, the District is relying in part on the information submitted in the September 29, 2005, letter from Shell responding to written questions from the District. 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

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)

<u>S-#</u>	<u>Description</u>	<u>Daily Limit</u>	<u>Annual Limit</u>
1764	OPCEN Dimersol Plant (DIMER)	3,200 bbl/day dimate produced	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 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)

<u>S-#</u>	<u>Description</u>	<u>Daily Limit</u>	<u>Annual Limit</u>
1764	OPCEN Dimersol Plant (DIMER)	3,200 4,000 bbl/day dimate produced	365 x Daily Limit

RECOMMENDATION

Waive the AC, and issue Shell a PO for the proposed alterations at the following sources:

S-1426 CP Catalytic Cracking Unit

S-1427 CP Catalytic Gas Plant

S-1430 CP Alkylation Plant

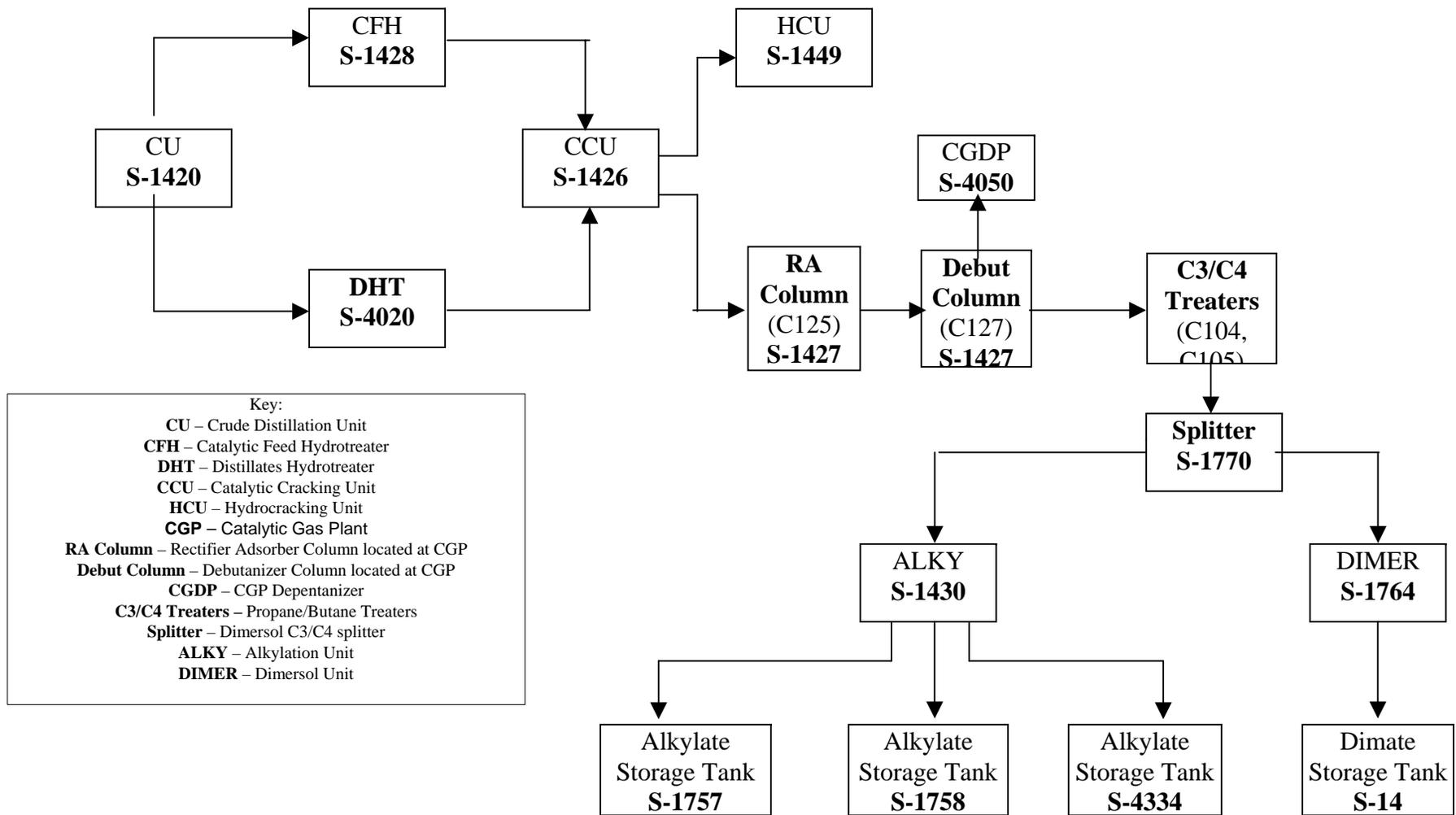
Modify permit condition 18618 as proposed for the following equipment:

S-1764 OPCEN Dimersol Plant (DIMER)

K. R. Bhagavan
Air Quality Engineer II
Engineering Division

Date

Figure 1: Process Flow Diagram



ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11
Application: 13078

Background

Shell has submitted this application to replace burners at the following sources located at the Catalytic Reformer Unit (CRU) and the Saturates Gas Plant (SGP):

- 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
- S-1500 DH F-55 SGP Heat Medium; 167 MMBTU/hr
- S-1762 DH F-128 CRU Interheater; 200 MMBTU/hr

Per Regulation 2-1-233.1, the replacement of the burners at the above sources is an alteration, and will not impact any portions of Shell’s Title V permit.

Shell has proposed to replace the existing burners at the above sources, except for S-1500, with Ultra Low NOx Burners (ULNBs), 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 existing burners at source S-1500 will be replaced with Low Emission (LE) NOx Burners. The net effect of the above modifications will be to enhance the compliance of sources S-1495, S-1496, S-1497, S-1498, S-1499, S-1500, and S-1762 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-1495, S-1496, S-1497, S-1498, S-1499, S-1500, and S-1762 are equipped with NOx and O₂ CEMS²⁴ and are governed by permit condition 18265, which outlines Shell’s “IERC²⁵ Alternative Compliance Plan”. The proposed alterations to sources S-1495, S-1496, S-1497, S-1498, S-1499, S-1500, and S-1762 will not result in any changes to either of the above two permit conditions. Because of the use of NOx and O₂ 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-1495, S-1496, S-1497, S-1498, S-1499, S-1500, and S-1762, and their corresponding NOx and CO emission rates/concentrations.

Table 1
“Pre-Project” Summary²⁶

<u>Source ID</u>	<u>Burner Manufacturer</u>	<u>Burner Model(s)</u>	<u>NOx (ppm @ 3% O₂)</u>	<u>NOx (lb/MMBTU)</u>	<u>CO (ppm @ 3% O₂)</u>
<u>S-1495</u>	<u>John Zink</u>	<u>EFX-PC-20</u>	<u>65.4</u>	<u>0.088</u>	<u>10.3</u>

²⁴ CEMS – Continuous Emission Monitoring Systems
 CEMS information for Shell summarized in P:\GENERAL\ST\CEMLIST.doc

²⁵ IERC – Interchangeable Emission Reduction Credits

²⁶ 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.

		<u>EFX-PC-18</u>			
<u>S-1496</u>	<u>John Zink</u>	<u>EFX-PC-20</u>	<u>65.4</u>	<u>0.088</u>	<u>10.3</u>
		<u>EFX-PC-18</u>			
<u>S-1497</u>	<u>John Zink</u>	<u>EFX-PC-20</u>	<u>65.4</u>	<u>0.088</u>	<u>10.3</u>
		<u>EFX-PC-18</u>			
<u>S-1498</u>	<u>NAO</u>	<u>#30 Model CP</u>	<u>135.6</u>	<u>0.169</u>	<u>< 5</u>
<u>S-1499</u>	<u>NAO</u>	<u>#30 Model CP</u>	<u>108.7</u>	<u>0.13</u>	<u>< 5</u>
<u>S-1500</u>	<u>NAO</u>	<u>#30 Model CP</u>	<u>168</u>	<u>0.202</u>	<u>73.1</u>
<u>S-1762</u>	<u>John Zink</u>	<u>EFX-PC-24</u>	<u>25.1</u>	<u>0.04</u>	<u>< 5</u>

Table 2 below summarizes information on the proposed alterations at sources S-1495, S-1496, S-1497, S-1498, S-1499, S-1500, and S-1762, and their corresponding NOx and CO emission rates/concentrations. The CO concentrations i.e. 50 ppm @ 3% O₂, 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

<u>Source ID</u>	<u>“Callidus” Burner Model(s)</u>	<u>Number of burners</u>	<u>Burner design firing rates (MMBTU/hr)</u>	<u>NOx (lb/MMBTU)²⁷</u>	<u>CO (ppm @ 3% O₂)</u>
<u>S-1495</u>	<u>CUBL-10W-Flex</u>	<u>10</u>	<u>9</u>	<u>0.033</u>	<u>< 50</u>
	<u>CUBL-8W-Flex</u>	<u>10</u>	<u>7.40</u>		
<u>S-1496</u>	<u>CUBL-10W-Flex</u>	<u>15</u>	<u>9</u>	<u>0.033</u>	<u>< 50</u>
	<u>CUBL-8W-Flex</u>	<u>6</u>	<u>7.40</u>		
<u>S-1497</u>	<u>CUBL-10W-Flex</u>	<u>5</u>	<u>9</u>	<u>0.033</u>	<u>< 50</u>
	<u>CUBL-8W-Flex</u>	<u>8</u>	<u>7.40</u>		
<u>S-1498</u>	<u>CUBL-8P</u>	<u>4</u>	<u>8.25</u>	<u>0.030</u>	<u>< 50</u>
<u>S-1499</u>	<u>CUBL-8P</u>	<u>3</u>	<u>8</u>	<u>0.030</u>	<u>< 50</u>
<u>S-1500</u>	<u>LE-CSG-12W</u>	<u>8</u>	<u>13.75</u>	<u>0.028</u>	<u>< 50</u>
<u>S-1762</u>	<u>CUBL-14P-Flex</u>	<u>7</u>	<u>12.10</u>	<u>0.031</u>	<u>< 50</u>
	<u>CUBL-10P-Flex</u>	<u>2</u>	<u>7.40</u>		

It can be seen from Tables 1 and 2 above that the proposed alterations at sources S-1495, S-1496, S-1497, S-1498, S-1499, S-1500, and S-1762 will not result in a net increase in NOx emissions at Shell.

Regulation 9-10-301 outlines a refinery wide NOx emission limit of 0.033 lb/MMBTU (~ 30 ppmv @ 3% O₂) for sources such as S-1495, S-1496, S-1497, S-1498, S-1499, S-1500, and S-1762. It can be seen from Table 2 above that the proposed alterations will result in a reduction in NOx emissions. 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 (i.e. S-1495 – 190 MMBTU/hr, S-1496 – 225 MMBTU/hr, S-1497 – 106 MMBTU/hr, S-1498 – 39 MMBTU/hr, S-1499 – 31 MMBTU/hr, S-1500 – 167 MMBTU/hr, and S-1762 – 200 MMBTU/hr).

²⁷ Sources S-1495, S-1496, and S-1497 share a common convection section, and stack. Therefore, the emission rates summarized for the above heaters in Table 2 are the same.

Statement Of Compliance

The proposed project will enhance Shell's compliance with Regulation 9, Rule 10, by reducing NOx emission from sources S-1495, S-1496, S-1497, S-1498, S-1499, S-1500, and S-1762.

The proposed alterations to S-1495, S-1496, S-1497, S-1498, S-1499, S-1500, and S-1762 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 ULNB and LE retrofit project, could potentially result in an increase in CO emissions – the secondary pollutant of the retrofit project. However, per Regulation 2-2-113, the installation of the ULNBs and LE at sources S-1495, S-1496, S-1497, S-1498, S-1499, S-1500, and S-1762 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, there will be no changes to any of the applicable requirements contained in Shell's Title V permit for the above sources.

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

CEQA Categorical Exemption and CEQA "Common Sense Exemption":

Though the District concludes that the alterations to sources 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, 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 proposed alterations to S-1495, S-1496, S-1497, S-1498, S-1499, S-1500, and S-1762 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" 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 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 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.

Permit Conditions

Sources S-1495, S-1496, S-1497, S-1498, S-1499, S-1500, and S-1762 are currently subject to permit condition 16688, which limits the maximum firing rate at the above sources to 190 MMBTU/hr, 225 MMBTU/hr, 106 MMBTU/hr, 39 MMBTU/hr, 31 MMBTU/hr, 167 MMBTU/hr, and 200 MMBTU/hr, respectively. As previously discussed in the "Background" section above, sources S-1495, S-1496, S-1497, S-1498, S-1499, S-1500, and S-1762 are equipped with NO_x and O₂ CEMS and are governed by permit condition 18265, which outlines Shell's "IERC Alternative Compliance Plan". The proposed alterations to sources S-1495, S-1496, S-1497, S-1498, S-1499, S-1500, and S-1762 will not result in any changes to either of the above two permit conditions. Because of the use of NO_x and O₂ 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-1495 DH F-49 CRU Preheat

Callidus "CUBL-10W-Flex" and "CUBL-8W-Flex" Ultra Low-NO_x Burners
Maximum Firing Rate: 190 MMBTU/hr

S-1496 DH F-50 CRU

Callidus "CUBL-10W-Flex" and "CUBL-8W-Flex" Ultra Low-NO_x Burners
Maximum Firing Rate: 225 MMBTU/hr

S-1497 DH F-51 CRU

Callidus "CUBL-10W-Flex" and "CUBL-8W-Flex" Ultra Low-NO_x Burners
Maximum Firing Rate: 106 MMBTU/hr

S-1498 DH F-52 CRU Reboil

Callidus "CUBL-8P" Ultra Low-NO_x Burners
Maximum Firing Rate: 39 MMBTU/hr

S-1499 DH F-53 CRU Regen

Callidus "CUBL-8P" Ultra Low-NO_x Burners
Maximum Firing Rate: 31 MMBTU/hr

S-1500 DH F-55 SGP Heat Medium

Callidus "LE-CSG-12W" Low Emission NO_x Burners
Maximum Firing Rate: 167 MMBTU/hr

S-1762 DH F-128 CRU Interheater

Callidus "CUBL-14P-Flex" and "CUBL-10P-Flex" Ultra Low-NO_x Burners
Maximum Firing Rate: 200 MMBTU/hr

K. R. Bhagavan
Air Quality Engineer II

Date

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11
Application: 13085 & 13086

BACKGROUND

Shell Oil Products US – Martinez Refinery (Shell) has submitted this application to modify part 18 of permit condition 12271. This condition governs the operation of sources that were part of Shell’s Clean Fuels Project (CFP) permit application # 8407. The proposed amendments to permit condition 12271 will affect the following two delayed coker unit (DCU) heaters that are part of Shell’s CFP:

- S-4002 Delayed Coker Unit Heater, DC F-13425-A, 105 MMBTU/hr
Abated by A-4002 Delayed Coker Unit SCR #1
- S-4003 Delayed Coker Unit Heater, DC F-13425-B, 105 MMBTU/hr
Abated by A-4003 Delayed Coker Unit SCR #2

Part 18 of permit condition 12271 in Shell’s existing Title V permit states the following: “All combustion sources installed, modified or replaced as part of the CFP shall fire natural gas, refinery fuel gas, pressure swing absorber (PSA) gas, ultra low sulfur distillate (ULSD), liquefied petroleum gases, or flexigas. In no case shall any combustion source burn a fuel with: (1) an H₂S concentration exceeding 50 ppm, 24 hour average; or (2) a total reduced sulfur content exceeding 70 ppm, annual average. [basis: offsets, cumulative increase]”

In 1998, the District approved Shell’s request under permit application 18185 to voluntarily reduce the total reduced sulfur (TRS) concentration limit from 100 ppm to 70 ppm TRS on an annual average basis. The current permit application (i.e. 13086) requests revision of the permit condition so that the permanence of the emission reduction be based on an emission limit rather than a TRS limit.

Summary of the Current Situation:

In or about 2004, Shell began to gradually modify the crude oil slate processed at the refinery which resulted in increased concentrations of carbonyl sulfide (COS) in the flexigas (FXG) - a low BTU²⁸ gas, generated at the flexicoker (S-1759). The only CFP sources at Shell capable of combusting FXG are the DCU heaters (S-4002 and S-4003) and the steam methane reformer (SMR) furnace (S-4161). The DCU heaters are capable of combusting either FXG or refinery make gas (RMG) or both. The increased concentrations of COS in the FXG led to higher TRS levels at the DCU heaters. Rolling 365-day TRS calculations performed by Shell on May 26, 2005 revealed that the facility was in violation of the 70 ppm TRS annual average limit at the DCU heaters since February 26, 2005. In contrast, source S-4161 at hydrogen plant # 3 (HP-3) combusts FXG in combination with PSA gas – which is an off-gas from the hydrogen purification step. Since the TRS concentration in the PSA gas is very low, S-4161 was able to comply with the 70 ppm TRS annual average concentration limit. According to Shell, no FXG has been combusted at the DCU heaters since May 26, 2005.

Assuming the DCU heaters exclusively combust RFG, Shell expects to come back into compliance with the 70 ppm TRS annual average limit using a 365-day rolling average by

²⁸ BTU ~ heating value

September 15, 2005. However, Shell has indicated that it cannot operate in this mode indefinitely without encountering a loss in productivity for the following reasons:

- The DCU heaters are designed to burn a low BTU gas such as FXG. Exclusively burning a high BTU gas such as RMG in them will result in increased and more rapid coking, which will require frequent service outages to de-coke the DCU heaters.
- FXG has always been and continues to be combusted at non-CFP sources at Shell that do not have the 70 ppm TRS annual average limit. If one or more of the non-CFP sources is taken out of service for maintenance, and Shell is unable to burn FXG in the DCU heaters, then this could result in a slow down of the Flexicoker (S-1759) which would mean a reduction in production at the refinery.

In light of the above, Shell entered into a Compliance and Enforcement (C&E) agreement with the District on July 12, 2005 and agreed to do the following:

- Submit within fifteen days of the effective date of the C&E agreement a permit application to modify the TRS limit outlined in part 18 of permit condition 12271.
- Ensure that the SO₂ emission cap of 139.7 TPY outlined in part A of permit condition 12271 is not violated during the term of the C&E agreement.
- Affirm that it has remained below the 70 ppmv daily average TRS at sources S-4002 and S-4003 since May 26, 2005, and ensure that it would comply with a TRS 70 ppm rolling seven-day average at the above sources during the term of the C&E agreement.
- Pay the District a monetary civil penalty of \$ 24,000 to resolve that portion of the violation with the TRS limit, which occurred from February 2005 to May 2005.
- Surrender to the District 0.5 tons of SO₂ emission reduction credits to cover the excess emissions that occurred at the refinery due to the high TRS levels in the FXG combusted at sources S-4002 and S-4003.

History of Shell's CFP Emissions Cap:

The current text of part 18 of permit condition 12271 resulted from several permit applications done in 1993, 1995, and 1998. To help clarify the origin of this condition each of the applications is summarized below.

Year 1993:

Table 1 summarizes the criteria pollutant emission increases (in TPY) at Shell from the CFP sources that were part of Application 8407.

Table 1

<u>POC</u>	<u>NO_x</u>	<u>SO₂</u>	<u>CO</u>	<u>NPOC</u>	<u>PM/ PM₁₀</u>
<u>317</u>	<u>204</u>	<u>218</u>	<u>298</u>	<u>14.7</u>	<u>61.4</u>

The 218 TPY increase in SO₂ emissions was attributable to a 179.2 TPY increase from combustion sources, a 3.8 TPY increase from rail transport emissions, and a 35 TPY from sulfur recovery plant (SRU) # 4 emissions. Since the SO₂ offset ratio was 1.1: 1, Shell was required to provide the District with 239.8 TPY in emission offsets. It should be noted that the combustion emissions i.e. 179.2 TPY, summarized in Table 1 above were estimated assuming a TRS concentration of 100 ppm on an annual average basis. As a result, all CFP sources were limited to a TRS concentration of 100 ppm under part 18 of permit condition 12271. The limit was later revised to 70 ppm as it currently exists in Shell's existing Title V permit. Please refer to the discussion under year 1998 below.

Rather than provide the District with emission offsets, Shell accepted lower SO₂ limits at the three existing CO boilers (S-1507, S-1509, and S-1512). Specifically, Shell anticipated the additional hydrotreating of the feed to the FCCU (S-1426) at the Distillate Hydrotreater (S-4020), which was to be constructed as part of CFP project, would reduce the sulfur in the feed. Since the exhaust from the FCCU would be used as fuel in the CO boilers, a reduction of the amount of sulfur in the feed to the FCCU would reduce the sulfur in the fuel to the CO boilers which would be later oxidized to SO₂. In other words, lower sulfur in the fuel to the CO boilers would reduce the SO₂ emissions exhausting out of the CO boiler stacks.

Baseline SO₂ emissions from the three CO boilers for calendar year 1991 was 1427.2 TPY. As part of the CFP project, Shell agreed to limit the SO₂ emissions from the CO boilers to 1162.8 TPY as outlined in part 90 of permit condition 12271. The reduction of 264.4 TPY (1427.2 – 1162.8) was intended to meet the 239.8 TPY SO₂ offset requirement and also 24.6 TPY²⁹ of PM₁₀ emissions. In light of this, the 365-day SO₂ emission profile contained in permit condition 7618 was reduced by 1449 lbs/day, i.e. 264.4 tons/yr x 2000 lbs/ton /365 days/yr. In addition, parts 91 through 95 of permit condition 12271 were crafted to track the SO₂ emission reductions from the CO boilers. SO₂ emissions from the CFP sources were capped by part A of permit condition 12271 at 217.2 TPY.

Year 1995:

Under Application 14577, Shell planned to change the heater duties to several combustion sources that were part of the CFP. The net effect of the changes resulted in a decrease of 7.5 TPY SO₂ emissions from combustion sources, **179.2 TPY to 171.7 TPY**. Parts 90 through 95 of permit condition 12271 were amended to reflect the above change. In addition, the SO₂ emissions cap of 217.2 TPY in part A of permit condition 12271 was reduced by 7.5 TPY to **209.7 TPY** (~ 171.7 TPY + 3.8 TPY from railcar + 35 TPY from SRU 4).

Year 1998:

Under Application 18185, Shell voluntarily reduced the TRS concentration limit from 100 ppm to 70 ppm on an annual average basis. This resulted in a 70 TPY reduction from CFP combustion sources i.e. from **171.7 TPY to 101.7 TPY**. Rather than bank these emission reductions, Shell reclaimed the SO₂ offsets it provided to the District under the CFP by increasing the SO₂ emission limit for the CO boilers – combustion sources that were not part of the CFP. Specifically, the CFP SO₂ 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 boilers³⁰, and part 91 of permit condition 12271 was amended from 2,141 lb/day/CO boiler to 2,262 lb/day/CO boiler³¹.

Year 2005:

Table 2 summarizes the CFP emissions cap as it currently exists in part A of permit condition 12271 in Shell's existing Title V permit.

²⁹ Calculated at a PM10 to SO₂ offset ratio of 1:4 and a 10% utilization of SO₂ reductions to offset PM10 emissions. (61.4 x 4/1 x 0.10 = 24.6 TPY).

³⁰ (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

³¹ (6805 lb/day/three CO boilers) / (3 CO boilers) ~ 2,262 lb/day/CO boiler

Table 2

<u>POC</u>	<u>NOx</u>	<u>SO₂</u>	<u>CO</u>	<u>NPOC</u>	<u>PM/ PM₁₀</u>
<u>132</u>	<u>199.4</u>	<u>139.7</u>	<u>252.4</u>	<u>14.7</u>	<u>59.1</u>

The BACT Issue:

The District's BACT determination (Document #: 94.3.1; dated August 12, 1994) for refinery process heaters, such as the CFP combustion sources, limited the TRS of the treated refinery gas to less than 100 ppmv. The District under Application 18185 revised the TRS level in the fuel burned at the CFP combustion sources from 100 ppm to 70 ppm. This is because Shell voluntarily accepted a lower TRS limit that was neither required by District regulations and/or the above referenced BACT determination. The 70 ppm TRS level was mistakenly labeled a BACT limit during the preparation of the Title V permit.

In light of the above, the basis in part 18 of the proposed condition will be revised as follows:

- For CFP sources, excluding the DCU heaters:
The basis for the H2S limit of 50 ppm will be BACT; and the basis for the TRS limit of 70 ppm will be offsets & cumulative increase.
- For the DCU heaters:
The basis for the H2S limit of 50 ppm, and the basis of the TRS limit of 100 ppm will be BACT & cumulative increase.

In addition, the following changes will be made:

- Reword part 18 to exclude the DCU heaters;
- Rephrase part 18 to ensure that the average daily H2S concentration limit of 50 ppm and the annual average total reduced sulfur (TRS) concentration limit of 70 ppm are met when CFP sources, excluding the DCU heaters, burn either a single type of fuel, or a combination of fuels;
- Create a new and separate sub-part 18.a for the DCU heaters that will ensure the average daily H2S concentration limit of 50 ppm and the annual average total reduced sulfur (TRS) concentration limit of 100 ppm are met when the DCU heaters, burn either a single type of fuel, or a combination of fuels.

EMISSIONS CALCULATION

The maximum firing rate for the DCU heaters outlined in part 1 of permit condition 16688 is 105 MMBTU/hr/DCU heater. Therefore, the pre-project and post-project SO₂ emissions from the above sources is calculated as follows:

Pre-Project SO₂ Emissions (@ TRS of 70 ppm):

$$= \frac{105 \text{ MMBTU/hr} \times 10E6 \text{ BTU/MMBTU} \times \text{scf}/1000 \text{ BTU} \times \text{lb-mol}/387 \text{ scf} \times 64 \text{ lb/lb-mol}}{8760 \text{ hr/yr} \times \text{ton}/2000 \text{ lb} \times 70/10E6}$$

$$= 5.32 \text{ TPY/DCU heater}$$

Post-Project SO₂ Emissions (@ TRS of 100 ppm):

$$= \frac{105 \text{ MMBTU/hr} \times 10E6 \text{ BTU/MMBTU} \times \text{scf}/1000 \text{ BTU} \times \text{lb-mol}/387 \text{ scf} \times 64 \text{ lb/lb-mol}}{8760 \text{ hr/yr} \times \text{ton}/2000 \text{ lb} \times 100/10E6}$$

$$= 7.61 \text{ TPY/DCU heater}$$

It can be seen from above that the proposed amendments to part 18 of permit condition 12271 will result in an increase of 2.29 TPY/DCU heater i.e. (7.61 TPY – 5.32 TPY). However, since

Shell has not requested the District to make any changes to the SO2 CFP emission cap, the offsets generated under Application 18185 will not be affected. However, it is Shell's responsibility to operate the CFP combustion sources, including the DCU heaters, in a manner that ensures the SO2 emissions from all CFP combustion sources are within the SO2 emissions cap of 139.7 TPY.

Therefore, the proposed changes to part 18 of permit condition 12271 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.”

Since the proposed amendments to permit condition 12271 will not result in an increase in emissions at Shell, Air Toxics, BACT, Cumulative Increase, and Offsets are not triggered.

STATEMENT OF COMPLIANCE

There will be no change made to the applicable requirements contained in Shell's Title V permit under Tables IV-BG and CP as it relates to the DCU heaters. However, the reference to part 18 under permit condition 12271 in Table IV-CP will be amended to reference part 18.a.

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 2.4 “Process Heaters” and BACT/TBACT Workbook (Document #: 94.3.1; dated August 12, 1994). 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 12271 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 18 of permit condition 12271 as it exists in Shell’s Title V permit:

18. All combustion sources installed, modified or replaced as part of the CFP shall fire natural gas, refinery fuel gas, pressure swing absorber (PSA) gas, ultra low sulfur distillate (ULSD), liquefied petroleum gases, or flexigas. In no case shall any combustion source burn a fuel with: (1) an H2S concentration exceeding 50 ppm, 24 hour average; or (2) a total reduced sulfur content exceeding 70 ppm, annual average. [basis: offsets, cumulative increase]

Proposed amendments to part 18 of permit condition 12271:

18. All combustion sources installed, modified or replaced as part of the CFP shall fire natural gas, refinery fuel gas, pressure swing absorber (PSA) gas, ultra low sulfur distillate (ULSD), liquefied petroleum gases, or flexigas. In no case shall any combustion source, except for S4002 and S4003 burn a fuel any combination of fuels with: (1) an H2S concentration exceeding 50 ppm, 24 hour average; [basis: BACT] or (2) a total reduced sulfur content exceeding 70 ppm, annual average. [basis: offsets, cumulative increase]

18.a. Sources S4002 and S4003 shall fire natural gas, refinery fuel gas, pressure swing absorber (PSA) gas, ultra low sulfur distillate (ULSD), liquefied petroleum gases, or flexigas. In no case shall source S4002 or S4003 burn any combination of fuels with: (1) an H2S concentration exceeding 50 ppm, 24 hour average; or (2) a total reduced sulfur content exceeding 100 ppm, annual average. [basis: BACT, cumulative increase]

Summary of changes to Shell’s Title V permit:

Section IV: Source Specific Applicable Requirements

No changes will be made to any of the applicable requirements under Tables IV-BG and CP as it relates to the DCU heaters i.e. sources S-4002 and S-4003. However, the reference to part 18 under permit condition 12271 in Table IV-CP will be amended to reference part 18.a. as follows:

Table IV - CP
Source-specific Applicable Requirements
S4002 – DC F-13425-A DCU
S4003 – DC F-13425-B DCU

<u>Applicable Requirement</u>	<u>Regulation Title or Description of Requirement</u>	<u>Federally Enforceable (Y/N)</u>	<u>Future Effective Date</u>
	<u>See Table IV – BG for additional requirements.</u>		
<u>BAAQMD Condition # 12271</u>			
Part 18 18.a.	Fuel usage limitation [basis: Offsets, Cumulative Increase]	Y	

Section VI: Permit Conditions

Part 18 of permit condition 12271 will be amended as follows:

18. All combustion sources installed, modified or replaced as part of the CFP shall fire natural gas, refinery fuel gas, pressure swing absorber (PSA) gas, ultra low sulfur distillate (ULSD), liquefied petroleum gases, or flexigas. In no case shall any combustion source, except for S4002 and S4003 burn a fuel any combination of fuels with: (1) an H2S concentration exceeding 50 ppm, 24 hour average; [basis: BACT] or (2) a total reduced sulfur content exceeding 70 ppm, annual average. [basis: offsets, cumulative increase]
- 18.a. Sources S4002 and S4003 shall fire natural gas, refinery fuel gas, pressure swing absorber (PSA) gas, ultra low distillate (ULSD), liquefied petroleum gases, or flexigas. In no case shall source S4002 or S4003 burn any combination of fuels with: (1) and H2S concentration exceeding 50 ppm, 24 hour average; or (2) a total reduced sulfur content exceeding 100 ppm, annual average. [basis: BACT, cumulative increase]

Section VII: Applicable Limits and Compliance Monitoring Requirements

The reference to part 18 under permit condition 12271 in Table VII-BY will be amended to reference part 18.a., and the TRS limit will be amended from 70 ppm to 100 ppm, as follows:

Table VII – BY
Applicable Limits and Compliance Monitoring Requirements
S4002 – DC F-13425-A DCU,
S4003 – DC 13425-B DCU

<u>Type of Limit</u>	<u>Citation of Limit</u>	<u>FE Y/N</u>	<u>Future Effective Date</u>	<u>Limit</u>	<u>Monitoring Requirement Citation</u>	<u>Monitoring Frequency (P/C/N)</u>	<u>Monitoring Type</u>
See Table VII – AW for additional requirements.							
SO ₂	BAAQMD Condition #12271, Part 15 and 4818.a.	Y		Refinery fuel gas limited to 50 ppmv H ₂ S, 24-hour average; 0.1 grain/dscf (163 ppm) H ₂ S, 3-hour average; and 70 100 ppm TRS expressed as H ₂ S, 12-month average	BAAQMD Condition #12271 Part 16, 16A, 17, L and M	C	H ₂ S and TRS analyzer records and reporting

RECOMMENDATION

Modify permit condition 12271 as proposed for the following equipment:

S-4002 Delayed Coker Unit Heater, DC F-13425-A, 105 MMBTU/hr
 Abated by A-4002 Delayed Coker Unit SCR #1

S-4003 Delayed Coker Unit Heater, DC F-13425-B, 105 MMBTU/hr
 Abated by A-4003 Delayed Coker Unit SCR #2

 K. R. Bhagavan
 Air Quality Engineer II
 Engineering Division

 Date

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11
Application: 13410

Background

Shell has submitted this application to replace burners at the following sources:

S-1510 CP F-66 CCU Feed Preheater (F-66); 200 MMBTU/hr
S-1511 CP F-67 CCU LGO Reboiler (F-67); 60 MMBTU/hr

Per Regulation 2-1-233.1, the replacement of the burners at the above sources is an alteration, and will not impact any portions of Shell's Title V permit..

Shell has proposed to replace the existing burners at the above sources with Ultra Low NOx Burners (UNLBs), 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 modifications will be to enhance the compliance of sources S-1510, and S-1511 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-1510 and S-1511 are equipped with NOx and O₂ CEMS³² and are governed by permit condition 18265, which outlines Shell's "IERC³³ Alternative Compliance Plan". The proposed alterations to sources S-1510 and S-1511 will not result in any changes to either of the above two permit conditions. Because of the use of NOx and O₂ CEMs, no additional permit conditions are proposed to require source testing of the above sources for compliance.

Emissions Summary

There are no emission increases associated with this alteration.

Regulation 9-10-301 outlines a refinery wide NOx emission limit of 0.033 lb/MMBTU (~ 30 ppmv @ 3% O₂) for sources such as S-1510 and S-1511. The UNLBs manufactured by Callidus, which will be installed at sources S-1510 and S-1511 are capable of achieving a NOx emission rate of 0.012 lb/MMBTU (10 ppmv @ 3% O₂)³⁴. Therefore, the proposed alterations will result in a reduction in NOx emissions. 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 (i.e. S-1510 – 200 MMBTU/hr, and S-1511 – 60 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-1510 and S-1511.

³² CEMS – Continuous Emission Monitoring Systems

³³ IERC – Interchangeable Emission Reduction Credits

³⁴ Based on information contained in the following URL:

http://www.tcet.state.tx.us/PDF/052102Tech_Conf/Stationary%20Technologies/Callidus%20Houston%20Meeting.PDF

The proposed alterations to S-1510 and S-1511 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 UNLB retrofit project, could potentially result in an increase in CO emissions – the secondary pollutant of the UNLB retrofit project. However, per Regulation 2-2-113, the installation of the UNLBs at sources S-1510 and S-1511 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, there will be no changes to any of the applicable requirements contained in Shell’s Title V permit for the above sources.

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 2.4 “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 to the ministerial exemption determination above, the District has also determined that the CEQA categorical exemption of Section 2-1-312.11 of the District Rules and Regulations and the CEQA "Common Sense Exemption" apply.

CEQA Categorical Exemption and CEQA "Common Sense Exemption":

Though the District concludes that the alterations to sources 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, 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 proposed alterations to S-1510 and S-1511 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" 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 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 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.

Permit Conditions

Sources S-1510 and S-1511 are currently subject to permit condition 16688, which limits the maximum firing rate at the above sources to 200 MMBTU/hr and 60 MMBTU/hr, respectively. As previously discussed in the “Background” section above, sources S-1510 and S-1511 are equipped with NOx and O₂ CEMS and are governed by permit condition 18265, which outlines Shell’s “IERC Alternative Compliance Plan”. The proposed alterations to sources S-1510 and S-1511 will not result in any changes to either of the above two permit conditions. Because of the use of NOx and O₂ 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-1510 CP F-66 CCU Feed Preheater (F-66);
Callidus “CUBL-8W” Ultra Low-NOx Burners
Maximum Firing Rate: 200 MMBTU/hr

S-1511 CP F-67 CCU LGO Reboiler (F-67)
Callidus “CUBL-6W” Ultra Low-NOx Burners
Maximum Firing Rate: 60 MMBTU/hr

K. R. Bhagavan
Air Quality Engineer II

Date

ENGINEERING EVALUATION
Shell Oil Products US – Martinez Refinery, Plant: 11
Application: 14224

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:

S-6062 Ethanol Tank

Internal Floating Roof Tank

Tank height: 30 feet; Tank diameter: 60 feet

Total volume³⁵: 15,000 bbl; Working volume: 10,070 bbl

Annual throughput: 1,500,000 bbl/yr

Shell plans to demolish S-129 - an aging and out-of-service 15,000 bbl floating roof tank used for storing gasoline that currently exists at a tank farm in the northwest part of the refinery, and intends to erect S-6062 at S-129’s existing location. Ethanol stored in S-6062 will be denatured with 5% gasoline and will replace the use of isooctane. Ethanol will be blended along with gasoline prior to being loaded into tank trucks at Plant 11956³⁶ “Equilon Enterprises LLC” (Equilon) located at “1801 Marina Vista” in Martinez, CA. The loading and unloading of ethanol to (from truck to tank) and from (from tank to truck) will occur at Equilon via pumps and pipelines. It can be seen from Figure 2-3 entitled "Proposed Ethanol Offload, Storage & Blending" that S-6062 and Equilon are in very close proximity - albeit located on different plant sites. Please refer to the Attachments.

As part of this project, Shell also plans to install 14 new valves, 56 new flanges, and 2 new pumps.

Emissions Calculations

US EPA TANKS 4.0.9d was used to estimate the VOC (~ POC³⁷) emissions from S-6062. Table 1 summarizes certain tank fitting attributes that were manually input into the TANKS 4.0.9d program to estimate POC emissions from S-6062.

Table 1		
<u>Fitting type</u>	<u>Status</u>	<u>Quantity</u>
<u>Access Hatch (24” diameter)</u>	<u>Bolted cover, Gasketed</u>	<u>2</u>
<u>Automatic Gauge Float Well</u>	<u>Bolted cover, Gasketed</u>	<u>1</u>
<u>Ladder Well (36” diameter)</u>	<u>Sliding cover, Gasketed</u>	<u>1</u>
<u>Roof Leg (3” diameter)</u>	<u>Adjustable, Pontoon area, Gasketed</u>	<u>20</u>
<u>Slotted Guide-Pole/Sample Well</u>	<u>Gasketed sliding cover, with float sleeve wiper</u>	<u>1</u>
<u>Vacuum breaker (10” diameter)</u>	<u>Weighted mechanical actuation, gasketed</u>	<u>1</u>

³⁵ Total volume of the tank = $[(\pi d^2/4) * h * 7.45 \text{ gal/ft}^3] / [42 \text{ gal/bbl}]$; where d = 60 feet and h = 30 feet

³⁶ Old plant # 3694.

³⁷ POC – Precursor Organic Compound

Table 2 summarizes results from the TANKS 4.0.9d program.

Table 2					
Type of loss	Rim Seal Loss	Withdrawal Loss	Deck Fitting Loss	Deck Seam Loss	Total POC Emissions
<u>Emissions estimated by the District</u>	<u>24.15</u>	<u>233.83</u>	<u>70.56</u>	<u>0</u>	<u>328.54</u>
<u>Emissions estimated by Shell</u>	<u>42.19</u>	<u>232.69</u>	<u>184.93</u>	<u>0</u>	<u>459.81</u>

Table 3 summarizes the increase in POC emissions associated with the addition of the following new/retrofitted fugitive components in “light liquid” service i.e. valves, pumps, flanges, etc., using leak rates similar to those that were used by the District under Application 1821³⁸, in “light liquid” service.

Table 3						
Type/service	Number of components¹	Emission factor (lb/hr/component)²	POC, lb/hr	POC, lb/day	POC, lb/yr	POC, TPY
<u>Valves/Gas/Light Liquid</u>	<u>14</u>	<u>0.0000231</u>	<u>0.0003234</u>	<u>0.0078</u>	<u>2.85</u>	<u>0.0014</u>
<u>Pump seals/Gas/Light Liquid</u>	<u>2</u>	<u>0.000704</u>	<u>0.001408</u>	<u>0.0338</u>	<u>12.34</u>	<u>0.0062</u>
<u>Flanges/All³</u>	<u>56</u>	<u>0.00017</u>	<u>0.00952</u>	<u>0.2285</u>	<u>83.40</u>	<u>0.0417</u>
Totals	72		0.0112514	0.2701	98.59	0.0493

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.

Toxic Risk Screen Analysis

Table 4 summarizes the Toxic Air Contaminants (TAC) contained in the ethanol that will be stored in S-6062, which will be denatured with 5% gasoline.

Table 4		
TAC	CAS Number	Maximum Concentration of TAC (% by wt.)
<u>1,2,4-Trimethylbenzene</u>	<u>95-63-6</u>	<u>0.12</u>
<u>2,2,4-Trimethylpentane (Isooctane)</u>	<u>00540-84-1</u>	<u>0.24</u>
<u>Benzene</u>	<u>00071-43-2</u>	<u>0.06</u>

³⁸ An AC and PO were issued to Shell under Application 1821 in January 2002 and August 2002, respectively.

Table 4		
TAC	CAS Number	Maximum Concentration of TAC (% by wt.)
<u>Ethyl alcohol</u>	<u>00064-17-5</u>	<u>98.77</u>
<u>Ethylbenzene</u>	<u>00100-41-4</u>	<u>0.06</u>
<u>Hexane (-n)</u>	<u>00110-54-3</u>	<u>0.07</u>
<u>Isopropyl benzene</u>	<u>00098-82-8</u>	<u>0.01</u>
<u>Napthalene</u>	<u>00091-20-3</u>	<u>0.02</u>
<u>Toluene</u>	<u>00108-88-3</u>	<u>0.30</u>
<u>Xylene (-m)</u>	<u>01330-20-7</u>	<u>0.35</u>
Total		100

Table 5 summarizes the TAC emissions that will be emitted from the fugitive components summarized in Table 3 above using the maximum concentrations for TAC's summarized in Table 4 above.

Table 5		
Fugitive Component TAC Emissions		
TAC	CAS Number	TAC Emissions (lbs/yr)
<u>1,2,4-Trimethylbenzene</u>	<u>95-63-6</u>	<u>0.12</u>
<u>2,2,4-Trimethylpentane (Isooctane)</u>	<u>00540-84-1</u>	<u>0.24</u>
<u>Benzene</u>	<u>00071-43-2</u>	<u>0.06</u>
<u>Ethyl alcohol</u>	<u>00064-17-5</u>	<u>97.38</u>
<u>Ethylbenzene</u>	<u>00100-41-4</u>	<u>0.06</u>
<u>Hexane (-n)</u>	<u>00110-54-3</u>	<u>0.07</u>
<u>Isopropyl benzene</u>	<u>00098-82-8</u>	<u>0.01</u>
<u>Napthalene</u>	<u>00091-20-3</u>	<u>0.02</u>
<u>Toluene</u>	<u>00108-88-3</u>	<u>0.30</u>
<u>Xylene (-m)</u>	<u>01330-20-7</u>	<u>0.35</u>
Total		98.61

The maximum concentrations for TAC's summarized in Table 4 above was manually entered into the US EPA TANKS 4.0.9d program. Table 6 summarizes the results obtained from the US EPA TANKS 4.0.9d program.

Table 6		
Ethanol tank TAC Emissions		
TAC	CAS Number	TAC Emissions (lbs/yr)
<u>1,2,4-Trimethylbenzene</u>	<u>95-63-6</u>	<u>0.28</u>
<u>2,2,4-Trimethylpentane (Isooctane)</u>	<u>00540-84-1</u>	<u>0.76</u>
<u>Benzene</u>	<u>00071-43-2</u>	<u>0.24</u>
<u>Ethyl alcohol</u>	<u>00064-17-5</u>	<u>324.99</u>
<u>Ethylbenzene</u>	<u>00100-41-4</u>	<u>0.15</u>
<u>Hexane (-n)</u>	<u>00110-54-3</u>	<u>0.35</u>
<u>Isopropyl benzene</u>	<u>00098-82-8</u>	<u>0.02</u>
<u>Napthalene</u>	<u>00091-20-3</u>	<u>0.05</u>
<u>Toluene</u>	<u>00108-88-3</u>	<u>0.84</u>
<u>Xylene (-m)</u>	<u>01330-20-7</u>	<u>0.86</u>

Table 6 Ethanol tank TAC Emissions		
TAC	CAS Number	TAC Emissions (lbs/yr)
Total		328.54

Table 7 summarizes the sum total of TAC emissions that will result from the fugitive components summarized in Table 5 above and from the ethanol tank summarized in Table 6 above, and compares the resulting TAC emissions to their corresponding District TAC Trigger Levels in Table 2-5-1 of Regulation 2, Rule 5.

Table 7 Fugitive Component + Ethanol Tank TAC Emissions					
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)
1,2,4-Trimethylbenzene	95-63-6	0.40	NA	NA	NA
2,2,4-Trimethylpentane (Isooctane)	00540-84-1	1.00	NA	NA	NA
Benzene	00071-43-2	0.30	2.9	6.4	No
Ethyl alcohol	00064-17-5	422.37	NA	NA	NA
Ethylbenzene	00100-41-4	0.21	NA	77,000	No
Hexane (-n)	00110-54-3	0.42	NA	270,000	No
Isopropyl benzene	00098-82-8	0.03	NA	NA	NA
Napthalene	00091-20-3	0.07	NA	5.3	No
Toluene	00108-88-3	1.14	82	12,000	No
Xylene (-m)	01330-20-7	1.21	49	27,000	No
Total		427.15			

As previously discussed under the “Background” section above, the ethanol stored in S-6062 will be delivered to Equilon from local ethanol suppliers. As it currently exists, Shell intends to purchase ethanol from a local supplier in Richmond, CA. The ethanol will be delivered to Equilon via diesel tanker trucks. The delivery route that the tanker trucks will most likely use will be from Richmond on Highway 4 to Martinez via Highway 680 to "1801 Marina Vista Avenue". The average ethanol delivery capacity of each tanker truck is approximately 200 bbl. On a typical day, Shell anticipates to not have more than 5 tanker truck deliveries of ethanol. However, if S-6062 is permitted at a maximum annual throughput level of 1,500,000 bbl/yr, there will be at least 20 tanker truck deliveries³⁹ from Richmond to Equilon on a daily basis.

A memo from Dr. Glen Long – Supervising Air Quality Engineer, Toxics Evaluation Section to Barry Young – Supervising Air Quality Engineer, 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 (HRSAs) is not required for such projects.

³⁹ (1.5 Million bbl/yr) / (200 bbl/truck x 365 days/yr) = 20.5 trucks/day

As previously discussed under the “Background” section above, S-6062 will be erected at a location where an aging and out-of-service 15,000 bbl floating roof tank used for storing gasoline 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 30 deliveries of 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 150 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, the increased diesel fueled delivery truck traffic associated with the installation and operation of S-6062 does not warrant a 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 the emission calculations presented in Table 3 above that the cumulative emissions from the 72 additional fugitive components that will be installed at process units (~ ethanol tank) that are part of this application is below 10 lb/day i.e. 0.2701 lb/day. The fugitive components, summarized in Table 3 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 new ethanol tank summarized in Table’s 5 and 6 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 7 above.
- Regulation 2-1-317:
The new ethanol tank and the additional fugitive components are not a public nuisance source, since they are designed to minimize emissions and are subject to the inspection and maintenance programs in Regulation 8, Rule 5 and Regulation 8, Rule 18, respectively.
- 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 new ethanol tank and/or the additional fugitive components. Please refer to Table’s 5 and 6 above.

- Regulation 2-1-319:

The “post-control” emissions (~ assuming the tank seals on the new ethanol tank serve as passive abatement devices) of any regulated air pollutant (~ POC) from process units (~ new ethanol tank) that are part of this application is below 5 TPY i.e. 0.16 TPY – please refer to Table 6 above.

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 3 above are exempt from permitting per Regulation 2-1-128.21. However, Shell has voluntarily accepted to 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 August 12, 1994, and the BACT 2 level for the pumps (500 ppm expressed as methane) outlined in BACT Guidance Document #137.1 dated June 30, 1995.

The highest daily emissions from S-6062 are expected to be below the BACT trigger level of 10 lbs/highest day i.e. 1.26 lbs/day⁴⁰. Therefore, BACT is not triggered. However, S-6062 meets the District’s BACT 2 for an internal floating roof tank outlined in BACT/TBACT Document #: 167.4.1 dated March 3, 1995 for the following reasons: the tank will be equipped with a mechanical shoe tight fit primary seal⁴¹ and a zero gap secondary rim seal; all roof penetrations will be gasketed; the slotted guide-pole/sample well will be gasketed with float sleeve wiper; and the adjustable roof legs will be gasketed. (Please refer to Table 1 above)

Cumulative Increase & Offsets

Shell is an existing facility. Table 8 summarizes the cumulative increase in criteria pollutant emissions that will result at Plant 11 from the operation of S-6062.

Table 8				
Cumulative Increase				
<u>Pollutant</u>	<u>Increase in plant emissions prior to April 5, 1991⁴² (TPY)</u>	<u>Increase in plant emissions since April 5, 1991⁴³ (TPY)</u>	<u>Increase in plant emissions associated with this application (TPY)</u>	<u>Cumulative increase in emissions (Post 4/5/91 + Current application increase)⁴⁴ (TPY)</u>
<u>NOx</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
<u>POC</u>	<u>25.86</u>	<u>0.186</u>	<u>0.23⁴⁵</u>	<u>0.416</u>

⁴⁰ (328.54 lbs/yr from Table 2) / (260 days/yr) = 1.26 lbs/day

⁴¹ Please refer to an e-mail from Julian Elliott dated August 15, 2005 in which a consensus was reached that installation of mechanical shoe seals, which are more reliable and longer lasting than liquid mounted seals, meets BACT 2.

⁴² In PSDP do the following to obtain emissions data at the plant prior to April 5, 1991: option 1 → option 2.

⁴³ 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).

⁴⁴ 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.

⁴⁵ It can be seen from Table 2 above that Shell’s estimate (of 459.81 lbs/yr) of POC emissions from the TANKS program is higher than the District’s estimate (of 328.54 lbs/yr). Therefore, the higher of the above two estimates will be used for the purposes of cumulative increase and offsets.

<u>CO</u>	<u>0</u>	<u>298.00</u>	<u>0</u>	<u>298.00</u>
<u>PM</u>	<u>0.05</u>	<u>0</u>	<u>0</u>	<u>0</u>
<u>PM10</u>	<u>0.11</u>	<u>0</u>	<u>0</u>	<u>0</u>
<u>SO2</u>	<u>0</u>	<u>0⁴⁶</u>	<u>0</u>	<u>0</u>
<u>NPOC</u>	<u>11.00</u>	<u>14.70</u>	<u>0</u>	<u>14.70</u>

Table 9 Offsets					
Pollutant	Permitted plant emissions (TPY) Pre-April 5, 1991⁴⁷ + Post-April 5, 1991	Actual plant emissions⁴⁸ (TPY)	Increase in plant emissions associated with this application (TPY)	Total emissions (Higher of Permitted/Actual Emissions + Emissions associated with this application)⁴⁹ (TPY)	Regulation 2-2-302 and 2-2-303 Offset Triggers (TPY)
<u>NOx</u>	<u>0</u>	<u>1783.89</u>	<u>0</u>	<u>1783.89</u>	<u>≥ 35</u>
<u>POC</u>	<u>26.046</u>	<u>1743.83</u>	<u>0.23</u>	<u>1744.06</u>	<u>≥ 35</u>
<u>CO</u>	<u>298.00</u>	<u>708.90</u>	<u>0</u>	<u>708.90</u>	<u>NA</u>
<u>PM</u>	<u>0.05</u>	<u>0</u>	<u>0</u>	<u>0.05</u>	<u>NA</u>
<u>PM10</u>	<u>0.11</u>	<u>425.85</u>	<u>0</u>	<u>425.85</u>	<u>≥ 1</u>
<u>SO2</u>	<u>0</u>	<u>1605.80</u>	<u>0</u>	<u>1605.80</u>	<u>≥ 1</u>
<u>NPOC</u>	<u>25.70</u>	<u>0</u>	<u>0</u>	<u>25.70</u>	<u>NA</u>

It can be seen from Table 9 above that offsets are warranted for POC, since the emissions of the above pollutant is greater than the 35 TPY offset trigger. It can also be seen 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 (0.186 TPY) that have not been offset are added to the emissions expected from S-6062 (0.23 TPY). Therefore, Shell will have to surrender to the District 0.48 TPY of POC Emission Reduction Credits (ERC) at an offset ratio of 1.15:1⁵⁰.

Statement Of Compliance

Source S-6062 is an internal floating roof tank equipped with a vacuum breaker valve that actuates when the tank roof is supported on the legs; it has no add-on control/abatement devices; it is neither pressurized or blanketed; it has no pressure/vacuum valves. Therefore, S-6062 is subject to and is expected to comply with the Sections 111, 112, 301, 302, 305, 320, 321, 322, 328, 402, 404, 405, 501, 502, 503, and 601 through 605 in Regulation 8, Rule 5 “Storage of Organic Liquids”.

The fugitive components summarized in Table 3 above will be subject to Sections 301, 302, 303, 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. In similar fashion, Section 303 requires, among other things, that organic compound leaks, not exceed 500 ppm for pumps and compressors. Section 8-5-306 limits the

⁴⁶ SO2 emissions listed as -4.310

⁴⁷ 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.

⁴⁸ Db → q2 → p → all

⁴⁹ 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.

⁵⁰ Per Regulation 2-2-302 i.e. (0.186 + 0.23) x 1.15 = 0.4784 ~ 0.48 TPY.

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.

Source S-6062 is 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) for the following reasons: the new ethanol tank will be constructed after July 23, 1984; the tank has a design storage capacity greater than 369,900 gallons i.e. 15,000 bbl ~ 630,000 gallons; and because ethanol has a vapor pressure of 6.1 kPa (~ 0.88 psia) at 70°F. Compliance of S-6062 with NSPS Kb will be established through inspection.

A “process unit” is defined in Section 60.591 of 40 CFR Part 60, Subpart GGG “Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries” (NSPS GGG) as follows: “means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.”

It can be seen from above that S-6062 does not meet the above definition of a process unit in NSPS GGG. Therefore, the fugitive components summarized in Table 3 above are not subject to the above rule.

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 7.7 kilopascals and annual average HAP liquid concentration greater than 2 percent by weight total organic HAP.”

Although the vapor pressure of ethanol that will be stored in S-6062 is 6.1 kPa (~ 0.88 psia) at 70°F, the tank is a Group 2 tank under MACT CC because the HAP content of the liquids that will be stored in the new tank will be less than 2% by weight i.e. 1.11% by weight. Specifically, Table 1 in MACT CC contains a list of HAPs that must be taken into account to determine whether a tank qualifies as a Group 1/Group 2 tank. For tanks that qualify as Group 1 tanks, MACT CC requires the emissions from the tanks to be abated/controlled. All HAPs presented in Table 4 above are listed in Table 1 of MACT CC, with the exception of “1,2,4-Trimethylbenzene” and “Ethyl Alcohol”.

Source S-6062 also meets the requirements for new tanks storing petroleum liquids with a TVP greater than or equal to 3.4 kPa under MACT CC for the following reasons: it is equipped with a floating roof; it meets the rim seal requirements; and the hatches and openings for guide poles and other equipment on the floating roof are gasketed and sealed to reduce evaporation (please refer to Table 1 above). 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.

MACT CC applies to various refinery operations including miscellaneous process vents and equipment leaks. The fugitive components summarized in Table 3 above must comply with MACT

CC and/or 40 CFR Part 60 Subpart VV “Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry” if they will be used “in organic HAP service” which 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 HAP content of the liquids that will be handled by the fugitive components will be less than 5% by weight i.e. 1.11% by weight. Specifically, Table 1 in MACT CC contains a list of HAPs that must be taken into account to determine the total organic HAP content. All HAPs presented in Table 4 above are listed in Table 1 of MACT CC, with the exception of “1,2,4-Trimethylbenzene” and “Ethyl Alcohol”.

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 4.2 “Organic Liquid Storage Tanks – 20,000 gallons or greater” and the BACT/TBACT Workbook [Document #'s: 167.4.1; dated March 3, 1995 (for the new ethanol tank); 136.1; dated August 12, 1994 (for the process valves) & 137.1 dated June 30, 1995 (for the pumps)]. 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 3 is exempt from Regulation 2-1-301 per Regulation 2-1-128.21. As a result, the 0.05 TPY (~ 98.59 lbs/yr) increase in POC emissions summarized in Table 3 above will not be counted toward the cumulative increase in emissions at Shell. Shell will fully offset the 0.23 TPY (~ 459.81 lbs/yr) increase in POC emissions associated with the operation of S-6062 by surrendering ERC (Certificate of Deposit #: 812). 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 ethanol, which will be stored in S-6062 is flammable and will be denatured with up to 5% gasoline. Shell has indicated that S-6062 and loading racks at Equilon 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. Shell has addressed the water quality protection issues stemming from the operation of S-6062 in their SPCC and SWPPP.

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 on August 4, 2005, 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 these guidelines in the Appendix H, Environmental Information Form provided in Appendix E of this application.

- 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.*

The new ethanol storage tank will be a double-bottomed internal floating roof tank as profiled in Appendix A, Form T and Appendix C, Emissions Calculations, Tanks 4 Detail Report. The tank will be constructed per API 653 with ethanol compatible materials in order to minimize the potential for cracking, corrosion and other integrity issues. Upon reconstruction, 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 floating deck, 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 require tank leak detection system checks.

Inspection requirements established for internal floating roof tanks are provided in BAAQMD Regulation 8-5-402. The entire circumference and outermost seals will be inspected at least twice per year, as well as other tank fittings. This is more frequent than required by New Source Performance Standards (NSPS) Subpart Kb. Subpart Kb also requires checks for volatile liquids on the floating deck, and if the deck is resting on the liquid surface. If defects or seal tears are found when the tank is emptied, Shell will repair the items prior to refilling the tank with ethanol.

- 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?*

All piping associated with the Ethanol Tank Project will be installed above ground. Prior to usage, the piping and pumps will be inspected and pressure tested in order to verify adequate integrity of the system. The associated piping components and pumps will also be entered into the facility-wide leak detection and repair program and maintained per BAAQMD Regulation 8-18. This piping will then be visually inspected each shift (twice per day) as well as pressure tested on intervals established by API 570 guidelines.

- 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 ethanol spill with potential for impacting surface water and groundwater? Please explain.*

There is minimal potential for the Ethanol Tank Project to increase the risk of an ethanol 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. Shell has prepared and implemented a SWPPP and a SPCC to prevent water quality contamination.

Loading and Withdrawal from the New Ethanol Storage Tank:

Drivers and operators are trained in loading and withdrawal procedures. A check valve prevents spillage from the hose in the event of a disconnect. Trucks are parked in a paved containment area which would capture any spills and prevent runoff to unpaved areas.

New Ethanol Storage Tank and Piping:

The new ethanol 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 stormwater 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 ethanol spill due to this project.

Spills are prevented through the training, daily inspections and maintenance programs at Shell. 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, per the SPCC plan the tank basin in which the new ethanol storage tank will be located holds more than 110 percent of the contents of the new ethanol storage tank when full.

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?

Yes, the new ethanol 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 Prevention Control and Countermeasures Plan? If so, please submit copies of the plans.

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. The new ethanol storage tank will be located in Stormwater Drainage Basin 74 as described in the SWPPP.

f. 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. The new ethanol storage tank will be located in the West Valley groundwater basin. Groundwater residing under this location is captured by the hydraulic system.

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

The new ethanol 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.

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

a. How and from where will ethanol be delivered to the new tank?

Ethanol will be delivered to the new ethanol storage tank from local ethanol suppliers. The current ethanol supplier is located in Richmond, California. Ethanol will be delivered by diesel truck. The most likely route for delivery will be from Richmond on Highway 4 to Martinez via Highway 680 to Marina Vista Avenue. The tank will be loaded at the Martinez Distribution Terminal located at 1801 Marina Vista Avenue.

b. If diesel-fueled trucks are used to deliver ethanol, 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)?

The average ethanol delivery truck capacity is 200 barrels (8,400 gallons). Ethanol truck deliveries are anticipated to be five trucks per day typical. Based on an annual throughput of 1,500,000 barrels per year, up to 20 trucks per day would be delivered to the new ethanol storage 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. Other than the ethanol deliveries described in the response to question 5b above, there will be no additional trucks at the Martinez Distribution Terminal. Ethanol replaces iso-octane for use in gasoline blending, and no additional diesel-

fueled gasoline delivery tank trucks will be loaded as a result of the Ethanol Tank Project.

d. 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 Ethanol Tank Project will require up to about 180 days. During this time, approximately 30 diesel-fueled truck deliveries of materials will occur. During construction, a diesel-fueled crane will be used for up to about 150 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?

The most likely route for delivery of construction materials to the Ethanol Tank Project construction site will be via Highway 680 to Marina Vista Avenue. The most likely route for delivery of ethanol to the new ethanol storage tank will be via Highway 680 to Marina Vista Avenue. The new ethanol storage tank will be loaded from the Martinez Distribution Terminal.

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 installation of the fugitive components/construction of the new ethanol tank 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 the new ethanol tank is not necessarily linked to any of these. Specifically, construction of the new ethanol 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 ethanol 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

All references to S-129 - an aging and out-of-service 15,000 bbl floating roof tank used for storing gasoline that will be demolished, will be deleted from part 1 of permit condition 18618 as follows:

S-#	Description	Daily Limit	Annual Limit
<u>129</u>	<u>Tank 129</u>		S129+ S1031+S1046+S1051+S1134+S1159+S1753 +S1754+S1755+S1756 < 508,114 bbl/day x 365
1031	Tank 1031		S129+ S1031+S1046+S1051+S1134+S1159+S1753 +S1754+S1755+S1756 < 508,114 bbl/day x 365
1046	Tank 1046		S129+ S1031+S1046+S1051+S1134+S1159+S1753 +S1754+S1755+S1756 < 508,114 bbl/day x 365
1051	Tank 1051		S129+ S1031+S1046+S1051+S1134+S1159+S1753 +S1754+S1755+S1756 < 508,114 bbl/day x 365
1134	Tank 1134		S129+ S1031+S1046+S1051+S1134+S1159+S1753 +S1754+S1755+S1756 < 508,114 bbl/day x 365
1159	Tank 1159		S129+ S1031+S1046+S1051+S1134+S1159+S1753 +S1754+S1755+S1756 < 508,114 bbl/day x 365
1753	Tank 1332 Gasoline		S129+ S1031+S1046+S1051+S1134+S1159+S1753 +S1754+S1755+S1756 < 508,114 bbl/day x 365
1754	Tank 1333 Gasoline		S129+ S1031+S1046+S1051+S1134+S1159+S1753 +S1754+S1755+S1756 < 508,114 bbl/day x 365
1755	Tank 1334 Gasoline		S129+ S1031+S1046+S1051+S1134+S1159+S1753 +S1754+S1755+S1756 < 508,114 bbl/day x 365
1756	Tank 1335 Gasoline		S129+ S1031+S1046+S1051+S1134+S1159+S1753 +S1754+S1755+S1756 < 508,114 bbl/day x 365

The following permit condition (# 23003) will be imposed on the new ethanol tank:

1. The owner/operator of S-6062 shall not exceed 1,500,000 bbl of denatured ethanol throughput during any twelve-month period. The owner operator may store materials other than denatured ethanol 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, Rule 2-5)
2. The owner/operator of S-6062 shall maintain records of storage tank throughput, 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, Rule 2-5)

Summary of changes to Shell's Title V permit:

1. Delete S-129 from Table's II-A, IV-B, IV-Ja, VII-A, VII-H, and IX.B-1. Delete references to S-129 from part 1 of permit condition 18618 in Section VI.
2. Add S-6062 to Table's II-A, IV-R, VII-P, and IX.B-2 in Shell's Title V permit. Add permit condition 23003 in Section VI.

RECOMMENDATION

Modify permit condition 18618 as proposed.

Waive the AC, and issue Shell a PO for the following equipment:

S-6062 Ethanol Tank

Internal Floating Roof Tank

Tank height: 30 feet; Tank diameter: 60 feet

Total volume: 15,000 bbl; Working volume: 10,070 bbl

Annual throughput: 1,500,000 bbl/yr

K. R. Bhagavan
Air Quality Engineer II