Bay Area Air Quality Management District
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Permit Evaluation
and
Statement of Basis
for
MAJOR FACILITY REVIEW PERMIT
Reopening – Revision 2
April 2005

for

Shell Martinez Refinery, Shell Oil Products US
Facility #A0011

Facility Address:
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Martinez, CA 94553

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April 2005

Application 12430

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Title V Statement of Basis

A. Background

This facility is subject to the Operating Permit requirements of Title V of the federal Clean Air Act, Part 70 of 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. On December 16, 2004, the District issued the modified and permit to amend flare and Regulation 9, Rule 10 requirements, add new permitted sources, and correct typographical and other inadvertent errors (Revision 1 Permit).

By letter dated October 8, 2004, EPA submitted comments and objections to five refinery Title V permits, including Shell's initial permit. A copy of the October letter is attached as Appendix B.

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. It also provides additional analysis supporting applicability determinations made previously by the District. In some instances, the additional analysis did not result in a permit change. In those instances, the District is not reopening the permit, and the analysis is provided for information only.

The 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 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.

B. Facility Description

The facility description can be found in the Statement of Basis that was prepared for the reopened permit that was issued December 16, 2004. It 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 revise 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.

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) 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 61.101(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 abatement devices are combusting gas generated at a refinery, the 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, SOCMI 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 or 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 is 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 Incorporate 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, 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 established a consistent record of interpreting NSPS J to apply broadly and according to its literal terms. <u>See</u>, 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 proposes incorporation into the Title V permit of the NSPS J as applicable 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 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. 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 practice 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 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). 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 revision 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" as 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 is also incorrect. The following change will be made to the permit in Revision 2.

> 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 refinery. Therefore, 61.342(e)(1) 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 will add to the proposed permit a permit condition requiring (# 22165) requiring the 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 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 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 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 now believes that compliance with 9-1-313.2 is sufficiently assured without the addition of Title V monitoring.

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

Regarding 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. 9-1-313 prohibits operation of a refinery of a certain size unless one of three conditions is met, one of which (§ 313.2) is that "*there is a* sulfur removal and recovery system that removes and recovers, on a refinery wide basis, 95% of H2S from refinery fuel gas" (emphasis added). This phrasing places primacy on the presence of a system capable of achieving a reduction, rather than achievement of the reduction. Moreover, another of the three possible methods of compliance with Section 313 (§ 313.3) allows (prior to a certain date) compliance merely by way of an enforceable commitment to construct such a system. This third compliance option reinforces the inference that the primary intent of Section 313 was to require operation of a sulfur recovery and removal system.

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

The discussion that follows explains why periodic monitoring would not be appropriate even if the 95% reduction requirement of section 313.2 is characterized as a performance standard. Although the following discussion can stand alone as a justification for not imposing additional monitoring, it can also be viewed as overlapping with discerning the original intent of the rule. The technical considerations weighing against establishing monitoring through Title V 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 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, 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 60.13(i).

The District will incorporate the requirements of 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 District will add 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 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 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." 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. In light of the above, Sections 110 and 110.3 of Regulation 8, Rule 1 in Table IV-AW will be deleted from Shell's permit.

Table IV-AW lists NSPS Subpart A requirements applicable to S1470 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 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 to the permit will be made.

Event based visible emissions check 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 S1470 when abating organic compound emissions from S4338 to be 98.5% by weight has been deleted.

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 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 check 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 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 part 13 of the permit condition 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. 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 1, will be deleted from Tables IV-AXa and AXb in Shell's permit. In addition, Sections 306, 328.1.2, 502, 603.1 and 603.2 of Regulation 8, Rule 5, will be added to the above tables, and testing & monitoring provisions contained in Sections 502, 603.1, and 603.2 will 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 "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 part 13 of the permit condition to maintain records outlining the quantity of vent gas combusted at the above flares on an hourly basis.

EPA Comment:

Source S2007 (Dissolved Nitrogen Floatation Unit) and S2008 (Dissolved Nitrogen Floatation 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 the District to revise the permit to specify how Shell will comply with 40 CFR 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), when the total annual benzene quantity from the facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), a facility is required to manage and treat both aqueous and non-aqueous waste streams in accordance with the requirements in Section 61.342(c). As an alternative to complying with the requirements in 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 their facility waste 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) 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 benzene containing wastes are sent to an ETP-1 sewer during a maintenance activity (e.g. pump maintenance), 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 thefacility 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). Section 61.354(c)(7) addresses carbon adsorption systems that regenerate the carbon bed directly in the control device (carbon canisters). 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), Shell is required to monitor them 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. 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 will be made to the permit.

EPA Comment:
EPA requested the District to review Shell's Cogen unit increase 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 (HRSG[1]), 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 Title V 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 capacity of the 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 permit 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. The equipment that was installed, however, has a higher capacity. The equipment has not been modified since 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.

[1] HRSG →Heat Recovery Steam Generators

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	Abatement of sulfur pit emissions from Sulfur Recovery Unit (SRU): 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. Please refer to a copy of the engineering evaluation in Appendix C.	**Table II-A:** 1. Assigned source number S1766 to sulfur pit located at SRU 3. **Table II-B:** 1. Under the column titled "Source(s) controlled" added S1766 to the row corresponding to A1518.
4106	Removal of Stretford Plant (A75), Installation of Flexsorb Unit (A751), and Modifications to Sulfur Plant 3 (S1765): 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 (SO_2) control devices because they are used to reduce hydrogen sulfide (H_2S) in FXG fuel before it is combusted and oxidized to SO_2 in refinery heaters and other combustion devices. Please refer to a copy of the engineering evaluation in Appendix C.	Changes to permit discussed under Application 9699.
4192	Modification of Hydrogen Plant #3/HP-3 (S4160): 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	**Section VI:** 1. Modified part 33 of permit condition 12271 as proposed.

Application #	Application Summary	Summary of Changes made to Shell's Title V permit in Rev. 2
	Methane Reformer/SMR (S4161) thereby reducing damage to furnace refractory caused by water impinging on refractory tiles. Please refer to a copy of the engineering evaluation in Appendix C.	
4688	<u>Loss of Exemption (LOE) I.C. Engine:</u> Modify permit condition 19097 to include S-5140 permitted under Application 7568. Please refer to a copy of the engineering evaluation in Appendix C.	**<u>Section VI:</u>** 1. Modified part 1 of permit condition 19097 to include S-5140.
4695	<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. Please refer to a copy of the engineering evaluation in Appendix C.	**<u>Table II-A:</u>** 1. Assigned source numbers S1578 and S1579 to sulfur pits located at SRU 1 and SRU 2, respectively. **<u>Table II-B:</u>** 1. Under the column titled "Source(s) controlled" added S1578 and S1579 to rows corresponding to A1501 and A1517.
6745	**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. Please refer to a copy of the engineering evaluation in Appendix C.	**<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.
9504	**Modification of Crude Unit (S1420):** Shell discontinued production of a specialty lube oil that used to be produced from San Joaquin Valley (SJV) crude oil, among other products,	**<u>Table's II-A & II-B:</u>** 1. Deleted references to S1411. **<u>Table's IV-B & AL:</u>** 1. Deleted references to S1411.

Application #	Application Summary	Summary of Changes made to Shell's Title V permit in Rev. 2
	at the Lubes Distillation Unit (S1411). Shell modified S1420 by rerouting 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. Please refer to a copy of the engineering evaluation in Appendix C.	**<u>Section VI:</u>** 1. Deleted S1411 from part 1 of permit condition 18618. 2. Changed daily throughput listed under S1420 in part 1 of permit condition 18618 from 160,000 bb/day to 178,800 bbl/day. 3. 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. **<u>Table's VII-A & AE:</u>** 1. Deleted reference to S1411.
9699	<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. Please refer to a copy of the engineering evaluation in Appendix C.	**<u>Table II-B:</u>** Deleted A-75; Added A-751 **<u>Tables IV-AR & VII-AI (for S1765):</u>** Incorporated applicable requirements contained in the new permit condition 19748. **<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. . **<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,

Application #	Application Summary	Summary of Changes made to Shell's Title V permit in Rev. 2
		E.2.c, and E.2.d are referenced in Table VII-BI. . **Section VI:** 1. Deleted references to A75 in part 1 of permit condition 4041. 2. Deleted A75 from part E.2 of permit condition 7618. 3. Amended existing permit condition 7618 (parts E.2.a through E.2.d) to include startup and shutdown conditions for S1759. 4. Reduced the SO2 REFEMS cap in Table IV-B of permit condition 7618 by 80 lbs/day. 5. 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. 6. Added a new permit condition 19748 for S1765 to ensure SRU modifications will comply with the expected reductions in SO2 and H2S.
10053	**Flexicoker Coke Transloading Operation (S6061):** 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. Please refer to a copy of the engineering evaluation in Appendix C.	**Table II-A:** 1. Included new source S6061. **Table IV-DX & VII-CZ:** 1. Created a new table to include S6061 and pertinent applicable requirements. **Section VI:** 1. Added new permit condition 21671.
11157 & 11158	**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 overall NOx emissions at the plant. In order for the US EPA to grant Shell	**Section VI:** 1. Created a new permit condition 22119

Application #	Application Summary	Summary of Changes made to Shell's Title V permit in Rev. 2
	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. Please refer to a copy of the engineering evaluation in Appendix C.	
11159	**<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). Please refer to a copy of the engineering evaluation in Appendix C.	**<u>Table II-A:</u>** 1. Deleted sources 858, 860, 861, 1004, 1023, 1050, 1409, 1415, 1478, 1479, 1539, 1540, and 2009. **<u>Table II-B:</u>** 1. Deleted sources 860, 861, 1004, 1409, 1539, and 1540. **<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. **<u>Tables IV-R, IV-S, VII-P, VII-Q,</u>** **<u>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 since they pertain to source 858.

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

Application #	Application Summary	Summary of Changes made to Shell's Title V permit in Rev. 2
		VII-BT, and Permit condition 5077: 1. Deleted references to source 2009 in Tables IV-R, VII-P, and permit condition 5077 (parts 10 through 12). 2. Deleted tables IV-CI and VII-BT since they pertain to source 2009. **Table IV-DW:** 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.
11613 & 11614	**Alterations to FCCU Catalyst Regenerator:** 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.	No changes made to the permit
Compliance with Regulation 9-1-313.2		The District is 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 system that achieves 95% reduction of H2S from refinery fuel gas. Conditions

Application #	Application Summary	Summary of Changes made to Shell's Title V permit in Rev. 2
		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.

II. Equipment

- 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, except for source S1411, were deleted under Application 11159, and source S1411 was deleted under Application 9504.

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, deleted table IV-S since it pertains to source 858.
- Deleted references to sources 860, 861, and 1004 in table IV-B.
- Deleted references to sources 1023 and 1050 in Table IV-R. Likewise, deleted table IV-X since it pertains to sources 1023 and 1050.
- Deleted references to sources 1409 and 1415 in 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. Likewise, deleted table IV-CI 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.

V. Schedule of Compliance

No change has been made to this section.

VI. Permit Conditions

As part of the Title V permit reopening, the District is proposing changes made to several permit conditions. These include: conditions regarding 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 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.
- 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 condition18265, 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

  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, frequency of monitoring, and type of monitoring. The applicable requirements for monitoring are completely contained in Sections IV, Source-Specific Applicable Requirements, and VI, Permit Conditions, of the permit.

- 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.

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.

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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)

NOx
Oxides of nitrogen.

NSPS
Standards of Performance for New Stationary Sources. Federal standards for emissions from new stationary sources. Mandated by Title I, Section 111 of the Federal Clean Air Act, and implemented by 40 CFR Part 60 and District Regulation 10.

NSR
New Source Review. A federal program for pre-construction review and permitting of new and modified sources of pollutants for which criteria have been established in accordance with Section 108 of the Federal Clean Air Act. Mandated by Title I of the Federal Clean Air Act and implemented by 40 CFR Parts 51 and 52 and District Regulation 2, Rule 2. (Note: There are additional NSR requirements mandated by the California Clean Air Act.)

Offset Requirement
A New Source Review requirement to provide federally enforceable emission offsets for the emissions from a new or modified source. Applies to emissions of POC, NOx, PM10, and SO2.

Phase II Acid Rain Facility
A facility that generates electricity for sale through fossil-fuel combustion and is not exempted by 40 CFR 72 from Titles IV and V of the Clean Air Act.

POC

Precursor Organic Compounds

PM
Particulate Matter

PM10
Particulate matter with aerodynamic equivalent diameter of less than or equal to 10 microns

PSD
Prevention of Significant Deterioration. A federal program for permitting new and modified sources of those air pollutants for which the District is classified "attainment" of the National Air Ambient Quality Standards. Mandated by Title I of the Act and implemented by both 40 CFR Part 52 and District Regulation 2, Rule 2.

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 **<u>Martinez Refining Co.</u>**
Application # **<u>4106</u>**
Plant # **<u>11</u>**

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 (SO_2) control devices because they are used to reduce hydrogen sulfide (H_2S) in FXG fuel before it is combusted and oxidized to SO_2 in refinery heaters and other combustion devices.

<u>Flexsorb® System</u>

The Flexsorb® System uses an amine scrubbing technology that selectively removes H_2S from process gas streams. Removal of H_2S in FXG fuel with the new Flexsorb® System will be at least as effective as the existing Stretford Unit. However, an improved H_2S removal efficiency is expected with the Flexsorb® System and will result in reduced SO_2 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.

<u>FXG Treating Column</u>

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 (CO_2) (totaling approximately 70 volume percent), combustible quantities of carbon monoxide, hydrogen, H_2S, 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 H_2S from the FXG fuel stream. The solvent passes through filters and heat exchange equipment, and into the amine regenerator/H_2S stripper column. The H_2S 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, H_2S 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 H_2S from SCOT-3 is converted to SO_2 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 H_2S 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 (NOx) 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.

<u>Other Emission Sources Associated with Project</u>

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 H_2S 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:

<u>Flexsorb® System Emissions</u>

Part E.2 of Condition # 7618 currently limits the H_2S 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 Flexisorb System (S-1765). As a result, flexigas must bypass the Flexisorb 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 H_2S 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).

<u>SRU-3 Emissions</u>

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 SO_2 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 H_2S to SO_2. 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 H_2S and SO_2 emissions.

TABLE 1

Category	Potential Emissions, tons per year	
	SO_2	H_2S
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_2S, 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 H_2S 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, NOx, POC, NPOC and PM10. Additionally, the reduced nitrogen levels with an Oxy-Claus will result in a decreased formation of NOx 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 H_2S 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 H_2S from SRU-3. There will be a decrease in H_2S 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 H_2S 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 uneffected by the proposed project. The existing Stretford Unit (A75) does not restrict the quantity of FXG fuel production and the new Flexsorb® System (A751) will not allow for increased Flexicoker® throughput. Part E.2 of Condition # 7618 which currently limits the H_2S 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 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.

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 NOx, SO_2, 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.

Flexsorb® System. Since the new Flexsorb® 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 (SO_2) 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 SO_2 corrected to 0 percent oxygen. Based on a search of Reasonable Available Control Technology (RACT) levels in other

California air districts, the 250 ppmv SO_2 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 SO_2 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 H_2S 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 H_2S 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 SO_2 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 SO_2 and oxygen concentrations. MRC currently complies with these requirements and will be required to comply after the modification of SRU-3.

Offsets

SO_2 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 SO_2) is greater than the potential emissions after the proposed modification (28 TPY of SO_2). 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 SO_2).

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 Flexsorb 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 SO_2 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 H_2S 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 H_2S to SO_2). 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 SO_2 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 SO_2 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 H_2S 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.

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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, SO_2 or PM_{10}. 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 charges 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 OPCEN[2] Sulfur Plant 3 (SRU[3]3) 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 (H_2S) and sulfur dioxide (SO_2). Specifically, H_2S laden Flexigas fuel (FXG) from the Flexicoker (S-1759) is routed to A-751, which selectively removes H_2S from FXG fuel. The FXG fuel is then combusted and the sulfur compounds in the fuel are oxidized to SO_2 in the various refinery heaters and other combustion devices. The acid gas containing H_2S 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 H_2S gas remaining after treatment at S-1765 and A-76 is oxidized to SO_2 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 SO_2 and H_2S emissions by 6 TPY and 0.18 TPY, respectively.

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[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 H_2S 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 SO_2 and H_2S 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 SO_2 and H_2S 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, SO_2 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 SO_2) [4] is greater than the *post-project* emissions (27.7 TPY of SO_2) [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 SO_2 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 SO_2 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 "Offests" discussion under the "Statement of Compliance" section of the engineering evaluation report for AN 4106 in Attachment 1.

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[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 SO_2 and H_2S emissions a new permit condition 19748 was included under AN 4106. Specifically, parts 1 and 2 of permit condition 19748 limit the SO_2 and H_2S 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 SO_2 and H_2S 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 SO_2 and H_2S 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 SO_2 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			
<u>Part E.2.a.</u>	<u>Duration of startups and shutdowns</u>	<u>Y</u>	
<u>Part E.2.d.</u>	<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 FLEXICOKER (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.							
Duration of startups and shutdowns	BAAQMD Condition # 7618, Part E.2.a.	Y		Duration of startup < 48 hours/event; Duration of shutdown < 96 hours/event	BAAQMD Condition #7618, Parts E.2.d. and G	P/E	Records

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.	Limit on the duration and mass emissions when flaring untreated flexigas during startups	Y	
Part E.2.c.	Limit on the duration and mass emissions when flaring untreated flexigas during shutdowns	Y	

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
Duration and SO2 mass emissions when flaring untreated flexigas during startups	BAAQMD Condition # 7618, Part E.2.b.	Y		Duration of startup < 48 hours/event; SO2 emissions < 5 tons/event	BAAQMD Condition #7618, Parts E.2.d. and G	P/E	Records
Duration and SO2 mass emissions when flaring untreated flexigas during shutdowns	BAAQMD Condition # 7618, Part E.2.c.	Y		Duration of shutdown < 96 hours/event; SO2 emissions < 8 tons/event	BAAQMD Condition #7618, Parts E.2.d. and G	P/E	Records

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~~ Flexsorb® 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 Flexsorb 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."

As previously discussed in the "Offsets" section of this evaluation, the post-project SO_2 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 SO_2 emissions baseline was reduced by 80 lbs/day[8].

[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)

SO2 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

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326 to 365    14659"
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The following is a text of Table IV *after* amending the permit condition:

"TABLE IV.

FACILITY BASELINE PROFILE-SOX EMISSIONS
(LB/DAY)

SO2 baseline reduced 1398 lb/day per Condition ID# 12271.
(AN 1362, Feb. 2002)
SO2 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 SO_2 emissions level was based on a throughput of 73 equivalent long tons sulfur load per day. The post - Flexsorb® project SO_2 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 SO_2 and H_2S 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.

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Prior to the source test, the owner/operator shall
notify and obtain approval of the source test
procedures from the District's Source Test Section.
(basis: Cumulative Increase)"
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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.

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K. R. Bhagavan
AQE II

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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 **FXU[9] 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 (PM_{10}) 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 PM_{10} emissions at Shell. Please refer to Attachment 2.

[9] **F**le**x**icoker **U**nit (FXU)

The daily PM_{10} emissions using the AP-42 emission factor is
= (0.00099 lbs PM_{10}/ ton of coke unloaded) x (450 tons of coke unloaded/day)
= 0.45 lbs PM_{10}/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 PM_{10} 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 PM_{10} 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 PM_{10} emissions of 0.45 lbs/day. Since this increase in PM_{10} emissions is below the BACT trigger level of 10 lbs/day, BACT is not triggered.

OFFSETS

Information on PM_{10} emissions at Plant 11 in the District's database is presented in Table 3. The increase in PM_{10} emissions associated with this application is 0.08 TPY.

Table 3:
Emission Offsets

Emissions (TPY)	Current [13] (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 PM_{10} 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 PM_{10} 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 PM_{10} 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/dscf[14]. We can therefore conclude that the post-control PM_{10} 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 (lbs/hr) = 0.026 * $P^{0.67}$, where "P" is the actual process rate in lbs/hr.

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[13] Db → q2 →p → all
[14] (0.45 lbs/day) x (7,000 grains/lb) / (1440 minutes/day) x (1600 ft^3/min) = 0.001 grains/ ft^3

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/hr[15]. 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/hr[16]. 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 PM_{10} 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 PM_{10} 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**

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K. R. Bhagavan
AQE II

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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.

<u>Permit Condition:</u> (# 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) NOx emissions shall be the source's maximum permitted daily heat input rate of 3336 MMBTU (HHV)/day expressed on a 24-hour basis as 139 MMBTU (HHV)/hr.
[basis: Shell-EPA Consent Decree]

Recommendation:

Since the above maximum daily and hourly firing rates were previously incorporated into Shell's Title V permit (part 1 of permit condition16688), I recommend incorporating the above permit condition into Shell's Title V permit.

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K.R. Bhagavan

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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.

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K.R. Bhagavan

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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.

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K.R. Bhagavan

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Date