

Bay Area Air Quality Management District

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

for
**Valero Refining Co. - California
Facility #B2626**

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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 modified and issued the 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 Valero’s initial permit.

Today, the District has reopened the Revision 1 Permit solely to incorporate modifications in response to EPA’s October 8, 2004 comments; to include new requirements imposed by Authorities to Construct approved by the District since 2003; and to correct typographical and inadvertent errors. (Again, not all of EPA’s October 8, 2004 comments and objections concern Valero’s permit.)

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

The Revision 2 Permit statement of basis discusses the changes made by this limited reopening. 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.

Revisions to this permit produce no significant increase in facility emissions. The majority of the changes are corrections and clarifications. The revisions incorporate the following recent District permit applications into the permit:

Application Number(s)	Description
10355	S-244 Aqueous Cationic Polymer Solution Tank (Exempt)
10665/10692	S-103 TK-1793 Secondary Seal Installation
11017/11018	S-245 Wastewater Membrane Filter (Exempt)
11307	NOx Box Condition 21233 Update

The incorporation of these applications produces no increase in emissions. Sources S-244 and S-245 are exempt from the permitting requirements of Regulation 2-1-301 and 2-1-302 and will have insignificant emissions. The S-103 Secondary Seal Installation will reduce emissions (previously the tank did not have a secondary seal). Application 11307 does not impact emissions because the application updates the NOx Box Condition 21233 that prescribes monitoring requirements for compliance with Regulation 9-10.

Details of significant permit changes are listed in Section F of this document.

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 follows. Changes to each permit sections are described in the order presented in the permit.

I. Standard Conditions

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

into the BAAQMD Manual of Procedures, Volume II, Part 3, Section 4, and therefore must appear in the permit.

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

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 of the condition is to reiterate that the permit holder is responsible for ensuring that all activities at the facility are performed in accordance with all applicable requirements.

II. Equipment

This section of the permit lists all permitted or significant sources. Each source is identified by an S and a number (e.g., S24 or S-24).

Permitted sources are those sources that require a BAAQMD operating permit pursuant to BAAQMD Rule 2-1-302. The Permitted sources are shown in the Permit Table II A.

The exempt sources may or may not have a source number. The exempt sources are shown in the Permit Table II B.

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

All abatement (control) devices that control permitted or significant sources are listed. Each abatement device whose primary function is to reduce emissions is identified by an A and a number (e.g., A24 or A-24). This abatement equipment is shown in the Permit Table II C. If a source is also an abatement device, such as when an engine controls VOC emissions, it will be listed in the abatement device table but will have an "S" number. An abatement device may also be a source (such as a thermal oxidizer that burns fuel) of secondary emissions. If the primary function of a device is to control emissions, it is considered an abatement (or "A") device. If the primary function of a device is a non-control function, the device is considered to be a source (or "S").

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

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

Following are explanations of the differences in the equipment list between this draft version of the permit and the equipment list contained in the December 16, 2004 final permit:

The following sources have been taken out of service:

S-144	Fixed Roof Tank, TK5013, Neutralizing Amine
S-170	Fixed Roof Tank, TK 2317, Cationic Polymer
S-171	Fixed Roof Tank, Methanol Storage Tank
S-177	Solvent Cleaning Station Dip Tank
S-180	Fixed Roof Tank, Demulsifier Storage Tank

The following sources were added:

S-244	TK-2317 Aqueous Cationic Polymer Solution Tank (Application 10355)
S-245	Wastewater Membrane Filter (Application 11017 and 11018)

The following sources are no longer owned by Valero Refining Company, California, and have been (or will be) removed from the permit (see paragraph on Application 7980 immediately below this list):

S-57	Crude Oil Tank TK-1701, External Floating Roof, 6300 kgal
S-58	Crude Oil Tank TK-1702, External Floating Roof, 18900 kgal
S-59	Crude Oil Tank TK-1703, External Floating Roof, 18900 kgal
S-60	Crude Oil Tank TK-1704, External Floating Roof, 6300 kgal
S-61	Crude Oil Tank TK-1705, External Floating Roof, 18900 kgal
S-62	Crude Oil Tank TK-1706, External Floating Roof, 18900 kgal
S-67	Gas Oil Tank TK-1715, External Floating Roof, 9450 kgal
S-68	Gas Oil Tank TK-1716, External Floating Roof, 8820 kgal
S-70	Resid Coker Feed Tank TK-1718, Vertical Fixed Roof, 5250 kgal
S-71	Resid Coker Feed Tank TK-1719, Vertical Fixed Roof, 15708 kgal
S-72	Gas Oil Tank TK-1720, External Floating Roof, 15204 kgal
S-74	HVN TK-1734, External Floating Roof, 7980 kgal

The District permit applications not included in this proposed permit are as follows:

- Application 5846: Valero Improvement Project. This Application was granted an Authority to Construct in July 2003. This project is a major revision to the refinery, to be implemented over a long period of time (5 to 10 years). The permit will be revised to incorporate project components as they are built.
- Application 7980: Transfer of Selected Storage Tank assets to Valero Logistic Operations Facility B5574. Currently the Title V permit for Valero Logistic Operations is being drafted. As soon as this Facility B5574 permit is final, the Tanks (listed above) will be removed from the B2626 Permit.

III. Generally Applicable Requirements

This section of the permit lists requirements that generally apply to all sources at a facility including insignificant sources and portable equipment that may not require a District permit. If a generally applicable requirement applies specifically to a source that is permitted or

significant, the standard will also appear in Section IV and the monitoring for that requirement will appear in Sections IV and VII of the permit. Parts of this section apply to all facilities (e.g., particulate, architectural coating, odorous substance, and sandblasting standards). In addition, standards that apply to insignificant or unpermitted sources at a facility (e.g., refrigeration units that use more than 50 pounds of an ozone-depleting compound) are placed in this section.

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

The only generally applicable requirement added to this revision is BAAQMD Regulation 8, Rule 16 for Solvent Cleaning Operations.

IV. Source-Specific Applicable Requirements

Quick Links:

Flares S-16, S-17, S-18 and S-19
MACT Subpart CC Applicability for Flares
NSPS Subpart J
Applicability Determination of NSPS 40 CFR Part 60 Subpart J to A-57 Thermal Oxidizer
Flare and Thermal Oxidizer Summary Table
Applicability Determination of 40 CFR Part 61 Subpart FF and 40 CFR Part 63 Subpart CC to Valero’s Sewer Pipeline and Process Drains
Applicability Determination of 40 CFR Part 60 Subpart QQQ to Valero’s Sewer Pipeline and Process Drains
Applicability Determination of 40 CFR Part 60 Subpart QQQ to Valero’s New Process Unit Water Collection System
Cooling Tower S-29
Electrostatic Precipitators A-1, A-2, A-3, A-4 and A-5

General Information

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

- District Rules
- SIP Rules (if any) are listed following the corresponding District rules. SIP rules are District rules that have been approved by EPA for inclusion in the California State Implementation Plan. SIP rules are “federally enforceable” and a “Y” (yes) indication will appear in the “Federally Enforceable” column. If the SIP rule is the current District rule, separate citation

of the SIP rule is not necessary and the “Federally Enforceable” column will have a “Y” for “yes”. If the SIP rule is not the current District rule, the SIP rule or the necessary portion of the SIP rule is cited separately after the District rule. The SIP portion will be federally enforceable; the non-SIP version will not be federally enforceable, unless EPA has approved it through another program.

- Other District requirements, such as the Manual of Procedures, as appropriate.
- Federal requirements (other than SIP provisions)
- BAAQMD permit conditions. The text of BAAQMD permit conditions is found in Section VI of the permit.
- Federal permit conditions. The text of Federal permit conditions, if any, is found in Section VI of the permit.

Section IV of the permit contains citations to all of the applicable requirements, a description of the requirement, and an indication of whether the requirement is federally enforceable. If applicable, a future effective date for the requirement is also specified. 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.

Complex Permit Issues and Applicability Determinations

Flares S-16, S-17, S-18 and S-19

Background Information

The Benicia Refinery has three separate flare header systems: 1) the main flare gas recovery header with flares S-18 and S-19, 2) the acid gas flare header with flare S-16, and 3) the butane flare header with flare S-17. Flares S-16 and S-18 were placed in service during the original refinery startup in 1968. Flare S-17 was placed in service with the butane tank TK-1726 in 1972. Flare S-19 was added to the main gas recovery header in 1974 to ensure adequate relief capacity for the refinery.

S-16, the Acid Gas Flare ST-2101AG serves the Claus Sulfur Recovery Units S-1 and S-2 and is only used during emergency malfunctions in those units. S-17, the Butane Flare ST-1701 serves the Butane Tank TK-1726. The off gas from this tank is recovered by a vapor recovery refrigeration system. The S-17 Butane Flare operates as backup during an emergency malfunction of this vapor recovery system.

S-18, the South Flare ST-2101, and S-19, the North Flare ST-2103, are part of the main refinery flare gas recovery header system. Any gas that flows into the main refinery flare gas recovery system is first abated by the Vapor Recovery Compressor A-13 and/or A-26 and routed to the refinery fuel gas system. Normally all the vapors are collected by A-13 and/or A-26 and there is no flow to S-18 and S-19. In the event (due to process upset or equipment malfunctions) that the gas flow to the main refinery flare gas recovery system exceeds the capacity of the Vapor Recovery Compressor, or due to an equipment malfunction neither compressor is operating, the

pressure in the flare header will reach a level where the water seal in the knockout drum to S-18 is broken and gas will be flared at S-18. If the pressure continues to build in the flare header, the water seal in the knockout drum to S-19 will also be broken and gas will be flared at S-19.

An overview of the flares and thermal oxidizers, including a summary of applicable requirements, is provided on a later page of this section. Specific applicability determinations follow.

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.

NSPS Subpart J

Applicability Determination of NSPS 40 CFR Part 60 Subpart J to S-18 South Flare:

40 CFR 60.100(a) specifies that fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and Claus sulfur recovery units greater than 20 long tons per day are subject to Subpart J. The term “fuel gas combustion device” is defined in 40 CFR 60.101(g) to include flares. Pursuant to 40 CFR 60.100(b), Subpart J applies to any fuel gas combustion device for which construction or modification is commenced after June 11, 1973. Since S-18 was constructed prior to June 11, 1973 and has not been modified since that date, S-18 is not subject to Subpart J.

Applicability Determination of NSPS 40 CFR Part 60 Subpart J to S-19 North Flare:

Because S-19 North Flare was added to the main gas recovery header in 1974, and construction did not commence before June 11, 1973, the flare is subject to NSPS Subpart J. There is only one requirement for flares subject to subpart J: a limitation on the hydrogen sulfide content of gas combusted, and the monitoring to demonstrate compliance. However, Subpart J exempts from this requirement the flaring of upset gases and fuel gas that is the result of relief valve leakage or other emergency malfunctions.

A flare that burns only gases from upsets or emergencies is exempt from the hydrogen sulfide limit and, pursuant to 40 CFR 60.105(a)(3), the associated monitoring. For S-19 North Flare, flare Permit Condition 20806 Part 7 imposes a condition to assure compliance with the exemption criteria. The condition requires S-19 to burn only process upset gases, as defined by 60.101(e), or fuel gas, as defined by 60.101(d), that is released to it as a result of relief valve leakage or other emergency malfunctions. As a result, S-19 is exempt from the hydrogen sulfide limit of Subpart J and the associated monitoring.

Applicability Determination of NSPS 40 CFR Part 60 Subpart J to A-57 Thermal Oxidizer

The Valero Benicia Refinery has one thermal oxidizer (A-57) at the Wastewater Treatment Plant (WWTP), which abates VOC emissions from tanks and primary separation equipment. The District is proposing to revise the permit to indicate the applicability of NSPS Subpart J at thermal oxidizer A-57.

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

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

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

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

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

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

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

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

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

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

Proposal to 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. See, e.g., December 2, 1999, letter from J. Rasnic, EPA, to P. Guillemette, Koch Refining Co. The District assumes that EPA’s longstanding interpretation would receive substantial deference from a reviewing court. Incremental changes to regulatory language over time, though sometimes unexplained, have tended to support these broader readings. The District speculates that the broader interpretation finds its policy justification in the desire to close potential loopholes -- that is, to remove any incentive to route treatable gas streams away from treatment. Though this may not be consistent with how some understand the original intent of the rule, it is nevertheless a legitimate and rational regulatory goal that finds ample support in the plain language of the rule. The District notes that, to its knowledge, EPA has never analyzed the technical feasibility, benefits, and costs of alternative controls and their application to gas streams not compatible with amine treatment. As a result, the practical consequences of application of NSPS J to the thermal oxidizers in question are not clear.

The District proposes incorporation into the Title V permit of the NSPS J as applicable to certain thermal oxidizers, and solicits comment on this proposal. If this 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.

Valero Flare and Thermal Oxidizer Summary Table

Flare or Oxidizer	Year Built	Design Capacity Lb/hr	Is Flare the Primary Abatement Device?	Service or Usage	Possible Sources Abated when Flare in Use	NSPS and NESHAPS Applicability			
						40 CFR 60 Subpart A	40 CFR 60 Subpart J	40 CFR 63 Subpart A	40 CFR 63 Subpart CC
S-16 Acid Gas Flare	1968	79,000	No	Backup abatement device when A24/A64 Tail Gas Unit and/or A56 Flexsorb Unit fails.	S1 and S2, Claus Sulfur Recovery Units	No. Not an Affected Facility per 60.2	No, per 60.100(b): Built before 6/11/73	No. Not an Affected Facility per 63.1(a)(2)	No, per 640(d)(4). Sulfur plant vents.
S-17 Butane Tank Flare	1972	16,000	No	Backup abatement device when vapor recovery refrigeration system fails	TK-1726 (exempt Butane Storage Tank)	No. Not an Affected Facility per 60.2	No, per 60.100(b): Built before 6/11/73	No. Not an Affected Facility per 63.1(a)(2)	No, per 63.640(a)(2) Butane is not a HAP on Table 1
S-18 South Flare	1968	1,200,000	No	Backup abatement device when A13/A26 flare gas recovery system capacity is exceeded and water seal in S18 South Flare knockout drum is broken.	S9 Blowdown System S51 HCU Sandfilter S52 HCU Sandfilter S133 Spent Acid Tank S188 Oil/Water Separator S189 Oil/Water Separator S211 Alkylate Debutanizer	No. Not an Affected Facility per 60.2	No, per 60.100(b): Built before 6/11/73	No. Not an Affected Facility per 63.1(a)(2)	No, per 640(d)(5): Affected sources routed to fuel gas.
S-19 North Flare	1974	886,000	No	Backup abatement device when A13/A26 flare gas recovery system capacity is exceeded and water seals in both S-18 South Flare and S-19 North Flare knockout drums are broken.	S1002 Diesel Hydrofiner S1003 Hydrocracker S1004 Catalytic Reformer S1005 Cat Feed Hydrofiner S1006 Crude Unit S1007 Alkylation Unit S1008 Gasoline Hydrofiner S1009 Jet Fuel Hydrofiner S1010 Hydrogen Plant S1011 HCN Hydrofiner S1012 Dimersol Unit S1014 Cracked Light Ends S1020 Heartcut Tower S1021 Heartcut Saturation S1022 Cat Reformer T-90 S1023 Cat Naphtha T-90 S1024 LCN Hydrotreater S1026 C5/C6 Splitter S1027 C5 Rail Load Rack	Yes. Note that 60.18 does not apply since S-19 is not subject to any subpart that refers to 60.18 per 60.18(a).	Yes, but exempt from 60.104(a)(1) since only burns process upset gas or fuel gas from relief valve leakage or other emergencies	No. Not an Affected Facility per 63.1(a)(2)	No, per 640(d)(5): Affected sources routed to fuel gas.
A-57 WWTP Thermal Oxidizer	1998	N/A	Yes	WWTP vapors flow continuously to A-57 and/or carbon adsorption A-37. A-57 heat for hydrocarbon decomposition is from electrical power.	S131 Wastewater Sludge Drum S150 Primary Sludge Thickener S194 Oil/Water Separator S195 Oil/Water Separator S197 Oil/Water Separator S198 Oil/Water Separator S199 Oil Collection Drum S200 Collection Drum	Yes. Note that 60.18 does not apply since A-57 is not subject to any subpart that refers to 60.18 per 60.18(a).	Yes (See discussion in Statement of Basis)	Yes, except 63.11 does not apply since A-57 is not a flare.	Yes
A-14 & A-15 Sulfur Plant Incinerators	1968	N/A	No	Alternate backup abatement device when A24/A64 Tail Gas Unit and/or A56 Flexsorb Unit fails.	S1 and S2, Claus Sulfur Recovery Units	No. Not an Affected Facility per 60.2	No, per 60.100(b): Built before 6/11/73	No. Not an Affected Facility per 63.1(a)(2)	No, per 640(d)(4).

Sewer Systems and Process Drains

Applicability Determination of 40 CFR Part 60 subpart QQQ to Valero's New Process Unit Water Collection System

The subject of this determination is whether NSPS subpart QQQ applies to the process water collection system from the new process units installed after the May 4, 1987 effective date of the subpart. The finding is that NSPS subpart QQQ applies but that the petroleum refinery MACT also applies and requires compliance with its provisions rather than those of NSPS subpart QQQ when both the MACT and the NSPS apply.

The process water collection system from the new process units is not a typical sewer line, but is instead a "hard-piped" system with no openings to the atmosphere. The connections between the process vessels and the system are direct flanged connections. Process wastewater passes through these flanged connections and is conveyed through hard piping to the D-2130 Flare Drum before being pumped to the gravity separation tanks (S-81 and S-104), where the entrained hydrocarbon product is recovered. After the product is recovered, the effluent water is conveyed to the Sour Water Stripper Feed Tank TK-2801 (S-55), to the Sour Water Stripper T-2831 and then to the wastewater treatment plant BIOX treatment units. All streams are contained in steel pipe at all points between the process vessels and the BIOX units. There is no contact between wastewater and the atmosphere until wastewater enters the Equalization Tank TK-1790 just upstream of the BIOX units.

The only NSPS subpart QQQ standard that could apply to the process water collection system is §60.692-2 Standards: Individual drain systems. This standard requires water seals for open drains, and controls for junction boxes, catch basins, and cracks or gaps. Nothing in the standard would apply to this hard-piped system. In prior applicability determinations for closed systems, EPA has determined that, though subpart QQQ applies to closed systems, such systems constitute an alternative means of control.

The petroleum refinery MACT, 40 CFR part 63, subpart CC, also applies to the wastewater collection system. Assuming that NSPS subpart QQQ does apply to the water collection system from the new process units, the MACT states, at 40 CFR 63.640(o)(1), that when NSPS subpart QQQ and the MACT both apply, then the equipment is required to comply only with MACT subpart CC. Therefore, the wastewater system is not required to comply with requirements in NSPS subpart QQQ.

Applicability Determination of 40 CFR Part 61 Subpart FF

EPA noted in previous discussions regarding applicability of the benzene waste NESHAP, 40 CFR part 61, subpart FF, that it was not clear that the permit contained requirements for non-aqueous waste streams (Reference EPA letter to Jack Broadbent, October 8, 2004, Attachment 2, Item 11). In response, the District committed to determine whether there were any such waste streams at the facility.

Valero has provided information showing that there is one waste stream that contains less than 10 % water. This is the waste stream from the analyzer building associated with the gasoline blending operation. The blending operation combines gasoline component streams from the various process units such as the MRU, the Cat Unit, the Dimersol Unit, and the Alkylation Unit. The analyzer determines the octane rating of the blended products, and the analyzer waste stream flows to a sump before being recycled (i.e. pumped back) to the refinery.

The octane analyzer sump is located in the refinery tank farm in the vicinity of the gasoline storage tanks and is not associated with any process unit or tank. The sump is 18.75 inches in diameter and about 6 feet high. The sump is controlled with a vapor barrier bladder on the vent line. Since the capacity is less than 260 gallons, the sump is exempt from permitting per BAAQMD Regulation 2-1-123.1, and the sump does not have a separate source number or a source specific table in Section IV of the permit.

40 CFR 61.342(e)(1) applies to this waste stream and is included in the Revision 1 permit in Table IV-Refinery. 40 CFR 61.342(c)(1) is also in Revision 1 of the permit. The sump is a tank as defined in 40 CFR 61.341 and complies with the NESHAP subpart FF tank standard found at 40 CFR 61.343(a)(1)(i)(B). This standard is not in the Revision 1 permit and is added in Revision 2.

Compliance with the benzene waste NESHAP is complicated. The following summarizes how Valero complies with subpart FF.

Subpart FF states that when a facility's total annual benzene quantity (TAB) is equal to or greater than 10 Mg/yr (11 ton/yr), the facility must manage its benzene containing waste streams (both aqueous and non-aqueous waste streams) in accordance with the general standard of section 61.342(c). The TAB is equal to the total annual quantity of benzene contained in all of the facility's aqueous waste streams. As an alternative to complying with section 61.342(c), NESHAP subpart FF allows a facility to manage its benzene containing wastes in accordance with the requirements of section 61.342(e). Valero has a TAB greater than 10 Mg/yr and has elected to manage the benzene-containing waste streams under section 61.342(e). That section requires Valero to manage its non-aqueous waste streams as required by section 61.342(e)(1) and its aqueous waste streams as required by sections 61.342(e)(2).

Section 61.342(e)(1) requires Valero to manage its one non-aqueous waste stream in accordance with section 61.342(c). Both 61.342(e)(1) and 61.342(c) are therefore included as applicable requirements in Table IV-Refinery.

Section 61.342(e)(2) requires that aqueous wastes (and wastes that become aqueous) are managed so that the benzene quantity for the wastes is equal to or less than 6.0 Mg/yr (called the "6BQ limit"). In order to verify compliance with the 6BQ limit, the benzene quantity in the aqueous waste is determined by the calculation method in section 61.355. The calculation method in Section 61.355 requires the uncontrolled waste stream to be calculated pursuant to section 61.355(k)(1), and the controlled waste stream to be calculated pursuant to section 61.355(k)(2). Under section 61.355(k)(1), the uncontrolled waste stream calculation is made at the point where the waste is generated as detailed in sections 61.355(a), 61.355(b), and 61.355(c). The controlled waste stream calculation is made at the point where the waste stream

enters the first non-complying waste management unit, as specified in section 61.355(k)(2)(i), and in the manner specified in section 61.355(k)(5).

Section 61.355(k)(6) states that the total benzene quantity used to demonstrate compliance with the 6.0 Mg/yr limit of section 61.342(e)(2) is determined by adding together the benzene quantities from the calculation of section 61.355(k)(1) for uncontrolled sources and the calculation of 61.355(k)(5) for controlled sources. Section 61.355(k)(4) states that the benzene waste entering an enhanced biodegradation unit shall not be included in determination of the benzene quantity determined by 61.355(k)(6). Two conditions must be met to allow the 61.355(k)(4) exclusion: the inlet benzene concentration to the biodegradation unit must be less than 10 ppm, and all prior waste management units must comply with the applicable standards in section 61.343 (tanks), section 61.344 (surface impoundments), section 61.345 (containers), section 61.346 (individual drain systems), section 61.347 (oil-water separators), or section 61.348(a) (treatment processes).

Valero's Biox Units S-154, S-155, and S-169 are considered enhanced biodegradation units as defined in section 61.348(b)(2)(ii)(B). They are also designated uncontrolled because they do not meet the requirements of section 61.348. The benzene concentration in the feed to the Biox units is less than 10 ppm. The waste management units upstream of the Biox units are both controlled and uncontrolled (i.e., some units comply with the applicable standard in section 61.343, 61.344, 61.345, 61.346, 61.347, or 61.348(a), and some units do not). Valero therefore applies this 61.355(k)(4) exclusion on a stream-by-stream basis. If an aqueous waste stream is managed by at least one unit that does not comply with the applicable standard ((e.g., the S-161 sewer is a such a "non-complying unit"), the benzene waste is determined pursuant to section 61.355(k)(1). If an aqueous waste stream is managed only by complying units (e.g., desalter water, which only flows through equipment controlled with vapor recovery), then the benzene waste is determined pursuant to sections 61.355(k)(2) and 61.355(k)(6). For streams like the desalter water, the benzene waste is determined pursuant to section 61.355(k)(2)(i) at the point where the waste stream enters the first non-complying waste management unit. However, the first non-complying units are the Biox units, which pursuant to section 61.355(k)(4), are excluded from the total benzene waste calculation of section 61.355(k)(6).

This stream-by-stream application of the section 61.355(k)(4) exclusion, which turns on whether upstream units are "controlled" or "uncontrolled," appears to be the reason that EPA raised questions regarding 6BQ application to uncontrolled waste streams only (Reference EPA letter to Jack Broadbent, October 8, 2004, Attachment 2, Item 12). Given the configuration of the Valero wastewater collection and treatment system, all controlled aqueous waste streams are counted where the waste stream enters the first non-complying waste management unit, or the Biox units. Because of the section 61.355(k)(4) Biox exclusion, however, these controlled waste stream are not counted in the section 61.355(k)(6) calculation that determines compliance with the 6.0 Mg/yr limit of 61.342(e)(2). Valero makes the calculations required for the 6BQ option of 61.342(e) correctly and is in compliance as reported in the Benzene Waste NESHAP Annual Report.

Cooling Tower S-29

Cooling Tower Monitoring

The District has determined that best modern practices for operation of refinery heat exchangers are 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. BAAQMD Regulation 8-2-114 states that 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. .

Valero performs a visual inspection, a conductivity test, and a free chlorine test on the cooling water three times per day. Typically the free chlorine runs about 2 ppm. If there is a hydrocarbon leak in a heat exchanger, the hydrocarbon will consume the chlorine bleach and the free chlorine will decline to 0 ppm. Valero also does a Total Organic Content test twice a week to trend organic loading. If either test indicates a leak is probably, a LEL detection device is used at the battery limits of the various cooling water users to isolate the location of the leak.

The District has determined that Valero is using best modern practice to monitor cooling tower water for indications of heat exchanger leaks. Regulation 8-2-301 has been removed from the source-specific applicable requirement Table IV-C5 for source S-29.

Electrostatic Precipitators A-1, A-2, A-3, A-4 and A-5

ESP Monitoring

The District has determined that the monitoring required for compliance with MACT UUU is an appropriate means of providing a reasonable assurance of compliance with Regulation 6. The District has added to the proposed permit a permit condition #22156 (shown below) 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.

COND# 22156

Valero Refining Company
3400 E. Second Street
Benicia, CA 94510
Electrostatic Precipitators (ESP) A-1, A-2, A-3, A-4 and A-5

1. The owner/operator of Electrostatic Precipitators (ESP) A-1, A-2, A-3, A-4 and A-5 that abate CO Boilers S-3 and S-4 shall conduct continuous monitoring of ESP operating parameters for reasonable assurance of compliance with Regulations 6-310. The owner/operator shall commence continuous monitoring and recording of the operating

parameters no later than the ESP monitoring commencement date required under 40 CFR Part 63, Subpart UUU. (Basis: Regulation 2-6-503)

2. The owner/operator shall conduct an initial compliance demonstration to establish a correlation between selected parameters and particulate mass emission by the deadline set forth in 40 CFR Part 63, Subpart UUU. The owner/operator shall submit the results to the District for its approval. (Basis: Regulation 2-6-503)
3. The owner/operator shall establish a range of compliance of the parametric value based on the results of the initial compliance demonstration. (Basis: Regulation 2-6-503)
4. Each time the measured parametric value exceeds the established range of compliance (pursuant to the initial compliance demonstration), the owner/operator shall conduct a source test to determine compliance with Regulations 6-310. The owner/operator shall conduct the source test within 45 days of detection of the exceedence. (Basis: Regulation 2-6-503)
5. Exceedences of parametric compliance range are deviations and shall be reported as deviations in all Title V reports. (Basis: Regulation 2-6-503)

Monitoring for Regulation 9-1-313.2 – 95% Reduction of H₂S in Refinery Fuel Gas

The District is proposing deletion of Title V permit conditions related to monitoring for compliance with 9-1-313.2 in the five Bay Area refinery permits, including this permit. Rule 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 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.

V. Schedule of Compliance

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

“409.10 A schedule of compliance containing the following elements:

- 10.1 A statement that the facility shall continue to comply with all applicable requirements with which it is currently in compliance;
- 10.2 A statement that the facility shall meet all applicable requirements on a timely basis as requirements become effective during the permit term; and
- 10.3 If the facility is out of compliance with an applicable requirement at the time of issuance, revision, or reopening, the schedule of compliance shall contain a plan by which the facility will achieve compliance. The plan shall contain deadlines for each item in the plan. The schedule of compliance shall also contain a requirement for submission of progress reports by the facility at least every six months. The progress reports shall contain the dates by which each item in the plan was achieved and an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.”

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

The BAAQMD Compliance and Enforcement Division has conducted a review of compliance over the past year and has no records of compliance problems at this facility during the past year.

VI. Permit Conditions

Conditions that were changed in this revision of the permit are as follows:

Condition 896: This condition was deleted since S-170 is no longer in service.

Condition 11888: Corrected equipment tag identifier for S-131 from D-2069 to TK-2069.

Condition 14318: Modified Part 6 by adding missing reference to Part 5.

Condition 18744: Deleted Parts 2 through 6. The deleted text is redundant with Regulation 9-8.

Condition 18748: Deleted Parts 2, 3, and 4, and revised Part 1. The deleted text is redundant with Regulation 9-8.

Condition 21233: This “NOx Box” condition was updated per Application 11307 that established the NOx Box for the affected sources. Minor text clarifications were also made.

Condition 20620: This condition was deleted. The requirements will be satisfied by meeting the requirements of 40 CFR 63 Subpart UUU.

Condition 22156: This condition was added for ESP monitoring. See Electrostatic Precipitators A-1, A-2, A-3, A-4 and A-5 in Section C.IV of this Statement of Basis.

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

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

VII. Applicable Limits and Compliance Monitoring Requirements

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

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

NOx Discussion:

There are no changes in the permit sources where NOx monitoring is missing or inadequate.

CO Discussion:

There are no changes in the permit sources where CO monitoring is missing or inadequate.

SO2 Discussion:

There are no changes in the permit sources where SO2 monitoring is missing or inadequate. There is a proposed change in fuel gas H2S reduction monitoring that could potentially impact SO2 emissions. See detailed Monitoring for Regulation 9-1-313.2 evaluation in Section C.IV of this Statement of Basis.

PM Discussion:

There are no changes in the permit sources where PM monitoring is missing or inadequate.

POC Discussion:

There are no changes in the permit sources where POC monitoring is missing or inadequate.

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 IV of the permit.

IX. Permit Shield

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

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

This facility has the first and second types of permit shield. However, since the December 16, 2004 permit, there has been no additional permit shields added. The permit shield shown in **Table IX A-5, Non Applicable Fugitive Sources** was deleted because the regulations shown in the table do apply and should not be shielded.

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.

F. Permit Updates and Changes since the Final December 16, 2004 Permit

List of changes to Final Revision 1 permit that resulted in the Draft Revision 2 permit.

Section I, II, III changes

1. Deleted S-170, S-171, S-177 and S-180 from Table IIA. These sources are no longer in service. (Valero 3/7/05 comment A7, A8, A9, A10.)
2. Deleted S-144 from Table IIB. This source is no longer in service. (Valero 3/7/05 comment A14)
3. Added additional A-57 abatement requirements in Table IIC. (Valero 3/7/05 comment A20)
4. Added Regulation 8, Rule 16, Solvent Cleaning Operations and a parent 40 CFR 82 subpart H to Table III. (Valero 3/7/05 comment A22, A27)
5. In Table III, changed the revision date of BAAQMD Regulation 8 Rule 28-302 and changed the rule to federally enforceable. (Valero 3/7/05 comment A23)
6. Updated several dates in Table III. (Valero 3/7/05 comments A25, A26 & A27))
7. In Table IIA, corrected firing rates of S-1030, S-1031, S-1032 and S-1033 to be consistent with Condition 19177, Part 16 in Section VI. (Valero 3/7/05 comment A30 & A31)
8. Corrected tag for S-131 from D-2069 to TK-2069. (Valero 3/7/05 comment A6)
9. Added Standard Condition I.B.12 stating that 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.
10. In Table IIB, added exemption basis for the LPG Truck Loading Rack, the Fresh Acid Tank TK-2710 and the Cogeneration Unit Cooling Tower. (EPA 15Mar05)

Order Item III.H.2)

11. Deleted Miscellaneous Condition J.5. The District addressed the applicability of 40 CFR 63, Subpart CC to certain flares in Item #1 of the February 15, 2005 letter to Deborah Jordan.
12. Deleted Miscellaneous Condition J.6. The District addressed the applicability of Regulation 8, Rule 2 to certain cooling towers in Item #4 of the February 15, 2005 letter to Deborah Jordan.
13. Deleted Miscellaneous Condition J.7. The District addressed the applicability of 40 CFR 61, Subpart QQQ to certain wastewater treatment sources in Item #9 of the February 15, 2005 letter to Deborah Jordan, and in the Revision 2 Statement of Basis.
14. Deleted Miscellaneous Condition J.8. The District addressed the applicability of 40 CFR 63, Subpart FF to certain waste streams in Item #11 of the February 15, 2005 letter to Deborah Jordan, and in the Revision 2 Statement of Basis.
15. Deleted Miscellaneous Condition J.9. The District addressed the ESP monitoring to assure compliance with SIP particulate standards in Item #13 of the February 15, 2005 letter to Deborah Jordan, and in the Revision 2 Statement of Basis.

Section IV, Applicable Requirements

1. The applicable requirements that were not in table form in Revision 1 were reformatted into table format.
2. In Table IV-J33, 40 CFR 63.640(o)(1) was added to clarify that NSPS subpart QQQ is not applicable to these tanks.
3. In Table IV-A15, in Condition 19466, Part 14, added missing text “Steam Generators: S-40, S-41”. (Valero 4/14/04 comment B73)
4. In Table IV-C5, Regulation 8-2-301 has been removed. The District has determined that Valero is using best modern practice to monitor cooling tower water for indications of heat exchanger leaks. Therefore, S-29 is exempt from Regulation 8-2 per Regulation 8-2-114.
5. In Table IV-J34, S-103 was added since a secondary seal was installed in 2004. Table IV-J35, the former location of S-103, was deleted. (Application 10665/10692, Valero 3/7/05 comment B95)
6. In Table IV-K1, the applicable citations from 40 CFR 60 subpart A and J have been added for thermal oxidizer A-57. (EPA 4/14/04 comment 18 & 43)
7. In Table IV-J41, deleted 40 CFR 60 subpart Kb citations that are not applicable for tanks that have a capacity less than 75 cubic meters. This change was a result of the

- 10/15/03 revision to subpart Kb. (Valero 3/7/05 comment B107, Valero Revision 1 Appeal Issue #4)
8. In Table IV-A21, deleted Condition 18748 Parts 2, 3, and 4, and revised Part 1. The deleted text is redundant with Regulation 9-8. (Valero 3/7/05 comment B34 & B35)
 9. In Table IV-A23, deleted Condition 18744 Parts 2 through 6. The deleted text is redundant with Regulation 9-8. (Valero 3/7/05 comment B40 & B41, Valero Revision 1 Appeal Issue # 6)
 10. In Table IV-Refinery, updated Regulation 8-8 and deleted 8-8-308, which only applies to S-161 and is contained in Table IV-H3. (Valero 3/7/05 comment B4)
 11. Corrected and updated several dates in Section IV. (Valero 3/7/05 comment B5, B6, B10, B12, B13, B15, B22, B24, B32, B36, B47, B63, B67, B68, B70, B71, B73, B77, B78, B94 & B110)
 12. Expanded the reporting requirements citations of Subpart FF in Table IV-Refinery. (Valero 3/7/05 comment B11)
 13. In Table IV-Refinery, the requirements of 40 CFR 63 Subpart A were rolled up into the main sections to be consistent with the requirements shown for 40 CFR 60, Subpart A and 40 CFR 61 Subpart A. (Valero 3/7/05 comment B12)
 14. In Table IV-Refinery, 40 CFR 63 Subpart B was moved into its proper sequential place but is not shown as a change in the permit. (Valero 3/7/05 comment B13)
 15. In Tables IV-Refinery General, IV-A1, -A2, -A4 and -D1, deleted detailed citations of 40 CFR 63 Subpart UUU, Subpart A and Condition 20620. There are options available to comply with Subpart UUU and applicable citations have not been selected yet. When the options are selected the applicable citations will be added. All of the requirements for Subpart UUU do not become effective until September 2005. (Valero Appeal Issue #14, Valero 3/7/05 comment B17, B19)
 16. In Table IV-A1, revised 30 days to 45 days in Condition 19466 Parts 1 and 8 to be consistent with the condition in Section VI. (Valero 3/7/05 comment B21)
 17. In Tables IV-A20, A22.1 and A22.2, added Regulation 1-523 citations for the parametric monitors at these sources. (Valero 3/7/05 comment B33)
 18. In Table IV-C4.1, corrected basis of Condition 19466 Part 2c to be consistent with the condition in Section VI. (Valero 3/7/05 comment B43)
 19. Deleted Table IV-G1 since S-177 is no longer in service. (Valero 3/7/05 comment B53)

20. Revised Tables IV-H1.1, H1.2, H2.1, H2.2, H3, H4.1, H4.2, H5.1 and H5.2 to reflect the new version of Regulation 8, Rule 8. Also added 40 CFR 61 Subpart FF citations to Table IV-H2.1, H2.2, H3. (Valero 3/7/05 comment B54, B55) Also deleted Condition 7015 from Table IV-H2.2 because it is redundant to Regulation 1-301. Also added S-245 Membrane Filter to Table IV-H2.2 (Application 11018).
21. In Table IV-J23, deleted S-171 and S-180 which have been taken out of service. (Valero 3/7/05 comment B87)
22. Deleted Table IV-J25 for S-170, which has been taken out of service. (Valero 3/7/05 comment B89)
23. In Table IV-J29, deleted S-144, which has been taken out of service. (Valero 3/7/05 comment B93)
24. In Table IV-J36, corrected S-131 tag number from D-2069 to TK-2069 and corrected basis of Condition 11888 Parts 1 & 2. (Valero 3/7/05 comment B96, B97, B98)
25. Added Tables IV-J42 and J43 for exempt LPG spheres and the Refrigerated Butane Tank. (Valero 3/7/05 comment B108)
26. In Table IV-K1, updated citations for Regulation 8 Rule 8 and added SIP Regulation 8 Rule 8, 40 CFR 61 Subpart FF and 40 CFR 63 Subpart CC. (Valero 3/7/05 comment B110)
27. In Table IV-Refinery, VII-Refinery and VII-H3, corrected the description of 61.342(e)(2)(i) to reflect the 6.0 Mg/yr Benzene allowance is for both controlled and uncontrolled streams. (EPA 15Mar05 Order Item III.A.2.e)
28. In Table IV-Refinery, 40 CFR Part 61, Subpart FF, 61.343 Tank Standards were added for the octane analyzer sump non-aqueous benzene waste stream. (EPA 8Oct04 letter to Jack Broadbent, Attachment 2, Item 11)
29. In Tables IV-A1 and A2, deleted Condition 19466, Part 1, monitoring for 95% H₂S and Ammonia reduction in fuel gas. See detailed analysis in Section C.IV of this Statement of Basis.
30. In Table IV-A3, added Condition 22156, Parts 1 through 5, consistent with Section VI.

Section VI, Permit Conditions

1. Condition 21233 was updated per Application 11307 that established the NO_x Box for the affected sources. Minor text clarifications were also made. Application 11307, Valero 3/7/05 comments C26, C27, C28, C29, C30, C32, C35, C36, C37 and C38.

2. Deleted Condition 18748 Parts 2, 3, and 4, and revised Part 1. The deleted text is redundant with Regulation 9-8. (Valero 3/7/05 comment C18)
3. Deleted Condition 18744 Parts 2 through 6. The deleted text is redundant with Regulation 9-8. (Valero 3/7/05 comment C17, Valero Revision 1 Appeal Issue # 6)
4. Deleted Condition 896 since S-170 is no longer in service. (Valero 3/7/05 comment C3)
5. Added reference to Part 5 in Part 6 of Condition 14318. (Valero 3/7/05 comment C14)
6. In condition 11888, corrected tag for S-131 from D-2069 to TK-2069. (Valero 3/7/05 comment C13)
7. Deleted Condition 20620. This condition will be satisfied by meeting the requirements of 40 CFR 63 Subpart UUU. (Valero Appeal Issue #14, Valero 3/7/05 comment C25)
8. Added Condition 22156 for Electrostatic Precipitator (ESP) monitoring. (EPA 8Oct04 letter to Jack Broadbent, Attachment 2, Item 13)
9. Deleted Condition 19466, Part 1, monitoring for 95% H₂S and Ammonia reduction in fuel gas. See detailed analysis in Section C.IV of this Statement of Basis.

Section VII, Monitoring Requirements

1. In Table VII-A15, changed the FE status from 'N' to 'Y'. (Valero 4/14/04 comment D41)
2. In Table VII-J34, S-103 was added since a secondary seal was installed in 2004. Table VII-J35, the former location of S-103, was deleted. Application 10665/10692, Valero 3/7/05 comment D61)
3. In Table VII-K1, the applicable citation for H₂S monitoring from 40 CFR 60 subpart J has been added for thermal oxidizer A-57. (EPA 4/14/04 comment 18 & 43)
4. In Table VII-A23, deleted two of the three hours of operation monitoring requirements. The identical monitoring required by Regulation 9-8 remains. (Valero 3/7/05 comment D22 & D23, Valero Revision 1 Appeal Issue #6)
5. In Table VII-A21, deleted two of the three hours of operation monitoring requirements. The identical monitoring required by Regulation 9-8 remains. (Valero 3/7/05 comment D18 & D19)
6. In Table VII-J36 and K1, modified the Thermal Oxidizer Permit Condition monitoring to be consistent with Permit Condition 11888 in Section VI. (Valero 3/7/05 comment D67, D69, D74, D75, Valero Revision 1 Appeal Issue #16)

7. In Table VII-J37, modified the Thermal Oxidizer Permit Condition monitoring to be consistent with Permit Condition 11879 in Section VI. (Valero 3/7/05 comment D67, D69, D74, D75, Valero Revision 1 Appeal Issue #16)
8. In Table VII-J36, corrected S-131 tag number from D-2069 to TK-2069. (Valero 3/7/05 comment D62)
9. In Table VII-A18, replaced the Regulation 9-10-502.1 NO_x monitoring requirement citation with 2-6-503 to be consistent with other tables in Section VII. (Valero 3/7/05 comment D10)
10. In Table VII-C4.1, corrected the Opacity monitoring frequency and type to be consistent with Condition 19466 Part 3 in Section VI. (Valero 3/7/05 comment D25)
11. In Table VII-D1, deleted detailed citations of 40 CFR 63 Subpart UUU. There are options available to comply with Subpart UUU and applicable citations have not been selected yet. When the options are selected the citations will be added. All of the requirements for Subpart UUU do not become effective until September 2005. (Valero Appeal Issue #14, Valero 3/7/05 comment D27)
12. Deleted Table VII-G1 since S-177 is no longer in service. (Valero 3/7/05 comment D33)
13. Updated Tables VII-H1.1, H1.2, H3, H4.1, H4.2, H5.1, H5.2 and K1 to reflect the new Regulation 8 Rule 8. (Valero 3/7/05 comment D34, D35, D36, D39, D40, D42, D77)
14. In Table VII-H4.2, H5.2, K1 modified the Thermal Oxidizer Permit Condition monitoring to be consistent with Permit Condition 11319 in Section VI. (Valero 3/7/05 comment D41, D74, D75, Valero Revision 1 Appeal Issue #16)
15. In Table VII – H5.2, added VOC limit of 98.5% destruction per Condition 13319 Part 3.
16. In Table VII-J23, deleted S-171 and S-180 which have been taken out of service. (Valero 3/7/05 comment D52)
17. Deleted Table VII-J25 for S-170, which has been taken out of service. (Valero 3/7/05 comment D54)
18. In Table VII-J29, deleted S-144, which has been taken out of service. (Valero 3/7/05 comment D60)
19. In Tables VII-J36, J37, J38, J39 & J40, added missing monitoring for BAAQMD Regulation 8-5-306 gas tight emission control system. (Valero 3/7/05 comment D65)

20. In Tables VII-J36, J37 and J39, modified the VOC monitoring in the Carbon Canister section to show NMHC monitoring and clarified the description. (Valero 3/7/05 comment D68)
21. Added Tables VII-J42 and J43 for exempt LPG spheres and the Refrigerated Butane Tank. (Valero 3/7/05 comment D73)
22. In Table VII-K1, modified the VOC monitoring for Condition 11879, 11882, 11888 Part 10 and 13319 Part 15 to show NMHC monitoring and clarified the description. (Valero 3/7/05 comment D76)
23. In Table VII-K1, added VOC monitoring required by 40 CFR 61 Subpart FF. (Valero 3/7/05 comment D78)
24. In Table VII-K1, the description for the Temperature Limit monitoring was amended to show the averaging over 3 consecutive hours to be consistent with the permit conditions in Section VI. (Valero 3/7/05 comment D79)
25. In Tables VII-A1 and A2, deleted Condition 19466, Part 1, monitoring 9-1-313.2 and SIP 9-1-313.2. See detailed analysis in Section C.IV of this Statement of Basis.
26. In Table VII-A3, revised the FP monitoring for 6-310.3 to reflect the requirements of Condition 22156.

Section VIII, Test Methods

1. Added SIP to ST-4 Bulk Gasoline Loading Terminals since the BAAQMD ST-4 has been deleted. (Valero 3/7/05 comment E3)
2. Added test methods based on revisions to Regulation 8 Rule 8 and Regulation 8 Rule 18. (Valero 3/7/05 comment E4, E5)
3. Deleted test methods associated with 40 CFR 63 Subpart UUU. There are options available to comply with Subpart UUU and applicable citations have not been selected yet. When the options are selected the citations will be added. All of the requirements for Subpart UUU do not become effective until September 2005. (Valero Appeal Issue #14, Valero 3/7/05 comment E9)

Section IX, Permit Shield

1. Deleted Table IX A-5, Permit Shield for equipment leaks. The regulations shown in this table are applicable and should not be shielded. (Valero 4/14/04 comment F1 and Valero 3/7/05 comment F1)

APPENDIX A GLOSSARY

ACT

Federal Clean Air Act

APCO

Air Pollution Control Officer

ARB

Air Resources Board

BAAQMD

Bay Area Air Quality Management District

BACT

Best Available Control Technology

Basis

The underlying authority which allows the District to impose requirements.

CAA

The federal Clean Air Act

CAAQS

California Ambient Air Quality Standards

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

Cumulative Increase

The sum of permitted emissions from each new or modified source since a specified date pursuant to BAAQMD Rule 2-1-403, Permit Conditions (as amended by the District Board on 7/17/91) and SIP Rule 2-1-403, Permit Conditions (as approved by EPA on 6/23/95). Cumulative increase is used to determine whether threshold-based requirements are triggered.

District

The Bay Area Air Quality Management District

dscf

Dry Standard Cubic Feet

EPA

The federal Environmental Protection Agency.

Excluded

Not subject to any District regulations.

Federally Enforceable, FE

All limitations and conditions which are enforceable by the Administrator of the EPA including those requirements developed pursuant to 40 CFR Part 51, subpart I (NSR), Part 52.21 (PSD), Part 60 (NSPS), Part 61 (NESHAPs), Part 63 (MACT), and Part 72 (Permits Regulation, Acid Rain), including limitations and conditions contained in operating permits issued under an EPA-approved program that has been incorporated into the SIP.

FP

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

HAP

Hazardous Air Pollutant. Any pollutant listed pursuant to Section 112(b) of the Act. Also refers to the program mandated by Title I, Section 112, of the Act and implemented by 40 CFR Part 63.

Major Facility

A facility with potential emissions of: (1) at least 100 tons per year of regulated air pollutants, (2) at least 10 tons per year of any single hazardous air pollutant, and/or (3) at least 25 tons per year of any combination of hazardous air pollutants, or such lesser quantity of hazardous air pollutants as determined by the EPA administrator.

MFR

Major Facility Review. The District's term for the federal operating permit program mandated by Title V of the Federal Clean Air Act and implemented by District Regulation 2, Rule 6.

MOP

The District's Manual of Procedures.

NAAQS

National Ambient Air Quality Standards

NESHAPS

National Emission Standards for Hazardous Air Pollutants. See in 40 CFR Parts 61 and 63.

NMHC

Non-methane Hydrocarbons (Same as NMOC)

NMOC

Non-methane Organic Compounds (Same as NMHC)

NO_x

Oxides of nitrogen.

NSPS

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

NSR

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

Offset Requirement

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

Process Unit

For the purpose of start-up and shutdown reporting, a process unit is defined as in 40 CFR Part 60 Subpart GGG: Process Unit means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

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.

Start-up

For reporting purposes only, a start-up shall be defined as any of the following; the removal of boundary blinds, first fire to a furnace, or the introduction of process feed to a unit. A start-up only occurs following a shutdown unless it involves a newly constructed process unit.

Shutdown

For reporting purposes only, a shutdown shall be defined as any of the following; there is no process feed to a unit, no furnace fires, or the boundary blinds are installed.

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 (42 gallons)
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
kgal	=	thousands of gallons
max	=	maximum
m ²	=	square meter
min	=	minute
MM	=	million
MMbtu	=	million btu
MMBBL	=	millions of barrels
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 Permit Evaluations

for

Application 10665 Seal Replacement Alteration For S-103

TK-1793 Crude Water Draw Tank, Internal Floating Roof, 676K gallons

Application 10355 Exemption for S-244

Aqueous Cationic Polymer Solution Tank 5000 gallons

Application 11018 Exemption for S-245

Zenon Membrane Filter

Application 11307 NOx Box

**PLACE HOLDER FOR APPLICATION 11307 NOX BOX EVAL
(currently in draft form – final version will be included in proposed permit and is
available prior to proposed permit transmittal upon request)**

EVALUATION REPORT for Exempt Source(s)

Applicant Valero Refining Company – California.

Plant Number 12626

Application Number 10665

1. Background:

The Applicant has applied for a seal replacement alteration for:

S-103 TK-1793 Crude Water Draw Tank, Internal Floating Roof, 676K gallons

Currently this tank is equipped with a metallic shoe type primary seal and no secondary seal. This alteration will install a zero-gap secondary seal. In addition, the metallic shoe type primary seal will also be replaced while the tank is out of service. This alteration is exempt by Regulation 2-1-123.4:

123.4 Tank seal replacement. For any tank subject to Regulation 8, Rule 5, any new seal must comply with the applicable provisions of Regulation 8, Rule 5, and the District must receive written notification of the tank source number and seal type at least three days prior to the installation.

2. Emission Calculations:

There is no chargeable cumulative increase for the exempt equipment described in Section 1. This exempt equipment does not emit one or more toxic air contaminants in quantities that exceed the limits listed in Table 2-1-316 of Regulation 2-1.

3. Statement of Compliance:

The exempt alteration described in Section 1 is exempt from Sections 2-1-301 and 302, in accordance with the specific section of Regulation 2-1 cited in Section 1.

When the new seals are installed and the tank is returned to service, S-103 will comply with Regulation 8, Rule 5, NSPS Title 40, Part 60 Subpart Kb (Tanks) and Part 61 Subpart FF (Benzene Waste Operations).

4. Exemptions:

I recommend that the Applicant be issued exemption status for the alteration to the equipment described in Section 1:

Application Reviewed By: _____
 Arthur Valla.
Position: Air Quality Engineer II

Date

EVALUATION REPORT for Exempt Source(s)

Applicant Valero Refining Company

Plant Number 12626

Application Number 10355

1. Background:

Valero Refining uses a cationic polymer as a coagulant that aids in the solids removal from raw water utility stream. This polymer was stored in an aqueous solution in the 5470 gallon TK-2317 plastic tank permitted as S-170. Prior to the polymer solution service, S-170 stored hexane. The Valero 2002 and 2003 annual updates indicate that hexane has not been stored in S-170. In 3Q2003, a flange leak was discovered on the bottom of S-170. The Applicant has applied for an exemption for the replacement equipment that will be dedicated to the polymer solution:

S-244, Aqueous Cationic Polymer Solution Tank, 5000 gallons

The MSDS provided by the applicant indicates the flash point of the polymer solution to be above 200F. Therefore, S-244 is exempt by equivalency Regulation 2-1-128.19 and Regulation 2-1-123.3.3 (flash point above 130 degrees Fahrenheit). New tank S-244 will comply with the applicable standards of Regulation 6 and the District Risk Management Policy.

2. Emission Calculations:

There is no chargeable cumulative increase for the exempt equipment described in Section 1. This exempt equipment does not emit one or more toxic air contaminants in quantities that exceed the limits listed in Table 2-1-316 of Regulation 2-1 nor does it emit any hazardous substances above the quantities listed in Regulation 2-1-318, for a PSD Major Facility.

3. Statement of Compliance:

The exempt equipment described in Section 1 is exempt from Sections 2-1-301 and 302, in accordance with the specific sections of Regulation 2-1 cited in Section 1. I certify:

- This exempt equipment does not emit one or more toxic air contaminants in quantities that exceed the limits listed in Table 2-1-316 of Regulation 2-1. Hence, an Air Toxics Risk Screening is not required.
- This exempt equipment has not received two or more public nuisance violations, under Regulation 1-301 or Section 41700 of the California Health and Safety Code, within any consecutive 180-day period.
- This exempt equipment does not emit any hazardous substances in excess of the quantities listed in Regulation 2-1-318 (for PSD Major Facilities).

Regulation 10 - New Source Performance Standard and Regulation 11 - Hazardous Pollutants requirements are not triggered. Because this application is ministerial (exempt source), the requirements of the California Environmental Quality Act (CEQA) are not triggered.

4. Exemptions:

I recommend that the Applicant be issued exemption status for the exempt equipment described and listed in Section 1:

Application Reviewed By: Arthur P. Valla
Position: Air Quality Engineer II

Signature of Reviewer

Date

EVALUATION REPORT for Exempt Source(s)

Applicant Valero Refining Co.

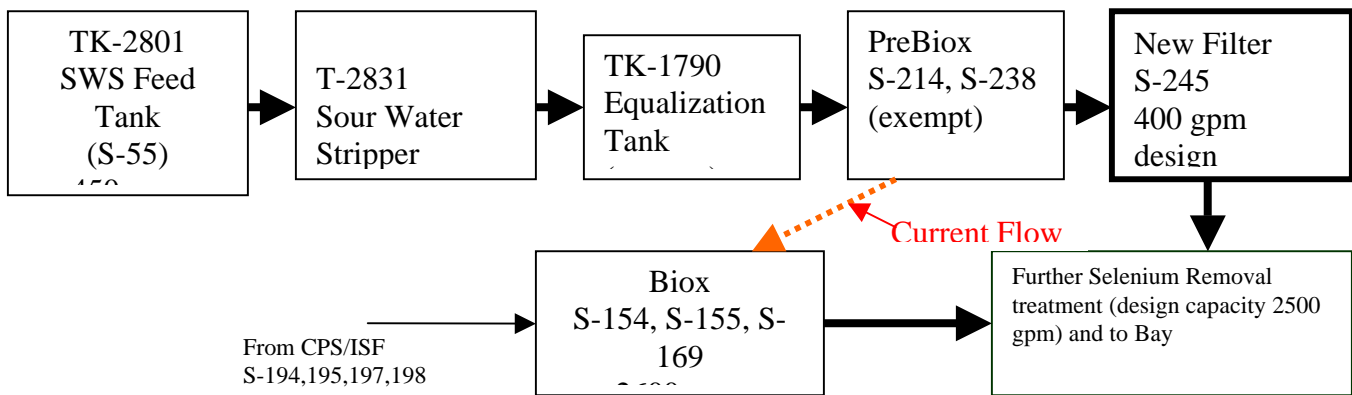
Plant Number 12626

Application Number 11018

1. Background:

The Applicant has applied for an exemption for the following equipment:

S-245 Zenon Filtration Unit, which is exempt by Regulation 2-1-123.2, organic content less than 1%.



S-245 will treat the effluent of the S-214/238 sour water pre-BIOX system. This new filtration unit will discharge directly into the final water treatment system (which removes selenium, adjusts pH, etc.) prior to discharge into the Bay. Currently the sour water pre-BIOX system discharges into the main BIOX system S- 154, S-155 and S-169 (which have a grandfathered throughput limit of 2600 gpm). The addition of this filter will provide some operational flexibility in these main BIOX units. However, the overall wastewater throughput will not increase because the system is capacity limited by the 2500 gpm design capacity of the final water treatment system.

2. Emission Calculations:

There is no chargeable cumulative increase for the exempt equipment described in Section 1. This exempt equipment does not emit one or more toxic air contaminants in quantities that exceed the limits listed in Table 2-1-316 of Regulation 2-1 nor does it emit any hazardous substances above the quantities listed in Regulation 2-1-318, for a PSD Major Facility.

3. Statement of Compliance:

The exempt equipment described in Section 1 is exempt from Sections 2-1-301 and 302, in accordance with the specific section of Regulation 2-1 cited in Section 1. I certify:

- This exempt equipment does not emit one or more toxic air contaminants in quantities that exceed the limits listed in Table 2-1-316 of Regulation 2-1. Hence, an Air Toxics Risk Screening is not required.

- This exempt equipment has not received two or more public nuisance violations, under Regulation 1-301 or Section 41700 of the California Health and Safety Code, within any consecutive 180-day period.
- This exempt equipment does not emit any hazardous substances in excess of the quantities listed in Regulation 2-1-318 (for PSD Major Facilities).

Regulation 10 - New Source Performance Standard and Regulation 11 - Hazardous Pollutants requirements are not triggered. Because this application is ministerial (exempt source), the requirements of the California Environmental Quality Act (CEQA) are not triggered.

NESHAP 40 CFR 61, Subpart FF. This equipment is part of the sour water stripper effluent water treatment system and is subject to Subpart FF NESHAPs for Benzene Waste Operations.

Permit Condition 7015:

COND# 7015 -----

For Sources S-214 (BIOX Aerator) and S-215 (BIOX Clarifier)

1. The Owner/Operator shall operate the S-214 (BIOX Aerator) and S-215 (BIOX Clarifier) in a manner that does not produce odors in such quantities as to cause a public nuisance under Regulation 1-301.
(Basis: BAAQMD 1-301)

Since S-245 will be integrated with the operation of the S-214, it follows that Contition 7015 would apply to S-245. However, all of the sources are exempt from permitting, so there should not be a permit condition. Research found that S-214 was granted a permit to operate at one time, so that is when Condition 7015 was imposed. When S-214 was granted an exemption, the condition should have been archived. Furthermore, all sources are subject to Regulation 1-301, so the Condition 7015 is not necessary. I recommend that Condition 7015 be archived.

4. Exemptions:

I recommend that the Applicant be issued exemption status for the exempt equipment described and listed in Section 1:

Application Reviewed By: Art Valla
Position: Air Quality Engineer II

Signature of Reviewer

Date