# $PM_{2.5}$ SIP Evaluation Report:
# Tesoro Refining & Marketing Company LLC

## Salt Lake City Nonattainment Area

**Utah Division of Air Quality**

**Major New Source Review Section**

**July 1, 2018**

**DAQ-2018-007379**

# $PM_{2.5}$ SERIOUS SIP EVALUATION REPORT
## Tesoro Refinery

### 1.0 Introduction

The following is part of the Technical Support Documentation (TSD) for Section IX, Part H.2 and Section IX, Part H.12 of the Utah SIP; to address the Salt Lake County $PM_{2.5}$ Nonattainment Area. This document specifically serves as an evaluation of the Tesoro Refining & Marketing Company LLC – Tesoro Refinery.

### 1.1 Facility Identification

*Name*: Tesoro Salt Lake City Refinery
*Address*: 474 West 900 North, Salt Lake City, Utah, Salt Lake County
*Owner/Operator*: Tesoro Refining & Marketing Company
*UTM coordinates:* 4,515,950 m Northing, 423,400 m Easting, Zone 12

### 1.2 Facility Process Summary

The Tesoro Refinery is a petroleum refinery capable of processing 57,500 barrels per day of crude oil. The source consists of a FCCU, catalytic reforming unit, hydrotreating units, a sulfur recovery unit, and cogeneration units. The source also has the usual assorted heaters, boilers, cooling towers, storage tanks, flares, and fugitive emissions. The source does not operate with flare gas recovery.

### 1.3 Facility Criteria Air Pollutant Emissions Sources

The following is a listing of the main emitting units from the Tesoro Refinery:

Crude Unit Furnace, with ultra-low $NO_x$ burners
Ultraformer Unit (UFU) Furnace, with low $NO_x$ burners
UFU Regeneration Heater, with low $NO_x$ burners
Fluid catalytic Cracking Unit (FCCU), Carbon Monoxide Boiler (Heat Recovery Unit), with $CONO_x$ oxygen injection, ammonia injection, electrostatic precipitator (ESP)
Distillate Desulfurization Unit (DDU) charge heater and rerun boiler, combined rating approx. 37.8 MMBtu/hr, equipped with "ultra-ultra" low-$NO_x$ burners
Hydrogen Compressors (Ultraformer compressors), with catalytic converters
South Flare (Flare covering Crude/UFU Unit/DDU)
North Flare (Flare covering FCCU/VRU/Alkylation Unit/GHT)
Sulfur Recovery Unit/Tail Gas Incinerator/Tail Gas Treatment Unit
Fuel Gas Desulfurization Unit/Sour Water Stripper (FGDU/SWS) Flare (this unit is physically integrated with the Sulfur Recovery Unit (SRU))
Emergency/Standby Sources
Waste Water Treatment Plant (WWTP) Generator
Electrical Generators
Plant Air Compressors

Miscellaneous Air Compressors
Fire Water Pumps
B-1 Air Preheater
Package Boilers
Gasoline Hydrotreater (GHT) Unit with 8.0 MMBtu/hr process heater
Benzene Saturation Unit (BSU): 3,000 bpd Bensat reactor and 10,000 bpd reformate splitter
Two cogeneration turbines (CG1 and CG2), 11.8 MW each with SoLo$NO_x$, and heat recovery steam generating units (HRSG) rated at approx. 157.8 MMBtu/hr
Loading/Unloading Racks
Cooling Towers
Fugitives
Tank Farm

This is not meant to be a complete listing of all equipment which may be involved or required during permitting activities at the refinery, rather it is a listing of all significant emission units or emission unit groups (such as the tank farm). Emission units such as a fluidized catalytic cracking unit (FCCU) which may have multiple individual component parts, but which can be treated as a single unit for purposes of RACT analysis and discussion, will be treated in such a manner.

### 1.4 Facility 2016 Baseline Actual Emissions and Current PTE

In 2016, Tesoro's baseline actual emissions were determined to be the following (in tons per year)[1]:

**Table 1: Actual Emissions**

| Pollutant | Actual Emissions (Tons/Year) |
|---|---|
| $PM_{2.5}$ | 89.4 |
| $SO_2$ | 708.3 |
| $NO_x$ | 358.1 |
| VOC | 250.4 |
| $NH_3$ | 3.8 |

The current PTE values for Tesoro, as established by the most recent AO issued to the source (DAQE-AN103350075-18)[2] are as follows:

**Table 2: Current Potential to Emit**

| Pollutant | Potential to Emit (Tons/Year) |
|---|---|
| $PM_{2.5}$ | 154.0 |
| $SO_2$ | 1637.0 |
| $NO_x$ | 638.0 |
| VOC | 767.9 |
| $NH_3$ | 6.6* |

* $NH_3$ emissions not quantified in the AO, PTE is estimated

1 see References: Item #10
2 see References: Item #7

## 2.0 Modeled Emission Values

A full explanation of how the modeling inputs are determined can be found elsewhere. However, a shortened explanation is provided here for context.

The base year for all modeling was set as 2016, as this is the most recent year in which a complete annual emissions inventory was submitted from each source. Each source's submission was then verified (QA-QC) – checking for condensable particulates, ammonia ($NH_3$) emissions, and calculation methodologies. Once the quality-checked 2016 inventory had been prepared, a set of projection year inventories was generated. Individual inventories were generated for each projection year: 2017, 2019, 2020, 2023, 2024, and 2026. If necessary, the first projection year, 2017, was adjusted to account for any changes in equipment between 2016 and 2017. For new equipment not previously listed or included in the source's inventory, actual emissions were assumed to be 90% of its individual PTE.

While some facilities were adjusted by "growing" the 2016 inventory by REMI growth factors; most facilities were held to zero growth. This decision was largely based on source type, and how each source type operates. The refineries have reported to UDAQ as a production group that they are operating at capacity and are not planning any production or major emission increases in the time frame covered by the SIP BACT analysis. In addition, each of the refineries has previously agreed to accept SIP allowable CAPs on emissions of $PM_{2.5}$ and $PM_{2.5}$ precursors in the moderate $PM_{2.5}$ SIP previously issued by UDAQ. For these reasons, UDAQ used zero growth for all projection years beyond the 2016 baseline inventory.

In the case of the Tesoro Refinery, there were a number of projects that were included both to complete the 2016 inventory, and to adjust the 2016 inventory for the first projection year of 2017. These projects are summarized as follows:

- DAQE-AN103350058B-13, although issued in 2013, the project was not completed until late 2014 – early 2015, so the $SO_2$ emission reduction did not appear until the 2016 emission inventory. This project was the Waxy Crude Processing Project, which included the addition of a TGTU on the SRU.
- DAQE-AN103350065-14, issued in 2014, this project was for flare gas minimization and was included in the 2016 inventory.
- DAQE-AN103350066-16, issued in April of 2016, this project addressed the addition of a wet gas scrubber to control emissions from the FCCU. The project was only completed in January of 2018 and will be covered extensively throughout this document as BACT-level control.

Following the process laid out above (applying no growth, but adjusting the baseline emissions to include permitted changes) for the Tesoro Refinery, this yielded the following modeled emission values – summarized in Table 3.

**Table 3: Modeled Emission Values**

| Pollutant | Potential to Emit (Tons/Year) |
|---|---|
| $PM_{2.5}$ | 89.4 |
| $SO_2$ | 544.4 |
| $NO_x$ | 360.1 |
| VOC | 249.3 |
| $NH_3$ | 3.8 |

Since a value of zero (0) growth was applied for all projection years, the values listed above (the 2017 corrected values) would then be propagated through for each of the subsequent projection years – 2019, 2020, 2023, 2024 and 2026.

Next, the effects of BACT would be applied during the appropriate projection year. Any controls applied between 2016 and 2017 (such as any RACT or RACM required as a result of the moderate $PM_{2.5}$ SIP), was already taken into account during the 2017 adjustment performed previously. Future BACT, meaning those items expected to be coming online between today and the regulatory attainment date (December 31, 2018), would be applied during the 2019 projection year. Notations in the appropriate projection year table of the emission inventory model input spreadsheet indicate the changes made and the source of those changes.

Similarly, Additional Feasible Measures (AFM) or Most Stringent Measures (MSM), which might be applied in future projection years beyond 2019 are similarly marked on the spreadsheet. The effects of those types of controls are applied on the projection year subsequent to the installation of each control – e.g. controls coming online in 2021 would be applied in the 2023 projection year, while controls installed in 2023 would be shown in 2024.

## 3.0 BACT Selection Methodology

The general procedure for identifying and selecting BACT is through use of a process commonly referred to as the "top-down" BACT analysis. The top-down process consists of five steps which consecutively identify control measures, and gradually eliminate less effective or infeasible options until only the best option remains. This process is performed for each emission unit and each pollutant of concern. The five steps are as follows:

1. Identify All Existing and Potential Emission Control Technologies: UDAQ evaluated various resources to identify the various controls and emission rates. These include, but are not limited to: federal regulations, Utah regulations, regulations of other states, the RBLC, recently issued permits, and emission unit vendors.

2. Eliminate Technically Infeasible Options: Any control options determined to be technically infeasible are eliminated in this step. This includes eliminating those options with physical or technological problems that cannot be overcome, as well as eliminating those options that cannot be installed in the projected attainment timeframe.

3. Evaluate Control Effectiveness of Remaining Control Technologies: The remaining control options are ranked in the third step of the BACT analysis. Combinations of various controls are also included.

4. Evaluate Most Effective Controls and Document Results: The fourth step of the BACT analysis evaluates the economic feasibility of the highest ranked options. This evaluation includes energy, environmental, and economic impacts of the control option.

5. Selection of BACT: The fifth step in the BACT analysis selects the "best" option. This step also includes the necessary justification to support the UDAQ's decision.

Should a particular step reduce the available options to zero (0), no additional analysis is required. Similarly, if the most effective control option is already installed, no further analysis is needed.

## 4.0 BACT for the FCCU Regenerator and CO Boiler

The fluidized catalytic cracking unit, or FCCU, is a reactor where pre-heated feedstock is combined with a very hot catalyst in order to "crack" or break the long-chain hydrocarbon molecules making up the feedstock. The long-chain molecules are broken down into shorter, lighter molecular weight hydrocarbons. These lighter materials then rise to the top of the reactor where they are removed and sent elsewhere in the refinery for further processing. The spent catalyst is removed from the recovered material through a series of two- or three-stage cyclones and sent to the regenerator section.

The regenerator in most FCCUs is a secondary vessel located alongside (in a side-by-side configuration) the main reactor vessel. The regenerator is used to remove residual carbon buildup from the surface of the catalyst. This residual carbon, also called "catalyst coke" or just coke, reduces catalyst performance simply by adhering and coating the active surfaces of the catalyst. The catalyst is quite hot when it exits the reactor, and simply introducing forced air is enough to cause the coke to combust. The additional heat from this combustion keeps the regenerator operating around 1300ºF. Catalyst coke contains a high amount of entrapped impurities depending on the chemical nature of the feedstock. Sulfur, various nitrogen compounds, trace metals and other compounds may be present. These materials will be released during combustion of the coke and depending on the design of the regenerator may be altered during the combustion process as well. The regenerator is the primary point of emissions from the FCCU.

Depending on the design of the FCCU, the unit may operate in either complete or partial burn mode. In complete burn units, the FCCU is operated to completely combust the coke and exhaust gases generating primarily $CO_2$. In partial burn units, such as the FCCU as the Tesoro Refinery, the unit is operated to produce mainly CO, which is then used as a fuel source for a downstream heat recovery boiler called a CO boiler (or COB). The COB uses the residual heat of the exhaust gases, plus the heat generated by combustion of the CO in the off-gas to produce steam for use elsewhere in the refinery. The exhaust gases from the COB are then sent through air pollution controls and out the exhaust stack. The air pollutants generated and types of air pollution controls are the same for both complete and partial burn units.

Currently Tesoro controls emissions from the FCCU/COB using a combination of electrostatic precipitation (ESP), wet gas scrubber (WGS) with LoTOx (an ozone treatment system for $NO_x$ control), and use of a low $SO_x$ catalyst ($DeSO_x$). These controls serve as the baseline for Tesoro's submitted analysis as well as UDAQ's BACT review.

### 4.1 $PM_{2.5}$

#### 4.1.1 Available Control Technology

For control of particulate emissions from a FCCU regenerator, a source can choose from the usual array of options, either high efficiency electrostatic precipitation (ESP) or fabric filtration (baghouse) being the primary choices depending on the electrical resistivity of the coke burn-off at the particular refinery. Two additional, more recent choices have also emerged: wet gas scrubbing (WGS) and a "flue gas blowback filter" (FGF). The FGF is an in-stack filter that operates in a similar fashion to a fabric filtration system, but on a smaller and faster cleaning scale. They are designed specifically for use with a FCCU, and have generally not been commercially applied in the U.S. but have seen successful application overseas. UDAQ has only found a single application of a FGF in the U.S., namely the one installed at Big West Oil's

(BWO) refinery, located in North Salt Lake, Utah. BWO was required to install a FGF as part of consent decree requirements prior to its inclusion as RACT for BWO's FCCU catalyst regenerator during development of the moderate $PM_{2.5}$ SIP.

The other control options normally available for combustion related activities, such as fuel switching or "good combustion controls," are inherently limited by the nature of the process. The chemical nature of the feedstock and the type of cracking catalyst do make some difference in the resulting particulates generated during the regeneration process, but an individual refinery is rather limited in which feedstocks it can accept based on physical configuration, geographical location, market forces (availability), and regulatory limits (on both the refinery emissions and the allowed final product). Ultimately, feedstock blending and catalyst changes have little to no effect on particulate emissions.

### 4.1.2 Evaluation of Technical Feasibility of Available Controls

All of the available controls are technically feasible; however the controls are mutually exclusive – they cannot (in most cases) be used together.

### 4.1.3 Evaluation and Ranking of Technically Feasible Controls

In terms of efficiency for control of particulate emissions, the available controls are all approximately equal.

- Pulse jet fabric filter
- FGF
- WGS
- ESP

Fabric filters have the highest efficiency but are designed only to control particulate emissions. Because of their high efficiency, they suffer from a problem other control options do not have. Particulate emissions from catalytic coke burn-off can be extremely sticky, and the fabric in these baghouses can easily become fouled and lead to blown bags. Higher cost bags can avoid this problem, but this application leads to higher operating costs.

The FGF option has a control efficiency nearly as high as a well maintained pulse jet fabric filter. While the installation cost is higher than that of a fabric filter, BWO evaluated this option primarily through negotiations with EPA over its consent decree. The consent decree AO was issued May 18, 2015, and the FGF was installed in the early spring of 2016. Subsequent testing conducted during 2016 has shown a reduction in particulate emissions of approximately 98%.

Both the fabric filter and FGF control only the filterable fraction of particulate emissions.

While the WGS system has the added benefit of removing condensable particulates, it is primarily designed as a control device for removal of $SO_2$ emissions. Installation and operation of a WGS is also far more expensive than any of the other options. Wet scrubbing inherently involves water treatment and disposal/discharge, which must be included in the operating cost. WGS, however, has an additional benefit over both of the above options in that it also controls the condensable fraction of particulate emissions – which can often be significantly larger than the filterable fraction.

Use of a high efficiency ESP is the typical default option. Holly used an ESP prior to the

installation of the WGS system, and the nearby Chevron refinery still employs an ESP as the final particulate control system. The Tesoro refinery employs both an ESP as the primary particulate control device, and the WGS as a secondary control device – in essence it acts almost as a polishing scrubber in this case.

### 4.1.4 Further Evaluation of Most Effective Controls

Should Tesoro have chosen to use a FGF or fabric filter control, emissions of 0.2 lb/1000 lb of coke burned are possible, although these values are filterable particulate only. WGS is slightly less efficient, with reported values of 0.3-0.5 lb/1000 lb coke burned. The default ESP option is typically limited to 0.5-0.7 lb/1000 lb coke burned, although this meets the various requirements of both the moderate $PM_{2.5}$ SIP as well as the emission limitations of 40 CFR 63 Subpart UUU and 40 CFR 60 Subpart Ja (limits are 1.0 lb PM/1000 lb coke burned). Tesoro did not provide an economic analysis of the various controls, as it has not removed the existing ESP and is adding a WGS as a secondary control system on the FCCU.

As the Tesoro refinery is already meeting the existing limitation required of all non-attainment area (NAA) refineries of 1.0 lb PM/1000 lb of coke burned with the existing ESP, and is adding additional control of a WGS, no additional analysis is necessary. This configuration is the only possible combination of two particulate control technologies that can functionally operate in series on a FCCU.

### 4.1.5 Selection of BACT Controls

UDAQ recommends that Tesoro continue to use the existing ESP and new WGS system to control emissions of particulate from the FCCU catalyst regenerator.

## 4.2 $SO_2$

### 4.2.1 Available Control Technology

There exist several options for removing sulfur from FCCUs:

- Feed hydrotreating removes the sulfur from FCCU feedstocks prior to cracking operations.
- $SO_x$ removing ($deSO_x$) catalyst injection prevents the sulfur from forming in the coke so it isn't burned off during regeneration forming $SO_2$.
- WGS allows for normal catalyst use, and then removes the $SO_2$ from the exhaust gases through wet contact scrubbing.

These options, while not necessarily mutually exclusive, do have impacts on the control options for other pollutants. Feed hydrotreating has some positive benefit on $NO_x$ formation. Using a $SO_x$ reducing catalyst additive creates additional sulfate (condensable $PM_{2.5}$). The use of WGS prevents the use of fabric filtration for particulate control, but allows for the use of LoTOx, a $NO_x$ control option.

### 4.2.2 Evaluation of Technical Feasibility of Available Controls

Save for feed hydrotreating, all of the controls are technically feasible and currently employed at the Tesoro refinery. Feed hydrotreating requires that the residual oil is removed from the feedstock prior to the introduction of hydrogen. This is accomplished through vacuum distillation to separate the vacuum gas oil from the residual oil. Tesoro does not operate a vacuum tower at

present, and considers this option to be technically infeasible. Although UDAQ disagrees that the process itself is inherently technically infeasible, it agrees that the addition of such a process would not add any value – emissions would not be further reduced, this would be an additional unnecessary expense, and the additional engineering, design, construction time and changes in FCCU feedstock from such an undertaking would push such a process change outside of the SIP BACT and even Additional Feasible Measures (AFM) windows.

### 4.2.3 Evaluation and Ranking of Technically Feasible Controls

Some combining of control options is possible. Feed hydrotreating and de$SO_x$ catalysts can be used in combination. WGS systems do not gain any additional benefit when combined with either of the other two control methods; however, neither are they harmed through combination with either control method.

The use of WGS technology can achieve the limits required by Subpart Ja: 50/25 ppmv (7-day/annual). As noted above in the summary for particulate control, WGS is a far more expensive option than either feed hydrotreating or De$SO_x$ catalyst. It also has the added disadvantage of water waste treatment and/or disposal.

The use of $SO_x$ reducing catalyst, can also meet the Subpart Ja limits. The known disadvantage of sulfate formation can be treated with effective particulate control systems.

As both remaining control options are viable, and have been deemed equally effective at reaching the required limits under Subpart Ja – further evaluation is required.

### 4.2.4 Further Evaluation of Most Effective Controls

Tesoro did not submit an economic analysis for either of these control options. However, since both control options have similar control efficiencies and Tesoro has elected to employ both control systems (De$SO_x$ and WGS), no additional analysis is required.

### 4.2.5 Selection of BACT Controls

UDAQ recommends that Tesoro continue to use De$SO_x$ catalyst and WGS as needed to meet the Subpart Ja FCCU $SO_2$ limits. These limits have already been established in Section IX, Part H.11.g of the SIP. Monitoring, recordkeeping and reporting requirements are included as well. As a refinery, Tesoro has a daily limitation on total plantwide $SO_2$ emissions which include emissions from the FCCU catalyst regenerator. These limits are as follows:

*No later than January 1, 2019, combined emissions of $SO_2$ shall not exceed 3.8 tons per day (tpd) and 300 tons per rolling 12-month period.*

## 4.3 $NO_x$

### 4.3.1 Available Control Technology

The available options for control of $NO_x$ from FCCUs are listed below:

- Low-$NO_x$ promoter catalysts
- Selective non-catalytic reduction (SNCR)
- Selective catalytic reduction (SCR)

- Feed hydrotreating
- LoTOx in conjunction with WGS

Low-$NO_x$ promoter catalysts and $NO_x$ reducing additives (as found in another BACT analysis) can be considered the same technology for purposes of this review. Both are catalytic additives (meaning they are not consumed in the process) although they serve slightly different purposes. The promoter catalysts specifically serve as FCC catalysts – providing sites for the cracking of long chain hydrocarbon molecules into shorter ones, but helping prevent the formation of $NO_x$ during the regeneration phase. The additives are supposed to prevent nitrogen from being trapped in the coke in the first place so that there is less "fuel-bound" nitrogen to form $NO_x$ during the regeneration process.

### 4.3.2 Evaluation of Technical Feasibility of BACT Controls

All control options are technically feasible, strictly speaking. However, Tesoro does not operate a vacuum tower and still considers feed hydrotreating to be technically infeasible. UDAQ has agreed that the addition of feed hydrotreating is outside the scope of SIP BACT, and does not need to be evaluated further.

Although LoTOx requires that a WGS system is simultaneously in use, this does not invalidate its technical feasibility. LoTOx is an add-on control system to the standard WGS where ozone is generated and injected into the exhaust gas stream prior to contact with the scrubbing liquid. The ozone reacts with the $NO_x$ present in the gas stream and generates $N_2O$, which is highly soluble in water (forming $N_2O_5$).

Tesoro, and to some degree the other refineries as well, has extensively investigated the use of $NO_x$ reducing additives and determined that they had no effect on $NO_x$ emissions. Low-$NO_x$ promoter catalysts are useful, and so only the promoter catalysts will be evaluated further.

The use of SNCR or direct ammonia injection into the FCCU regenerator exhaust cannot be used in conjunction with the WGS/LoTOx system because of the rapid cooling provided by the WGS. The use of SCR would also be severely hampered by a WGS/LoTOx system for much the same reason, although the injection of the ammonia would likely not harm the functionality of the WGS or LoTOx systems.

### 4.3.3 Evaluation and Ranking of Technically Feasible Controls

None of the refineries provided detailed analysis for the evaluation of SNCR beyond stating that no ammonia injection into the FCCU was occurring. Expected control efficiencies would be rather low, based on residence time, exhaust temperatures, and overall emission reductions of SNCR-based systems.

The remaining options of SCR, and WGS with LoTOx are approximately equal in terms of overall control effectiveness.

### 4.3.4 Further Evaluation of Most Effective Controls

SCR has an additional drawback in the form of ammonia slip. In order to control $NO_x$, ammonia is injected to reduce the $NO_x$ to N2 and water. Ideally, a stoichiometric amount of ammonia would be added – just enough to fully reduce the amount of $NO_x$ present in the exhaust stream. However, some amount of ammonia will always pass through the process unreacted; and since

the process possesses some degree of variability, a small amount of additional ammonia is added to account for minor fluctuations. The ammonia which passes through the process unreacted and exits in the exhaust stream is termed "slip" (sometimes "ammonia slip"). The amount varies from facility to facility, but ranges from almost zero to as high as 30 ppm in poorly controlled systems. In the case of SCR systems, the catalyst also degrades over time, and the degree of slip will gradually increase as increasing amounts of ammonia are needed to maintain $NO_x$ reduction performance.

WGS systems, with or without LoTOx, generate wastewater which must be treated before discharge or stored before disposal. Systems with LoTOx either have an acidic wastewater (nitric acid generated by $N_2O5$ in the aqueous phase), or one with soluble solids from neutralization of that acid (typically with NaOH or $Na_2CO$)

### 4.3.5 Selection of BACT Controls

UDAQ does not recommend any changes. Tesoro should continue to meet the rolling 365-day limit on $NO_x$ emissions from the FCCU using WGS with LoTOx. As this limit has too long an averaging time, it does not serve as a limitation suitable for inclusion in SIP based on a 24-hour-based standard. However, the FCCU is a combustion source and is therefore included in Tesoro's existing daily cap on $NO_x$ emissions. This would serve as a work practice standard and would not need to be included as an additional limitation. Tesoro's existing daily cap is as follows:

*No later than January 1, 2019, combined emissions of $NO_x$ shall not exceed 2.3 tons per day (tpd) and 475 tons per rolling 12-month period.*

## 4.4 VOC and Ammonia Considerations

UDAQ was unable to locate any additional controls to reduce emissions of VOCs from the FCCU/COB. In 2016, Tesoro's listed VOC emissions from this unit were 0 tons. Tesoro has not tested the emissions from this emitting unit, and thus UDAQ is unable to comment. However, in a review of other refineries, no viable add-on control device or technique was found to further reduce the emissions of VOCs from FCC catalyst regenerators. Typical VOC reduction controls such as thermal or catalytic oxidation require relatively high VOC concentrations and often additional heat input in the form of fuel burning (negating the controls already achieved for other pollutants). Control techniques such as fuel switching are negated by the nature of the process – the catalytic coke must be removed to continue the cracking process in the FCCU. Tesoro did list a VOC promoter catalyst which was immediately eliminated as being technically infeasible in partial burn units – UDAQ was unable to locate any additional information on this catalyst, and it is not in use at any of the other area refineries. The only remaining technique is simply good combustion practices, which is required by the other control systems already in place. No additional consideration for good combustion practices is required.

There are two possible mechanisms for ammonia emissions from the FCCU regenerator. Most refineries emit some amount of ammonia from the coke burn-off process itself, as trapped ammonia salts present in the coke are released during the regeneration process. These emissions are typically relatively small. The second mechanism is the injection of ammonia for control of $NO_x$ emissions using either SCR or SNCR as a control process. The injection of ammonia is fairly common among refineries in the U.S., but does not occur among the refineries in Utah. None of the refineries located in the Salt Lake City $PM_{2.5}$ NAA uses ammonia injection for $NO_x$ control.

Therefore, UDAQ recommends that no additional BACT limitations be required for these two pollutants.

## 5.0 BACT for Refinery Process Heaters and Boilers

UDAQ has separated the analysis of process heaters and boilers into two groups. For those heaters and boilers with heat input ratings less than 30 MMBtu/hr; UDAQ has included its analysis in a separate document which addresses similar emission units which are common to many sources – such as small heaters and boilers. Please refer to the $PM_{2.5}$ Serious SIP - BACT for Small Sources – Section 5 for details of the analysis for these smaller units. The remaining larger items are covered below.

Tesoro operates six (6) fired process heaters:
H-101 Crude Unit Furnace
F-1 Ultraformer Unit Furnace
F-15 Ultraformer Regeneration Heater
F-680 DDU Charge Heater
F-681 DDU Rerun Boiler
F-701 GHT Unit Heater

Steam for the refinery is primarily supplied by the COB and two cogeneration units (discussed elsewhere in this document), and through unfired waste heat boilers located in various process units. On various occasions Tesoro also operates temporary rental package boilers when steam is needed because of process unit shut down or when one or both of the cogeneration units may be out of service. The BACT review process for the rental boilers is the same as for the process heaters at the refinery, as these boilers are fired on natural gas and generally subject to the same federal standards. In addition, the boilers are also subject to 40 CFR 60.41b, which limits "time on site" to 180 days or less.

## 5.1 $PM_{2.5}$

No add-on controls for particulates were considered by UDAQ for these boilers. Given that these emission units are fired on gaseous fuels, with inherently low particulate formation, no controls are expected to be cost effective. UDAQ did review the usual particulate control options of good combustion practices, use of low sulfur fuels, wet gas scrubbers, electrostatic precipitators (ESPs), cyclones, and baghouse/fabric filtration; and determined that only good combustion practices and use of low sulfur gaseous fuels were technically feasible. Both refinery fuel gas and natural gas are low sulfur fuels. UDAQ reviewed one refinery's economic analysis of switching to using exclusively natural gas as fuel and determined such a switch to not be economically feasible, with a control cost in excess of $2.2 million/ton of particulate removed. Good combustion controls remains the only viable control option.

## 5.2 $SO_2$

Generally, $SO_2$ is formed from the combustion of sulfur present in the fuel. By limiting the sulfur content of the fuel, less $SO_2$ will be generated. Emissions of $SO_2$ can also be controlled by post combustion control devices or processes.

### 5.2.1 Available Control Technology

By consolidating all process heaters and boilers together into a single group for BACT

consideration UDAQ is able to consider controls on some emissions from this group which would ordinarily be dropped as being insignificant. However, it also limits the available options. In this particular case, only one option is available. The long term Subpart Ja refinery fuel gas $H_2S$ limit of 60 ppmv as well as the existing short term Subpart J limit of 162 ppmv on a 3-hour average.

The normally available options of flue gas desulfurization (FGD) or fuel switching are not available in this case. Fuel switching is not possible given the requirements of eliminating the refinery fuel gas generated during production of gasoline and other petroleum derivatives. The refinery fuel gas cannot be flared, and too much is produced to allow for reforming into heavier products (the energy losses would negate any positive benefit gained. Desulfurization systems rely on a relatively high concentration of sulfur compounds in the exhaust stream to function effectively and efficiently. By meeting the fuel gas $H_2S$ limits in Subparts J and Ja, the exhaust gas concentrations of $SO_2$ will naturally fall below the critical concentrations necessary for optimum control.

Refinery fuel gas, while still considered a low sulfur fuel, is higher in sulfur content than natural gas. Pipeline quality natural gas has a very low sulfur content of approximately 4 ppm – typically in the form of mercaptans used as odorants. The sulfur content of refinery fuel gas varies depending on the performance/removal efficiency of the amine scrubbing unit at the refinery. At the Tesoro refinery, the amine unit is designed to produce fuel gas with an average $H_2S$ content of 60 ppm on an annual average. However, short term spikes are allowed under the current rules of the SIP (the previously mentioned 162 ppmv on a 3-hour average). By way of comparison, ultra-low sulfur diesel fuel (ULSD) is 15 ppm sulfur.

Two other add-on controls wet gas scrubbing (WGS) and Emerachem EMx™ can be considered available technologies. A typical WGS system consists of either a packed bed tower or venturi-type scrubber. The flue gas to be cleaned passes through the absorber where misting nozzles form a dense curtain of liquid. The liquid reagent helps to cool the flue gas, neutralize the $SO_2$ in the flue gas, as well as trap any particulate matter in the gas. Liquid collects in the bottom of the scrubber where caustic soda (NaOH) is added to prevent the formation of sulfuric acid ($H_2SO_4$). The scrubbed gas continues upward through the vessel passing through filters prior to release into the atmosphere. Waste collected at the bottom of the scrubber is pumped off for additional treatment. This waste contains sulfites such as $NaHSO_3$ and $Na2SO_3$ along with residual catalyst fines and precipitated solids. Solids removal is done through a clarifier using flocculation to settle out the solids.

The EMx™ system uses a coated oxidation catalyst installed in the flue gas to remove both $NO_x$ and CO without a reagent such as ammonia. The NO emissions are oxidized to $NO_2$ and then absorbed onto the catalyst. A dilute hydrogen gas is passed through the catalyst periodically to de-absorb the $NO_2$ from the catalyst and reduce it to $N_2$ prior to exit from the stack. EMx™ prefers an operating temperature range between 500°F and 700°F. The catalyst uses a potassium carbonate coating that reacts to form potassium nitrates and nitrites on the surface of the catalyst. When all of the carbonate absorber coating on the surface of the catalyst has reacted to form nitrogen compounds, $NO_2$ is no longer absorbed, and the catalyst must be regenerated. Dampers are used to isolate a portion of the catalyst for regeneration. The regeneration gas consists of steam, carbon dioxide, and a dilute concentration of hydrogen. The regeneration gas is passed through the isolated portion of the catalyst while the remaining catalyst stays in contact with the flue gas. After the isolated portion has been regenerated, the next set of dampers close to isolate and regenerate the next portion of the catalyst. This cycle repeats continuously. At any one time, four oxidation/absorption cycles are occurring and one regeneration cycle is occurring.

### 5.2.2 Evaluation of Technical Feasibility of Available Controls

WGS is available for control of emissions from sources with higher concentrations of $SO_2$ or acid gases in the exhaust stream, but for these types of sources they are just not commercially available. To some degree this can also be viewed as a technical concern, but in either case the end result is the same. As WGS is not commercially available for emission sources of this concentration, WGS will not be considered further.

The EMx system is complex enough that the technology has not been proven to run longer than one year without a turnaround. Most refineries, the Tesoro Refinery included, require that the refinery heaters are able to operate at least three years between turnarounds. This type of control imposes a technical limitation on the operation of the refinery and is considered technically infeasible for control of $SO_2$ emissions. EMx will not be considered further.

This leaves only the use of low sulfur fuels and good combustion practices as technically feasible and available controls.

### 5.2.3 Evaluation and Ranking of Technically Feasible Controls

Both controls can be used in conjunction, so no ranking of control techniques is required.

### 5.2.4 Further Evaluation of Most Effective Controls

As mentioned previously, one area refinery did conduct an analysis of switching to running exclusively on pipeline quality natural gas as fuel versus using refinery fuel gas or a combination of refinery fuel gas and natural gas. While this analysis was conducted on particulate emissions and not $SO_2$, the difference in emission totals between particulate and $SO_2$ is about 4 tons (at the Tesoro refinery total particulate emissions from heaters and boilers ~ 13.4 tons/year, total emissions of SO from heaters and boilers ~ 9.3 tons/year), the economic analysis result is similar. Using exclusively natural gas as fuel is not economically feasible, with a control cost in excess of $3.2 million/ton of $SO_2$ removed.

### 5.2.5 Selection of BACT Controls

UDAQ recommends that Tesoro continue to use good combustion controls and refinery fuel gas or natural gas as fuel for control of $SO_2$ emissions from the refinery process heaters and boilers.

## 5.3 $NO_x$

$NO_x$, or oxides of nitrogen, are formed from the combustion of fuel. There are three mechanisms for the formation of $NO_x$: fuel $NO_x$, which is the oxidation of the nitrogen bound in the fuel; thermal $NO_x$, or the oxidation of the nitrogen ($N_2$) present in the combustion air itself; and prompt $NO_x$, which is formed from the combination of combustion air nitrogen ($N_2$) with various partially-combusted intermediary products derived from the fuel. For combustion within the process heaters and boilers, fuel $NO_x$ and thermal $NO_x$ are the major contributors, with prompt $NO_x$ contributing slightly only in the initial stages of combustion. All three processes are temperature dependent – combustion temperatures below 2700ºF greatly inhibit $NO_x$ formation.

### 5.3.1 Available Control Technology

The following technologies were identified as potential control methodologies for control of $NO_x$

emissions by Tesoro[3]: good combustion practices; low emission combustion (LEC); selective non-catalytic reduction (SNCR), the injection of ammonia or urea directly into the late stages of the combustion zone; selective catalytic reduction (SCR); flue gas recirculation (FGR); and EMx™ (previously known as SCONO$_x$™).

Low Emission Combustion (or LEC) is a summary term given to a host of different combustor designs and pre-combustion controls such as water or steam injection. These can be combined with a similar type of combustion control known as staged air/fuel combustion or overfire air injection. All serve the same general purpose – to reduce $NO_x$ formation by lowering the overall flame temperature. The various combustor (burner) designs, ranging from low-$NO_x$, through ultra-low-$NO_x$ and up to "next generation" ultra-low-$NO_x$ reduce flame temperature through a combination of flame diffusion, internal flue gas recirculation and some degree of staged combustion design. Water injection uses the inherent high specific heat of the injected water to absorb some of the combustion energy without increasing the ambient gas temperature. Staged air/fuel combustion limits the total amount of combustion air so that reducing and oxidizing sections are created in the combustion chamber. Combustion happens in stages, with intermediary products needing to physically move between sections before continuing combustion. Combustion is slowed down, limiting the "flux" (energy output/time) which lowers the total temperature.

Low-$NO_x$ Burners (LNB): Typically thought of as an advanced version of a standard burner, the LNB reduces $NO_x$ formation through the restriction of oxygen, flame temperature, and/or residence time. There are two main types of LNB: staged fuel and staged air burners. Staged fuel burners divide the combustion zone into two regions, limiting the amount of fuel supplied in the first zone with the standard amount of combustion air, and then supplying the remainder of the fuel in the second zone to combust with the un-combusted oxygen from the first zone. Staged air burners reverse this, limiting the combustion air in the first zone then supplying the remainder of the combustion air in the second zone to combust the remaining fuel. Staged fuel LNBs are more suited to natural gas-fired boilers as they are designed to restrict flame temperature.

Ultra-Low-$NO_x$ Burners (ULNB): Most commonly a combination of LNB technology with some internal flue gas recirculation. The burner recirculates some of the hot flue gases from the flame or firebox back into the combustion zone. Since these high temperature flue gases are oxygen depleted, the burner lowers the speed at which fuel can be combusted without reducing the flame temperature below the level needed for optimum combustion efficiency. Reducing oxygen concentrations in the firebox most directly impacts fuel $NO_x$ generation.

Flue Gas Recirculation (FGR): External FGR involves recycling of flue gas back into the firebox as part of the fuel-air mixture at the burner. Although similar to the concept of ULNB, rather than using burner design features to recirculate gases from within the firebox, FGR uses external ductwork to route a portion of the exhaust stream back to the inlet side of the boiler and return it into the boiler windbox.

In the SCR process, a reducing agent, such as aqueous ammonia, is introduced into the exhaust, upstream of a metal or ceramic catalyst. As the exhaust gas mixture passes through the catalyst bed, the reducing agent selectively reduces the nitrogen oxide compounds present in the exhaust to produce elemental nitrogen ($N_2$) and water ($H_2O$). Ammonia is the most commonly used reducing agent. Adequate mixing of ammonia in the exhaust gas and control of the amount of ammonia injected (based on the inlet $NO_x$ concentration) are critical to obtaining the required

3 see References: Item #8

reduction. For the SCR system to operate properly, the exhaust gas must maintain minimum $O_2$ concentrations and remain within a specified temperature range (typically between 480ºF and 800ºF with the most effective range being between 580°F and 650°F), with the range dictated by the type of catalyst. Exhaust gas temperatures greater than the upper limit (850°F) will pass the $NO_x$ and unreacted ammonia through the catalyst. The most widely used catalysts are vanadium, platinum, titanium, or zeolite compounds impregnated on metallic or ceramic substrates in a plate of honeycomb configuration. The catalyst life expectancy is typically 3 to 6 years, at which time the vendor can recycle the catalyst to minimize waste.

One final technology is CETEX, which is a process of descaling firebox steam tubes and then recoating these tubes – improving heat transfer and lowering total fuel consumption for a given amount of steam output.

### 5.3.2 Evaluation of Technical Feasibility of Available Controls

Most of the listed controls are technically feasible, although certain control techniques cannot be used in conjunction. For example, ULNB and FGR both use some degree of flue gas recirculation, making the use of both technologies redundant and counter-productive. FGR can only be applied on mechanical draft heaters/boilers with burners that can accommodate increased gas flows. Secondly, in order to physically connect FGR, a separation of at least three feet must exist between the windbox and the burner to prevent the accumulation of potentially explosive gas mixtures if a heater tube should fail.

Heaters F-1, H-101, F-680, and F-681 are already equipped with ULNB. Both F-15 and F-701 are small units less than 40 MMBtu/hour and have small furnace boxes unable to accommodate the FGR retrofit described above. FGR is eliminated from further consideration.

Next generation ULNB have proven less reliable than "normal" ULNB. They have been prone to plugging from impurities present in the fuel source. They also have not been shown to have any better emissions control than normal ULNB.

SCR and SNCR are opposed technologies as well, as SNCR is the use of ammonia injection without the added benefit of a catalyst bed to aid in pollutant reduction. Strictly speaking, SCR is simply the most commonly used catalytic reduction technique. More generally, NSCR (or non-selective catalytic reduction) represents those catalytic reduction techniques using alternative catalysts also capable of reducing $NO_x$. Often these catalysts reduce $NO_x$ in addition to many other compounds and are not specifically designed or optimized for $NO_x$ reduction. Efficient operation of these catalysts typically requires that the exhaust gases contain low oxygen concentrations – perhaps as low as 0.5% and no more than 4%. Since this requires the use of lean burn engines, furnaces and boilers, NSCR was eliminated by Tesoro as a valid control technique.

SNCR was eliminated based on a lack of load responsiveness. The control technique is somewhat crude by current standards, using only ammonia injection to reduce $NO_x$ emissions and relying on turbulence, temperature and residence time to allow the reaction to come to completion. The technical limitation of this technique is that as load changes $NO_x$ emissions can vary and change fairly rapidly, yet the only control mechanism is to change the amount of ammonia being injected into the flue gas. Periods of too little ammonia will be followed by periods of too much ammonia, both scenarios leading directly to an increase in $PM_{2.5}$ emissions.

The EMx process is highly sensitive to poisoning from sulfur compounds present in the exhaust gas. EMx has never been demonstrated in practice on refinery fuel gas-fired heaters or boilers

and is not deemed commercially available for this fuel type. EMx is therefore eliminated from consideration.

Water/steam injection is of limited effectiveness on process heaters and boilers. While some $NO_x$ reduction is possible, the benefit gained is minimal on units already equipped with low-$NO_x$ burners or better. Water/steam injection is typically employed on turbines where the increased mass of the steam-laden exhaust gas increases the efficiency of the turbine by improving the momentum transfer to the power generator. It is not typically employed on process heaters or boilers.

Low excess air firing (overfire/staged air combustion) was also eliminated based on flame lengthening problems. Reducing the oxygen concentration causes the combustion flame to lengthen, potentially causing flame impingement – where the flame comes into physical contact with one or more surfaces of the unit. This can cause severe damage to the unit and hazardous safety situations for refinery workers. This technique has also been eliminated from further consideration.

### 5.3.3 Evaluation and Ranking of Technically Feasible Controls

The remaining control techniques and their control effectiveness are listed below:

Table 5-1 $NO_x$ Control Effectiveness

| **Technology** | **Range of Control (%)** |
|---|---|
| ULNB + SCR | 85-99 |
| LNB + SCR | 80-99 |
| SCR | 80-90 |
| ULNB | 65-75 |
| LNB | 50-60 |
| CETEX | NA* |

* Not applicable, see below

Based on these control efficiencies, the use of SCR in combination with some form of $NO_x$ controlling burner (either LNB or ULNB) is the top ranked control option. The use of SCR without a burner upgrade can also be applied, but is rarely found in practice. The second ranked option is the use of ULNB alone, followed by LNB. Of the various process heaters at the Tesoro refinery, none are "boilers" in the traditional sense, requiring descaling such as that described under CETEX. Rather, the process unit may be described as a boiler or reboiler and is merely a process vessel with associated direct heating. Operations similar to CETEX could be performed on the rental package boilers, but would require disassembly of those units – something typically not performed on rental equipment. Thus CETEX is eliminated from further consideration.

### 5.3.4 Further Evaluation of Most Effective Controls

Tesoro provided additional analysis for the technically feasible controls[4]. Installing SCR can have adverse energy and environmental impacts. One potential source of concern with operation of SCR is the generation of ammonia slip. Unreacted ammonia, meaning any ammonia which does not react with the $NO_x$ present in the exhaust stream, may react with $SO_3$ to form ammonium sulfate/sulfite. This can occur either in the exhaust stream or in the ambient air. The unreacted

4 see References: Item #8

ammonia is referred to as "ammonia slip." Ammonia slip itself often requires permit limitations as a precursor pollutant.

Another source of concern is handling and disposal of the spent catalyst, which becomes a solid waste product. Operation of the SCR system reduces air flow, requiring additional energy in the form of fan power upgrades. Tesoro has not completed an engineering design analysis of installing SCR on any of the process heaters at the refinery and believes that design, construction, shake-down and testing could not be completed by December 31, 2018 – making such an endeavor technically infeasible. Tesoro has also expressed concerns about space availability for locating SCR on any of the process heaters. Given these concerns SCR has been eliminated as BACT at this time.

Installation of LNB or ULNB can change the heating pattern of the furnace or boiler by extending and cooling the flame.

Tesoro already operates with ULNB on four of the six process heaters. The remaining two units F-15 and F-701 are the smallest units and operate only with LNB in place. While these units could potentially be updated with ULNB, Tesoro has not conducted an analysis of design, engineering review, impingement concerns, time-to-construct, or economic considerations on these two units. UDAQ is unable to comment. A review of $NO_x$ emissions from these two units shows a total of 4.96 tons of $NO_x$ in 2016. Based on the difference in expected control efficiencies, perhaps a total of 1.65 tons of $NO_x$ could be reduced by switching to ULNB on both units. Given this low amount of possible reduction, no additional upgrades are recommended at this time.

### 5.3.5 Selection of BACT Controls

UDAQ recommends the existing $NO_x$ controls remain as BACT. As a refinery, Tesoro has an existing plant-wide cap on emissions of $NO_x$ from all combustion sources, rather than individual limitations on specific emission units. The plant-wide cap is as follows:

*No later than January 1, 2019, combined emissions of $NO_x$ shall not exceed 2.3 tons per day (tpd) and 475 tons per rolling 12-month period.*

This is found in Section IX, Part H.12.o.ii of the moderate $PM_{2.5}$ SIP. This section also contains additional monitoring, recordkeeping and reporting requirements to ensure compliance with the limits.

## 6.0 BACT for Cogeneration Units

The cogeneration units are a pair of gas-fired combustion turbines which produce electricity for the refinery. Each turbine's exhaust gas is also sent to a pair of heat recovery steam generators (HRSGs) that use the waste heat to produce steam for use in the refinery. The turbines are fired on natural gas and refinery fuel gas. The HRSGs heat input is supplemented with refinery fuel gas. Passive $NO_x$ control is provided through the design of the turbines – which are $SoLoNO_x$ lean pre-mix combustion technology.

## 6.1 $PM_{2.5}$

### 6.1.1 Available Control Technology

Controls for particulate emissions fall into one of three groups: pre-combustion controls, which seek to eliminate contaminants in the inlet air prior to the combustion chamber; combustion controls, such as specific burners or combustion design; and post-combustion controls, such as electrostatic precipitators or baghouses.

The identified controls are as follows:

Inlet air filters: primarily used to filter out small particulate matter in the inlet air to protect the combustion turbine. These filters can be static or self-cleaning, with the self-cleaning type requiring less maintenance.

Good combustion practice: this is nothing but properly operating the combustion turbines with the correct ratio of air to fuel in order to maximize combustion and minimize unburned fuel.

Clean burning fuels: includes the use of inherently low emitting fuels like natural gas.

Specific burner and/or combustion chamber design: the more efficiently a turbine is able to operate, the less pollution it will generate for a given amount of fuel combusted (or, to be more precise); as less fuel will be required to generate the same amount of power. This option includes both the use of high efficiency turbines, as well as inherently lower emitting burners such as dry low-$NO_x$ (DLN) combustors.

Add-on particulate controls: this final option includes traditional "add-on" control systems such as baghouses or electrostatic precipitators. These types of controls would be installed post combustion, and prior to the emissions exiting the stack.

### 6.1.2 Evaluation of Technical Feasibility of Available Controls

As a refinery, Tesoro is limited in the amount of fuel switching it can perform. Although some amount of natural gas is burned in the combustion turbines, refinery fuel gas is generated during the refining process and must be consumed in some fashion. The Tesoro refinery was designed to combust this fuel gas in cogeneration turbines supplementing Tesoro's power needs and limiting the amount of steam generation required by direct fired boilers. Switching the cogeneration units to run on exclusively natural gas would force diversion of the refinery fuel gas to the refinery flares – which may result in flow rates in excess of the refinery flare cap. This would also not reduce emissions, as the reduction from the turbines would be offset by the increased flaring emissions. Fuel switching is considered technically infeasible.

Post-combustion particulate controls such as baghouses and electrostatic precipitators have not been demonstrated in practice for use on combustion turbines. There are multiple factors that combine to eliminate these types of controls from consideration. 1) Combustion turbine particulate emissions have a small aerodynamic diameter – typically on the order of 1 micron or less – which makes the use of most direct physical capture systems problematic. 2) gaseous fuel-fired turbines generate little in the way of particulate emissions; yet also have high volume exhaust flows. This combination results in a low concentration of PM in the exhaust. 3) Post-combustion controls have difficulty operating efficiently or effectively in low concentration environments. Baghouse-style filtration systems rely on the buildup of a filter cake of captured particulates to enhance capture efficiency, while scrubbing systems require a reasonable particulate concentration in order to operate efficiently. Electrostatic precipitators can operate in low concentration conditions, but also suffer efficiency problems. In addition, a search was conducted for the use of ESPs with gaseous fuel-fired turbines and no results were found. A

single article which discussed a natural gas-fired bench-scale experiment was found, but no commercially available results[5]. The UDAQ was unable to identify any combustion turbines fired on gaseous fuels using post combustion controls for the control of particulate emissions. Post-combustion controls are therefore technically infeasible and removed from additional consideration.

All of the remaining control options are considered technically feasible and require additional evaluation.

### 6.1.3 Evaluation and Ranking of Technically Feasible Controls

The remaining control options under consideration are not mutually exclusive. A high-efficiency combustion turbine can be operated with inlet air filters and using good combustion practices. The turbine can be fired exclusively on gaseous fuel, and use properly designed combustors. Thus, the remaining controls do not need to be ranked – rather they need to be combined and considered as a group.

All of the remaining control options can be combined into this group (effectively: "high efficiency combustion"), so no further evaluation under step 3 is required.

### 6.1.4 Further Evaluation of Most Effective Controls

Tesoro did not evaluate the use of inlet air filters, but did review the remaining items and propose that the use of gaseous fuels, good combustion practices and a properly designed combustor should be considered BACT. UDAQ has evaluated the use of inlet air filters in its review of gas-fired turbines installed at power generation facilities (see e.g. the BACT analyses for PacifiCorp Gadsby, PacifiCorp Lake Side, UAMPS West Valley Power Plant). Inlet air filters function best on large combustion turbines with large volume air flows such as an F-Class turbine. Smaller turbines such as these cogeneration turbines receive little benefit from pre-filtering the inlet air.

### 6.1.5 Selection of BACT Controls

The cogeneration turbines are already fired on gaseous fuel and are operated with good combustion practices. As combustion sources they are included in Tesoro's plant-wide $PM_{2.5}$ emission cap. This emission cap is as follows:

*No later than January 1, 2019, combined emissions of $PM_{2.5}$ (filterable+condensable) shall not exceed 2.25 tons per day (tpd) and 179 tons per rolling 12-month period.*

## 6.2 $SO_2$

Emissions of $SO_2$ are directly a function of the amount of sulfur present in the fuel. As the fuel is burned, the fuel-bound sulfur is oxidized to $SO_2$.

### 6.2.1 Available Control Technology

Most sulfur control technologies require the use of some sort of acid reducing agent such as a lime slurry or limestone injection. This leads to residual solid or liquid waste which requires subsequent disposal. The remaining add-on control techniques rely on the post-combustion

5 see supplemental reference material

control of emissions of particulates and allowing any residual sulfur to be captured with the particulate. A second option would be to reduce the amount of sulfur present in the fuel, thus eliminating the source of the $SO_2$.

### 6.2.2 Evaluation of Technical Feasibility of Available Controls

Neither of the possible control options is technically feasible. The turbines and HRSGs are fired on a combination of natural gas and refinery fuel gas (the HRSGs are fired only on refinery fuel gas). The refinery fuel gas is treated prior to being used in the refinery and limited in fuel-sulfur content. Although refinery fuel gas is not as low in sulfur content as natural gas it is still considered a low-sulfur fuel with an annual average sulfur content of 60 ppmvd. Fuel switching to run on natural gas exclusively has been discussed in the $PM_{2.5}$ section (6.1.2 above) and is not technically feasible nor will it result in any decrease in emissions.

Post-combustion desulfurization systems, such as limestone injection or dry-lime scrubbing, are typically designed for exhaust streams with much higher $SO_2$ (and acid gas) concentrations than those found with combustion turbines fired on low-sulfur gaseous fuel. The low concentration leads to lowered control efficiencies. Effective control then requires longer residence times, longer exhaust stream runs, lowered exhaust temperatures, and worsened emission dispersal upon release. Tesoro has measured the $SO_2$ concentration in the cogeneration stack as 8 ppm (or lower) which is lower than the concentration required by (or even attainable) by add-on desulfurization systems.

### 6.2.3 Evaluation and Ranking of Technically Feasible Controls

Only the use of low-sulfur gaseous fuels was determined to be technically feasible. As this fuel is currently in use at Tesoro's cogeneration units, no further analysis is required.

### 6.2.4 Further Evaluation of Most Effective Controls

N/A, the only technically effective control is currently in use at the cogeneration units.

### 6.2.5 Selection of BACT Controls

UDAQ recommends that Tesoro continue to operate the cogeneration units using low sulfur gaseous fuel meeting the refinery fuel gas requirements of SIP Section IX.H.11.g.ii.A. Alternatively, Tesoro may continue to use the $SO_2$ monitoring methodology expressed in SIP Section IX.H.12.o.iii.C in lieu of direct fuel gas monitoring.

## 6.3 $NO_x$

$NO_x$, or oxides of nitrogen, are formed from the combustion of fuel in the turbine. There are three mechanisms for the formation of $NO_x$: fuel $NO_x$, which is the oxidation of the nitrogen bound in the fuel; thermal $NO_x$, or the oxidation of the nitrogen ($N_2$) present in the combustion air itself; and prompt $NO_x$, which is formed from the combination of combustion air nitrogen ($N_2$) with various partially-combusted intermediary products derived from the fuel. For combustion within the turbines, fuel $NO_x$ and thermal $NO_x$ are the major contributors, with prompt $NO_x$ contributing slightly only in the initial stages of combustion. All three processes are temperature dependent – combustion temperatures below 2700ºF greatly inhibit $NO_x$ formation.

### 6.3.1 Available Control Technology

The following technologies have been identified as potential control methodologies for control of $NO_x$ emissions: good combustion practices; low emission combustion (LEC); selective non-catalytic reduction (SNCR), the injection of ammonia or urea directly into the late stages of the combustion zone; selective catalytic reduction (SCR); and EMx™ (previously known as SCONO$_x$™).

In the SCR process, a reducing agent, such as aqueous ammonia, is introduced into the turbine's exhaust, upstream of a metal or ceramic catalyst. As the exhaust gas mixture passes through the catalyst bed, the reducing agent selectively reduces the nitrogen oxide compounds present in the exhaust to produce elemental nitrogen ($N_2$) and water ($H_2O$). Ammonia is the most commonly used reducing agent. Adequate mixing of ammonia in the exhaust gas and control of the amount of ammonia injected (based on the inlet $NO_x$ concentration) are critical to obtaining the required reduction. For the SCR system to operate properly, the exhaust gas must maintain minimum $O_2$ concentrations and remain within a specified temperature range (typically between 480ºF and 800ºF with the most effective range being between 580°F and 650°F), with the range dictated by the type of catalyst. Exhaust gas temperatures greater than the upper limit (850°F) will pass the $NO_x$ and unreacted ammonia through the catalyst. The most widely used catalysts are vanadium, platinum, titanium, or zeolite compounds impregnated on metallic or ceramic substrates in a plate of honeycomb configuration. The catalyst life expectancy is typically 3 to 6 years, at which time the vendor can recycle the catalyst to minimize waste.

The EMx™ system uses a coated oxidation catalyst installed in the flue gas to remove both $NO_x$ and CO without a reagent such as ammonia. The NO emissions are oxidized to $NO_2$ and then absorbed onto the catalyst. A dilute hydrogen gas is passed through the catalyst periodically to de-absorb the $NO_2$ from the catalyst and reduce it to $N_2$ prior to exit from the stack. EMx™ prefers an operating temperature range between 500°F and 700°F. The catalyst uses a potassium carbonate coating that reacts to form potassium nitrates and nitrites on the surface of the catalyst. When all of the carbonate absorber coating on the surface of the catalyst has reacted to form nitrogen compounds, $NO_2$ is no longer absorbed, and the catalyst must be regenerated. Dampers are used to isolate a portion of the catalyst for regeneration. The regeneration gas consists of steam, carbon dioxide, and a dilute concentration of hydrogen. The regeneration gas is passed through the isolated portion of the catalyst while the remaining catalyst stays in contact with the flue gas. After the isolated portion has been regenerated, the next set of dampers close to isolate and regenerate the next portion of the catalyst. This cycle repeats continuously. At any one time, four oxidation/absorption cycles are occurring and one regeneration cycle is occurring.

Two additional post-combustion control systems were also identified as being potentially applicable:

Linde's LoTOx™ technology uses ozone injection to oxidize NO and $NO_2$ to $N_2O$ which is highly soluble and easier to remove through the use of another control device such as a wet scrubber. UDAQ has seen and permitted the application of this technology in combination with a wet gas scrubber for emission control at a petroleum refinery.

Enviroscrub's Pahlmann™ Process is a sorbent-based control system which functions similarly to a dry scrubber. In this system, Pahlmanite (a manganese dioxide sorbent) is injected into the exhaust stream for $NO_x$ removal and then collected in a particulate control device like a baghouse. The sorbent is then regenerated in an aqueous process, filtered and dried, and is then ready for reinjection. The wastewater is sent offsite for disposal.

### 6.3.2 Evaluation of Technical Feasibility of Available Controls

All of the identified control options are potentially technically feasible; however some additional explanation is warranted:

In the case of LEC, more than one variant of combustor design exists:

- Dry-low-$NO_x$: The modern, dry low-$NO_x$ (DLN) combustor is typically a three-staged, lean, premixed design, which utilizes a central diffusion flame for stabilization. The lean, premixed approach burns a lean fuel-to-air mixture for a lower combustion flame temperature resulting in lower thermal $NO_x$ formation. The combustor operates with one of the lean premixed stages and the diffusion pilot at lower loads and the other stages at higher loads. This provides efficient combustion at lower temperatures, throughout the combustor-loading regime. The dry low-$NO_x$ combustor reduces $NO_x$ emissions by up to approximately 87 percent over a conventional combustor.
- Catalytic combustors: These combustors use a flameless catalytic combustion module to initiate the combustion process, followed by a more traditional combustion process downstream of the catalyst. This two-stage process lowers the overall combustion temperature.
- Xonon Cool Combustion®: Catalytica Energy Systems' Xonon Cool Combustion® System is a specific type of catalytic combustion process, and often mentioned independently in control technology reviews. In practical application, however, it functions similarly to other catalytic combustors.

Along with these types of burner designs, another pre-combustion process – water or steam injection – can also be used to lower the combustion temperature. Depending on the amount of water or steam used, this process can also increase both the maximum and actual power output of the turbine – by allowing more fuel to be burned without overheating, and by increasing the density of the exhaust flow through the turbine. However, water and steam injection tend to reduce combustion efficiency, prevent complete combustion leading to an increase in CO and VOC emissions, and are of limited effectiveness in combined cycle systems (turbine/HRSG systems) where the lowered temperature and increased specific heat of the turbine exhaust gas directly results in an increased need for duct firing in the HRSG unit.

Neither the LoTOx™ nor Pahlmann™ processes are determined to be technically feasible. While the LoTOx™ system is technically feasible from a mere engineering standpoint, it suffers from two flaws. It has not yet reached the commercial stage for large scale, combined-cycle, combustion turbines; and it requires the use of a second control system, such as a wet gas scrubber, for final removal of the $N_2O$. In the application of LoTOx™ UDAQ has previously permitted, the system was included as an additional module to a wet gas scrubber designed for removal of $SO_2$ and other acid gases. Achieving additional $NO_x$ removal at relatively low cost (on a $/ton basis) was the ideal fit for this technology. However, requiring the addition of another control system for final pollutant removal, especially where the secondary system does not add to emission reduction of other pollutants, demonstrates that LoTOx™ is not yet technically feasible. Similarly, the Pahlmann™ Process also requires the addition of: a baghouse for particulate removal (for capture of the sorbent), an aqueous sorbent regeneration process, and a wastewater treatment/disposal process. While the technology does show promise for control of multiple pollutants, it was not intended for control of only the $NO_x$ emissions from gas-fired turbines and is not commercially available for such units. Both processes are eliminated from further consideration.

The other control options (SNCR, SCR, good combustion practices, and burner design) have all been found to be technically feasible by UDAQ for various combustion turbine installations. However, Tesoro supplied counter-arguments for some of these technologies. Concerning water/steam injection, Tesoro contacted the manufacturer for a feasibility determination[6]. The manufacturer stated that water/steam injection was not available as a control system for that type of combustion turbine. Tesoro also argues that the design, installation, shakedown and testing period for SNCR, SCR, or installation of a new combustion turbine/HRSG system would be beyond the December 31, 2018 attainment date, even beyond any extension of that attainment date – were such to be granted. While no additional information was supplied supporting this claim (such that UDAQ is unable to comment), UDAQ has taken the arguments into consideration.

### 6.3.3 Evaluation and Ranking of Technically Feasible Controls

The combustion turbines installed at the Tesoro Refinery are built around the SoLoNO$_x$ combustor; Solar Turbines' specific brand of dry-low-NO$_x$ combustor. This particular system is a lean pre-mix burner design, which uses a combination of staged combustion and differing fuel-air mixing for each combustion stage to both lower the combustion temperature and still allow for complete combustion.

The use of additional pre-combustion controls is not technically feasible, regardless of the type of combustion technology chosen. As discussed in the previous section, the reduction in exhaust temperature and increased specific heat greatly increase the need for duct firing in the HRSG – a much less efficient process for generating power.

Switching to a Xonon-based combustor is not a viable option. Further review shows that the catalyst in Xonon systems is highly sensitive to sulfur compounds present in the exhaust gas, even a low sulfur fuel like refinery fuel gas contains too many sulfur-based compounds which will lead to poisoning the catalyst. The system was designed for use on pipeline quality natural gas-fired turbines only, and was never intended to be operated in a refinery setting.

In comparing SNCR and SCR, two factors come into play – the hypothetical effectiveness of control, and whether either system will work more effectively in the specific design of Tesoro's cogeneration units. In all of the SNCR designs available, ranging from simple ammonia/urea injection in the main combustion zone through Fuel Tech's NO$_x$OUT™ process, every one requires an exhaust gas temperature somewhere between 1600ºF and 2100ºF for most effective conversion of NO$_x$ to N$_2$. SCR systems, on the other hand, use a catalyst to lower this effective temperature range down to between 480ºF and 800ºF. The exhaust temperature from the Tesoro cogeneration units is approximately 320ºF, below even the effective temperature for SCR systems.

Combined with Tesoro's feasibility arguments, only the existing burner design and good combustion practices remain as viable options for NO$_x$ control.

### 6.3.4 Further Evaluation of Most Effective Controls

N/A The only remaining viable controls are both in effect on the cogeneration turbines/HRSG units.

6 see References: Item #8

### 6.3.5 Selection of BACT Controls

UDAQ recommends that the combustion turbines continue to be operated in conjunction with good operating practices. This is a work practice standard, so no additional monitoring, recordkeeping or reporting would ordinarily be required. However, the cogeneration units are combustion sources, and as such are included in the refinery's plant-wide $NO_x$ emission cap. This emission cap is as follows:

*No later than January 1, 2019, combined emissions of $NO_x$ shall not exceed 2.3 tons per day (tpd) and 475 tons per rolling 12-month period.*

## 6.4 Consideration of VOC and Ammonia

VOC emissions are the result of unburned hydrocarbons formed during incomplete combustion. To some degree the formation of VOCs is dependent on combustion system design, choice of fuel, combustion temperature (itself dependent on equipment design and operating practices), and operating practices (which can control the air-to-fuel ratio, timing, temperature, and other factors).

Only one type of post combustion control has been identified by UDAQ - the use of oxidation catalysts. An oxidation catalyst is similar in design and operation to a catalytic control system on a passenger vehicle, in that an inline, self-regenerating, catalyst system is placed within the exhaust stream prior to the final stack, so that emissions of both VOC and CO can be further oxidized to $CO_2$ and water. Oxidation of VOC can approach efficiencies of 70%, depending on initial concentrations and stack characteristics. However, efficiency drops off rapidly as concentration decreases – to the point that catalytic (and thermal) oxidation is ineffective below inlet VOC concentrations of 100 ppm. The VOC concentration from the cogeneration units is estimated at 13 ppm (or less). Oxidation catalysts are deemed technically infeasible.

Control techniques such as fuel switching are not helpful since gaseous fuels such as refinery fuel gas and natural gas are already the best available. The only control technique remaining is the use of good combustion practices (GCP). As GCP are already required or included as a part of the control techniques for the other pollutants listed previously no additional consideration is required.

There are few emissions of ammonia from the cogeneration units naturally (some minor amounts of ammonia may be generated as part of the combustion process). Ammonia emissions would be more of a concern if SCR or SNCR had been chosen as a viable control option. However, as no ammonia injection is being used, no ammonia slip can result. UDAQ does not recommend ammonia controls on the cogeneration units at this time.

# 7.0 BACT for the SRUs

## 7.1 $SO_2$

Tesoro operates a single well-controlled sulfur recovery plant meeting the established 95% sulfur recovery required under the $PM_{10}$ SIP (SIP Section IX, Part H.1). Generically, the sulfur recovery systems at the various refineries located in the $PM_{2.5}$ non-attainment areas are referred to as sulfur recovery units or SRUs. For purposes of this review a "well-controlled SRU" is one that is already operating with a tail gas treatment system followed by tail gas incineration.

There are only two pollutants of concern from a well-controlled SRU: $SO_2$ and $NO_x$. The system is designed to remove sulfur (primarily in the form of $H_2S$) from the refinery fuel gas through a combination of catalytic treatment and combustion. Particulate emissions are extremely low as the only emission source from the entire process is the Tail Gas Incinerator. This unit, fired on refinery fuel gas, is similar to other process heaters located at the refinery. The Tail Gas Incinerator oxidizes $H_2S$ to $SO_2$, but neither gas is considered a particulate. VOC emissions are also low, as few unburned VOCs are present in the inlet streams passed to the SRU, and the catalytic process does not generate additional VOCs. VOC generation from combustion of gaseous fuels is minimal. This review will focus on the control of $SO_2$ and $NO_x$ from operation of the Tesoro SRU.

The SRU at the Tesoro refinery operates as follows:

The sour water stripper gas and amine acid gas are sent to a burner to convert some of the $H_2S$ into $SO_2$, and all of the ammonia to nitrogen ($N_2$). The heated gas is fed to the first of three reactor stages where the $SO_2/H_2S$ mixture is converted to sulfur vapor over a catalyst bed – generating extra heat in the process. The sulfur vapor is cooled and separated, while the remaining mixture is reheated via heat exchanger. This cycle is repeated a total of three times (once time in each of the three reactor stages). After the last stage, the remaining gas, now called tail gas, is sent to the Tail Gas Treating Unit (TGTU). The separated sulfur, now in liquid form, is drained into a sulfur pit for temporary storage until it can be sold as elemental sulfur.

In the TGTU, the tail gas is reduced back to $H_2S$ for additional capture by an amine absorber and sent back to the front of the SRU. The outlet stream from the TGTU is sent to a thermal oxidizer (the Tail Gas Incinerator or TGI) which controls the reduced sulfur ($H_2S$) emissions. The TGI uses refinery fuel gas as a fuel source.

### 7.1.1 Available Control Technology

Three control systems were identified to further control emissions from a well-controlled SRU. For purposes of this review a "well -controlled SRU" is one that is already operating with a tail gas treatment system followed by tail gas incineration.

- LoCat
- WGS
- Caustic Scrubbing

LoCat is unusual in that it can serve as both a final treatment following the SRU (both in addition to, or in-lieu of a tail gas unit) or as a fuel gas sulfur removal unit (in case the SRU itself goes down).

WGS is a final control option, where the exhaust from the SRU is sent to the WGS in-lieu of tail gas treatment. It can also be utilized following application of a TGTU, but would rarely be implemented following a TGI.

Caustic scrubbing is typically used as a replacement for a SRU, such as a redundant back-up device, but can also be used as a final scrubbing process.

Tesoro also identified a fourth option, applicable only to the Tesoro refinery, which it termed a

"sulfur shedding plan.[7]" This option is to reduce $SO_2$ emissions by managing $H_2S$ generation in the refinery. Tesoro has an established limit on $SO_2$ emissions from the SRU at 60 tons per year. This limit was adjusted in 2018 as part of the negotiations for the $SO_2$ SIP, resulting in the following limit:

*$SO_2$ emissions from the SRU/TGTU/TGI shall be limited to:*
*A. 1.68 tons per day (tpd) for up to 21 days per rolling 12-month period, and*
*B. 0.69 tpd for the remainder of the rolling 12-month period.*

Both this limit and the previously established 60 ton limit can be found in the latest NSR permit issued to the Tesoro refinery (DAQE-AN103350075-18) as condition II.B.5.b.

### 7.1.2 Evaluation of Technical Feasibility of Available Controls

All controls are technically feasible.

### 7.1.3 Evaluation and Ranking of Technically Feasible Controls

Although all three technology options are technically feasible, none is a good option as an add-on control. Well-controlled SRUs can achieve 99.9% or better sulfur recovery/destruction efficiency rates. Tesoro installed a TGTU and TGI as an upgrade to the existing SRU as part of its Waxy Crude Processing Project beginning in 2013 (DAQE-AN103350058B-13). The project was completed in late 2015/early 2016, and the baseline emissions from 2016 reflect the drop in $SO_2$ emissions from this change. Prior to 2016, actual emissions from the SRU averaged approximately 195 tons of $SO_2$ annually. Beginning in 2016, total $SO_2$ emissions dropped to 30 tons annually.

Tesoro's sulfur shedding plan is considered a work practice standard, and difficult to establish and enforce. While technically feasible, drafting a limitation or enforceability provision which could be checked or followed up on would be a pointless endeavor. This exercise is left to Tesoro to implement of its own volition, but will not be investigated further.

### 7.1.4 Further Evaluation of Most Effective Controls

None of the control options will effectively reduce emissions below the levels already achieved. Although any of the control options could be applied in lieu of the existing controls, and either LoCat or WGS could be applied in addition to the existing controls, the costs of these additional add-on measures would be well above $250,000/ton.

### 7.1.5 Selection of BACT Controls

UDAQ recommends that Tesoro continue to operate the TGTU and TGI as $SO_2$ control for the SRU. The SRU is monitored by CEM and the monitored emissions are included in the daily plantwide $SO_2$ emissions cap for the refinery. Tesoro's SRU is also subject to two additional limitations which UDAQ recommends is added to the provisions of the SIP:

*$SO_2$ emissions from the SRU/TGTU/TGI shall be limited to:*
*A. 1.68 tons per day (tpd) for up to 21 days per rolling 12-month period, and*
*B. 0.69 tpd for the remainder of the rolling 12-month period.*

7 see References: Item #8

*Compliance with the daily limitations shall be determined as follows:*

*C. Daily sulfur dioxide emissions from the SRU/TGI/TGTU shall be determined by multiplying the $SO_2$ concentration in the flue gas by the mass flow of the flue gas. The sulfur dioxide concentration in the flue gas shall be determined by CEM as outlined in IX.H.11.f*

## 7.2 $NO_x$

In the traditional Claus SRU process (the process used at Tesoro), the reaction furnace is operated in a reducing environment, so that any ammonia in the acid gas feed is reduced to $N_2$. The SRU feed results in little fuel-based $NO_x$, and the heat within the reaction furnace is typically below the thermal $NO_x$ threshold of 1200ºF. Any thermal $NO_x$ generated is typically formed at the TGI, and this would be a minimal amount.

### 7.2.1 Available Control Technology

Tesoro identified only a single control technology as being available and technically feasible for control of $NO_x$ emissions from its SRU – Good Combustion Practices (GCP). UDAQ's review has shown that one other control technology is potentially viable as it is already in use at another local refinery. WGS has been shown to potentially reduce $NO_x$ emissions from a SRU when combined with a LoTOx unit.

### 7.2.2 Evaluation of Technical Feasibility of Available Controls

All controls are technically feasible. The use of GCP is the baseline case as it is already included as part of the operational requirements for the $SO_2$ limits on the SRU (see Section 7.1).

WGS with LoTOx is technically feasible as it is already in use at another area refinery. However, inclusion of LoTOx requires a large enough concentration of $NO_x$ to be operationally viable. Tesoro estimates that $NO_x$ emissions from the SRU are limited to 0.1 lb/MMBtu. A review of the 2016 baseline emission inventory[8] shows estimated $NO_x$ emissions from the SRU of just 0.56 tons annually. These values are below the levels necessary for LoTOx to be considered operationally viable. This technology will not be investigated further.

### 7.2.3 Evaluation and Ranking of Technically Feasible Controls

With the elimination of WGS, Tesoro is operating with the only remaining control option – GCP. No ranking or further evaluation is required.

### 7.2.4 Further Evaluation of Most Effective Controls

N/A The only remaining control option is already in use at the Tesoro SRU.

### 7.2.5 Selection of BACT Controls

UDAQ recommends that Tesoro continue to operate the SRU consistent with good operating practices. As a combustion source the SRU is included in Tesoro's plant-wide $NO_x$ emission cap as discussed earlier.

8 see References: Item #10

## 8.0 BACT for Fugitives

In this context, fugitives are referring to fugitive VOC emissions. While Tesoro does have fugitive dust emissions from items such as roads, spill containment berms, and similar earthworks – particulate emissions from these items have been evaluated separately. Please refer to the $PM_{2.5}$ Serious SIP - BACT for Small Sources – Section 12 for the evaluation.

Fugitive VOC emissions are those emissions that result from the various pipe connections; feedstock, intermediary, and product transfer activities; loading and unloading operations; and any and all equipment leaks. They do not typically include the VOC emissions from storage vessels (storage tanks), cooling towers, or wastewater treatment.

### 8.1 VOCs

#### 8.1.1 Available Control Technology

The only available control option is the low-leak LDAR program as outlined in 40 CFR 60 Subpart VVa and incorporated by reference (with some source category modifications) in 40 CFR 60 Subpart GGGa. Each refinery (including Tesoro) became subject to the requirements of low-leak LDAR (Subpart GGGa) as part of the requirements of the moderate $PM_{2.5}$ SIP.

#### 8.1.2 Evaluation of Technical Feasibility of Available Controls

N/A Low-leak LDAR is technically feasible, and Tesoro became subject to its requirements on January 1, 2017.

#### 8.1.3 Evaluation and Ranking of Technically Feasible Controls

N/A Tesoro is already implementing the requirements of 40 CFR 60 Subpart GGGa.

#### 8.1.4 Further Evaluation of Most Effective Controls

N/A Tesoro is already implementing the requirements of 40 CFR 60 Subpart GGGa.

#### 8.1.5 Selection of RACT Controls

UDAQ recommends that Tesoro continue to implement the general refinery SIP requirements regarding Leak Detection and Repair as outlined in Section IX, Part H.11.g.

## 9.0 BACT for Wastewater System

### 9.1 VOC

The wastewater treatment system consists primarily of a system of drains that route runoff water and storm water to the API separator, which separates entrained oils and volatiles from the wastewater. Tesoro currently operates the API separator with a fixed cover to limit VOC emissions.

#### 9.1.1 Available Control Technology

Only two control options were identified to reduce VOC emissions from the wastewater system. The collected vapors from the API separator can be routed to a control device for capture or destruction. Carbon canisters reduce emissions by capturing the VOCs using activated carbon filtration. Oxidation, using either thermal treatment or catalytic oxidation systems, is also a viable option for elimination of VOC emissions.

### 9.1.2 Evaluation of Technical Feasibility of Available Controls

Both options are technically feasible. Tesoro has supplied a counter argument that designing, installing, and beginning operation of either system could not be completed by the regulatory attainment date of December 31, 2018[9]. UDAQ disagrees with this argument, as the refineries were to begin looking into control of emissions from wastewater treatment during development of the moderate $PM_{2.5}$ SIP in 2014. In addition, another similar refinery is able to install carbon canisters for VOC control on its wastewater treatment plant which also has a covered API separator.

### 9.1.3 Evaluation and Ranking of Technically Feasible Controls

Installation of either control system would be equally effective in controlling VOC emissions from the wastewater treatment plant.

### 9.1.4 Further Evaluation of Most Effective Controls

Tesoro did not conduct an economic analysis of either control option. UDAQ has reviewed information received from other refineries on estimated control costs and adjusted the information based on potential emission reductions at the Tesoro refinery. With an estimated reduction in annual VOC emissions of 8-10 tons, the control cost of installing and using the carbon canister options is approximately $10-15,000/ton of VOC removed. Both thermal and catalytic oxidation have control costs of over $75,000/ton of VOC removed.

Based on these values, the use of the carbon canisters is economically feasible, while neither oxidation system is economically viable.

### 9.1.5 Selection of BACT Controls

UDAQ recommends that Tesoro continue to operate the existing wastewater treatment system with fixed API cover, plus install and operate a set of carbon canisters for VOC control. The carbon canisters shall achieve 90% or better removal.

## 10.0 BACT for Flares

### 10.1 Flare Gas Emissions

The refinery flares emit $PM_{2.5}$, $SO_2$, $NO_x$ and VOCs, as well as a minor amount of ammonia. However, rather than evaluate the flares based on the individual pollutant emissions, UDAQ has historically evaluated the emissions from the flares based on the gases sent to the flares. During development of the Moderate 2.5 SIP, UDAQ established that the refineries' flares were to be used primarily as safety devices and not as process control devices. Therefore, each refinery was required to meet the requirements of Subpart J and Ja for all hydrocarbon flares, and to install and

9 see References: Item #8

operate a flare gas recovery or minimization process by January 1, 2019.

### 10.1.1 Available Control Technology

There are two parts to refinery flares, as outlined in the Refinery General RACT Evaluation. The first is setting all refinery hydrocarbon flares as subject to the requirements of 40 CFR 60 Subpart Ja. The second is requiring all refineries to have a flare gas recovery system in place and operating by January 1, 2019 that meets the flare event limits listed in 40 CFR 60.103a(c).

### 10.1.2 Evaluation of Technical Feasibility of Available Controls

Neither part is technically infeasible.

### 10.1.3 Evaluation and Ranking of Technically Feasible Controls

The refinery general requirement of subjecting all hydrocarbon flares to the requirements of Subpart Ja has already been accepted by all listed refineries. As discussed in the Refinery General RACT Evaluation, most refineries will begin economic evaluations of flaring events beginning in November of 2015 to determine whether a flare gas recovery program is viable regardless of any imposing of such requirement by DAQ.

For its part, Tesoro implemented a flare gas recovery system in 2014 (DAQE-AN103350065-14). This system greatly reduced the emissions from both the North and South Flares, transforming both emission units essentially into upset-only flares. Tesoro also established a flare minimization plan, which includes limiting waste gas flow rates to these flares. These two changes (flare gas recovery and flare minimization plan) meet the requirements of SIP section IX.H.11.g.v.B.

### 10.1.4 Further Evaluation of Most Effective Controls

No additional analysis is required. The general requirements on refinery flares found at Section IX Part H.11.g.v.B of the moderate $PM_{2.5}$ SIP are the only viable techniques for the control of emissions from the refinery's flares. No additional analysis is required.

### 10.1.5 Selection of BACT Controls

DAQ recommends that Tesoro continue to operate its existing flare gas recovery system as outlined in its latest existing refinery AO; as well as implement the general refinery SIP requirement "Requirements on Hydrocarbon Flares" as outlined in the Refinery General RACT Evaluation. There are no expected emission reductions versus the 2016 "true-up" emission inventory as the flare gas recovery system was already included in that inventory.

## 10.2 SRU Flare

The SRU Flare is not subject to 40 CFR 60.18 or 40 CFR 63.11 and is designed to combust acid gases from the sour water stripper and amine treatment units during startup, shutdown and malfunction events. There is no routine waste gas venting to the SRU Flare. This flare does not qualify as a hydrocarbon flare, and thus is not subject to the same provisions of SIP Section IX.H.11.g.v as are the North and South Flares.

### 10.2.1 Available Control Technology

As a true upset-only flare, the SRU Flare is operated as a safety device. There are no add-on controls which can be applied to this unit as it is not feasible to enclose the flare tip of a safety flare. The only available control options are development of a flare management plan, and use of a clean-burning gaseous fuel for the pilot flame.

### 10.2.2 Evaluation of Technical Feasibility of Available Controls

Tesoro has developed a flare management plan which includes operational plans and contingencies for the SRU Flare and for the units controlled by the SRU Flare – the sour water stripper and amine treatment unit.

Currently the pilot flame is fired on refinery fuel gas. Tesoro has investigated the use of straight natural gas as fuel for the pilot flame and determined that it would be unable to make the modification before December 31, 2018 based on existing refinery planned outages and turnaround scheduling.

### 10.2.3 Evaluation and Ranking of Technically Feasible Controls

The implementation of a flare management plan is the only viable control option for the SRU Flare. Tesoro is currently implementing such a plan, so no further evaluation is required.

### 10.2.4 Further Evaluation of Most Effective Controls

No additional analysis is required. Tesoro has a flare management plan in place which includes the SRU Flare and those processes controlled by the SRU Flare.

### 10.2.5 Selection of BACT Controls

DAQ recommends that Tesoro continue to implement its existing flame management plan to limit emissions from the SRU Flare as needed. There are no expected emission reductions versus the 2016 “true-up” emission inventory.

## 11.0 BACT for Cooling Towers

There are two main pollutants of concern from cooling towers used in refinery settings. Like all industrial cooling towers, some particulate emissions will result during the evaporation of the cooling water. For further details on BACT controls for particulate emissions from cooling towers please refer to the $PM_{2.5}$ Serious SIP - BACT for Small Sources – Section 6 for the analysis.

Cooling towers found in refineries have a secondary concern. It is possible for the cooling water to pick up volatile compounds during the heat transfer process, and for these compounds to be released as VOCs. As the levels of VOCs in refinery cooling water can be large enough to deserve their own controls, a separate BACT analysis is provided.

## 11.1 VOCs

### 11.1.1 Available Control Technology

UDAQ employed the services of a contractor during review of the RACT evaluations for the

moderate $PM_{2.5}$ SIP[10]. Only a single control technique was determined to be "available." During that review, it became apparent that UDAQ's contractor was making the same recommendation to all of the refineries located in the $PM_{2.5}$ non-attainment area. Specifically, that each refinery apply the 40 CFR 63 Subpart CC requirements to all cooling towers servicing heat exchangers with high VOC content streams. These requirements are basically leak detection and repair programs that apply specifically to cooling towers by checking for the presence of VOCs in the cooling water on a periodic basis. If detected, then service or repair of the relevant heat exchanger is warranted.

### 11.1.2 Evaluation of Technical Feasibility of Available Controls

All the refineries located in the $PM_{2.5}$ non-attainment area agreed to an application of the MACT CC language which was included in the moderate $PM_{2.5}$ SIP in Section IX, Part H.11.g.

### 11.1.3 Evaluation and Ranking of Technically Feasible Controls

N/A This has become a refinery general SIP requirement.

### 11.1.4 Further Evaluation of Most Effective Controls

N/A This has become a refinery general SIP requirement.

### 11.1.5 Selection of BACT Controls

UDAQ recommends that Tesoro continue to follow the general refinery SIP requirements found in Section IX, Part H.11.g.

## 12.0 BACT for Loading/Offloading

Tesoro submitted an analysis for product loading and unloading operations. UDAQ has covered the analysis of loading and unloading operations in two different locations. For fugitive VOC emissions please refer to Section 8.0 of this document for further details. For more direct VOC emissions from loading/unloading operations please refer to the $PM_{2.5}$ Serious SIP - BACT for Small Sources – Section 13B for additional details.

## 12.1 VOC

Loading and offloading operations are a source of VOC emissions. Although Stage I and II vapor recovery have already been covered in UDAQ's BACT analysis for Small Sources, one additional VOC control option in common use at refinery loading racks is a vapor combustion unit or carbon capture system to treat the recovered VOC vapors. In this section, UDAQ focuses on BACT for the two transportation loading racks: the TLR and the BCLR and for the two liquefied petroleum gases (LPG) racks: a 6-bay rail loading and offloading rack, and a single-bay truck loading and offloading rack.

### 12.1.1 Available Control Technology

Once vapors have been recovered from loading/unloading operations, the recovered vapors need to be treated. While some vapor recovery units (VRUs) can return the recovered vapors back into

10 see References: Item #4

the system being controlled (depending on the system), some units require external treatment for final control. The use of regenerative thermal oxidation (RTO), non-regenerative thermal oxidation (flaring), or carbon capture via carbon canisters are all potentially available methods of controlling the recovered vapors.

### 12.1.2 Evaluation of Technical Feasibility of Available Controls

For destruction/control of the collected vapors, only the use of a RTO, carbon adsorption or flaring have been shown to be technically feasible control methods based on the volume of expected VOC emissions (typically less than 5 tons VOC/year).

All three methods are viable for the two transportation racks.

Carbon adsorption is not technically feasible for the LPG loading racks, as the low molecular weight of the LPG makes capture by activated carbon ineffective.

### 12.1.3 Evaluation and Ranking of Technically Feasible Controls

The transportation loading racks are subject to MACT CC (40 CFR 63.640 Subpart CC) requirements which establish an emission limit of 10 mg VOC/L of product loaded. Both carbon adsorption and thermal destruction are able to meet this limit. Since the use of carbon adsorption allows Tesoro to recover the vapors from the transportation loading racks as potential product (rather than simply increasing emissions through a thermal process), this is the top feasible control option.

For the LPG loading racks, only thermal destruction remains as a viable control option.

### 12.1.4 Further Evaluation of Most Effective Controls

Not required. Tesoro has selected the top control option in each case. No additional analysis is necessary.

### 12.1.5 Selection of BACT Controls

UDAQ recommends that Tesoro continue to control product loading and unloading operations using carbon adsorption on the transport loading racks and thermal oxidation on the LPG loading racks. As the transport loading racks are already subject to MACT CC requirements, no additional limitations are required. The LPG loading racks' thermal oxidizers shall be included in Tesoro's flare management plan. This is a work practice standard; no additional requirements are necessary.

## 13.0 BACT for Diesel- and Natural Gas-fired Emergency Engines

Tesoro submitted an analysis for both diesel and natural gas-fired emergency engines[11]. UDAQ has covered the analysis of both diesel-fired and natural gas fired emergency engines in a separate document. $PM_{2.5}$ Serious SIP - BACT for Small Sources – Section 8 for additional details.

## 14.0 BACT for the K1 Compressors

11 see References: Item #8

Tesoro submitted a separate analysis for the K1 compressor engines[12]. The K1 compressors are two compressors which recycle hydrogen into the UFU desulfurization reactor. They are each powered by a natural gas-fired internal combustion (IC) engine which is controlled by a catalytic convertor to control $NO_x$ emissions.

## 14.1 $PM_{2.5}$

### 14.1.1 Available Control Technology

None. UDAQ has been unable to identify any additional controls to further reduce emissions of $PM_{2.5}$ from natural gas-fired IC engines. Tesoro did offer that replacement of one compressor motor with an electric motor might be feasible, currently the engines are not scheduled for turnaround or maintenance until after the December 31, 2018 attainment date.

### 14.1.2 Evaluation of Technical Feasibility of Available Controls

None are technically feasible. As mentioned previously, replacement of one compressor motor with an electric motor was listed by Tesoro as available, but not until after the December 31, 2018 attainment date had elapsed. Replacing the motor is considered technically infeasible.

### 14.1.3 Evaluation and Ranking of Technically Feasible Controls

N/A no available options remain to be ranked.

### 14.1.4 Further Evaluation of Most Effective Controls

N/A no available options remain for further evaluation.

### 14.1.5 Selection of BACT Controls

UDAQ recommends that Tesoro continue to operate the K1 compressors in line with good operating practices. As this is a work practice standard, no additional limitations are required.

## 14.2 $SO_2$

### 14.2.1 Available Control Technology

None. The compressor engines are fired on natural gas, an inherently low-sulfur fuel. As stated previously, Tesoro did offer replacement of engine with an electric motor as available, but not technically feasible. No additional controls exist to further limit the emissions of $SO_2$ from natural gas-fired IC engines.

### 14.2.2 Evaluation of Technical Feasibility of Available Controls

None are technically feasible. As mentioned previously, replacement of one compressor motor with an electric motor was listed by Tesoro as available, but not until after the December 31, 2018 attainment date had elapsed. Replacing the motor is considered technically infeasible.

### 14.2.3 Evaluation and Ranking of Technically Feasible Controls

12 see References: Item #8

N/A no available options remain to be ranked.

### 14.2.4 Further Evaluation of Most Effective Controls

N/A no available options remain for further evaluation.

### 14.2.5 Selection of BACT Controls

UDAQ recommends that Tesoro continue to operate the K1 compressors in line with good operating practices. As this is a work practice standard, no additional limitations are required.

## 14.3 $NO_x$

### 14.3.1 Available Control Technology

The engines are controlled with a catalytic convertor to control emissions of $NO_x$. Larger-size natural gas-fired IC engines, such as these compressor engines, have also been controlled with SCR, SNCR, and replacement with electric motors.

### 14.3.2 Evaluation of Technical Feasibility of Available Controls

As mentioned previously, replacement of one compressor motor with an electric motor was listed by Tesoro as available, but not until after the December 31, 2018 attainment date had elapsed. Replacing the motor is considered technically infeasible.

SCR and SNCR are generally considered technically feasible but suffer from the same problem as direct replacement. Neither option can be designed, installed and tested prior to the regulatory attainment date of December 31, 2018. Plus the compressor engines cannot be taken offline prior to that date. Both control options are considered technically infeasible.

### 14.3.3 Evaluation and Ranking of Technically Feasible Controls

Continuing to fire the existing engines on natural gas and using a $NO_x$ controlling catalytic convertor remains the only viable control technique for the K1 compressors.

### 14.3.4 Further Evaluation of Most Effective Controls

Tesoro is operating with the only viable control option for the K1 compressors. The engines can emit up to 3.2 lb/hr using the existing controls – such limit is found in the most recent NSR permit issued to the refinery (condition II.B.7.c in DAQE-AN103350075-18). However, as a combustion source, these compressors are already included in the refinery's plant-wide $NO_x$ emission cap and do not need to be further limited, as no change in control technology is being applied.

### 14.3.5 Selection of BACT Controls

UDAQ recommends that Tesoro continue to operate the K1 compressors in line with good operating practices. $NO_x$ emissions shall be controlled using the existing catalytic convertors installed on both compressor engines. These engines shall be included in the refinery's plant-wide $NO_x$ emission cap. This emission cap is as follows:

*No later than January 1, 2019, combined emissions of $NO_x$ shall not exceed 2.3 tons per day (tpd) and 475 tons per rolling 12-month period.*

## 14.4 VOC and Ammonia

### 14.4.1 Available Control Technology

The existing catalytic convertor controls emissions of VOC. There are no available controls for reducing ammonia emissions from IC engines.

### 14.4.2 Evaluation of Technical Feasibility of Available Controls

Catalytic convertors, also known as oxidation catalysts remain the only viable method for controlling emissions of VOC from IC engines.

### 14.4.3 Evaluation and Ranking of Technically Feasible Controls

N/A, Tesoro is already using the only viable control technique for control of VOC emissions.

### 14.4.4 Further Evaluation of Most Effective Controls

VOC emissions from the engines are less than 0.03 lb/MMBtu on average. 2016 actual emissions for both engines combined were less than 0.5 tons of VOC annually. No additional limitation on VOC emissions is required. The catalytic convertors are already required by NSR permit, and for control of $NO_x$ emissions. $NO_x$ emission totals are included in the daily cap values. Imposing an additional VOC restriction would be of no benefit to limiting overall emissions or demonstrating good maintenance.

### 14.4.5 Selection of BACT Controls

UDAQ recommends that Tesoro continue to operate the K1 compressors in line with good operating practices. VOC emissions shall be controlled using the existing catalytic convertors installed on both compressor engines. This is a work practice requirement and no additional limitations are required.

## 15.0 BACT for Tanks

Although most of UDAQ's analysis of storage vessels, more commonly referred to as storage tanks (or just "tanks"), can be found in the $PM_{2.5}$ Serious SIP - BACT for Small Sources – Section 13, the refineries as a group were evaluated for two additional BACT controls beyond the small source controls. First, the refineries have some tanks that are larger than the 30,000 gallon cut-off used in the small source analysis. Second, during development of the moderate 2.5 SIP, the refineries were required to implement a tank degassing work practice standard.

## 15.1 VOC

### 15.1.1 Available Control Technology

Although tanks as a group were evaluated for tank degassing, individual tanks were not evaluated for working or breathing losses. While some VOCs are emitted during these periods, these can

only be controlled on a tank by tank basis. Larger tanks are already subject to floating roof and specific seal requirements such as those found in 40 CFR 60 Subpart Kb.

Some additional VOC reductions could be gained by including slotted guide poles and geodesic domes, but these gains are relatively minor. In the case of slotted guide poles, such requirements are more easily handled through individual NSR permitting requirements. Individual tanks can also be controlled by vapor recovery, vapor scrubbers, or vapor combustors. Geodesic domes have not been found to be economically or technically feasible.

### 15.1.2 Evaluation of Technical Feasibility of Available Controls

The use of slotted guide poles and vapor controls are both technically feasible. Tank degassing as a group control is also technically feasible, and was included as a requirement of the moderate $PM_{2.5}$ SIP.

### 15.1.3 Evaluation and Ranking of Technically Feasible Controls

Tank degassing was required as of the moderate $PM_{2.5}$ SIP. The remaining controls can be employed in conjunction with tank degassing. The various methods of individual tank vapor control (recovery, scrubbing, and combustion) are all similar in effectiveness and are employed primarily on a tank by tank basis. While some economy of scale could conceivably be achieved by combining the emissions from several tanks, tank vapors are primarily released during filling or unloading, and nearby tanks are rarely loaded or unloaded at the same time.

### 15.1.4 Further Evaluation of Most Effective Controls

Tesoro is already required to follow the tank degassing requirements of Section IX, Part H.11.g. In fact, Tesoro developed most of the requirements which were included in the tank degassing subsection prior to their inclusion in the moderate $PM_{2.5}$ SIP. The remaining vapor controls were all evaluated by Tesoro[13] and were found not to be economically feasible, with cost effectiveness values in excess of $200,000/ton of VOC control.

### 15.1.5 Selection of BACT Controls

UDAQ recommends that Tesoro continue to implement the SIP general refinery requirements on tank degassing as outlined in Section IX, Part H.11.g.

## 16.0 Additional Feasible Measures and Most Stringent Measures

### 16.1 Extension of SIP Analysis Timeframe

As outlined in 40 CFR 51.1003(b)(2)(iii):

*If the state(s) submits to the EPA a request for a Serious area attainment date extension simultaneous with the Serious area attainment plan due under paragraph (b)(1) of this section, such a plan shall meet the most stringent measure (MSM) requirements set forth at § 51.1010(b) in addition to the BACM and BACT and additional feasible measure requirements set forth at § 51.1010(a).*

13 see References: Item #8

Thus, with the potential for an extension of the SIP regulatory attainment date from December 31, 2019 to December 31, 2024, the SIP must consider the application of both Additional Feasible Measures (AFM) and Most Stringent Measures (MSM).

## 16.2 Additional Feasible Measures at Tesoro

As defined in Subpart Z, AFM is any control measure that otherwise meets the definition of "best available control measure" (BACM) but can only be implemented in whole or in part beginning 4 years after the date of reclassification of an area as Serious and no later than the statutory attainment date for the area. The Salt Lake City Nonattainment Area was reclassified as Serious on June 9, 2017. Therefore, any viable control measures that could only be implemented in whole or in part beginning 6/9/2021 (4 years after the date of reclassification) are classified as AFM.

After a review of the available control measures described throughout this evaluation report, Tesoro identified a number of control techniques which were subsequently eliminated because they could not be implemented by the regulatory attainment date of December 31, 2018. Tesoro did not provide any additional information allowing UDAQ to determine if these control measures could be implemented in whole or in part by 6/9/2021. In most cases, UDAQ was able to eliminate or require (in one case) the control technique after additional and more thorough review. There were two exceptions to this:

The K1 Compressor Engines – UDAQ did not receive enough information regarding these engines or planned refinery outages to determine if the engines could be replaced with electric motors, upgraded with more stringent controls, or left unaltered. UDAQ believes that some upgrade to the engines is likely and recommends that these be considered for AFM should such be required.

UDAQ recommended in this review that Tesoro install carbon canisters for control of VOC emissions at the wastewater treatment plant. This is a contradiction of Tesoro's claims that such upgrades could not be accomplished by the regulatory attainment date. Such claims may be valid, but UDAQ did not receive enough information to make this determination. UDAQ made its recommendation based on the information provided by another refinery with a similar wastewater treatment plant who is installing such canisters for VOC control. Should Tesoro's claims be validated in the short term, this may be an area for AFM consideration.

## 16.3 Most Stringent Measures at Tesoro

As defined in Subpart Z, MSM is defined as:

*… any permanent and enforceable control measure that achieves the most stringent emissions reductions in direct $PM_{2.5}$ emissions and/or emissions of $PM_{2.5}$ plan precursors from among those control measures which are either included in the SIP for any other NAAQS, or have been achieved in practice in any state, and that can feasibly be implemented in the relevant $PM_{2.5}$ NAAQS nonattainment area.*

This is further refined and clarified in 40 CFR 51.1010(b), to include the following Steps:

Step 1) The state shall identify the most stringent measures for reducing direct $PM_{2.5}$ and $PM_{2.5}$ plan precursors adopted into any SIP or used in practice to control emissions in any state.
Step 2) The state shall reconsider and reassess any measures previously rejected by the state

during the development of any previous Moderate area or Serious area attainment plan control strategy for the area.

Step 3) The state may make a demonstration that a measure identified is not technologically or economically feasible to implement in whole or in part by 5 years after the applicable attainment date for the area, and may eliminate such whole or partial measure from further consideration.

Step 4) Except as provided in Step 3), the state shall adopt and implement all control measures identified under Steps 1) and 2) that collectively shall achieve attainment as expeditiously as practicable, but no later than 5 years after the applicable attainment date for the area.

### 16.3.1 Step 1 – Identification of MSM

For purposes of this evaluation report UDAQ has identified for consideration the most stringent methods of control for each emission unit and pollutant of concern ($PM_{2.5}$ or $PM_{2.5}$ precursor). A summary is provided in the following table:

**Table 16-1:** Most Stringent Controls by Emission Unit

| Emission Unit | Pollutant | Most Stringent Control Method |
|---|---|---|
| FCCU Regenerator | $PM_{2.5}$ | GCP, fuel type, flue gas filter (FGF) / wet gas scrubber (WGS) |
| | $SO_2$ | $DeSO_x$ catalyst, WGS |
| | $NO_x$ | GCP, $deNO_x$ catalyst, feed hydro-treating, $deNO_x$ additive (?) |
| Heaters/Boilers | $NO_x$ | ULNB, SCR |
| | Ammonia | only if SCR is used, feedback controls |
| Flares | Flare Gas | flare minimization program |
| SRU | $SO_2$ | second tail gas treatment unit (TGTU), WGS |
| | $NO_x$ | WGS |
| Cooling Towers | VOC | MACT CC requirements |
| Fugitives | VOC | NSPS GGGa LDAR requirements |
| Tanks | VOC | tank degassing requirements |
| Wastewater Treatment | VOC | IAF/API separator; with carbon canister control / oxidation |

The above listed controls represent the most stringent level of control identified from all other state SIPs or permitting actions, but do not necessarily represent the final choice of MSM. That is determined in Step 4.

### 16.3.2 Step 2 – Reconsideration of Previous SIP Measures

Utah has previously issued a SIP to address the moderate $PM_{2.5}$ nonattainment areas of Logan, Salt Lake City, and Provo. The SIP was issued in parts: with the section devoted to the Logan nonattainment area being found at SIP Section IX.A.23, Salt Lake City at Section IX.A.21, and Provo/Orem at Section IX.A.22. Finally, the Emission Limits and Operating Practices for Large Stationary Sources, which includes the application of RACT at those sources, can be found in the SIP at Section IX Part H. Limits and practices specific to $PM_{2.5}$ may be found in subsections 11, 12, and 13 of Part H.

Accompanying Section IX Part H was a TSD that included multiple evaluation reports similar to this document for each large stationary source identified and listed in each nonattainment area. UDAQ conducted a review of those measures included in each previous evaluation report which contained emitting units which were at all similar to those installed and operating at Tesoro.

There were several technologies that had been eliminated from further consideration at some point during many of the previous reviews. Some emitting units were considered too small, or emissions too insignificant to merit further consideration at that time. The cost effectiveness considerations may have been set at too low a threshold (a question of cost in RACT versus BACT). And many cases of technology being technically infeasible for application – such as applying catalyst controls to infrequently used emitting units which may never reach an operating temperature where use of the catalyst becomes viable and effective.

In one particular case, these previously rejected control technologies were already brought forward and re-evaluated using updated information (more recent permits, emission rates and cost information) by Tesoro in its BACT analysis report. This was the deferment of VOC controls for the wastewater treatment systems at four Salt Lake City area refineries. Tesoro did include an analysis of the wastewater treatment system, and took into account previous steps (such as the IAF and RTO) previously undertaken to reduce emissions. This updated analysis has been reviewed as part of the UDAQ BACT review in Sections 9 and 16.2 above.

### 16.3.3 Step 3 – Demonstration of Feasibility

A control technology or control strategy can be eliminated as MSM if the state demonstrates that it is either technically or economically infeasible.

This demonstration of infeasibility must adhere to the criteria outlined under §51.1010(b)(3), in summary:

1) When evaluating technological feasibility, the state may consider factors including but not limited to a source's processes and operating procedures, raw materials, plant layout, and potential environmental or energy impacts
2) When evaluating the economic feasibility of a potential control measure, the state may consider capital costs, operating and maintenance costs, and cost effectiveness of the measure.
3) The SIP shall include a detailed written justification for the elimination of any potential control measure on the basis of technological or economic infeasibility.

This evaluation report serves as written justification of technological or economic feasibility/infeasibility for each control measure outlined herein. Where applicable, the most effective control option was selected, unless specifically eliminated for technological or economical infeasibility. Expanding on the previous table, the following additional information is provided:

**Table 16-2:** Feasibility Determination

| Emission Unit | Pollutant | MSM Previously Identified | Is Method Feasible? |
|---|---|---|---|
| FCCU Regenerator | $PM_{2.5}$ | GCP, fuel type, FGF/WGS | See below |
| | $SO_2$ | de$SO_x$ catalyst, WGS | See below |
| | $NO_x$ | GCP, de$NO_x$ catalyst, feed hydro-treating, de$NO_x$ additive | See below |
| Heaters/Boilers | $NO_x$ | ULNB, SCR | See below |
| | Ammonia | $NH_3$ feedback | See below |
| Flares | Flare Gas | flare minimization program | Yes |
| SRU | $SO_2$ | TGTU or WGS | No, high cost |
| | $NO_x$ | WGS | No, high cost |

| | | | |
|---|---|---|---|
| Cooling Towers | VOC | MACT CC | Yes |
| Fugitives | VOC | LDAR | Yes |
| Tanks | VOC | tank degassing | Yes |
| WW Treatment | VOC | carbon canister / oxidation | Yes, see below |

Most of the entries in the above table were determined to be feasible on a technological basis. However, in several cases two distinct paths exist that are mutually exclusive. Two control techniques could serve equally as BACT/BACM or MSM, but they are not simply interchangeable. Once a source has elected to follow a particular path for emission control, needing to change over to the alternative control path would involve considerable expense as well as complete removal of the existing system(s). In many cases this would also involve shutting down operation of the source for an extended period of time – posing additional economic burden on the source.

One particular example of this is the application (or lack) of WGS. Wet gas scrubbing has the capability of removing both particulates and acid gases ($SO_2$ and derivatives) and, if the LoTOx option has been pursued, $NO_x$ as well. However, this control system is not compatible with other control systems such as fabric filtration (baghouses or FGF), catalytic controls (SCR), or tail gas treatment (as these are also catalytic controls). If the WGS is installed secondary to the existing controls, these would render the use of WGS redundant and extremely cost ineffective (the inlet concentrations would simply be too low to be viable). Alternatively, the WGS would be installed as the primary control, creating a similar situation for the "existing" controls, but with an additional problem of a now water saturated exhaust stream and a greatly lowered exhaust temperature. Removing the existing controls to swap to the new control option is often millions of dollars above and beyond the millions already spent on the primary BACT level control. Tesoro employed WGS as the solution in one situation (the FCCU) but elected to install a more traditional TGTU in the second situation (the SRU). Both control techniques are viable, and reached BACT level of control.

The costs for WGS or a second TGTU on the SRU do not currently justify including either of these controls as MSM.

## 17.0 New $PM_{2.5}$ SIP – General Requirements

The general requirements for all listed sources are found in SIP Subsection IX.H.11. These serve as a means of consolidating all commonly used and often repeated requirements into a central location for consistency and ease of reference. As specifically stated in subsection IX.H.11.a below, these general requirements apply to all sources subsequently listed in either IX.H.12 (Salt Lake City) or IX.H.13 (Provo/Orem), and are in addition to (and in most cases supplemental to) any source-specific requirements found within those two subsections.

IX.H.11.a. This paragraph states that the terms and conditions of Subsection IX.H.11 apply to all sources subsequently addressed in the following subsections IX.H.12 and IX.H.13. It also clarifies that should any inconsistency exist between the general requirements and the source specific requirements, then the source specific requirements take precedence.

IX.H.11.b Paragraph i: States that the definitions found in State Rule 307-101-2, Definitions, apply to SIP Section IX.H. Since this is stated for the Section (IX.H), it applies equally to IX.H.11, IX.H.12 and IX.H.13. A second paragraph (ii), includes a new definition for natural gas curtailment for those sources in IX.H.12 and IX.H.13 that reference it.

IX.H.11.c This is a recordkeeping provision. Information used to determine compliance shall be recorded for all periods the source is in operation, maintained for a minimum period of five (5) years, and made available to the Director upon request. As the general recordkeeping requirement of Section IX.H, it will often be referred to and/or discussed as part of the compliance demonstration provisions for other general or source specific conditions. It also includes provisions referring to the reporting of emission inventories (paragraph ii) and reporting deviations (paragraph iii).

IX.H.11.d Statement that emission limitations apply at all times that the source or emitting unit is in operation, unless otherwise specified in the source specific conditions listed in IX.H.12 or IX.H.13. It also clarifies that particulate emissions consist of both the filterable and condensable fractions unless otherwise specified in IX.H.12 or IX.H.13.

This is the definitive statement that emission limits apply at all times – including periods of startup or shutdown. It may be that specific sources have separate defined limits that apply during alternate operating periods (such as during startup or shutdown), and these limits will be defined in the source specific conditions of either IX.H.12 or IX.H.13.

Conditions 1.a, 1.b and 1.d are declaratory statements, and have little in the way of compliance provisions. Rather, they define the framework of the other SIP conditions. As condition 1.c is the primary recordkeeping requirement, it shall be further discussed under item 4.2 below.

IX.H.11.e This is the main stack testing condition, and outlines the specific requirements for demonstrating compliance through stack testing. Several subsections detailing Sample Location, Volumetric Flow Rate, Calculation Methodologies and Stack Test Protocols are all included – as well as those which list the specific accepted test methods for each emitted pollutant species ($PM_{10}$, $NO_x$, or $SO_2$). Finally, this subsection also discusses the need to test at an acceptable production rate, and that production is limited to a set ratio of the tested rate.

IX.H.11.f This condition covers the use of CEMs and opacity monitoring. While it specifically details the rules governing the use of continuous monitors (both emission monitors and opacity monitors), it also covers visible opacity observations through the use of EPA reference method 9.

Both conditions 11.e and 11.f serve as the mechanism through which sources conduct monitoring for the verification of compliance with a particular emission limitation.

### 17.1 Monitoring, Recordkeeping and Reporting

As stated above, the general requirements IX.H.11.a through IX.H.11.f primarily serve as declaratory or clarifying conditions, and do not impose compliance provisions themselves. Rather, they outline the scope of the conditions which follow in the source specific requirements of IX.H.12 and IX.H.13.

For example, most of the conditions in those subsections include some form of short-term emission limit. This limitation also includes a compliance demonstration methodology – stack test, CEM, visible opacity reading, etc. In order to ensure consistency in compliance demonstrations and avoid unnecessary repetition, all common monitoring language has been consolidated under IX.H.11.e and IX.H.11.f. Similarly, all common recordkeeping and reporting provisions have been consolidated under IX.H.11.c.

## 18.0 Revised $PM_{2.5}$ SIP – General Refinery Requirements

The revised $PM_{2.5}$ SIP incorporates several new requirements that apply specifically to those petroleum refineries listed in Section IX.H.12 of the SIP. Some subsections of IX.H.11.g also apply more broadly and could affect additional petroleum refineries in addition to those listed in IX.H.12. Where this greater applicability exists for a particular condition or limitation, such will be noted in the discussion for that requirement.

IX.H.11.g.i.A This condition covers $SO_2$ emissions from fluidized catalytic cracking units (FCCUs). The limit is 50 ppmvd @ 0% excess air on a 7-day rolling average basis, as well as 25 ppmvd @ 0% excess air on a 365-day rolling average basis.

The condition is based on 40 CFR 60 Subpart Ja, and includes the same limitation found in that subpart. Compliance is demonstrated by CEM, as outlined in 40 CFR 60.105a(g) – also from Subpart Ja.

IX.H.11.g.i.B This condition addresses PM emissions from FCCUs. The limit is 1.0 lb PM per 1000 lb coke burned. The emission limit applies on a 3-hour average basis.

The emission limit is derived from 40 CFR 60 Subpart Ja, although Subpart Ja does not specifically state that the limit applies on a 3-hour average. Instead it states that compliance will be demonstrated via a performance test using Method 5, 5b or 5f, using an average of three 60-minute (minimum) test runs.

Compliance is demonstrated by stack test as outlined in 40 CFR 60.106(b). This stack testing procedure is from Subpart J, rather than Subpart Ja. The equations utilized and reference methods involved are identical between the two subparts; however, the protocol to follow for testing is much more direct and straightforward in §60.106(b).

The condition also requires the installation of a continuous parameter monitoring system (CPMS) to monitor and record operating parameters for determination of source-wide $PM_{10}$ emissions for inclusion in the 24-hour $PM_{2.5}$ Cap (see the individual source specific requirements of IX.H.12 for details on these Caps).

IX.H.11.g.ii This condition limits the $H_2S$ content of gases burned within any refinery located within (or affecting) an area of $PM_{2.5}$ nonattainment. The limit is 60 ppm $H_2S$ or less as described in 40 CFR 60.102a on a rolling average of 365 days.

As the $PM_{2.5}$ nonattainment areas encompasses the entirety of the $PM_{10}$ maintenance areas this condition potentially affects more than just the four refineries listed in IX.H.12. There is at least one minor source refinery (Silver Eagle Refinery) which is affected by this requirement. The Silver Eagle Refinery was previously listed in the original $PM_{10}$ SIP as Crysen Refining, Inc., but was delisted as the source is no longer a major source.

Compliance is demonstrated through continuous $H_2S$ monitoring, as outlined in 40 CFR 60.107a. Both the limitation and the compliance methodology are based on 40 CFR 60 Subpart Ja.

IX.H.11.g.iii This condition places limits on heat exchangers in VOC service.

The condition requires that all heat exchangers in VOC service meet the requirements of 40 CFR 63.654, which requires use of the "Modified El Paso Method" for calculation of VOC emissions.

Sources are allowed an option to use another EPA-approved method if allowed by the Director. An exemption is also given for heat exchangers that meet specific criteria that are outlined within the condition language.

IX.H.11.g.iv Leak Detection and Repair Requirements.

This condition subjects each source to the requirements of 40 CFR 60 Subpart GGGa – also known as Enhanced LDAR. The Sustainable Skip Period provisions of that subpart have also been retained.

IX.H.11.g.v This condition establishes new requirements on hydrocarbon flares.

First, it states that all hydrocarbon flares (defined as all non-dedicated SRU flare and header systems and all non-HF flare and header systems) are subject to Subpart Ja as of January 1, 2018 if not previously subject.

Second it requires that each major source refinery either: 1) install a flare gas recovery system designed to limit hydrocarbon flaring from each affected flare during normal operations below the values listed in Subpart Ja (specifically 40 CFR 60.103a(c)), or 2) limit flaring during normal operations to 500,000 scfd or less for each affected flare.

This requirement is based on Subpart Ja, and is designed to incorporate the flare gas recovery requirements of that subpart ahead of the normal implementation schedule. The refineries located in, or impacting, the nonattainment areas are relatively small. As a consequence, the possibility that they would trigger the flare gas recovery provisions of Subpart Ja in the near term (5-10 years) was very small. Although one of the refineries had elected to install a flare gas recovery system voluntarily, the system only addressed a part of the refinery's total flaring capacity, and was not originally designed to Subpart Ja specifications.

IX.H.11.g.vi This condition requires that vapor control devices be employed during tank degassing operations. Some provisions are made for connecting and disconnecting degassing equipment. Notification must also be made to the Director prior to performing such an operation – unless an emergency situation is at play.

This condition applies to sources beyond just refineries – any owner/operator of any stationary tank meeting the outlined criteria must fulfill the requirements of this condition.

IX.H.11.g.vii No Burning of Liquid Fuel Oil in Stationary Sources – Establishes that no petroleum refineries in or affecting any PM nonattainment or maintenance area shall be allowed to burn liquid fuel oil in stationary sources except during natural gas curtailments or as specified in the individual subsections of Section IX, Part H. The use of diesel fuel meeting the specifications of 40 CFR 80.510 in standby or emergency equipment is exempt from this requirement.

This requirement addresses a provision of the original $PM_{10}$ SIP, which prevented the refineries from burning liquid fuel oil in any capacity – including in emergency or standby equipment. This brings forward the original intent, maintains consistency with the $PM_{10}$ maintenance plan provisions of IX.H.1.g, and addresses the problem of emergency and standby equipment.

IX.H.11.g.viii This is a placeholder provision, inserted in anticipation of future requirements for Tier III fuels. As it is unknown at this time whether the need to produce Tier III fuels will require addition emissions (in the form of emission offset credits or not), this placeholder provision has been included to allow for such future expansion.

## 18.1 Monitoring, Recordkeeping and Reporting

The new petroleum refinery requirements establish several specific emission limitations. Primarily these limits are monitored continuously – such as the $SO_2$ CEM on the FCCU or the $H_2S$ monitor on fuel gas. Where continuous monitoring is used, the requirements of IX.H.11.f apply, which incorporates by reference R307-170, 40 CFR 60.13 and 40 CFR 60, Appendix B – Performance Specifications.

Under R307-170, paragraph 170-8 addresses Recordkeeping, while 170-9 addresses Reporting.

The FCCU PM limit is demonstrated by stack test. This stack test requirement is subject to the requirements of IX.H.11.e. In addition, any source with a direct stack emission limitation is subject to the requirements of R307-165.

These conditions are also subject to the general recordkeeping and reporting requirements of IX.H.11.c.

## 19.0 Revised $PM_{2.5}$ SIP – Tesoro Specific Requirements

The Tesoro specific conditions in Section IX.H.12 address those limitations and requirements that apply only to the Tesoro Refinery in particular.

IX.H.12.o.i This condition establishes a source-wide Cap on $PM_{10}$ emissions on a ton per day and ton per 12-month rolling period basis. Emissions are calculated on a filterable+condensable basis from all sources, each day. These limits are 2.25 tons per day and 179 tons per rolling 12-month period.

Tesoro has not yet completed installation of the wet gas scrubber which serves as the primary control device on the FCCU (the largest direct $PM_{2.5}$ emission point at the refinery). Obviously, this prevents completion of adequate testing and monitoring to establish the ratio of filterable to condensable particulate emissions to properly address how compliance with a condensable limit would be determined. Tesoro has established a limit based on expected performance of the wet gas scrubber and emission inventory submissions (for all other sources). Thus, this condition also contains a requirement to conduct stack testing to verify the condensable limitation by January 1, 2019.

The requirement does include the procedure for establishing emission factors, the stack test frequency, and the compliance methodology for both listed emission limits. Finally, a definition of "day" has been established as being from midnight until the following midnight.

IX.H.12.o.ii This condition establishes a source-wide Cap on $NO_x$ emissions on a ton per day and ton per rolling 12-month period basis. Emissions are calculated from all emission points daily. These limits are 1.988 tons $NO_x$ per day and 475 tons per rolling 12-month period.

This condition includes the same definition of "day" as being from midnight until the following midnight. Compliance shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included.

IX.H.12.o.iii This condition establishes a source-wide Cap on $SO_2$ emissions on a ton per day and ton per rolling 12-month period basis. Emissions are calculated from all emission points daily. These limits are 3.1 tons $SO_2$ per day and 300 tons per rolling 12-month period.

This condition includes the same definition of "day" as both of the previous conditions as being from midnight until the following midnight. Compliance shall be determined daily by applying the listed emission factors or emission factors determined from the most current performance test to the relevant quantities of fuel combusted. Default emission factors are then listed for each fuel type (including fuel oil, although with the caveat that it is only to be used during natural gas curtailments). The equations to be used for the emission calculations are also included. Sub-paragraph C allows the refinery the option to limit the $SO_2$ concentration at each combustion stack below 8 ppm rather than limit the fuel gas concentration of $H_2S$ below 60 ppm. The values are equivalent as established in 40 CFR 60.102a.

IX.H.12.o.iv This condition brings forward the $SO_2$ limits on the SRU from the $SO_2$ SIP and lists the compliance method for those limits.

Both the 0.69 ton per day "normal" limit and the 1.68 ton per day limit for up to 21 days per rolling 12-month period are included in sub-paragraphs A and B. Sub-paragraph C lists the method of compliance – which is to measure the $SO_2$ concentration in the flue gas by CEM and multiply by the mass flow of the flue gas.

IX.H.2.o.v This condition addresses specific fuel sulfur requirements for the refinery, allowing the use of diesel-fired emergency equipment as an exception to IX.H.1.g.vii.

Tesoro currently has a number of small diesel-fired emergency engines listed in its AO. No specific provision has ever been made to allow for the use of diesel-fired emergency equipment at the refineries – and while it is clear that the provisions of the original $PM_{10}$ SIP were meant for the burning of liquid fuel in heaters and boilers and not for the application of emergency equipment, such language was not included nor brought forward. This condition (and similar conditions for the other refineries) addresses that oversight.

**19.1 Monitoring, Recordkeeping and Reporting**

Monitoring for all three conditions is addressed through a variety of methods, depending on the emission point in question. Stack testing, CEMs, parameter monitoring – all are viable options, and have been included in the language of IX.H.12.p.i through IX.H.12.p.iii. As appropriate, these monitoring requirements are complemented by the general provisions of IX.H: specifically, 11.e for stack testing, 11.f for CEMs and other continuous monitors, and 11.c for recordkeeping and reporting.

Where necessary, additional monitoring, recordkeeping and/or reporting requirements have been

directly included in the language of IX.H.12.p to address specific concerns. One example would be the use of leveling gauges on all fuel oil tanks to determine daily fuel oil consumption.

No specific monitoring, recordkeeping or reporting is required for IX.H.12.p.iv, as this condition serves merely as a specific exception to the general refinery requirement prohibiting the burning of liquid fuel oils. Such exception is authorized under the language of IX.H.1.g.vii itself.

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MAY -5 2017
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TESORO

Tesoro Refining & Marketing Company LLC
474 West 900 North
Salt Lake City, UT 84103

May 5, 2017

Mr. Marty D. Gray
Manager, New Source Review Section UDAQ
195 N 1950 W
Salt Lake City, UT 84114Regional Administrator
U.S. Environmental Protection Agency

HAND DELIVERED

**RE: Best Available Control Technology (BACT) Assessment for**
**Tesoro Refining & Marketing Company LLC and Tesoro Logistics Operations LLC**
**Salt Lake City Utah**

Tesoro Refining & Marketing Company LLC (Tesoro) – Salt Lake City Refinery is submitting the attached Best Available Control Technology (BACT) assessment per the Utah Department of Environmental Quality Division of Air Quality (UDAQ) request received February 2, 2017. For purposes of this submittal Tesoro has included emission units within the Tesoro Refinery and Tesoro Logistics Operations LLC (TLO) organizations. The facilities within the Tesoro Refinery and the TLO Truck Loading Rack and Remote Tank Farm are a single major source.

If you have any questions regarding this submittal, please contact Michelle Bujdoso of my staff at 801.366.2036.

Sincerely,

Karma M. Thomson

Karma M. Thomson
Vice President, Tesoro Salt Lake City Refinery

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# $PM_{2.5}$ Serious Nonattainment SIP
# Best Available Control Technology Analysis

***Tesoro Marketing and Refining Company LLC***
***Tesoro Logistics Operations LLC***

Prepared for
Tesoro Marketing and Refining Company LLC

April 2017

Best Available Control Technology Analysis

# *Tesoro Salt Lake City Refinery*

Prepared for
Tesoro Refining & Marketing Company LLC

April 2017

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# Best Available Control Technology Analysis

## April 2017

## Contents


1.0 Executive Summary ..... 1

2.0 BACT Methodology ..... 0

2.1 Top-Down BACT Approach ..... 0

Step 1 - Identify all Available Control Technologies ..... 0

Step 2 - Eliminate Technically Infeasible Control Technologies ..... 1

Step 3 - Rank Technically Feasible Technologies by Control Effectiveness ..... 2

Step 4 - Evaluate Technically Feasible Control Technologies ..... 2

Step 5 - Select BACT ..... 2

3.0 Overview of Available Control Technologies ..... 3

4.0 BACT for Fluidized Catalytic Cracking Unit (FCCU) and Carbon Monoxide Boiler (COB) ..... 7

4.1 FCCU and COB $PM_{2.5}$ Emissions ..... 8

4.1.1 Step 1 – Identify All Available Control Technologies ..... 8

4.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 8

4.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 8

4.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 8

4.1.5 Step 5 – BACT Selection ..... 8

4.2 FCCU and COB $SO_2$ Emissions ..... 9

4.2.1 Step 1 – Identify All Available Control Technologies ..... 9

4.2.2 Step 2 – Technical Feasibility of Control Technologies ..... 9

4.2.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 9

4.2.4 Step 4 – Evaluation of Feasible Control Technologies ..... 10

4.2.5 Step 5 – BACT Selection ..... 10

4.3 FCCU and COB $NO_X$ Emissions ..... 10

4.3.1 Step 1 – Identify All Available Control Technologies ..... 10

4.3.2 Step 2 – Technical Feasibility of Control Technologies ..... 10

4.3.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 11

4.3.4 Step 4 – Evaluation of Feasible Control Technologies ..... 11

4.3.5 Step 5 – BACT Selection ..... 12

4.4 FCCU and COB VOC Emissions ..... 12

4.4.1 Step 1 – Identify All Available Control Technologies ..... 12
4.4.2 Step 2 – Technical Feasibility of Control Technologies ..... 12
4.4.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 13
4.4.4 Step 4 – Evaluation of Feasible Control Technologies ..... 13
4.4.5 Step 5 – BACT Selection ..... 13
4.5 FCCU and COB Ammonia Emissions ..... 13
4.5.1 Step 1 – Identify All Available Control Technologies ..... 13
4.5.2 Step 2 – Technical Feasibility of Control Technologies ..... 13
4.5.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 14
4.5.4 Step 4 – Evaluation of Feasible Control Technologies ..... 14
4.5.5 Step 5 – BACT Selection ..... 14
5.0 BACT for Process Heaters ..... 14
5.1 Process Heaters $PM_{2.5}$ Emissions ..... 14
5.1.1 Step 1 – Identify All Available Control Technologies ..... 14
5.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 15
5.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 15
5.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 15
5.1.5 Step 5 – BACT Selection ..... 15
5.2 Process Heaters $SO_2$ Emissions ..... 16
5.2.1 Step 1 – Identify All Available Control Technologies ..... 16
5.2.2 Step 2 – Technical Feasibility of Control Technologies ..... 16
5.2.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 17
5.2.4 Step 4 – Evaluation of Feasible Control Technologies ..... 17
5.2.5 Step 5 – BACT Selection ..... 17
5.3 Process Heaters VOC Emissions ..... 17
5.3.1 Step 1 – Identify All Available Control Technologies ..... 17
5.3.2 Step 2 – Technical Feasibility of Control Technologies ..... 17
5.3.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 18
5.3.4 Step 4 – Evaluation of Feasible Control Technologies ..... 18
5.3.5 Step 5 – BACT Selection ..... 18
5.4 Process Heaters Ammonia Emissions ..... 19
5.4.1 Step 1 – Identify All Available Control Technologies ..... 19
5.4.2 Step 2 – Technical Feasibility of Control Technologies ..... 19
5.4.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 19

5.4.4 Step 4 – Evaluation of Feasible Control Technologies ..... 19
5.4.5 Step 5 – BACT Selection ..... 20
5.5 Process Heaters $NO_X$ Emissions ..... 20
5.5.1 Step 1 – Identify All Available Control Technologies ..... 20
5.5.2 Step 2 – Technical Feasibility of Control Technologies ..... 20
5.5.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 21
5.5.4 Step 4 – Evaluation of Feasible Control Technologies ..... 21
5.5.5 Step 5 – BACT Selection ..... 21
6.0 BACT for Cogeneration Units ..... 22
6.1 Cogeneration Units $PM_{2.5}$ Emissions ..... 22
6.1.1 Step 1 – Identify All Available Control Technologies ..... 22
6.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 22
6.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 22
6.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 23
6.1.5 Step 5 – BACT Selection ..... 23
6.2 Cogeneration Units $SO_2$ Emissions ..... 23
6.2.1 Step 1 – Identify All Available Control Technologies ..... 23
6.2.2 Step 2 – Technical Feasibility of Control Technologies ..... 23
6.2.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 24
6.2.4 Step 4 – Evaluation of Feasible Control Technologies ..... 25
6.2.5 Step 5 – BACT Selection ..... 25
6.3 Cogeneration Units $NO_X$ Emissions ..... 25
6.3.1 Step 1 – Identify All Available Control Technologies ..... 25
6.3.2 Step 2 – Technical Feasibility of Control Technologies ..... 25
6.3.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 26
6.3.4 Step 4 – Evaluation of Feasible Control Technologies ..... 26
6.3.5 Step 5 – BACT Selection ..... 26
6.4 Cogeneration Units VOC Emissions ..... 27
6.4.1 Step 1 – Identify All Available Control Technologies ..... 27
6.4.2 Step 2 – Technical Feasibility of Control Technologies ..... 27
6.4.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 27
6.4.4 Step 4 – Evaluation of Feasible Control Technologies ..... 28
6.4.5 Step 5 – BACT Selection ..... 28
6.5 Cogeneration Units Ammonia Emissions ..... 28

6.5.1 Step 1 – Identify All Available Control Technologies ..... 28
6.5.2 Step 2 – Technical Feasibility of Control Technologies ..... 28
6.5.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 29
6.5.4 Step 4 – Evaluation of Feasible Control Technologies ..... 29
6.5.5 Step 5 – BACT Selection ..... 29
7.0 BACT for Sulfur Recovery Unit (SRU) ..... 30
7.1 SRU $PM_{2.5}$ Emissions ..... 30
7.1.1 Step 1 – Identify All Available Control Technologies ..... 30
7.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 30
7.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 31
7.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 31
7.1.5 Step 5 – BACT Selection ..... 31
7.2 SRU $SO_2$ Emissions ..... 31
7.2.1 Step 1 – Identify All Available Control Technologies ..... 31
7.2.2 Step 2 – Technical Feasibility of Control Technologies ..... 31
7.2.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 32
7.2.4 Step 4 – Evaluation of Feasible Control Technologies ..... 32
7.2.5 Step 5 – BACT Selection ..... 32
7.3 SRU $NO_X$ Emissions ..... 33
7.3.1 Step 1 – Identify All Available Control Technologies ..... 33
7.3.2 Step 2 – Technical Feasibility of Control Technologies ..... 33
7.3.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 33
7.3.4 Step 4 – Evaluation of Feasible Control Technologies ..... 33
7.3.5 Step 5 – BACT Selection ..... 34
7.4 SRU VOC Emissions ..... 34
7.4.1 Step 1 – Identify All Available Control Technologies ..... 34
7.4.2 Step 2 – Technical Feasibility of Control Technologies ..... 34
7.4.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 34
7.4.4 Step 4 – Evaluation of Feasible Control Technologies ..... 35
7.4.5 Step 5 – BACT Selection ..... 35
7.5 SRU Ammonia Emissions ..... 35
8.0 BACT for Fugitive Equipment ..... 36
8.1 Fugitive Equipment VOC Emissions ..... 36
8.1.1 Step 1 – Identify All Available Control Technologies ..... 36

8.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 36
8.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 36
8.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 36
8.1.5 Step 5 – BACT Selection ..... 36
9.0 BACT for Refinery Wastewater System ..... 37
9.1 Refinery Wastewater VOC Emissions ..... 37
9.1.1 Step 1 – Identify All Available Control Technologies ..... 37
9.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 37
9.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 37
9.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 38
9.1.5 Step 5 – BACT Selection ..... 38
10.0 BACT for Refinery Drains ..... 39
10.1 Refinery Drains VOC Emissions ..... 39
10.1.1 Step 1 – Identify All Available Control Technologies ..... 39
10.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 39
10.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 40
10.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 40
10.1.5 Step 5 – BACT Selection ..... 40
11.0 BACT for North and South Flares ..... 41
11.1 North and South Flares $PM_{2.5}$ Emissions ..... 42
11.1.1 Step 1 – Identify All Available Control Technologies ..... 42
11.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 42
11.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 42
11.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 43
11.1.5 Step 5 – BACT Selection ..... 43
11.2 North and South Flares $SO_2$ Emissions ..... 43
11.2.1 Step 1 – Identify All Available Control Technologies ..... 43
11.2.2 Step 2 – Technical Feasibility of Control Technologies ..... 43
11.2.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 44
11.2.4 Step 4 – Evaluation of Feasible Control Technologies ..... 44
11.2.5 Step 5 – BACT Selection ..... 44
11.3 North and South Flares $NO_X$ Emissions ..... 44
11.3.1 Step 1 – Identify All Available Control Technologies ..... 45
11.3.2 Step 2 – Technical Feasibility of Control Technologies ..... 45

11.3.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 45
11.3.4 Step 4 – Evaluation of Feasible Control Technologies ..... 45
11.3.5 Step 5 – BACT Selection ..... 45
11.4 North and South Flares VOC Emissions ..... 46
11.4.1 Step 1 – Identify All Available Control Technologies ..... 46
11.4.2 Step 2 – Technical Feasibility of Control Technologies ..... 46
11.4.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 46
11.4.4 Step 4 – Evaluation of Feasible Control Technologies ..... 47
11.4.5 Step 5 – BACT Selection ..... 47
11.5 North and South Flares Ammonia Emissions ..... 47
11.5.1 Step 1 – Identify All Available Control Technologies ..... 47
11.5.2 Step 2 – Technical Feasibility of Control Technologies ..... 47
11.5.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 47
11.5.4 Step 4 – Evaluation of Feasible Control Technologies ..... 48
11.5.5 Step 5 – BACT Selection ..... 48
12.0 BACT for SRU Flare ..... 49
12.1 SRU Flare $PM_{2.5}$ Emissions ..... 49
12.1.1 Step 1 – Identify All Available Control Technologies ..... 49
12.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 49
12.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 50
12.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 50
12.1.5 Step 5 – BACT Selection ..... 50
12.2 SRU Flare $SO_2$ Emissions ..... 50
12.2.1 Step 1 – Identify All Available Control Technologies ..... 50
12.2.2 Step 2 – Technical Feasibility of Control Technologies ..... 50
12.2.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 51
12.2.4 Step 4 – Evaluation of Feasible Control Technologies ..... 51
12.2.5 Step 5 – BACT Selection ..... 51
12.3 SRU Flare $NO_X$ Emissions ..... 51
12.3.1 Step 1 – Identify All Available Control Technologies ..... 51
12.3.2 Step 2 – Technical Feasibility of Control Technologies ..... 51
12.3.3 Step 3 –Effectiveness of Feasible Control Technologies ..... 52
12.3.4 Step 4 – Evaluation of Feasible Control Technologies ..... 52
12.3.5 Step 5 – BACT Selection ..... 52

12.4 SRU Flare VOC Emissions ..... 52
12.4.1 Step 1 – Identify All Available Control Technologies ..... 52
12.4.2 Step 2 – Technical Feasibility of Control Technologies ..... 52
12.4.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 53
12.4.4 Step 4 – Evaluation of Feasible Control Technologies ..... 53
12.4.5 Step 5 – BACT Selection ..... 53
12.5 SRU Flare Ammonia Emissions ..... 53
12.5.1 Step 1 – Identify All Available Control Technologies ..... 53
12.5.2 Step 2 – Technical Feasibility of Control Technologies ..... 54
12.5.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 54
12.5.4 Step 4 – Evaluation of Feasible Control Technologies ..... 54
12.5.5 Step 5 – BACT Selection ..... 54
13.0 BACT for Cooling Towers ..... 55
13.1 Cooling Tower $PM_{25}$ Emissions ..... 55
13.1.1 Step 1 – Identify All Available Control Technologies ..... 55
13.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 55
13.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 55
13.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 56
13.1.5 Step 5 – BACT Selection ..... 56
13.2 Cooling Tower VOC Emissions ..... 56
13.2.1 Step 1 – Identify All Available Control Technologies ..... 56
13.2.2 Step 2 – Technical Feasibility of Control Technologies ..... 56
13.2.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 56
13.2.4 Step 4 – Evaluation of Feasible Control Technologies ..... 57
13.2.5 Step 5 – BACT Selection ..... 57
14.0 BACT for Loading Racks ..... 58
14.1 Transportation Rack VOC Emissions ..... 58
14.1.1 Step 1 – Identify All Available Control Technologies ..... 58
14.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 58
14.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 58
14.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 58
14.1.5 Step 5 – BACT Selection ..... 59
14.2 LPG Loading Rack VOC Emissions ..... 59
14.2.1 Step 1 – Identify All Available Control Technologies ..... 59

14.2.2 Step 2 – Technical Feasibility of Control Technologies ..... 59
14.2.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 59
14.2.4 Step 4 – Evaluation of Feasible Control Technologies ..... 59
14.2.5 Step 5 – BACT Selection ..... 60
15.0 BACT for K1 Compressors ..... 61
15.1 K1 Compressors $PM_{2.5}$ Emissions ..... 61
15.1.1 Step 1 – Identify All Available Control Technologies ..... 61
15.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 61
15.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 61
15.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 61
15.1.5 Step 5 – BACT Selection ..... 62
15.2 K1 Compressors $SO_2$ Emissions ..... 62
15.2.1 Step 1 – Identify All Available Control Technologies ..... 62
15.2.2 Step 2 – Technical Feasibility of Control Technologies ..... 62
15.2.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 62
15.2.4 Step 4 – Evaluation of Feasible Control Technologies ..... 62
15.2.5 Step 5 – BACT Selection ..... 63
15.3 K1 Compressors $NO_X$ Emissions ..... 63
15.3.1 Step 1 – Identify All Available Control Technologies ..... 63
15.3.2 Step 2 – Technical Feasibility of Control Technologies ..... 63
15.3.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 63
15.3.4 Step 4 – Evaluation of Feasible Control Technologies ..... 64
15.3.5 Step 5 – BACT Selection ..... 64
15.4 K1 Compressors VOC Emissions ..... 64
15.4.1 Step 1 – Identify All Available Control Technologies ..... 64
15.4.2 Step 2 – Technical Feasibility of Control Technologies ..... 64
15.4.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 65
15.4.4 Step 4 – Evaluation of Feasible Control Technologies ..... 65
15.4.5 Step 5 – BACT Selection ..... 65
15.5 K1 Compressors Ammonia Emissions ..... 65
15.5.1 Step 1 – Identify All Available Control Technologies ..... 65
15.5.2 Step 2 – Technical Feasibility of Control Technologies ..... 65
15.5.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 66
15.5.4 Step 4 – Evaluation of Feasible Control Technologies ..... 66

15.5.5 Step 5 – BACT Selection ..... 66
16.0 BACT for Fixed Roof Tanks ..... 67
16.1 Fixed Roof Tanks VOC Emissions ..... 67
16.1.1 Step 1 – Identify All Available Control Technologies ..... 67
16.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 67
16.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 68
16.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 68
16.1.5 Step 5 – BACT Selection ..... 68
17.0 BACT for Internal Floating Roof Tanks ..... 69
17.1 Internal Floating Roof Tanks VOC Emissions ..... 69
17.1.1 Step 1 – Identify All Available Control Technologies ..... 70
17.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 70
17.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 71
17.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 71
17.1.5 Step 5 – BACT Selection ..... 71
18.0 BACT for External Floating Roof Tanks ..... 72
18.1 External Floating Roof Tanks VOC Emissions ..... 72
18.1.1 Step 1 – Identify All Available Control Technologies ..... 72
18.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 72
18.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 73
18.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 73
18.1.5 Step 5 – BACT Selection ..... 74
19.0 BACT for Emergency Engines ..... 75
19.1 Emergency Engine $PM_{2.5}$ Emissions ..... 75
19.1.1 Step 1 – Identify All Available Control Technologies ..... 75
19.1.2 Step 2 – Technical Feasibility of Control Technologies ..... 75
19.1.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 75
19.1.4 Step 4 – Evaluation of Feasible Control Technologies ..... 76
19.1.5 Step 5 – BACT Selection ..... 76
19.2 Emergency Engine $SO_2$ Emissions ..... 76
19.2.1 Step 1 – Identify All Available Control Technologies ..... 76
19.2.2 Step 2 – Technical Feasibility of Control Technologies ..... 76
19.2.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 76
19.2.4 Step 4 – Evaluation of Feasible Control Technologies ..... 77

19.2.5 Step 5 – BACT Selection ..... 77
19.3 Emergency Engine $NO_X$ Emissions ..... 77
19.3.1 Step 1 – Identify All Available Control Technologies ..... 77
19.3.2 Step 2 – Technical Feasibility of Control Technologies ..... 77
19.3.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 78
19.3.4 Step 4 – Evaluation of Feasible Control Technologies ..... 78
19.3.5 Step 5 – BACT Selection ..... 78
19.4 Emergency Engine VOC Emissions ..... 78
19.4.1 Step 1 – Identify All Available Control Technologies ..... 78
19.4.2 Step 2 – Technical Feasibility of Control Technologies ..... 78
19.4.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 79
19.4.4 Step 4 – Evaluation of Feasible Control Technologies ..... 79
19.4.5 Step 5 – BACT Selection ..... 79
19.5 Emergency Engine Ammonia Emissions ..... 79
20.0 BACT for Temporary Boilers ..... 80
20.1 Temporary Boilers $PM_{2.5}$ Emissions ..... 80
20.2 Temporary Boilers $SO_2$ Emissions ..... 80
20.3 Temporary Boilers VOC Emissions ..... 80
20.4 Temporary Boilers Ammonia Emissions ..... 81
20.5 Temporary Boilers $NO_X$ Emissions ..... 81
20.5.1 Step 1 – Identify All Available Control Technologies ..... 81
20.5.2 Step 2 – Technical Feasibility of Control Technologies ..... 81
20.5.3 Step 3 – Effectiveness of Feasible Control Technologies ..... 82
20.5.4 Step 4 – Evaluation of Feasible Control Technologies ..... 82
20.5.5 Step 5 – BACT Selection ..... 82

# List of Tables


Table 1-1 Summary of Emission Units and Pollutants subject to BACT ..... 2
Table 1-2 $PM_{2.5}$ BACT ..... 4
Table 1-3 $SO_2$ BACT ..... 5
Table 1-4 $NO_X$ BACT ..... 6
Table 1-5 VOC BACT ..... 7
Table 1-6 Ammonia BACT ..... 8
Table 1-7 Summary of Emissions Reductions ..... 8
Table 3-1 Available Emission Control Technologies ..... 4
Table 4-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for FCCU and COB ..... 8
Table 4-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for FCCU and COB ..... 8
Table 4-3 Technical Feasibility of $SO_2$ Control Technologies for FCCU and COB ..... 9
Table 4-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for FCCU and COB ..... 10
Table 4-5 Technical Feasibility of $NO_X$ Control Technologies for FCCU and COB ..... 11
Table 4-6 Control Effectiveness Ranking of $NO_X$ Control Technologies for FCCU and COB ..... 11
Table 4-7 Technical Feasibility of VOC Control Technologies for FCCU and COB ..... 12
Table 4-8 Control Effectiveness Ranking of VOC Control Technologies for FCCU and COB ..... 13
Table 4-9 Technical Feasibility of Ammonia Control Technologies for FCCU and COB ..... 13
Table 4-10 Control Effectiveness Ranking of Ammonia Control Technologies for FCCU and COB ..... 14
Table 5-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for Process Heaters ..... 15
Table 5-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for Process Heaters ..... 15
Table 5-3 Technical Feasibility of $SO_2$ Control Technologies for Process Heaters ..... 16
Table 5-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for Process Heaters ..... 17
Table 5-5 Technical Feasibility of VOC Control Technologies for Process Heaters ..... 18
Table 5-6 Control Effectiveness Ranking of VOC Control Technologies for Process Heaters ..... 18
Table 5-7 Technical Feasibility of Ammonia Control Technologies for Process Heaters ..... 19
Table 5-8 Control Effectiveness Ranking of Ammonia Control Technologies for Process Heaters ..... 19
Table 5-9 Technical Feasibility of $NO_X$ Control Technologies for Process Heaters with ULNB Installed (H-101, F-1, F-680, and F-681) ..... 20
Table 5-10 Technical Feasibility of $NO_X$ Control Technologies for Process Heaters with LNB Installed (F-15, F-701) ..... 20
Table 5-11 Control Effectiveness Ranking of $NO_X$ Control Technologies for Process Heaters ..... 21
Table 6-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for Cogeneration Units ..... 22
Table 6-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for Cogeneration Units ..... 23
Table 6-3 Technical Feasibility of $SO_2$ Control Technologies for Cogeneration Units ..... 24
Table 6-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for Cogeneration Units ..... 24
Table 6-5 Technical Feasibility of $NO_X$ Control Technologies for Cogeneration Units ..... 26
Table 6-6 Control Effectiveness Ranking of $NO_X$ Control Technologies for Cogeneration Units ..... 26
Table 6-7 Technical Feasibility of VOC Control Technologies for Cogeneration Units ..... 27
Table 6-8 Control Effectiveness Ranking of VOC Control Technologies for Cogeneration Units ..... 28

Table 6-9 Technical Feasibility of Ammonia Control Technologies for Cogeneration Units ..... 28
Table 6-10 Control Effectiveness Ranking of Ammonia Control Technologies for Cogeneration Units ..... 29
Table 7-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for SRU ..... 30
Table 7-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for SRU ..... 31
Table 7-3 Technical Feasibility of $SO_2$ Control Technologies for SRU ..... 32
Table 7-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for SRU ..... 32
Table 7-5 Technical Feasibility of $NO_X$ Control Technologies for SRU ..... 33
Table 7-6 Control Effectiveness Ranking of $NO_X$ Control Technologies for SRU ..... 33
Table 7-7 Technical Feasibility of VOC Control Technologies for SRU ..... 34
Table 7-8 Control Effectiveness Ranking of VOC Control Technologies for SRU ..... 35
Table 8-1 Technical Feasibility of VOC Control Technologies for Fugitive Equipment ..... 36
Table 8-2 Control Effectiveness Ranking of VOC Control Technologies for Fugitive Equipment ..... 36
Table 9-1 Technical Feasibility of VOC Control Technologies for Refinery Wastewater System ..... 37
Table 9-2 Control Effectiveness Ranking of VOC Control Technologies for Refinery Wastewater System ..... 38
Table 10-1 Technical Feasibility of VOC Control Technologies for Refinery Drains ..... 39
Table 10-2 Control Effectiveness Ranking of VOC Control Technologies for Refinery Drains ..... 40
Table 11-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for North and South Flares ..... 42
Table 11-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for North and South Flares 43
Table 11-3 Technical Feasibility of $SO_2$ Control Technologies for North and South Flares ..... 44
Table 11-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for North and South Flares .. 44
Table 11-5 Technical Feasibility of $NO_X$ Control Technologies for North and South Flares ..... 45
Table 11-6 Control Effectiveness Ranking of $NO_X$ Control Technologies for North and South Flares . 45
Table 11-7 Technical Feasibility of VOC Control Technologies for North and South Flares ..... 46
Table 11-8 Control Effectiveness Ranking of VOC Control Technologies for North and South Flares. 46
Table 11-9 Technical Feasibility of Ammonia Control Technologies for North and South Flares ..... 47
Table 11-10 Control Effectiveness Ranking of Ammonia Control Technologies for North and South Flares ..... 48
Table 12-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for SRU Flare ..... 49
Table 12-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for SRU Flare ..... 50
Table 12-3 Technical Feasibility of $SO_2$ Control Technologies for SRU Flare ..... 50
Table 12-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for SRU Flare ..... 51
Table 12-5 Technical Feasibility of $NO_X$ Control Technologies for SRU Flare ..... 51
Table 12-6 Control Effectiveness Ranking of $NO_X$ Control Technologies for SRU Flare ..... 52
Table 12-7 Technical Feasibility of VOC Control Technologies for SRU Flare ..... 53
Table 12-8 Control Effectiveness Ranking of VOC Control Technologies for SRU Flare ..... 53
Table 12-9 Technical Feasibility of Ammonia Control Technologies for SRU Flare ..... 54
Table 12-10 Control Effectiveness Ranking of Ammonia Control Technologies for SRU Flare ..... 54
Table 13-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for Cooling Tower ..... 55
Table 13-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for Cooling Towers ..... 56

Table 13-3 Technical Feasibility of VOC Control Technologies for Cooling Towers ..... 56
Table 13-4 Control Effectiveness Ranking of VOC Control Technologies for Cooling Towers ..... 57
Table 14-1 Technical Feasibility of VOC Control Technologies for Loading Racks ..... 58
Table 14-2 Control Effectiveness Ranking of VOC Control Technologies for Loading Racks ..... 58
Table 14-3 Technical Feasibility of VOC Control Technologies for Loading Racks ..... 59
Table 14-4 Control Effectiveness Ranking of VOC Control Technologies for Loading Racks ..... 59
Table 15-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for K1 Compressors ..... 61
Table 15-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for K1 Compressors ..... 61
Table 15-3 Technical Feasibility of $SO_2$ Control Technologies for K1 Compressors ..... 62
Table 15-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for K1 Compressors ..... 62
Table 15-5 Technical Feasibility of $NO_X$ Control Technologies for K1 Compressors ..... 63
Table 15-6 Control Effectiveness Ranking of $NO_X$ Control Technologies for K1 Compressors ..... 64
Table 15-7 Technical Feasibility of VOC Control Technologies for K1 Compressors ..... 64
Table 15-8 Control Effectiveness Ranking of VOC Control Technologies for K1 Compressors ..... 65
Table 15-9 Technical Feasibility of Ammonia Control Technologies for K1 Compressors ..... 66
Table 15-10 Control Effectiveness Ranking of Ammonia Control Technologies for K1 Compressors ..... 66
Table 16-1 Technical Feasibility of VOC Control Technologies for Fixed Roof Tanks ..... 67
Table 16-2 Fixed Roof Tanks to Be Updated to MACT CC Controls with Anticipated Upgrade Date ..... 68
Table 16-3 Control Effectiveness Ranking of VOC Control Technologies for Fixed Roof Tanks ..... 68
Table 17-1 Technical Feasibility of VOC Control Technologies for Internal Floating Roof Tanks ..... 70
Table 17-2 Internal Floating Roof Tanks to Be Updated to RSR Controls with Anticipated Upgrade Date ..... 71
Table 17-3 Control Effectiveness Ranking of VOC Control Technologies for Internal Floating Roof Tanks ..... 71
Table 18-1 Technical Feasibility of VOC Control Technologies for External Floating Roof Tanks ..... 73
Table 18-2 Control Effectiveness Ranking of VOC Control Technologies for External Floating Roof Tanks ..... 73
Table 18-3 External Floating Roof Tanks to Be Updated to MACT CC Controls with Anticipated Upgrade Date ..... 74
Table 19-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for Emergency Engines ..... 75
Table 19-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for Emergency Engines ..... 76
Table 19-3 Technical Feasibility of $SO_2$ Control Technologies for Emergency Engines ..... 76
Table 19-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for Emergency Engines ..... 77
Table 19-5 Technical Feasibility of $NO_X$ Control Technologies for Emergency Engines ..... 77
Table 19-6 Control Effectiveness Ranking of $NO_X$ Control Technologies for Emergency Engines ..... 78
Table 19-7 Technical Feasibility of VOC Control Technologies for Emergency Engines ..... 78
Table 19-8 Control Effectiveness Ranking of VOC Control Technologies for Emergency Engines ..... 79
Table 20-1 Technical Feasibility of $NO_X$ Control Technologies for Temporary Boilers) ..... 81
Table 20-2 Control Effectiveness Ranking of $NO_X$ Control Technologies for Temporary Boilers ..... 82

# 1.0 Executive Summary

The Utah Department of Environmental Quality Division of Air Quality (UDAQ) requested in a letter dated January 23, 2017 Tesoro Refining & Marketing Company LLC (Tesoro) complete a Best Available Control Technology (BACT) assessment for their existing emission units at the Salt Lake City refinery in Salt Lake County, Utah. For purposes of this submittal Tesoro has included emission units within the Tesoro Refining & Marketing Company LLC and Tesoro Logistics Operations LLC (TLO) organizations. The facilities within Tesoro (Refinery) and the TLO (Truck Loading Rack and Remote Tank Farm) are a single major source.

The BACT Assessment will assist UDAQ in determining acceptable pollution controls as necessary by a Serious Designation for $PM_{2.5}$ by performing an evaluation of existing emission units emitting direct $PM_{2.5}$ and $PM_{2.5}$ precursors including the following:

- Particulate matter with an aerodynamic diameter of less than 2.5 microns ($PM_{2.5}$)
- Sulfur dioxide ($SO_2$)
- Oxides of nitrogen ($NO_X$)
- Volatile organic compounds (VOC)
- Ammonia

Table 1-1 lists the project-related emission units and pollutants that have been included in the BACT review.

**Table 1-1 Summary of Emission Units and Pollutants subject to BACT**

| Emissions Unit | $PM_{2.5}$ SIP Pollutants Emitted |
|---|---|
| FCCU/CO Boiler | $PM_{2.5}$, $SO_2$, $NO_X$, VOC, Ammonia |
| H-101 Crude Unit Furnace | $PM_{2.5}$, $SO_2$, $NO_X$, VOC, Ammonia |
| F-1 Ultraformer Unit Furnace | $PM_{2.5}$, $SO_2$, $NO_X$, VOC, Ammonia |
| F-15 Ultraformer Regeneration Furnace | $PM_{2.5}$, $SO_2$, $NO_X$, VOC, Ammonia |
| F-680 DDU Furnace | $PM_{2.5}$, $SO_2$, $NO_X$, VOC, Ammonia |
| F-681 DDU Furnace | $PM_{2.5}$, $SO_2$, $NO_X$, VOC, Ammonia |
| F-701 GHT Furnace | $PM_{2.5}$, $SO_2$, $NO_X$, VOC, Ammonia |
| Cogeneration Units (2) | $PM_{2.5}$, $SO_2$, $NO_X$, VOC, Ammonia |
| Sulfur Recovery Unit (SRU) | $PM_{2.5}$, $SO_2$, $NO_X$, VOC, Ammonia |
| Fugitive Equipment | VOC |
| Refinery Wastewater System | VOC |
| Refinery Drains | VOC |
| North and South Flares | $PM_{2.5}$, $SO_2$, $NO_X$, VOC, Ammonia |
| SRU Flare | $PM_{2.5}$, $SO_2$, $NO_X$, VOC, Ammonia |
| Reformer Regeneration Vent | VOC |
| Cooling Tower UU2 | $PM_{2.5}$, VOC |
| Cooling Tower UU3 | $PM_{2.5}$, VOC |
| Transport Loading Racks (2) | VOC |
| LPG Loading Rack | VOC |
| K1 Compressors (2) | $PM_{2.5}$, $SO_2$, $NO_X$, VOC, Ammonia |
| Fixed Roof Tanks | VOC |
| Internal Floating Roof Tanks | VOC |
| External Floating Roof Tanks | VOC |
| Emergency Engines | $PM_{2.5}$, $SO_2$, $NO_X$, VOC |
| Temporary Boilers | $PM_{2.5}$, $SO_2$, $NO_X$, VOC, Ammonia |

This BACT analysis follows EPA's five-step top-down approach, as specified in the U.S. EPA's draft New Source Review Workshop Manual, (October 1990).[1]

- Step 1 – Identify All Available Control Technologies
- Step 2 – Eliminate Technically Infeasible Options

[1] The workshop manual can be found at U.S. EPA's website http://www.epa.gov/NSR/ttnnsr01/gen/wkshpman.pdf.

- Step 3 – Rank Remaining Control Technologies by Control Effectiveness
- Step 4 – Evaluate Most Effective Control Technologies and Document Results
- Step 5 – Select BACT

A key consideration for the technical feasibility of control technologies is the schedule for installation. Per UDAQ's stated timeline the control technology must be in place for one year in advance of the attainment date of December 31, 2019. If due to the time for engineering design, the refinery operating schedule, or the equipment lead time, it is not feasibly possible to install and operate prior to December 31, 2018, that technology is determined to be technically infeasible and eliminated from further consideration. For these control technologies that cannot be installed by December 31, 2018, Tesoro did not complete further evaluation of technical and economic feasibility. Upon a more detailed review, Tesoro may determine that these control technologies are not technically or economically feasible. Due to the limited timeframe of this requested evaluation, Tesoro has not completed these evaluations for control technologies that cannot be installed by December 31, 2018.

Table 1-2 to Table 1-6 below summarize BACT for each project-related emission unit and pollutant and control technologies which cannot be installed by December 31, 2018.

**Table 1-2 $PM_{2.5}$ BACT**

| Source Description | BACT | Basis |
|---|---|---|
| FCCU/CO Boiler | Electrostatic Precipitator (ESP) + Wet Gas Scrubber (WGS) | The new WGS will be operational by 12/31/18. The performance of the system will meet BACT. |
| H-101 Crude Unit Furnace<br>F-1 Ultraformer Unit Furnace<br>F-15 Ultraformer Regen Furnace<br>F-680 DDU Furnace<br>F-681 DDU Furnace<br>F-701 GHT Furnace | Good Design Methods and Good Operating Practices | Add-on controls are technically infeasible.<br><br>Firing only natural gas instead of treated refinery fuel gas is technically infeasible. |
| Cogeneration Units (2) | | |
| Sulfur Recovery Unit (SRU) | | |
| Temporary Boiler | | |
| North and South Flares | Flare Gas Recovery System (FGRS), Flare Minimization Plan, Flare Caps, and Flare Combustion Efficiency | Flare Gas Recovery System (FGRS), Flare Minimization Plan, Flare Caps, and Flare Combustion Efficiency meet BACT. |
| SRU Flare | Flare Minimization Plan | Minimizing flow meets BACT. |
| Cooling Tower UU2 | Current Drift Eliminator and Good Operating Practices | Upgrades to the drift eliminator are not technically feasible by 12/31/18. |
| Cooling Tower UU3 | | |
| K1 Compressors (2) | Natural Gas and Good Operating Practices | Replacing one natural gas engine with an electric motor isn't technically feasible by 12/31/18. |
| Emergency Engines | Ultra-Low Sulfur Diesel, Good Operating Practices, and Compliance with MACT ZZZZ | Limited hours of operation and good combustion practices meets BACT |

**Table 1-3 $SO_2$ BACT**

| Source Description | BACT | Basis |
|---|---|---|
| FCCU/CO Boiler | Wet Gas Scrubber (WGS) | The new WGS will be operational by 12/31/18. The performance of the system will meet BACT. |
| H-101 Crude Unit Furnace<br>F-1 Ultraformer Unit Furnace<br>F-15 Ultraformer Regen Furnace<br>F-680 DDU Furnace<br>F-681 DDU Furnace<br>F-701 GHT Furnace<br>Temporary Boilers | Low $H_2S$ Content Fuel Gas (60 ppm annual average, 162 ppm 3-hour average) | Upgrades to the amine treatment system are not technically feasible by 12/31/18. |
| Cogeneration Units (2) | Turbines: Low $H_2S$ Content Combined Gas<br><br>HRSGs: Low $H_2S$ Content Refinery Fuel Gas (60 ppm $H_2S$ annual average, 162 ppm $H_2S$ 3-hour average) | Current turbine combined gas meets low $H_2S$ content.<br><br>Upgrades to the amine treatment system are not technically feasible by 12/31/18. |
| Sulfur Recovery Unit (SRU) | Tail Gas Treatment Unit and Sulfur Shedding Plan | Upgrades to the TGTU or installing a wet gas scrubber are not technically feasible by 12/31/18. |
| North and South Flares | Flare Gas Recovery System (FGRS), Flare Minimization Plan, Flare Caps, and Flare Combustion Efficiency | Flare Gas Recovery System (FGRS), Flare Minimization Plan, Flare Caps, and Flare Combustion Efficiency meet BACT. |
| SRU Flare | Flare Minimization Plan | Minimizing flow meets BACT. Exclusive use of natural gas for the pilot isn't technically feasible by 12/31/18. |
| K1 Compressors (2) | Natural Gas and Good Operating Practices | Replacing one natural gas engine with an electric motor isn't technically feasible by 12/31/18. |
| Emergency Engines | Ultra-Low Sulfur Diesel and Good Combustion Practices | Using Ultra-Low Sulfur Diesel meets BACT. |

**Table 1-4 $NO_x$ BACT**

| Source Description | BACT | Basis |
|---|---|---|
| FCCU/CO Boiler | Wet Gas Scrubber (WGS) and LoTOx unit | The new WGS and LoTOx will be operational by 12/31/18. The performance of the system will meet BACT. |
| H-101 Crude Unit Furnace | Ultra Low NOx Burners (ULNB) | ULNB meets BACT. There are no technically feasible options because there is no plot space available for an SCR or SNCR. |
| F-1 Ultraformer Unit Furnace | ULNB | ULNB meets BACT. There are no technically feasible options because there is no plot space available for an SCR or SNCR. |
| F-15 Ultraformer Regen Furnace | Low NOx Burners (LNB) | LNB meets BACT. Installation of ULNB is technically infeasible due to burner impingment. , SCR, or SNCR is not technically feasible by 12/31/18. |
| F-680 DDU Furnace | ULNB | Installation of SCR or SNCR is not technically feasible by 12/31/18. |
| F-681 DDU Furnace | ULNB | Installation of SCR or SNCR is not technically feasible by 12/31/18. |
| F-701 GHT Furnace | LNB | LNB meets BACT. Installation of ULNB is technically infeasible due to burner impingement. SCR, or SNCR is not technically feasible by 12/31/18. |
| Cogeneration Units (2) | SoLoNOx Technology | Installation of advanced combustion controls, SCR, or SNCR is not technically feasible by 12/31/18. |
| Sulfur Recovery Unit (SRU) | Good Design Methods and Operating Practices | Good design methods and operating practices meet BACT. |
| North and South Flares | Flare Gas Recovery System (FGRS), Flare Minimization Plan, Flare Caps, and Flare Combustion Efficiency | Flare Gas Recovery System (FGRS), Flare Minimization Plan, Flare Caps, and Flare Combustion Efficiency meet BACT. |
| SRU Flare | Flare Minimization Plan | Minimizing flow meets BACT. |
| K1 Compressors (2) | Catalytic Converter, Natural Gas and Good Operating Practices | Replacing one natural gas engine with an electric motor isn't technically feasible by 12/31/18. |
| Emergency Engines | Good Combustion Practices and Emergency Engine requirements from MACT ZZZZ | Upgrading to Tier 4 engine is not technically feasible. |
| Temporary Boilers | Use of Gaseous Fuels and Operate boiler on temporary basis per 40 CFR 60.41b | $NO_x$ performance is limited by rental boiler availability |

**Table 1-5 VOC BACT**

| Source Description | BACT | Basis |
|---|---|---|
| FCCU/CO Boiler | Operation of a CO Boiler, Good Combustion Practices | Operation of a CO Boiler and following good combustion practices meets BACT. |
| H-101 Crude Unit Furnace<br>F-1 Ultraformer Unit Furnace<br>F-15 Ultraformer Regen Furnace<br>F-680 DDU Furnace<br>F-681 DDU Furnace<br>F-701 GHT Furnace<br>Cogeneration Units (2)<br>Sulfur Recovery Unit (SRU)<br>Temporary Boiler | Good Design Methods and Operating Practices | Good design methods and operating practices meets BACT. |
| Fugitive Equipment | LDAR Program (40 CFR 60 Subpart GGGa) | An LDAR program compliant with Subpart GGGa meets BACT. |
| Refinery Wastewater System | API Separator Covers (Non QQQ) | Installation QQQ API Separator Covers, vapor recovery to a vapor combustor or carbon adsorption unit is not feasible by 12/31/18. |
| Uncontrolled Refinery Drains | Good Operating Practices | Replacement or retrofit controls are not feasible by 12/31/18. |
| North and South Flares | Flare Gas Recovery System (FGRS), Flare Minimization Plan, Flare Caps, and Flare Combustion Efficiency | Flare Gas Recovery System (FGRS), Flare Minimization Plan, Flare Caps, and Flare Combustion Efficiency meet BACT. |
| SRU Flare | Flare Minimization Plan | Minimizing flow meets BACT. |
| Cooling Tower UU2<br>Cooling Tower UU3 | Compliance with 40 CFR 63 Subpart CC | A leak detection program compliant with Subpart CC meets BACT. |
| Transport Loading Rack (2) | Vapor Recovery Unit with Carbon adsorption | Operation of a vapor recovery unit with carbon adsorption meets BACT. |
| LPG Loading Rack | Flare | Operation of a flare meets BACT. |
| K1 Compressors (2) | Catalytic Converter | Operation of a catalytic converter meets BACT. |
| Fixed Roof Tanks | Good Design Methods and Operating Practices | Good design methods and operating practices meets BACT. |
| Internal Floating Roof Tanks | Upgrade to MACT CC controls or operate using NSPS Kb required controls | Some tanks are anticipated to be upgraded by 12/31/18. Upgrading all tanks is technically not feasible by 12/31/18. |
| External Floating Roof Tanks | Upgrade to MACT CC controls or operate using NSPS Kb required controls | Some tanks are anticipated to be upgraded by 12/31/18. Upgrading all tanks is technically not feasible by 12/31/18. |
| Emergency Engines | Good Combustion Practices and Emergency Engine requirements from MACT ZZZZ | Upgrading to Tier 4 engine is not technically feasible |

**Table 1-6 Ammonia BACT**

| Source Description | BACT | Basis |
|---|---|---|
| FCCU/CO Boiler | Operation of a CO Boiler, Good Combustion Practices | Operation of a CO Boiler and following good combustion practices meets BACT. |
| H-101 Crude Unit Furnace<br>F-1 Ultraformer Unit Furnace<br>F-15 Ultraformer Regen Furnace<br>F-680 DDU Furnace<br>F-681 DDU Furnace<br>F-701 GHT Furnace<br>Cogeneration Units (2)<br>K1 Compressors (2)<br>Temporary Boiler | Good Design Methods and Operating Procedures | Good design methods and operating procedures meets BACT. |
| North and South Flares | Flare Gas Recovery System (FGRS), Flare Minimization Plan, Flare Caps, and Flare Combustion Efficiency | Flare Gas Recovery System (FGRS), Flare Minimization Plan, Flare Caps, and Flare Combustion Efficiency meet BACT. |
| SRU Flare | Flare Minimization Plan | Minimizing flow meets BACT.<br>FGRS technically infeasible |

Based upon the BACT determinations indicated above, Tesoro has committed to significant emissions reductions since the 2014 baseline period by December 31, 2018. These emissions reductions are achieved by significant investments in emissions control technologies. A summary of the emission reductions compared to 2014 is provided below in Table 1-7.

**Table 1-7 Summary of Emissions Reductions**

| Source Description | BACT | Pollutant | Actual Emissions Reductions by 12/31/18 (tpy) |
|---|---|---|---|
| FCCU/CO Boiler | Wet Gas Scrubber and LoTOx | $SO_2$ | 458.43 |
| | | $NO_x$ | 103.24 |
| F-1 Ultraformer Unit Furnace | Ultra Low NOx Burners | $NO_x$ | 15.12 |
| Sulfur Recovery Unit (SRU) | Tail Gas Treatment Unit | $SO_2$ | 135.33 |
| North and South Flares | Flare Gas Recovery | All | (Variable) |

Tesoro has also completed additional projects to reduce emissions from storage tanks by installing guidepole controls, retrofitting storage tanks with internal floating roofs, replacing tanks and by controlling degassing emissions with a portable thermal oxidizer.

# 2.0 BACT Methodology

BACT is defined as an emission limitation based on the maximum emission reduction achievable after a case-by-case review of potential emission controls which takes into account energy, environmental and economic impacts. This emissions limit may be achieved by a variety of means, such as control technologies, clean fuels, inherently lower polluting processes or alternative operating practices.[2]

## 2.1 Top-Down BACT Approach

This BACT analysis has been conducted in accordance with Section 165(a) (4) of the Clean Air Act (at 40 CFR Part 52.21(j)), and 40 CFR 51.1010(a). BACT technologies have been selected using the "top-down" approach specified in U.S. EPA's draft New Source Review Workshop Manual, (October 1990),[3] using the five-step process.

### Step 1 - Identify all Available Control Technologies

All available control technologies are identified for each emission unit. A control technology is considered available for a specific pollutant if it could practically be applied to the specific emission unit. To identify all available control technologies, the following sources were consulted:

- U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC)
- U.S. EPA's New Source Review (NSR) website
- U.S. EPA draft permit review comments on recent PSD permits
- State/local agency air quality permits and the associated agency review documents
- Permit applications and BACT reports for recent projects

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[2] "Best available control technology means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

[3] The workshop manual can be found at U.S. EPA's website http://www.epa.gov/NSR/ttnnsr01/gen/wkshpman.pdf.

- Air pollution control technology vendors and consultants
- Manufacturer's recommendations
- Technical journals, reports, webinars, conferences and seminars

Recent court and regulatory agency determinations[4] have held that "clean fuels" must be considered as one of the emission control technologies in a BACT analysis. The fuels analysis is based on pollutant emissions directly associated with use of a particular fuel. EPA has recognized that the initial list of control technologies for a BACT analysis does not need to include "clean fuel" technologies that would fundamentally redefine the source. Such technologies that do not need to be included in the analysis include those that would require a facility to switch to a primary fuel type (i.e., coal, natural gas, or biomass) other than the type of fuel used for its primary combustion process.

## Step 2 - Eliminate Technically Infeasible Control Technologies

Each control technology identified in Step 1 is evaluated, using source-specific factors, to determine if it is technically feasible. If physical, chemical and engineering principles demonstrate that a technology could not be successfully used on the emission unit, then that technology is determined to be technically infeasible. Economics are not considered in the determination of technical feasibility. Technologies which are determined to be infeasible are eliminated from further consideration.

In this step, the control technology is also evaluated for feasibility of installation and operation before December 31, 2018. The control technology must be in place for one year in advance of the attainment date of December 31, 2019. If, due to the time for engineering design, the refinery operating schedule, or the equipment lead time it is not feasibly possible to install and operate prior to December 31, 2018, that technology is determined to be technically infeasible, and will be eliminated from further consideration.

Factors considered in estimating installation schedules for emission control technologies include:

- Does the emission source need to be out of service to complete the installation?
- If a shutdown is required, when is the next maintenance shutdown (turnaround) planned for that emission unit? Turnarounds (TARs) occur once every 5 to 7 years. 2016 was the most recent refinery TAR.
- Can the engineering design, equipment procurement, construction contracts and construction planning be accomplished prior to the next scheduled maintenance shutdown?
- Can funding for the project be approved before the next TAR?
- Can air quality permits be obtained prior to the start of construction? This would include and construction activities which are needed to occur prior to the TAR.

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[4] Northern Michigan University Ripley Heating Plant – PSD Appeal No. 08-02 before the US EPA Environmental Appeals Board and Petition Numbers IV-2008-1 and IV-2008-2 to the US EPA for re-consideration of Title V/PSD Air Quality Permit #V-07-017 for Cash Creek Generation, LLC facility located in Henderson, Kentucky.

## Step 3 - Rank Technically Feasible Technologies by Control Effectiveness

All technically feasible technologies are ranked in order of overall control effectiveness. Rankings are based on the level of emission control expressed as emissions per unit of production, emissions per unit of energy used, the concentration of a pollutant emitted from the source, control efficiency, or a similar measure. The control effectiveness listed will be representative of the level of emission control which can be achieved by the control technology at the operating conditions of the emission unit being reviewed. If the most effective control technology is selected as BACT, then Step 4 need not be completed.

## Step 4 - Evaluate Technically Feasible Control Technologies

The economic, environmental, and energy impacts of each technically feasible control technology are evaluated. Step 4 is only required if the most effective control technology is not proposed as BACT. As the top control technology was chosen in all cases, the economic, environmental, and energy impact analyses were not required for this evaluation.

The environmental impact analysis assesses collateral environmental impacts associated with control of the regulated pollutant in question. Impacts considered may include solid or hazardous waste generation, wastewater discharges from a control device, visibility impacts, collateral increases in emissions of other criteria or non-criteria pollutants, increased water consumption, and land use. The environmental impact analysis is conducted based on consideration of site-specific circumstances.

The energy impact analysis considers whether use of an emission control technology results in any significant or unusual energy penalties or benefits. Energy use may be evaluated on an energy used per unit of production basis; energy used per ton of pollutant controlled or total annual energy use. Energy impacts may consider whether or not use of an emission control technology will have an adverse impact on local energy supplies due to increased fuel consumption or the loss of fuel production or power generation.

## Step 5 - Select BACT

Based on technical considerations and economic, environmental and energy impacts the proposed BACT for each emissions unit will include:

- A pollutant-specific emission control technology as BACT, or a combination of controls when appropriate
- Document approach is consistent with NSPS requirements (BACT floor) i.e. equal to, or more stringent than the applicable NSPS.

Relevant RBLC determinations are discussed for comparison purposes.

# 3.0 Overview of Available Control Technologies

Available emission control technologies for the $PM_{2.5}$ SIP pollutants evaluated in this report are listed in Table 3-1. This table summarizes the results of Step 1 of the BACT analysis to identify all available control technologies. Further evaluation of these control technologies for each emissions unit is completed in the remainder of this report.

**Table 3-1 Available Emission Control Technologies**

| Pollutant | Control Technology |
|---|---|
| $PM_{2.5}$ | **Add On $PM_{2.5}$ Control Technologies** |
| | Wet Gas Scrubber |
| | Electrostatic Precipitator (ESP) |
| | Drift Eliminator Upgrades |
| | **Other $PM_{2.5}$ Control Options** |
| | Use of Natural Gas |
| | Good Design Methods and Operating Practices |
| | Flare Gas Recovery |
| | Flare Management Plan |
| | Flare Cap |
| | Flare Combustion Efficiency |
| | Current Drift Eliminators and Good Operating Practices |
| | Electric Motor |
| | Ultra-Low Sulfur Diesel |
| | Comply with emergency engine requirements of MACT ZZZZ |
| | Replace engine with Tier 4 Engine |
| $SO_2$ | **Add On $SO_2$ Control Technologies** |
| | Wet Gas Scrubber |
| | Off Gas Scrubber |
| | Add on Caustic Spray tower scrubbers on heater exhaust |
| | Tail Gas Treatment Unit |
| | Standby Secondary Tail Gas Treatment Unit |
| | **Other $SO_2$ Control Technologies** |
| | Feed Hydrotreating |
| | DeSOx Catalyst |
| | Use of Low Sulfur Natural Gas |
| | Low $H_2S$ content fuel gas |
| | Polishing amine or caustic scrubber after existing amine scrubbing system |
| | Good Design Methods and Operating Practices |
| | Sulfur Recovery Unit and Tail Gas Treatment Unit Reliability Upgrades |
| | Sulfur Shedding Plan |
| | Flare Gas Recovery |
| | Flare Management Plan |
| | Flare Cap |
| | Flare Combustion Efficiency |
| | Electric Motor |

| Pollutant | Control Technology |
|---|---|
| | Ultra-Low Sulfur Diesel |
| | Comply with emergency engine requirements of MACT ZZZZ |
| $NO_X$ | **Add On $NO_X$ Control Technologies** |
| | $LoTO_X$ |
| | Low $NO_X$ Burners (LNB)/Ultra Low $NO_X$ Burners (ULNB) |
| | Selective Catalytic Reduction (SCR) |
| | Selective Non-Catalytic Reduction (SNCR)/Enhanced SNCR |
| | Catalytic Converter |
| | Catalytic Converter with 3-way catalyst |
| | **Other $NO_X$ Control Technologies** |
| | Feed Hydrotreating |
| | $NO_X$ Reduction Additives |
| | Use of Natural Gas |
| | Good Design Methods and Operating Practices |
| | Steam/Water Injection |
| | SoLoNOx (Combustion Control) Technology |
| | Solar Turbines Advanced Combustion Controls |
| | Flare Gas Recovery |
| | Flare Management Plan |
| | Flare Cap |
| | Flare Combustion Efficiency |
| | Electric Motor |
| | Comply with emergency engine requirements of MACT ZZZZ |
| | Replace engine with Tier 4 engine |
| | Use of Gaseous Fuel |
| | Operate temporary boiler on temporary basis per 40 CFR 60.41b |
| VOC | **Add on VOC Control Technologies** |
| | CO Boiler (COB) with Good Combustion Practices |
| | Catalytic Control |
| | Catalytic Oxidation |
| | Thermal Oxidation |
| | Vapor Recovery System |
| | Vapor Combustion Unit |
| | Flare |
| | Carbon Adsorption |
| | **Other VOC Control Technologies** |
| | CO Promoter Catalyst Additive |

| Pollutant | Control Technology |
|---|---|
| | VOC Promoter with ESP |
| | Good Design Methods and Operating Procedures |
| | Use of Natural Gas |
| | LDAR Program |
| | API Separator Floating Covers |
| | API Separator Floating Roof Covers meeting QQQ Standards |
| | Replace uncontrolled drains |
| | Retrofit controls |
| | Controlled Drains at QQQ Process Units |
| | Flare Gas Recovery |
| | Flare Management Plan |
| | Flare Cap |
| | Flare Combustion Efficiency |
| | Comply with emergency engine requirements of MACT ZZZZ |
| | Replace engine with Tier 4 engine |
| | Compliance with 40 CFR Part 63, Subpart CC |
| | Low emitting drift eliminators |
| | Electric Motor |
| | NSPS Kb Controls |
| | RSR Controls |
| | Degassing controls when storage tanks are taken out of service |
| | Vent tank to a Control Device |
| | Retrofit to an IFR |
| | Dome Retrofit |
| | Installation of a vapor recovery system VOC control |
| Ammonia | **Add-on Ammonia Control** |
| | CO Boiler (COB) |
| | Water Based Strippers |
| | Thermal Oxidation |
| | **Other Ammonia Control Technologies** |
| | Good design methods and operating procedures |
| | Use of Natural Gas |
| | Flare Gas Recovery |
| | Flare Management Plan |

# 4.0 BACT for Fluidized Catalytic Cracking Unit (FCCU) and Carbon Monoxide Boiler (COB)

In the FCCU process, coke is formed on the FCCU catalyst and must be removed in the regenerator to maintain catalyst performance. In the regenerator, combustion air is added to burn off the coke in the catalyst. The regenerator is operated in partial burn mode, in which the regenerator is operated to produce Carbon Monoxide (CO), which fuels the downstream CO Boiler (COB). Regenerator off-gas is analyzed by O2, CO, and CO2 continuous emission monitoring systems (CEMS) prior to entry to the COB. Spare CO, O2, and CO2 analyzers are also installed and can be switched to at any time to minimize CEMS downtime.

The COB is used to recover residual heat from the FCCU Regenerator and create steam, while also oxidizing CO from the regenerator. To support the FCCU Reactor, residual coke from the circulated FCCU catalyst is burned off in the FCCU Regenerator so the catalyst can be reused in the reactor. The flue gas from this regeneration process is fed to the COB and is mixed with flue gases from combustion of refinery fuel gas. This mixture heats boiler feed water to create high-pressure steam. Emissions are directed out the top of the COB to the Electrostatic Precipitator (ESP) for particulate removal. The ESP acts as a control device to remove particulate matter from the COB exhaust. The ESP utilizes an electric field to impact negative charge on the catalyst fines which then attach to positively charged grids. These fines are periodically removed from the grids.

Tesoro is installing a wet gas scrubber (WGS) and LoTOx™ systems downstream of the ESP. The systems will be operational by January 1, 2018. The LoTOx™ system injects ozone into the FCCU/CO Boiler exhaust stream within the WGS. NOX compounds are oxidized with ozone to form compounds that are removed from the flue gas in the WGS. SO2 is removed from the FCCU/CO Boiler exhaust gas stream by contacting the exhaust gas with water, buffered with a sodium reagent (either sodium hydroxide, NaOH or soda ash or Na2CO), in the spray tower. These same liquid sprays also remove particulates from the flue gas. Liquid containing these compounds is collected and purged from the scrubber. It is then processed by a Purge Treatment Unit (PTU), which separates and dewaters the particulate. The system is designed to discharge a neutral pH liquid stream. The final effluent is low in total suspended solids (TSS), and contains up to 10% total dissolved solids (TDS) from sodium sulfate and sodium nitrate.

There is a bypass stack located upstream of the COB that enables emissions from the FCCU Regenerator to be discharged directly to the atmosphere, bypassing the COB and ESP, during process upset conditions. Flue gas from the regenerator enters the F-54 seal tank, which contains an exhaust stem that connects to the COB and a separate connection to the F-55 Seal Tank. The F-55 seal tank contains an exhaust stem that routes emissions to the COB/ESP Bypass Stack. Each of the two seal drums can be filled with water to create a water seal that prevents flue gas from escaping up the exhaust stem.

## 4.1 FCCU and COB $PM_{2.5}$ Emissions

Currently, an ESP is installed downstream of the COB to capture particulate matter from the COB exhaust gas. Tesoro is required by AO DAQE-AN1033350071-16 to install a Wet Gas Scrubber to further capture and control particulate matter from the COB by January 1, 2018.

### 4.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $PM_{2.5}$ emissions from a review of available information are listed in Table 3-1.

### 4.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $PM_{2.5}$ emissions are summarized in Table 4-1. The following sections provide additional detail.

**Table 4-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for FCCU and COB**

| Technology | Technically Feasible? |
|---|---|
| ESP | Yes |
| ESP + Wet Gas Scrubber | Yes |

All control technologies are technically feasible.

### 4.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 4-2, according to their control effectiveness.

**Table 4-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for FCCU and COB**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | ESP + Wet Gas Scrubber | To Be Determined | -- |
| 2 | ESP | 1 lb/1,000-lb coke burn filterable PM | Existing Control at Tesoro SLC, Meets NSPS Subpart Ja |

### 4.1.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 4.1.5 Step 5 – BACT Selection

BACT for $PM_{2.5}$ emissions from the FCCU is an ESP with a Wet Gas Scrubber. Tesoro is installing a Belco 8-6000 model wet gas scrubber, the best model offered. Tesoro is required to have the Wet Gas Scrubber operational by January 1, 2018, and complete an initial emissions performance test after startup. Recent

BACT determinations for FCCUs with a Wet Gas Scrubber show limits of 0.5-1 lb filterable PM emissions per 1000 pounds of coke burn. The NSPS Ja standard for FCCUs is 1 lb filterable PM emissions per 1000 pounds of coke burn which is consistent with Tesoro's current limit.

## 4.2 FCCU and COB $SO_2$ Emissions

$SO_2$ emissions are a result of the catalyst regeneration process. Currently, a low $SO_X$ catalyst, $DeSO_X$, is utilized to reduce $SO_2$ emissions. By January 1, 2018, a wet gas scrubber is required to be installed on the flue gas outlet downstream of the COB, further reducing $SO_2$ emissions.

### 4.2.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $SO_2$ emissions from a review of available information are listed in Table 3-1.

### 4.2.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $SO_2$ emissions are summarized in Table 4-3. The following sections provide additional detail.

**Table 4-3 Technical Feasibility of $SO_2$ Control Technologies for FCCU and COB**

| Technology | Technically Feasible? |
|---|---|
| Feed Hydrotreating | No |
| Wet Gas Scrubber | Yes |
| DeSOx Catalyst | Yes |

Hydrotreatment of the feed is considered a technically infeasible option at Tesoro. Tesoro does not have a vacuum tower to separate the vacuum gas oil from the residual oil and there is no viable technology to hydrotreat FCCU feed that contains residual oil. Since Tesoro does not have the process equipment to operate a feed hydrotreatment unit, it is not considered to be an applicable control technology.

### 4.2.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 4-4, according to their control effectiveness.

**Table 4-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for FCCU and COB**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Wet Gas Scrubber | 10 ppmvd @ 0% $O_2$ on a 365-day rolling average<br><br>18 ppmvd @ 0% $O_2$ on a 7-day rolling average | Consent Decree / AO |
| 2 | DeSOx Additive | 9.8 lb/1,000-lb | Approval Order |

### 4.2.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 4.2.5 Step 5 – BACT Selection

BACT for $SO_2$ emissions from the FCCU and COB is a Wet Gas Scrubber. This control requirement is more stringent than recent BACT determinations, with the most stringent being equivalent to the emission limitations listed for FCCUs in NSPS Ja. Tesoro will be subject to the following limits as of January 1, 2018:

- 10 ppmvd @ 0% $O_2$ on a 365-day rolling average
- 18 ppmvd @ 0% $O_2$ on a 7-day rolling average

## 4.3 FCCU and COB $NO_X$ Emissions

$NO_X$ emissions are the result of catalyst regeneration and combustion in the CO Boiler. Tesoro is required to install a $LoTO_X$ unit along with a Wet Gas Scrubber by January 1, 2018.

### 4.3.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $NO_X$ emissions from a review of available information are listed in Table 3-1.

### 4.3.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $NO_X$ emissions are summarized in Table 4-5. The following sections provide additional detail.

**Table 4-5 Technical Feasibility of $NO_X$ Control Technologies for FCCU and COB**

| Technology | Technically Feasible? |
|---|---|
| Feed Hydrotreating | No |
| $NO_X$ Reduction Additives | No |
| $LoTO_X$ | Yes |
| Low $NO_X$ Burners | No |
| SCR | Yes |
| SNCR/Enhanced SNCR | Yes |

As discussed in 4.2.2, Tesoro does not have the required process equipment to operate a feed hydrotreatment unit, and therefore a hydrotreatment unit is not considered further for analysis.

As indicated by multiple vendors, $NO_X$ reduction additives are not effective reducing agents in partial combustion FCCU's. As Tesoro operates a partial combustion FCCU, $NO_X$ reduction additives are not feasible and are not considered further for analysis.

Most $NO_X$ emissions from the COB are due to the oxidation of reduced nitrogen compounds entering the COB in the catalyst regenerator off gas. Low $NO_X$ Burners (LNB) in the COB have no effect on fuel-based $NO_X$ formation, and therefore are not considered further for analysis.

### 4.3.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 4-6, according to their control effectiveness.

**Table 4-6 Control Effectiveness Ranking of $NO_X$ Control Technologies for FCCU and COB**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | $LoTO_X$ | 10 ppmvd @ 0% $O_2$ on a 365-day rolling average<br><br>20 ppmvd @ 0% $O_2$ on a 7-day rolling average | Consent Decree / AO |
| 2 | SCR | 20 ppm at 0% $O_2$ | Vendor Information |
| 3 | SNCR/Enhanced SNCR | 60 ppmv @ 0% $O_2$ | Vendor information |

### 4.3.4 Step 4 – Evaluation of Feasible Control Technologies

The installation of SCR, SNCR, or enhanced SNCR results in ammonia slip and incremental condensable PM emissions. The installation of these units may require the installation of a wet gas scrubber for ammonium nitrates and sulfate control.

Tesoro plans to install a LoTO$_X$ unit, which is the top control efficiency, and therefore no cost evaluation is required. The use of LoTO$_X$ eliminates ammonia slip, but will increase the nitrates in the wastewater and increases electricity use due to the ozone generators.

### 4.3.5 Step 5 – BACT Selection

BACT for $NO_X$ emissions from the FCCU and COB is a LoTO$_X$ unit. This is consistent with recent BACT determinations, with the most stringent being:

- 10 ppmvd @ 0% $O_2$ on a 365-day rolling average
- 20 ppmvd @ 0% $O_2$ on a 7-day rolling average

Recent BACT and LAER determinations for NOx emissions from FCCUs are more stringent than the BACT floor emission limits for $NO_X$ from FCCUs listed in NSPS Ja.

## 4.4 FCCU and COB VOC Emissions

VOC is the result of catalyst regeneration. Currently, Tesoro operates a COB to reduce the VOC emissions.

### 4.4.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 4.4.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 4-7. The following sections provide additional detail.

**Table 4-7 Technical Feasibility of VOC Control Technologies for FCCU and COB**

| Technology | Technically Feasible? |
|---|---|
| COB with Good Combustion Practices | Yes |
| VOC Promoter with ESP | No |
| Add-on Catalytic Control | No |
| CO Promoter Catalyst Additive | No |

A VOC Promoter with an ESP works well with full burn regeneration, however since Tesoro uses partial burn regeneration this technology is infeasible and is not considered for further analysis. Also, a CO promoter catalyst additive can only be used in full burn FCCU catalyst regenerators, a CO promoter is infeasible and not considered further.

Due to the extremely low concentration of VOCs in the exhaust stream following the COB, add on catalytic control is not technically feasible and is not considered for further analysis.

### 4.4.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 4-8, according to their control effectiveness.

**Table 4-8 Control Effectiveness Ranking of VOC Control Technologies for FCCU and COB**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | COB with Good Combustion Practices | 0.005 lb/MMBtu | AP-42 Table 1.4-2 |

### 4.4.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is already installed.

### 4.4.5 Step 5 – BACT Selection

BACT for VOC emissions from the FCCU and COB is a COB with good combustion practices. This proposal is consistent with recent RBLC determinations for FCCUs. During unit startup or shutdown, good combustion practices will be followed in order to minimize VOC emissions.

## 4.5 FCCU and COB Ammonia Emissions

The operation of catalyst regeneration on partial burn mode generates ammonia and reduced nitrogen compounds. These reduced nitrogen compounds are oxidized in the COB.

### 4.5.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for Ammonia emissions from a review of available information are listed in Table 3-1.

### 4.5.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for Ammonia emissions are summarized in Table 4-9. The following sections provide additional detail.

**Table 4-9 Technical Feasibility of Ammonia Control Technologies for FCCU and COB**

| Technology | Technically Feasible? |
|---|---|
| COB | Yes |
| Add-on Ammonia Control | No |

Ammonia created due to combustion is present in extremely low concentrations within the outlet stream of the FCCU and COB, lower than add-on control technology is able to achieve. Therefore, add-on ammonia control technology is infeasible and is not considered further.

### 4.5.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 4-10, according to their control effectiveness.

**Table 4-10 Control Effectiveness Ranking of Ammonia Control Technologies for FCCU and COB**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | COB | 60 ppmv @ 0% $O_2$ | EEP, Section 5 – Process Vents, Table 5-4 |

It should be noted that Tesoro's plan to install a wet gas scrubber has the potential to reduce ammonia emissions, as the best in class wet gas scrubber is planned to be installed.

### 4.5.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 4.5.5 Step 5 – BACT Selection

BACT for ammonia emissions from the FCCU is the operation of a COB. This proposal is consistent with recent RBLC determinations for FCCUs. During unit startup or shutdown, good combustions practices will be followed in order to minimize ammonia emissions.

# 5.0 BACT for Process Heaters

The refinery has six fired process heaters:

- H-101 Crude Unit Furnace
- F-1 Ultraformer Unit Furnace
- F-15 Ultraformer Regeneration Heater
- F-680 DDU Charge Heater
- F-681 DDU Rerun Boiler
- F-701 GHT Unit Heater

The emissions from these process heaters are discussed in total in the sections which follow.

## 5.1 Process Heaters $PM_{2.5}$ Emissions

According to the AP-42 emission factors, particulate matter emissions from combustion of gaseous fuels are typically low and consist of filterable and condensable fractions.

### 5.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $PM_{2.5}$ emissions from a review of available information are listed in Table 3-1.

### 5.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $PM_{2.5}$ emissions are summarized in Table 5-1. The following sections provide additional detail.

**Table 5-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for Process Heaters**

| Technology | Technically Feasible? |
|---|---|
| Use of Natural Gas | No |
| Good Design Methods and Operating Practices | Yes |
| Add On $PM_{2.5}$ Control | No |

$PM_{2.5}$ concentration in the flue gas is well below the range achievable by add-on control devices, and thus post-combustion $PM_{2.5}$ control is technically infeasible.

The use of a clean fuel, natural gas, instead of refinery fuel gas is not feasible for Tesoro. Importing natural gas for combustion in the process heaters would result in diversion of the excess fuel gas to the flare, which may result in flow rates to the flares in excess of the permitted refinery flare cap and no facility-wide net reduction in emissions.

### 5.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 5-2, according to their control effectiveness.

**Table 5-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for Process Heaters**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Good Design Methods and Operating Practices | 0.0075 lb/MMBtu | AP-42 Table 1.4-2 |

### 5.1.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 5.1.5 Step 5 – BACT Selection

Since add-on control devices for $PM_{2.5}$ is not feasible, BACT for $PM_{2.5}$ emissions from the process heaters is good design methods and operating practices. This proposal is consistent with recent RBLC determinations for fuel gas process heaters. During unit startup or shutdown, good operating practices will be followed in order to minimize PM emissions.

## 5.2 Process Heaters $SO_2$ Emissions

$SO_2$ emissions from combustion of refinery fuel gas arise from trace amounts of sulfur present in the fuel. Currently, Tesoro treats their fuel gas to remove $H_2S$.

### 5.2.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $SO_2$ emissions from a review of available information are listed in Table 3-1.

### 5.2.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $SO_2$ emissions are summarized in Table 5-3. The following sections provide additional detail.

**Table 5-3 Technical Feasibility of $SO_2$ Control Technologies for Process Heaters**

| Technology | Technically Feasible? |
|---|---|
| Use of Low Sulfur Natural Gas | No |
| Low $H_2S$ content fuel gas | Yes |
| Polishing amine or caustic scrubber after existing amine scrubbing system | No |
| Off Gas Scrubber | No |
| Add on Caustic Spray tower scrubbers on heater exhaust | No |

The use of a clean fuel, natural gas, instead of refinery fuel gas is not feasible for Tesoro. Importing natural gas for combustion in the process heaters would result in diversion of the excess fuel gas to the flare, which may result in flow rates to the flares in excess of the permitted refinery flare cap and no facility-wide net reduction in emissions.

$SO_2$ concentration in the process heater stacks are below 5 ppm, which is below the levels current off gas scrubbers and add-on caustic spray towers can meet. Therefore, add on scrubbers are technically infeasible.

Low $H_2S$ content fuel gas is used at Tesoro. With the current equipment, Tesoro can reliably achieve $H_2S$ concentrations of less than or equal to 60 ppm on an annual average in their fuel gas. Although a secondary polishing amine or caustic scrubber downstream of the existing amine scrubber may be feasible to further reduce the $H_2S$ concentration in the fuel gas, such technology is not able to be designed, installed, and in operation prior to December 31, 2018. Therefore, a secondary polishing scrubber is technically infeasible.

### 5.2.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 5-4, according to their control effectiveness.

**Table 5-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for Process Heaters**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Low $H_2S$ content fuel gas | Existing system (less than 60 ppm $H_2S$ on an annual average, 162 ppm on a 3-hour average) | NSPS Subpart Ja |

### 5.2.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 5.2.5 Step 5 – BACT Selection

BACT for $SO_2$ emissions from the process heaters is the use of low $H_2S$ content fuel gas. Recent RBLC determinations range from 25 ppm $H_2S$ on an annual average to 100 ppm $H_2S$ on a 24 hour average in the fuel gas, while the NSPS Ja limit is 60 ppm $H_2S$ on an annual average and 162 ppm $H_2S$ on a 3 hour average. As discussed in Step 2, Tesoro cannot reliably achieve 25 ppm $H_2S$ on an annual average or 100 ppm $H_2S$ on a 24-hr average with existing equipment. Therefore, compliance with the NSPS Ja limits represent BACT.

## 5.3 Process Heaters VOC Emissions

VOC emissions from the process heaters are a result of incomplete combustion of the refinery fuel gas.

### 5.3.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 5.3.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 5-5. The following sections provide additional detail.

**Table 5-5 Technical Feasibility of VOC Control Technologies for Process Heaters**

| Technology | Technically Feasible? |
|---|---|
| Good Design Methods and Operating Procedures | Yes |
| Use of Natural Gas | No |
| Catalytic Oxidation | No |
| Thermal Oxidation | No |

All VOC control techniques seek to oxidize products of incomplete combustion, with excess oxygen typically present.

The application of thermal oxidation or catalytic oxidation technology within a process heater is concluded to not be technically feasible. Thermal oxidation and catalytic oxidation has been shown to be ineffective below VOC concentrations of 100 ppm. The concentration in process heater exhaust streams are estimated to be below 13 ppm, making thermal or catalytic oxidation technically infeasible.

The use of a clean fuel, natural gas, instead of refinery fuel gas is not feasible for Tesoro. Importing natural gas for combustion in the process heaters would result in diversion of the excess fuel gas to the flare, which may result in flow rates to the flares in excess of the permitted refinery flare cap and no facility-wide net reduction in emissions.

### 5.3.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 5-6, according to their control effectiveness.

**Table 5-6 Control Effectiveness Ranking of VOC Control Technologies for Process Heaters**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Good Design Methods and Operating Procedures | 0.0055 lb/MMBtu | AP-42 Table 1.4-2 |

### 5.3.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 5.3.5 Step 5 – BACT Selection

BACT for VOC from the process heaters is using good design methods and operating procedures. This proposal is consistent with recent RBLC determinations, with recent limits being 0.005 lb/MMBtu on a 1 hour average. During unit startup or shutdown, good operating practices will be followed in order to minimize VOC emissions.

## 5.4 Process Heaters Ammonia Emissions

Ammonia emissions are the result of combustion, and according to the EPA WebFIRE emission factors are extremely low (0.0031 lb/MMBtu) for natural gas combustion.

### 5.4.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for Ammonia emissions from a review of available information are listed in Table 3-1.

### 5.4.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for Ammonia emissions are summarized in Table 5-7. The following sections provide additional detail.

**Table 5-7 Technical Feasibility of Ammonia Control Technologies for Process Heaters**

| Technology | Technically Feasible? |
|---|---|
| Add-on Ammonia Control | No |
| Good design methods and operating procedures | Yes |

Due to the extremely low concentration of ammonia in the flue gas (0.0031 lb generated per MMBtu of heat input), any add on ammonia control is technically infeasible. For exhaust streams with higher concentrations, control technologies such as water-based strippers and thermal oxidation are typical add-on ammonia control technologies.

### 5.4.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 5-8, according to their control effectiveness.

**Table 5-8 Control Effectiveness Ranking of Ammonia Control Technologies for Process Heaters**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Good design methods and operating procedures | 0.0031 lb/MMBtu | EPA WebFIRE Database |

### 5.4.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 5.4.5 Step 5 – BACT Selection

BACT for ammonia from the process heaters is using good design methods and operating procedures. There are no BACT determinations for ammonia generated from combustion. During unit startup or shutdown, good operating practices will be followed in order to minimize ammonia emissions.

## 5.5 Process Heaters $NO_X$ Emissions

There are three mechanisms by which NOx production occurs during combustion including thermal, fuel, and prompt NOx formation. In the case of gaseous fuel combustion, the primary mechanism of NOx formation is through thermal NOx formation. The H-101, F-1, F-680, and F-681 process heaters have ULNB currently installed to assist with reducing NOx formed from the fuel. Process heaters F-15 and F-701 have LNB currently installed.

### 5.5.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $NO_X$ emissions from a review of available information is listed in Table 3-1.

### 5.5.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $NO_X$ emissions are summarized in Table 5-9 and Table 5-10. The following sections provide additional detail.

**Table 5-9 Technical Feasibility of $NO_X$ Control Technologies for Process Heaters with ULNB Installed (H-101, F-1, F-680, and F-681)**

| Technology | Technically Feasible? |
|---|---|
| ULNB | Yes |
| SCR + ULNB | No |
| SNCR + ULNB | No |

**Table 5-10 Technical Feasibility of $NO_X$ Control Technologies for Process Heaters with LNB Installed (F-15, F-701)**

| Technology | Technically Feasible? |
|---|---|
| ULNB | No |
| LNB + SCR/SNCR | No |
| SCR + ULNB | No |
| SNCR + ULNB | No |

There is no plot space available for an SCR reactor at H-101 or F-1. Tesoro is limited by rail tracks and the Salt Lake City sewer line easement restrictions in the immediate area where an SCR reactor would be placed. Although the addition of SCR or SNCR to the heater may be feasible for other heaters, such

technology is not able to be designed, installed, and in operation prior to December 31, 2018. Therefore, ULNB with SCR or SNCR is considered technically infeasible for all process heaters.

As F-15 and F-701 both use Low NOx burners, it may be theoretically feasible to upgrade the burners to ULNB; a detailed engineering review has not been completed and would be necessary to determine if technically feasible for the noted heaters. Regardless, such technology is not able to be designed, installed, and in operation prior to December 31, 2018. Therefore, an upgrade to ULNB is considered technically infeasible for F-15 and F-701. In addition burner impingement is a significant concern when retrofitting small furnace boxes such as F-15 and F-701 with ULNB tips.

### 5.5.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 5-11, according to their control effectiveness.

**Table 5-11 Control Effectiveness Ranking of $NO_X$ Control Technologies for Process Heaters**

| Heater | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| F-1 | ULNB | 0.04 – 0.065 lb/MMBtu | Approval Order |
| H-101 | | 0.054 lb/MMBtu | Approval Order |
| F-680 | | 0.049 lb/MMBtu | Approval Order |
| F-681 | | 0.052 lb/MMBtu | Approval Order |
| F-15 | LNB | 0.079 lb/MMBtu | Approval Order |
| F-701 | | 0.074 lb/MMBtu | Approval Order |

### 5.5.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required. The top technically feasible control for each heater based upon current control technology is selected.

### 5.5.5 Step 5 – BACT Selection

$NO_X$ from process heaters is the existing burner configuration because upgrades are technically infeasible.

NSPS Ja for heaters greater than 40 MMBtu/hr with a natural draft must be less than 0.04 lb/MMBtu (or 40 ppmvd @ 0% excess air). Forced draft must be less than 0.06 lb/MMBtu (60 ppmvd @ 0% excess air) regardless of size. However, NSPS Ja standards for $NO_x$ do not apply to any of these process heaters, and process heaters F-15 and F-701 have capacities less than 40 MMBtu/hr.

# 6.0 BACT for Cogeneration Units

The Cogeneration system consists of two turbine trains, designated as the East and West Cogen system trains. Each turbine burns both natural gas and SRU Sweet Gas; natural gas serves as the primary fuel for the combustion turbines while supplemental refinery fuel gas consists of up to 30% of the mixture. The combustion exhaust drives a turbine to produce electricity for the refinery and electrical grid, and is then sent to the heat recovery steam generators (HRSG). The HRSG produces steam for the refinery. The HRSG is fired with refinery fuel gas. There are no add-on or tail gas emission controls. Passive $NO_X$ control on the turbine is accomplished by the SoLoNO$_X$ lean pre-mix combustion technology.

## 6.1 Cogeneration Units $PM_{2.5}$ Emissions

According to the AP-42 emission factors, particulate matter emissions from combustion of gaseous fuels are typically low and consist of filterable and condensable fractions.

### 6.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $PM_{2.5}$ emissions from a review of available information are listed in Table 3-1.

### 6.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $PM_{2.5}$ emissions are summarized in Table 6-1. The following sections provide additional detail.

**Table 6-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for Cogeneration Units**

| Technology | Technically Feasible? |
|---|---|
| Use of Natural Gas | No |
| Good Design Methods and Operating Procedures | Yes |
| Add-on $PM_{2.5}$ control | No |

$PM_{2.5}$ concentration in the flue gas is well below the range achievable by add-on control devices, and thus post-combustion $PM_{2.5}$ control is technically infeasible.

The use of a clean fuel, natural gas, instead of refinery fuel gas is not feasible for Tesoro. Importing natural gas for exclusive combustion in the turbines and HRSGs would result in diversion of the excess fuel gas to the flare, which may result in flow rates to the flares in excess of the permitted refinery flare cap and no facility-wide net reduction in emissions. Also, the operation of the Cogen units to burn fuel gas is listed as a flaring minimization measure in the Consent Decree Flare Management Plan and NSPS Ja.

### 6.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 6-2, according to their control effectiveness.

**Table 6-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for Cogeneration Units**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Good Design Methods and Operating Procedures | 0.0075 lb/MMBtu | AP-42 Table 1.4-2 |

### 6.1.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 6.1.5 Step 5 – BACT Selection

Since add-on control devices for $PM_{2.5}$ is not feasible and a switch to 100% natural gas firing would not result in a facility-wide decrease in emissions, BACT for $PM_{2.5}$ emission from the Cogens is good design methods and operating practices. This proposal is consistent with recent RBLC determinations for cogeneration turbines of 0.0075 lb/MMBtu on a 3 hour average. During unit startup or shutdown, good operating practices will be followed in order to minimize PM emissions.

## 6.2 Cogeneration Units $SO_2$ Emissions

$SO_2$ emissions from combustion of refinery fuel gas arise from trace amounts of sulfur present in the fuel. Each turbine fires a mixture of SRU Sweet Gas and natural gas. The combined gas to the turbines is generally less than 25 ppm $H_2S$ on an annual average. Each HRSG fires refinery fuel gas, which is treated to remove $H_2S$ and meets NSPS Ja standard of 60 ppm $H_2S$ on an annual average.

### 6.2.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $SO_2$ emissions from a review of available information are listed in Table 3-1.

### 6.2.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $SO_2$ emissions are summarized in Table 6-3. The following sections provide additional detail.

**Table 6-3 Technical Feasibility of $SO_2$ Control Technologies for Cogeneration Units**

| Technology | Technically Feasible? |
|---|---|
| Use of Natural Gas | No |
| Low $H_2S$ content fuel gas | Yes |
| Polishing amine or caustic scrubber after existing amine scrubbing system | No |
| Off Gas Scrubber | No |
| Add on Caustic Spray tower scrubbers on heater exhaust | No |

The exclusive use of a clean fuel, natural gas, instead of refinery fuel gas is not feasible for Tesoro. Importing natural gas for exclusive combustion in the turbines and HRSGs would result in diversion of the excess fuel gas to the flare, which may result in flow rates to the flares in excess of the permitted refinery flare cap and no facility-wide net reduction in emissions. Also, the operation of the Cogen units to burn fuel gas is listed as a flaring minimization measure in the Consent Decree Flare Management Plan.

$SO_2$ concentration in the Cogen stack is below 8 ppm @ 0% O2 on an annual average, which is below the levels current off gas scrubbers and add-on caustic spray towers can meet. Therefore, add on scrubbers are technically infeasible.

Although a secondary polishing amine or caustic scrubber downstream of the existing amine scrubber may be feasible, such technology is not able to be designed, installed, and in operation prior to December 31, 2018. Therefore, a secondary polishing scrubber is technically infeasible.

### 6.2.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 6-4, according to their control effectiveness.

**Table 6-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for Cogeneration Units**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Low $H_2S$ content fuel gas | HSRG: Existing system (less than 60 ppm $H_2S$ on an annual average, 162 ppm $H_2S$ on a 3-hour average)<br><br>Turbines: Existing system (less than 25 ppm $H_2S$ in the combined gas on an annual average) | NSPS Subpart Ja |

### 6.2.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control options are selected.

### 6.2.5 Step 5 – BACT Selection

BACT for $SO_2$ emissions from the Cogens is the use of low $H_2S$ content fuel gas meeting NSPS Ja standards.

Recent RBLC determinations range from 25 ppm $H_2S$ on an annual average to 100 ppm $H_2S$ on a 24 hour average in the fuel gas, while the NSPS Ja limit is 60 ppm $H_2S$ on an annual average and 162 ppm $H_2S$ on a 3 hour average. As discussed in Step 2, Tesoro cannot reliably achieve 25 ppm $H_2S$ on an annual average or 100 ppm $H_2S$ on a 24-hr average for the refinery fuel gas fired at the HRSGs with existing equipment. Therefore, compliance with the NSPS Ja limits represent BACT for the HRSGs

Tesoro can achieve 25 ppm $H_2S$ on an annual average at the turbines with the existing equipment. The combined high pressure natural gas and refinery fuel gas combusted in the turbines meet the NSPS Ja limits of 60 ppm $H_2S$ on an annual average and 162 ppm $H_2S$ on a 3 hour average. Therefore, compliance with the NSPS Ja limits represent BACT for the Turbines.

## 6.3 Cogeneration Units $NO_X$ Emissions

There are three mechanisms by which NOx production occurs during combustion including thermal, fuel, and prompt NOx formation. In the case of gaseous fuel combustion, the primary mechanism of NOx formation is through thermal NOx formation. The Cogen turbines utilize SoLoNOx™ controls to reduce the NOx emissions by a lean-premix technology to optimize the air/fuel mixture.

### 6.3.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $NO_X$ emissions from a review of available information are listed in Table 3-1.

### 6.3.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $NO_X$ emissions are summarized in Table 6-5. The following sections provide additional detail.

**Table 6-5 Technical Feasibility of $NO_x$ Control Technologies for Cogeneration Units**

| Technology | Technically Feasible? |
|---|---|
| SoLoNOx Technology | Yes |
| Solar Turbines Advanced Combustion Controls | No |
| SCR | No |
| SNCR | No |
| Steam/Water Injection | No |

Although SCR, SNCR, and Solar advanced combustion controls may feasible technologies, it is not feasible to design, install, and begin to operate any of these technologies prior to December 31, 2018. Therefore, SCR, SNCR, and Solar advance combustion controls are technically infeasible.

Tesoro contacted the manufacturer of the Cogens to determine if steam/water Injection may be feasible. This control system is not available for Tesoro's Solar Cogens and is therefore considered technically infeasible.

### 6.3.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 6-6, according to their control effectiveness.

**Table 6-6 Control Effectiveness Ranking of $NO_x$ Control Technologies for Cogeneration Units**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | SoLoNOx Technology | 32 ppm @ 15% $O_2$ | SOLAR performance guarantee |
| | | 18 ppm @ 15% $O_2$ | Performance test results |

### 6.3.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control options are selected.

### 6.3.5 Step 5 – BACT Selection

BACT for $NO_x$ emissions from the Cogens is the continuation of the SoLoNOx Technology. The most recent BACT determination from the RBLC database include limits of 15 ppm @ 15% $O_2$ for SoLoNOx technology in 2010, with newer technology than was available when the Cogen units were installed. Additional controls are technically infeasible by December 31, 2018.

## 6.4 Cogeneration Units VOC Emissions

VOC emissions from the Cogens are a result of incomplete combustion of the natural gas and fuel gas.

### 6.4.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 6.4.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 6-7. The following sections provide additional detail.

**Table 6-7 Technical Feasibility of VOC Control Technologies for Cogeneration Units**

| Technology | Technically Feasible? |
|---|---|
| Good Design Methods and Operating Procedures | Yes |
| Use of Natural Gas | No |
| Catalytic Oxidation | No |
| Thermal Oxidation | No |

All VOC control techniques seek to oxidize products of incomplete combustion, with excess oxygen typically present.

The application of thermal oxidation or catalytic oxidation technology following the Cogens is concluded to not be technically feasible. Thermal oxidation and catalytic oxidation has been shown to be ineffective below VOC concentrations of 100 ppm. The concentration in the Cogen exhaust streams are estimated to be below 13 ppm, making thermal or catalytic oxidation technically infeasible.

The use of a clean fuel, natural gas, instead of refinery fuel gas is not feasible for Tesoro. Importing natural gas for exclusive combustion in the turbines and HRSGs would result in diversion of the excess fuel gas to the flare, which may result in flow rates to the flares in excess of the permitted refinery flare cap and no facility-wide net reduction in emissions. Also, the operation of the Cogen units to burn fuel gas is listed as a flaring minimization measure in the Consent Decree Flare Management Plan.

### 6.4.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 6-8, according to their control effectiveness.

**Table 6-8 Control Effectiveness Ranking of VOC Control Technologies for Cogeneration Units**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Good Design Methods and Operating Procedures | 0.0021 lb/MMBtu | AP-42 Table 3.1-2a |

### 6.4.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 6.4.5 Step 5 – BACT Selection

BACT for VOC from the Cogens is using good design methods and operating procedures. This proposal is consistent with recent RBLC determinations for cogeneration turbines, with limits of 0.005 lb/MMbtu on a 3 hour average. During unit startup or shutdown, good design methods and operating practices will be followed in order to minimize VOC emissions.

## 6.5 Cogeneration Units Ammonia Emissions

Ammonia emissions from the Cogen units are the result of combustion.

### 6.5.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for Ammonia emissions from a review of available information are listed in Table 3-1.

### 6.5.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for Ammonia emissions are summarized in Table 6-9. The following sections provide additional detail.

**Table 6-9 Technical Feasibility of Ammonia Control Technologies for Cogeneration Units**

| Technology | Technically Feasible? |
|---|---|
| Good Design Methods and Operating Procedures | Yes |
| Add-on ammonia control | No |

Due to the extremely low concentration of ammonia in the Cogen flue gas (0.0031 lb generated per MMBtu of heat input), any add on ammonia control is technically infeasible. For exhaust streams with higher concentrations, control technologies such as water-based strippers and thermal oxidation are typical add-on ammonia control technologies.

### 6.5.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 6-10, according to their control effectiveness.

**Table 6-10 Control Effectiveness Ranking of Ammonia Control Technologies for Cogeneration Units**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Good Design Methods and Operating Procedures | 2 ppmvd @ 15% $O_2$ | EPA WebFIRE Emission Factor (0.0031 lb/MMBtu) |

### 6.5.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 6.5.5 Step 5 – BACT Selection

BACT for ammonia emissions from the Cogen units is good design methods and operating procedures. This proposal is consistent with recent RBLC determinations of 2 ppmvd @ 15% $O_2$ for cogeneration turbines. During unit startup or shutdown, good design methods and operating practices will be followed in order to minimize ammonia emissions.

# 7.0 BACT for Sulfur Recovery Unit (SRU)

The Sulfur Recovery Unit (SRU) complex reduces sulfur emissions from refinery processes by removing $H_2S$ from the refinery sour water and sour fuel gas systems and converting it into elemental sulfur. In the SRU process, the sour water stripper acid gas and amine acid gas are sent to a burner to convert some of the $H_2S$ to $SO_2$ and all of the ammonia to nitrogen. The heated gas mixture is fed to the first of three reactor stages, where the $SO_2/H_2S$ mixture is converted to sulfur vapor over a catalyst bed, generating heat in the process. The elemental sulfur vapor is condensed via cooling and separated, while the remaining mixture is reheated through a heat exchanger. The cycle of gas reheated, passing the mixture over a catalyst reactor stage, and condensing the sulfur is repeated a total of three times; the remaining gas vapor, known as tail gas, is directed to the Tail Gas Treating Unit (TGTU). The liquid sulfur that is isolated from the acid gas is drained through sealed legs to a sulfur pit, where it is stored and sold as elemental sulfur product. In the TGTU, the tail gas is reduced to $H_2S$ for additional capture by an amine absorber and recycling to the front of the SRU. The outlet stream from the TGTU is routed to a thermal oxidizer to control reduced sulfur emissions. The oxidizer uses refinery fuel gas as a fuel source.

## 7.1 SRU $PM_{2.5}$ Emissions

According to the AP-42 emission factors, particulate matter emissions from combustion of gaseous fuels are typically low and consist of filterable and condensable fractions. There are no process emission factors available for SRUs.

### 7.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $PM_{2.5}$ emissions from a review of available information are listed in Table 3-1.

### 7.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $PM_{2.5}$ emissions are summarized in Table 7-1. The following sections provide additional detail.

**Table 7-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for SRU**

| Technology | Technically Feasible? |
|---|---|
| Good Design Methods and Operating Practices | Yes |
| Use of Natural Gas (Incinerator) | No |
| Add-on $PM_{2.5}$ Control | No |

$PM_{2.5}$ concentration in the flue gas is well below the range achievable by add-on control devices, and thus post-combustion $PM_{2.5}$ control is technically infeasible.

The use of a clean fuel, natural gas, instead of refinery fuel gas is not feasible for Tesoro. Importing natural gas for combustion in the incinerator may result in diversion of the excess fuel gas to the flare, which may result in flow rates to the flares in excess of the permitted refinery flare cap and no facility-wide net reduction in emissions.

### 7.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 7-2, according to their control effectiveness.

**Table 7-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for SRU**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Good Design Methods and Operating Practices | 0.0075 lb/MMBtu | AP-42 Table 1.4-2 |

### 7.1.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 7.1.5 Step 5 – BACT Selection

Since add-on control devices for $PM_{2.5}$ are not feasible, BACT for $PM_{2.5}$ emissions from the SRU is use of good design methods and operating practices. There are no BACT determinations for $PM_{2.5}$ from SRUs in the RBLC database. During unit startup or shutdown, good operating practices will be followed in order to minimize $PM_{2.5}$ emissions.

## 7.2 SRU $SO_2$ Emissions

Uncaptured $SO_2$ in the Claus unit is contained in the tail gas and is the major source of $SO_2$ from the SRU. Tesoro uses a TGTU to recover additional sulfur from the tail gas, which was installed after the 2014 SIP baseline period. During times of startup, shutdown, or malfunction, a sulfur shedding plan is utilized to reduce the amount of sulfur being sent to the SRU, reducing $SO_2$ emissions.

### 7.2.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $SO_2$ emissions from a review of available information are listed in Table 3-1.

### 7.2.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $SO_2$ emissions are summarized in Table 7-3. The following sections provide additional detail.

**Table 7-3 Technical Feasibility of $SO_2$ Control Technologies for SRU**

| Technology | Technically Feasible? |
|---|---|
| Wet Gas Scrubber | No |
| SRU and TGTU Reliability Upgrades | No |
| Standby Secondary TGTU | No |
| Sulfur Shedding Plan | Yes |
| TGTU | Yes |

Although a wet gas scrubber, standby secondary TGTU, or reliability upgrades to the TGTU/SRU may be feasible, it is not feasible to design, install, and operate any of this equipment prior to December 31, 2018. Therefore, a wet gas scrubber, standby secondary TGTU, and TGTU/SRU reliability upgrades are considered technically infeasible.

### 7.2.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 7-4, according to their control effectiveness.

**Table 7-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for SRU**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | TGTU | 95% Sulfur Recovery<br>60 tons per year | Approval Order |
| 2 | Sulfur Shedding Plan | Reduces $SO_2$ emissions by managing $H_2S$ generation in the refinery | -- |

### 7.2.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 7.2.5 Step 5 – BACT Selection

BACT for $SO_2$ emissions from the SRU is a TGTU and a sulfur shedding plan.

Recent RBLC determinations include limits of 250 ppmvd @ 0% $O_2$ on a 12-hour basis, equivalent to the NSPS Ja $SO_2$ emission limit from SRUs. Tesoro is currently unable to meet this limitation without upgrades, which are technically infeasible by December 31, 2018. During unit startup, shutdown or SRU malfunction, the refinery sulfur shedding plan will be utilized to decrease $SO_2$ emissions.

## 7.3 SRU $NO_X$ Emissions

There are three mechanisms by which NOx production occurs during combustion including thermal, fuel, and prompt NOx formation. In the case of Claus sulfur recovery, the SRU reaction furnace is operated in a reducing environment, where ammonia in the acid gas feed is reduced to $N_2$. A negligible amount of $NO_X$ is formed from thermal or fuel formation mechanisms.

### 7.3.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $NO_X$ emissions from a review of available information are listed in Table 3-1.

### 7.3.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $NO_X$ emissions are summarized in Table 7-5. The following sections provide additional detail.

**Table 7-5 Technical Feasibility of $NO_X$ Control Technologies for SRU**

| Technology | Technically Feasible? |
|---|---|
| Good Design Methods and Operating Procedures | Yes |
| Add-on NOx control | No |

NOx is assumed to be present in low concentrations within the outlet stream of the SRU unit, lower than add-on control technology is able to achieve. Therefore, add-on NOx control technology is infeasible and is not considered further.

### 7.3.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 7-6, according to their control effectiveness.

**Table 7-6 Control Effectiveness Ranking of $NO_X$ Control Technologies for SRU**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Good Design Methods and Operating Procedures | 0.10 lb/MMBtu | EEP, Section 5 – Process Vents, Table 5-7 |

### 7.3.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, because Tesoro selects the top control option.

### 7.3.5 Step 5 – BACT Selection

BACT for NOx from the SRU is using good design methods and operating procedures. This proposal is consistent with recent RBLC determinations for SRUs with Tail Gas Treatment units, ranging from 0.02 lb/MMBtu to 0.2 lb MMBtu. During unit startup or shutdown, good operating practices will be followed in order to minimize NOx emissions.

## 7.4 SRU VOC Emissions

VOCs are introduced into the SRU from the in the acid gas feed streams. VOC emissions from the SRU are a result of incomplete combustion of the fuel in the incinerator.

### 7.4.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 7.4.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 7-7. The following sections provide additional detail.

**Table 7-7 Technical Feasibility of VOC Control Technologies for SRU**

| Technology | Technically Feasible? |
|---|---|
| Good Design Methods and Operating Procedures | Yes |
| Use of Natural Gas | No |
| Catalytic Oxidation | No |
| Thermal Oxidation (Tail Gas Incinerator) | Yes |

All VOC control techniques seek to oxidize products of incomplete combustion, with excess oxygen typically present.

The application of catalytic oxidation technology is not feasible, as sulfur levels in the TGTU exhaust can poison oxidation catalysts.

The use of a clean fuel, natural gas, instead of refinery fuel gas is not feasible for Tesoro. Importing natural gas for combustion in the incinerator would result in diversion of the excess fuel gas to the flare, which may result in flow rates to the flares in excess of the permitted refinery flare cap and no facility-wide net reduction in emissions.

### 7.4.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 7-8, according to their control effectiveness.

**Table 7-8 Control Effectiveness Ranking of VOC Control Technologies for SRU**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Thermal Oxidation (Tail Gas Incinerator)<br>Good Design Methods and Operating Procedures | 0.0014 lb/MMBtu | EEP, Section 5 – Process Vents, Table 5-7 |

### 7.4.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 7.4.5 Step 5 – BACT Selection

BACT for VOC from the SRU is using the tail gas incinerator with good design methods and operating procedures. This proposal is consistent with recent RBLC determinations for SRUs, with a lowest limit of 0.0004 lb/MMBtu for a thermal oxidizer with an optimized air-fuel ratio. During unit startup or shutdown, good operating practices will be followed in order to minimize VOC emissions.

## 7.5 SRU Ammonia Emissions

The feed to the SRU contains ammonia, primarily from the sour water system overhead. Ammonia control is accomplished in the SRU by operating in sub-stoichiometric mode, creating a reducing atmosphere in which ammonia is converted to $N_2$, resulting in minimal ammonia emissions. Therefore, there are negligible ammonia emissions from the SRU and a BACT evaluation is not completed.

# 8.0 BACT for Fugitive Equipment

## 8.1 Fugitive Equipment VOC Emissions

Control strategies for volatile organic compound emissions from fugitive components are based on LDAR program work practice requirements, which identify and then reduce emissions from process equipment components.

### 8.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 8.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 8-1. The following sections provide additional detail.

**Table 8-1 Technical Feasibility of VOC Control Technologies for Fugitive Equipment**

| Technology | Technically Feasible? |
|---|---|
| LDAR Program | Yes |

### 8.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 8-2, according to their control effectiveness.

**Table 8-2 Control Effectiveness Ranking of VOC Control Technologies for Fugitive Equipment**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | LDAR Program | N/A | N/A |

### 8.1.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 8.1.5 Step 5 – BACT Selection

BACT for VOC emissions from fugitive equipment is an LDAR program, as required by 40 CFR Part 60 Subpart GGGa and Tesoro's Consent Decree. This proposal is consistent with recent RBLC determinations for fugitive emissions.

# 9.0 BACT for Refinery Wastewater System

## 9.1 Refinery Wastewater VOC Emissions

All wastewater and storm water streams within the refinery is treated in the Wastewater Treatment Plant (WWTP). Oil is recovered from the WWTP and is stored and/or reprocessed in the refinery. The API separators are fitted with floating roof covers.

### 9.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 9.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 9-1. The following sections provide additional detail.

**Table 9-1 Technical Feasibility of VOC Control Technologies for Refinery Wastewater System**

| Technology | Technically Feasible? |
|---|---|
| Good design methods and operating practices | Yes |
| API Separator Floating Covers | Yes |
| API Separator Floating Roof Covers meeting NSPS QQQ standards | No |
| Vapor Combustion Unit | No |
| Carbon Adsorption | No |

Although the addition of API separator meeting NSPS Subpart QQQ standards or vapor recovery to a vapor combustor or carbon adsorption unit may be feasible, it is not feasible to design, install, any of this equipment before December 31, 2018. Therefore, an API separator meeting QQQ standards, vapor combustion and carbon adsorption are considered technically infeasible.

### 9.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 9-2, according to their control effectiveness.

**Table 9-2 Control Effectiveness Ranking of VOC Control Technologies for Refinery Wastewater System**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | API Floating Separator Covers, Good design methods and operating practices | 0.20 lb/Mgal wastewater | AP-42 Table 5.1-3 |

### 9.1.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 9.1.5 Step 5 – BACT Selection

BACT for VOC from the waste water treatment plant is API floating separator covers with good design methods and operating practices. Although recent BACT determinations from the RBLC database show vapor combustion or carbon adsorption as BACT, it is technically infeasible to install and operate either type of equipment prior to December 31, 2018.

# 10.0BACT for Refinery Drains

## 10.1 Refinery Drains VOC Emissions

All wastewater and storm water streams within the refinery are collected and drained to the plant sewer system. The wastewater is then directed to the Wastewater Treatment Plan (WWTP) for treatment. Drains within the refinery are either controlled or uncontrolled. Controlled drains (water seal or closed system) meeting NSPS QQQ standards were installed when the DDU, GHT, BSU, and FGR were constructed. Other miscellaneous drains in the refinery are also controlled. Uncontrolled drains exist throughout the refinery in process units built prior to the NSPS QQQ standards. Currently, emissions from all drains are monitored on an annual basis per Utah Rule R307-326-9.

### 10.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 10.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 10-1. The following sections provide additional detail.

**Table 10-1 Technical Feasibility of VOC Control Technologies for Refinery Drains**

| Technology | Technically Feasible? |
|---|---|
| Good operating practices | Yes |
| Controlled drains at QQQ process units | Yes |
| Replace uncontrolled drains | No |
| Retrofit controls | No |

The replacement of individual drains is technically infeasible. The refinery sewer system located in process areas which existed prior to NSPS QQQ standards are not able to be upgraded due to the age and location around process equipment.

Installing retrofit controls, i.e. p-trap inserts, limits the flow capacity of the drains. The effective open area of a drain pipe would be cut in half to create the water seal inside the drain insert, which may backup and cause standing water issues during firefighting conditions. The inserts may also cause drain cup overflows when large amounts of fluids need to be removed quickly from process vessels during upsets or preparations for turnarounds. A complete refinery hydraulic study would need to be completed prior to installing the retrofit controls to ensure process safety issues were not created with the individual retrofit installations. Upon completion of the study it may be determined that some drains can be retrofitted with controls. It is not feasible to complete a refinery wide hydraulic study, design, install, and operate these

retrofit controls prior to December 31, 2018. Therefore, installing retrofit controls on drains is technically infeasible.

### 10.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 10-2, according to their control effectiveness.

**Table 10-2 Control Effectiveness Ranking of VOC Control Technologies for Refinery Drains**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Controlled drains at QQQ process units | 0.032 lb/hr | Background Information Document to proposed NSPS QQQ, February 1985, pages 4-9 |
| 2 | Good operating practices | 0.064 lb/hr | AP-42 Table 5.1-3 |

### 10.1.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 10.1.5 Step 5 – BACT Selection

BACT for VOC emissions from uncontrolled refinery drains is good operating practices. BACT for VOC emissions from refinery drains at the DDU, GHT, BSU, and FGR is compliance with NSPS Subpart QQQ. Recent RBLC determinations require compliance with 40 CFR Part 61, Subpart FF using controls. Additional controls are technically infeasible by December 31, 2018.

# 11.0 BACT for North and South Flares

Process gases are routed to the North and South Flare Gas Recovery (FGR) Seal Drums. During normal operations, gases are routed to the FGR compressor and directed to the amine absorber prior to being routed to the refinery fuel gas system. The North and South Flare are subject to the following flare caps:

- 181,003 SCFD (365-day rolling average)
- 271,505 SCFD (30-day rolling average)

Tesoro implements Flare Minimization Practices to avoid flaring by preventing breaking the FGR water seals or venting fuel gas and to minimize flaring when these events occur.

Tesoro is required to ensure one FGR compressor is available for operation to recover flare gas 98% of the time over a rolling 8,760 clock hour (1 year) period. In addition, two compressors must be available for operation (or in operation) to recover flare gas 95% of the time over a rolling 8,760 clock hour (1 year) period. Tesoro maintains a spare flare gas compressor in addition to the two available for operation or in operation.

Tesoro implements the following Good Air Pollution Control Practices including during periods of startup, shutdown, and/or malfunction to minimize flare emissions:

A continuous flare pilot shall be maintained at all times.
The presence of a flare pilot flame shall be continuously monitored. If an alarm indicates that the pilot flame is lost, operations personnel are to promptly attempt to reignite the pilot, document any corrective actions taken.
Flares are operated without visible emissions, while minimizing the flare Steam/Vent Gas (S/VG) ratio to 3 or less.
Flare operating personnel monitor flare operation using the flare video monitoring system. If smoke is detected by the operators, or by other technical or operations personnel, adhere to the practice outlined in Section 7 below.

Tesoro is not permitted to allow the flares to smoke nor have visible emissions at any time. If visible emissions are observed either firsthand or through the video monitoring system:

Operators increase steam flow to the flare until the visible emissions are eliminated while minimizing the flare Steam/Vent Gas (S/VG) ratio to 3 or less.
Operators address the cause of visible emissions
Operators initiate Method 22 observations

During non-routine operations, the process gases from the process vessels are discharged to the North and South flare systems. When the flow of gas exceeds the capacity of the FGR compressors, gas breaks through the water seal and is routed to the flare stack for combustion.

The flares are operated in compliance with the applicable standards at 40 CFR 60.18, 40 CFR 63.11 and *Tesoro's Consent Decree.*

## 11.2 North and South Flares $PM_{2.5}$ Emissions

$PM_{2.5}$ is generated from the combustion of vent gas at the flare tip.

### 11.2.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $PM_{2.5}$ emissions from a review of available information are listed in Table 3-1.

### 11.2.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $PM_{2.5}$ emissions are summarized in Table 11-1. The following sections provide additional detail.

**Table 11-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for North and South Flares**

| Technology | Technically Feasible? |
|---|---|
| Flare Gas Recovery | Yes |
| Flare Cap | Yes |
| Flare Combustion Efficiency | Yes |
| Flare Management Plan | Yes |
| Add-on $PM_{2.5}$ Control | No |
| Use of Natural Gas for Pilot | Yes |

Any add on $PM_{2.5}$ control technology is not technically feasible, as it is not feasible to enclose a safety flare tip.

### 11.2.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 11-2, according to their control effectiveness.

**Table 11-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for North and South Flares**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Flare Gas Recovery<br>Flare Cap<br>Flare Management Plan | 181,003 SCFD (365-day rolling average)<br>271,505 SCFD (30-day rolling average) | Consent decree |
| 1 | Use of Natural Gas for Pilot<br>Flare Combustion Efficiency | 0.0075 lb/MMBtu | AP-42 Table 1.4-2 |

### 11.2.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options is not required, as the top feasible control option is selected.

### 11.2.5 Step 5 – BACT Selection

BACT for $PM_{2.5}$ from the North and South flares is a flare gas recovery system, flare cap, flare management plan, use of natural gas for pilot, and flare combustion efficiency. Tesoro will limit waste gas flow rates to 181,003 SCFD (365 day rolling average) and 271,505 SCFD (30 day rolling average) for these flares. The recent RBLC determinations include emission limits based upon AP-42 for natural gas combustion of 0.0075 lb/MMBtu. During periods of startup and shutdown, the flare management plan will be used in conjunction with good operating procedures to minimize flaring.

## 11.3 North and South Flares $SO_2$ Emissions

$SO_2$ is generated from the combustion of $H_2S$ and other sulfur-containing gases in the vent gas stream.

### 11.3.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $SO_2$ emissions from a review of available information are listed in Table 3-1.

### 11.3.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $SO_2$ emissions are summarized in Table 11-3. The following sections provide additional detail.

**Table 11-3 Technical Feasibility of $SO_2$ Control Technologies for North and South Flares**

| Technology | Technically Feasible? |
|---|---|
| Flare Gas Recovery | Yes |
| Flare Management Plan | Yes |
| Flare Cap | Yes |
| Use of Natural Gas for Pilot | Yes |
| Add on $SO_2$ controls | No |

Add on $SO_2$ technology is not technically feasible, as it is not feasible to enclose a safety flare tip.

### 11.3.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 11-4, according to their control effectiveness.

**Table 11-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for North and South Flares**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Flare Gas Recovery<br>Flare Cap<br>Flare Management Plan | 181,003 SCFD (365-day rolling average)<br>271,505 SCFD (30-day rolling average) | Consent decree |
| 1 | Use of Natural Gas for Pilot | 0.0006 lb/MMBtu (for natural gas) | AP-42 Table 1.4-2 |

### 11.3.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of the technically feasible control options is not required, as the top feasible control option is selected.

### 11.3.5 Step 5 – BACT Selection

BACT for $SO_2$ emissions from the North and South flares is a flare gas recovery system, flare cap, flare management plan, use of natural gas for pilot. Tesoro will limit waste gas flow rates to 181,003 SCFD (365 day rolling average) and 271,505 SCFD (30 day rolling average) for these flares. During periods of startup and shutdown, the flare management plan will be used in conjunction with good operating procedures to minimize flaring.

## 11.4 North and South Flares $NO_X$ Emissions

There are three mechanisms by which NOx production occurs during combustion including thermal, fuel, and prompt NOx formation. In the case of gaseous fuel combustion, the primary mechanism of NOx formation is through thermal NOx formation.

### 11.4.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $NO_X$ emissions from a review of available information are listed in Table 3-1.

### 11.4.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $NO_X$ emissions are summarized in Table 11-5. The following sections provide additional detail.

**Table 11-5 Technical Feasibility of $NO_X$ Control Technologies for North and South Flares**

| Technology | Technically Feasible? |
|---|---|
| Flare Gas Recovery | Yes |
| Flare Cap | Yes |
| Flare Combustion Efficiency | Yes |
| Flare Management Plan | Yes |
| Add-on NOx control | No |

Add on NOx control is not technically feasible as it is not possible to enclose a safety flare tip.

### 11.4.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 11-6, according to their control effectiveness.

**Table 11-6 Control Effectiveness Ranking of $NO_X$ Control Technologies for North and South Flares**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Flare Gas Recovery<br>Flare Cap<br>Flare Management Plan | 181,003 SCFD (365-day rolling average)<br>271,505 SCFD (30-day rolling average) | Consent decree |
| 2 | Use of Natural Gas for Pilot<br>Flare Combustion Efficiency | 0.068 lb/MMBtu | AP-42 Table 1.4-1 |

### 11.4.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of the technically feasible control options is not required, as the top feasible control option is selected.

### 11.4.5 Step 5 – BACT Selection

BACT for $NO_X$ from the North and South flares is a flare gas recovery system, flare cap, flare management plan, use of natural gas for pilot, and flare combustion efficiency. Tesoro will limit waste gas flow rates to

181,003 SCFD (365 day rolling average) and 271,505 SCFD (30 day rolling average) for these flares. In reviewing the RBLC determinations, there is no clear BACT precedent for NOx from flares. During periods of startup and shutdown, the flare management plan will be used in conjunction with good operating procedures to minimize flaring.

## 11.5 North and South Flares VOC Emissions

VOCs from the North and South flares are a result of incomplete combustion of the vent gas.

### 11.5.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 11.5.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 11-7. The following sections provide additional detail.

**Table 11-7 Technical Feasibility of VOC Control Technologies for North and South Flares**

| Technology | Technically Feasible? |
|---|---|
| Flare Gas Recovery | Yes |
| Flare Cap | Yes |
| Flare Combustion Efficiency | Yes |
| Flare Management Plan | Yes |
| Add-on VOC Control | No |

Add on VOC control is not technically feasible as it is not possible to enclose a safety flare.

### 11.5.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 11-8, according to their control effectiveness.

**Table 11-8 Control Effectiveness Ranking of VOC Control Technologies for North and South Flares**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Flare Gas Recovery<br>Flare Cap<br>Flare Management Plan | 181,003 SCFD (365-day rolling average)<br>271,505 SCFD (30-day rolling average) | Consent decree |
| 1 | Flare Combustion Efficiency | 96.5% combustion efficiency | MACT Subpart CC |

### 11.5.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of the technically feasible control options is not required, as the top feasible control option is selected.

### 11.5.5 Step 5 – BACT Selection

BACT for VOC from the North and South flares is a flare gas recovery system, flare caps, flare management plan, use of natural gas for pilot, and flare combustion efficiency. Tesoro will limit waste gas flow rates to 181,003 SCFD (365 day rolling average) and 271,505 SCFD (30 day rolling average) for these flares. The recent RBLC determinations include a 98% destruction efficiency at the flare, which is equivalent to 96.5% combustion efficiency according to MACT Subpart CC. During periods of startup and shutdown, the flare management plant will be used in conjunction with good operating procedures to minimize flaring.

## 11.6 North and South Flares Ammonia Emissions

Ammonia is generated from the combustion of the vent gas and the oxidation of nitrogen compounds in the vent gas stream.

### 11.6.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for ammonia emissions from a review of available information are listed in Table 3-1.

### 11.6.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for ammonia emissions are summarized in Table 11-9. The following sections provide additional detail.

**Table 11-9 Technical Feasibility of Ammonia Control Technologies for North and South Flares**

| Technology | Technically Feasible? |
|---|---|
| Flare Gas Recovery | Yes |
| Flare Cap | Yes |
| Flare Combustion Efficiency | Yes |
| Flare Management Plan | Yes |
| Add-on Ammonia Control | No |

Add on ammonia control is not technically feasible as it is not feasible to enclose a safety flare.

### 11.6.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 11-10, according to their control effectiveness.

**Table 11-10 Control Effectiveness Ranking of Ammonia Control Technologies for North and South Flares**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Flare Gas Recovery<br>Flare Cap<br>Flare Management Plan | 181,003 SCFD (365-day rolling average)<br>271,505 SCFD (30-day rolling average) | Consent decree |
| 1 | Flare Combustion Efficiency | 0.0031 lb/MMBtu | EPA WebFIRE Database |

## 11.6.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of the technically feasible control options is not required, as the top feasible control option is selected.

## 11.6.5 Step 5 – BACT Selection

BACT for ammonia from the North and South flares is a flare gas recovery system, flare caps, flare management plan, use of natural gas for pilot, and flare combustion efficiency. Tesoro will limit waste gas flow rates to 181,003 SCFD (365 day rolling average) and 271,505 SCFD (30 day rolling average) for these flares. There are no BACT determinations in the RBLC for ammonia emissions from flares. During periods of startup and shutdown, the flare management plan will be used in conjunction with good operating procedures to minimize flaring.

# 12.0 BACT for SRU Flare

During startup, shutdown, and malfunction events, process gases from the sour water stripper and amine treatment units may be sent directly to a flare knockout drum and routed to the SRU flare stack for combustion. Fuel gas is burned at the flare tip as pilot and purge gases, however there is no routine waste gas venting to the SRU flare.

The SRU Flare is not subject to 40 CFR 60.18 or 40 CFR 63.11, and cannot feasibly comply with those standards due to the nature of acid gas combustion. Tesoro implements a Flare Management Plan which include flare minimization per the standards of NSPS Subpart Ja for the SRU Flare. Sulfur Shedding is also implemented throughout the refinery in the event of an acid gas flaring event.

## 12.1 SRU Flare $PM_{2.5}$ Emissions

$PM_{2.5}$ is generated from the combustion of vent gas at the flare tip.

### 12.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $PM_{2.5}$ emissions from a review of available information are listed in Table 3-1.

### 12.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $PM_{2.5}$ emissions are summarized in Table 12-1. The following sections provide additional detail.

**Table 12-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for SRU Flare**

| Technology | Technically Feasible? |
|---|---|
| Flare Management Plan | Yes |
| Add-on $PM_{2.5}$ Control | No |
| Flare Gas Recovery | No |
| Natural Gas for Pilot | No |

Add-on $PM_{2.5}$ controls are not feasible, as it is not feasible to enclose a flare tip to capture the $PM_{2.5}$ generated. A flare gas recovery compressor is not feasible because the SRU flare is used only during startup and shutdown of the SRU which normally receives all of the acid gases, and there are no alternate processing methods. The flare management plan includes provisions for shutting down the sour water stripper and storing of the sour water when feasible until the SRU is back online.

Although exclusive use of natural gas for the pilot may be feasible, Tesoro is not able to complete this modification prior to December 31, 2018.

### 12.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 12-2, according to their control effectiveness.

**Table 12-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for SRU Flare**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Flare Management Plan | Varies | N/A |

### 12.1.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 12.1.5 Step 5 – BACT Selection

BACT for $PM_{2.5}$ from the SRU flare is the implementation of a flare management plan for use during normal, startup, and shutdown operations. This proposal is consistent with recent RBLC determinations.

## 12.2 SRU Flare $SO_2$ Emissions

$SO_2$ is generated from the combustion of $H_2S$ and other gases in the vent gas stream.

### 12.2.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $SO_2$ emissions from a review of available information are listed in Table 3-1.

### 12.2.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $SO_2$ emissions are summarized in Table 12-3. The following sections provide additional detail.

**Table 12-3 Technical Feasibility of $SO_2$ Control Technologies for SRU Flare**

| Technology | Technically Feasible? |
|---|---|
| Flare Management Plan | Yes |
| Add on $SO_2$ Control | No |
| Flare Gas Recovery | No |
| Natural Gas for Pilot | No |

Add-on $SO_2$ controls are not feasible, as it is not feasible to enclose a flare tip to capture the $SO_2$ generated. A flare gas recovery compressor is not feasible because the SRU flare is used only during startup and shutdown of the SRU which normally received all of the acid gases, and there are no alternate

processing methods. The flare management plan includes provisions for shutting down the sour water stripper and storing of the sour water when feasible until the SRU is back online.

Although exclusive of natural gas for the pilot may be feasible, Tesoro is not able to complete this modification prior to December 31, 2018.

### 12.2.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 12-4, according to their control effectiveness.

**Table 12-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for SRU Flare**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Flare Management Plan | Varies | N/A |

### 12.2.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 12.2.5 Step 5 – BACT Selection

BACT for $SO_2$ from the SRU flare is the implementation of a flare management plan for normal, startup, and shutdown operation. This proposal is consistent with recent RBLC determinations.

## 12.3 SRU Flare $NO_X$ Emissions

NOx emissions from the SRU flare are due to the combustion of the vent gas.

### 12.3.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $NO_X$ emissions from a review of available information are listed in Table 3-1.

### 12.3.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $NO_X$ emissions are summarized in Table 12-5. The following sections provide additional detail.

**Table 12-5 Technical Feasibility of $NO_X$ Control Technologies for SRU Flare**

| Technology | Technically Feasible? |
|---|---|
| Flare Management Plan | Yes |
| Add-on NOx control | No |
| Flare Gas Recovery | No |

Add-on NOx controls are not feasible, as it is not feasible to enclose a flare tip to capture the NOx generated. A flare gas recovery compressor is not feasible because the SRU flare is used only during startup and shutdown of the SRU which normally received all of the acid gases, and there are no alternate processing methods. The flare management plan includes provisions for shutting down the sour water stripper and storing of the sour water when feasible until the SRU is back online.

### 12.3.3 Step 3 –Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 12-6, according to their control effectiveness.

**Table 12-6 Control Effectiveness Ranking of NOx Control Technologies for SRU Flare**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Flare Management Plan | Varies | N/A |

### 12.3.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 12.3.5 Step 5 – BACT Selection

BACT for NOx from the SRU flare is the implementation of a flare management plan for normal, startup, and shutdown operation. This proposal is consistent with recent RBLC determinations.

## 12.4SRU Flare VOC Emissions

VOCs from the SRU flare are a result of incomplete combustion of the vent gas.

### 12.4.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 12.4.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 12-7. The following sections provide additional detail.

**Table 12-7 Technical Feasibility of VOC Control Technologies for SRU Flare**

| Technology | Technically Feasible? |
|---|---|
| Flare Management Plan | Yes |
| Add-on VOC control | No |
| Flare Gas Recovery | No |
| Natural Gas for Pilot | No |

Add-on VOC controls are not feasible, as it is not feasible to enclose a flare tip to capture the VOCs generated. A flare gas recovery compressor is not feasible because the SRU flare is used only during startup and shutdown of the SRU which normally received all of the acid gases, and there are no alternate processing methods. The flare management plan includes provisions for shutting down the sour water stripper and storing of the sour water when feasible until the SRU is back online.

Although exclusive use of natural gas for the pilot may be feasible, Tesoro is not able to complete this modification prior to December 31, 2018.

### 12.4.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 12-8, according to their control effectiveness.

**Table 12-8 Control Effectiveness Ranking of VOC Control Technologies for SRU Flare**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Flare Management Plan | Varies | N/A |

### 12.4.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 12.4.5 Step 5 – BACT Selection

BACT for VOC from the SRU flare is the implementation of a flare management plan for normal, startup, and shutdown operation. This proposal is consistent with recent RBLC determinations.

## 12.5 SRU Flare Ammonia Emissions

Ammonia is generated from the combustion of the vent gas and the oxidation of nitrogen compounds in the vent gas stream.

### 12.5.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for ammonia emissions from a review of available information are listed in Table 3-1.

### 12.5.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for ammonia emissions are summarized in Table 12-9. The following sections provide additional detail.

**Table 12-9 Technical Feasibility of Ammonia Control Technologies for SRU Flare**

| Technology | Demonstrated In Practice? | Technically Feasible? |
|---|---|---|
| Flare Management Plan | Yes | Yes |
| Add-on Ammonia control | No | No |
| Flare Gas Recovery | Yes | No |

Add-on ammonia controls are not feasible, as it is not feasible to enclose a flare tip to capture the ammonia generated. A flare gas recovery compressor is not feasible because the SRU flare is used only during startup and shutdown of the SRU which normally received all of the acid gases, and there are no alternate processing methods. The flare management plan includes provisions for shutting down the sour water stripper and storing of the sour water when feasible until the SRU is back online.

### 12.5.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 12-10, according to their control effectiveness.

**Table 12-10 Control Effectiveness Ranking of Ammonia Control Technologies for SRU Flare**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Flare Management Plan | Varies | |

### 12.5.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 12.5.5 Step 5 – BACT Selection

BACT for ammonia from the SRU flare is the implementation of a flare management plan for normal, startup, and shutdown operation. This proposal is consistent with recent RBLC determinations.

# 13.0BACT for Cooling Towers

Utilities Unit #2 (UU2) and Utilities Unit #3 (UU3) are cooling towers which reduce the temperature of cooling water that serve heat exchangers throughout the refinery process units. Water is cooled in the cooling tower when it is trickled past flowing air; cooling occurs as a portion of the water is evaporated to the atmosphere. Potential emissions include particulate matter, due to minerals in the water, and VOCs during unplanned heat exchanger leaks into the cooling water.

## 13.1 Cooling Tower $PM_{2.5}$ Emissions

Cooling towers have direct contact between the water and the air, and some of the water may become entrained in the air stream and can be carried out of the tower as particulate emissions. Tesoro's cooling towers currently use a drift eliminator to reduce $PM_{2.5}$ emissions.

### 13.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $PM_{2.5}$ emissions from a review of available information are listed in Table 3-1.

### 13.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $PM_{2.5}$ emissions are summarized in Table 13-1. The following sections provide additional detail.

**Table 13-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for Cooling Tower**

| Technology | Technically Feasible? |
|---|---|
| Drift Eliminator Upgrades | No |
| Current Drift Eliminator and Good Operating Practices | Yes |

Upgrades to the current drift eliminators may be feasible, but such upgrades are not able to be designed, installed, and in operation prior to December 31, 2018. Therefore, drift eliminator upgrades are considered technically infeasible.

### 13.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 13-2, according to their control effectiveness.

**Table 13-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for Cooling Towers**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Current Drift Eliminator and Good Operating Practices | 0.012 lb/MMGal | AP-42, Section 13.4 |

### 13.1.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 13.1.5 Step 5 – BACT Selection

BACT for $PM_{2.5}$ emissions from the cooling towers is the current drift eliminator coupled with good operating practices. This is consistent with recent RBLC determinations, with limits of 0.03 lb/MMgal.

## 13.2 Cooling Tower VOC Emissions

VOC emissions from cooling towers result from leaks of process fluid into the cooling water stream.

### 13.2.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 13.2.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 13-3. The following sections provide additional detail.

**Table 13-3 Technical Feasibility of VOC Control Technologies for Cooling Towers**

| Technology | Technically Feasible? |
|---|---|
| Compliance with 40 CFR Part 63, Subpart CC | Yes |
| Drift Eliminator Upgrades | No |

Upgrades to the current drift eliminators may be feasible, but are not able to be designed, installed, and in operation before December 31, 2018. Therefore, drift eliminator upgrades are considered to be technically infeasible.

### 13.2.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 13-4, according to their control effectiveness.

**Table 13-4 Control Effectiveness Ranking of VOC Control Technologies for Cooling Towers**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Compliance with 40 CFR Part 63, Subpart CC | 0.7 lb/MMGal | EPA AP-42 Table 5.1-2 |

### 13.2.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 13.2.5 Step 5 – BACT Selection

BACT for VOC emissions from cooling towers is complying with 40 CFR Part 63, Subpart CC, which requires monitoring for hydrocarbons in the cooling water return. This control technology is consistent with recent RBLC determinations.

# 14.0 BACT for Loading Racks

## 14.1 Transportation Rack VOC Emissions

Tesoro and TLO operate two transportation loading racks, the TLR and the BCLR, for loading and unloading refinery products into and out of trucks and railcars. VOC vapors are discharged from the tankers as they are filled, and each loading rack is operated with a vapor recovery unit with carbon adsorption as the control device.

### 14.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 14.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 14-1. The following sections provide additional detail.

**Table 14-1 Technical Feasibility of VOC Control Technologies for Loading Racks**

| Technology | Technically Feasible? |
|---|---|
| Carbon adsorption | Yes |
| Flare/Thermal Oxidizer | Yes |

All control options are technically feasible.

### 14.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 14-2, according to their control effectiveness.

**Table 14-2 Control Effectiveness Ranking of VOC Control Technologies for Loading Racks**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Carbon Adsorption | 10 mg/L product loaded | MACT CC |
| 1 | Flare/Thermal Oxidizer | 10 mg/L product loaded | MACT CC |

### 14.1.4 Step 4 – Evaluation of Feasible Control Technologies

The use of a flare/thermal oxidizer results in additional combustion related emissions from the controlled VOC. In comparison, a carbon adsorption unit recovers product which would otherwise be emitted and results in no collateral emissions. Therefore, a carbon adsorption unit is considered the top feasible control option in this case. The economic and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 14.1.5 Step 5 – BACT Selection

BACT for VOC from the transport loading racks is a vapor recovery unit with carbon adsorption. This proposal is consistent with recent RBLC determinations.

## 14.2 LPG Loading Rack VOC Emissions

The Salt Lake City Refinery operates two liquefied petroleum gases (LPG) racks: a 6-bay rail loading and offloading rack and a single-bay truck loading and offloading rack. The rack utilizes arms for liquid and vapor loading and unloading. Following loading/unloading operations, LPG is recovered from the arms using a compressor and then the remaining vapors in the arms are vented to the FGR system.

### 14.2.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 14.2.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 14-3. The following sections provide additional detail.

**Table 14-3 Technical Feasibility of VOC Control Technologies for Loading Racks**

| Technology | Technically Feasible? |
|---|---|
| Carbon adsorption | No |
| FGR | Yes |

Carbon adsorption is not technically feasible, as the LPG being loaded contains low molecular weight compounds which are not effectively captured by activated carbon.

### 14.2.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 14-4, according to their control effectiveness.

**Table 14-4 Control Effectiveness Ranking of VOC Control Technologies for Loading Racks**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | FGR | 181;003 SCFD (365-day rolling average)<br>271,505 SCFD (30-day rolling average) | Consent Decree |

### 14.2.4 Step 4 – Evaluation of Feasible Control Technologies

The economic and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 14.2.5 Step 5 – BACT Selection

BACT for VOC from the LPG loading rack is routing the recovered LPG to the FGR system. No RBLC determinations for LPG loading racks were identified.

# 15.0 BACT for K1 Compressors

The K1 compressors are two compressors operated in parallel to recycle hydrogen into the UFU desulfurization reactor. They are each driven by an internal combustion engine fired by natural gas. The exhaust goes through a catalytic converter that controls $NO_X$ emissions prior to release to the atmosphere.

## 15.1 K1 Compressors $PM_{2.5}$ Emissions

$PM_{2.5}$ emissions result from the combustion of natural gas in the engine.

### 15.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $PM_{2.5}$ emissions from a review of available information are listed in Table 3-1.

### 15.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $PM_{2.5}$ emissions are summarized in Table 15-1.

**Table 15-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for K1 Compressors**

| Technology | Technically Feasible? |
|---|---|
| Use of Natural Gas | Yes |
| Good Operating Practices | Yes |
| Electric Motor | No |

Although replacing one motor with an electric motor may be feasible for one of the compressors, such upgrades are not able to be designed, installed, and in operation prior to December 31, 2018. Therefore, an upgrade to the motors is considered technically infeasible.

### 15.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 15-2, according to their control effectiveness.

**Table 15-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for K1 Compressors**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Natural Gas and Good Operating Practices | 0.019 lb/MMBtu | AP-42, Table 3.2-3 |

### 15.1.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 15.1.5 Step 5 – BACT Selection

BACT for $PM_{2.5}$ emissions from the K1 Compressors is the use of natural gas and good operating practices. This control technology is consistent with recent RBLC determinations. During startup and shutdown, good operating practices will be used to minimize emissions.

## 15.2 K1 Compressors $SO_2$ Emissions

$SO_2$ emissions occur from combustion of natural gas due to trace amounts of sulfur present in the fuel.

### 15.2.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $SO_2$ emissions from a review of available information are listed in Table 3-1.

### 15.2.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $SO_2$ emissions are summarized in Table 15-3. The following sections provide additional detail.

**Table 15-3 Technical Feasibility of $SO_2$ Control Technologies for K1 Compressors**

| Technology | Technically Feasible? |
|---|---|
| Use of Natural Gas | Yes |
| Good Operating Practices | Yes |
| Electric Motor | No |

Although replacing the motor with an electric motor may be feasible for one of the compressors, such upgrades are not able to be designed, installed, and in operation prior to December 31, 2018. Therefore, an upgrade to the motors is considered technically infeasible.

### 15.2.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 15-4, according to their control effectiveness.

**Table 15-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for K1 Compressors**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Natural Gas and Good Operating Practice | 0.00059 | AP-42 Table 3.2-3 |

### 15.2.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 15.2.5 Step 5 – BACT Selection

BACT for $SO_2$ emissions from the K1 Compressors is the use of natural gas and good operating practices. This is consistent with recent RBLC determinations. During startup and shutdown good operating practices will be used to minimize emissions.

## 15.3 K1 Compressors $NO_X$ Emissions

There are three mechanisms by which $NO_x$ production occurs during combustion including thermal, fuel, and prompt $NO_x$ formation. In the case of gaseous fuel combustion, the primary mechanism of NOx formation is through thermal $NO_x$ formation.

### 15.3.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $NO_X$ emissions from a review of available information are listed in Table 3-1.

### 15.3.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $NO_X$ emissions are summarized in Table 15-5. The following sections provide additional detail.

**Table 15-5 Technical Feasibility of $NO_X$ Control Technologies for K1 Compressors**

| Technology | Technically Feasible? |
|---|---|
| Electric Motor | No |
| SCR | No |
| Catalytic Converter | Yes |
| Combustion control systems | No |
| Use of Natural Gas | Yes |
| Good Operating Practices | Yes |

Although replacing the motor with an electric motor for one of the compressors, installing an SCR, or upgrading the combustion control systems may be feasible, such upgrades are not able to be designed, installed, and in operation prior to December 31, 2018. Therefore, an upgrade to the motors, SCR, and upgrades to combustion control systems is considered technically infeasible.

### 15.3.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 15-6, according to their control effectiveness.

**Table 15-6 Control Effectiveness Ranking of NOx Control Technologies for K1 Compressors**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Catalytic Converter, Natural Gas and Good Operating Practices | 3.2 lb/hr | Approval Order Limit II.B.6.c |

### 15.3.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 15.3.5 Step 5 – BACT Selection

BACT for NOx from the K1 Compressors is the use of a catalytic converter, natural gas and good operating practices, with an emissions limit of 3.2 lb/hr. Additional controls are not technically feasible as BACT.

## 15.4 K1 Compressors VOC Emissions

VOC emissions from the furnaces are a result of incomplete combustion of the refinery fuel gas. Tesoro utilizes a catalytic converter for VOC control on the compressors.

### 15.4.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 15.4.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 15-7. The following sections provide additional detail.

**Table 15-7 Technical Feasibility of VOC Control Technologies for K1 Compressors**

| Technology | Technically Feasible? |
|---|---|
| Catalytic Converter | Yes |
| Catalyst upgrade to 3-way catalyst | No |
| Electric Motor | No |
| Use of Natural Gas | Yes |
| Good Operating Practices | Yes |

Although replacing the motor with an electric motor for one of the compressors or upgrading the catalyst in the catalytic converter may be feasible, it is not feasible to design, install, and begin operating either of these control technologies prior to December 31, 2018 as these compressors are not scheduled to go

through a maintenance shutdown. Therefore, an upgrade to the motors and upgrades to the catalyst is considered technically infeasible.

### 15.4.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 15-8, according to their control effectiveness.

**Table 15-8 Control Effectiveness Ranking of VOC Control Technologies for K1 Compressors**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Catalytic Converter, Natural Gas and Good Operating Practices | 0.03 lb/MMBtu | AP-42 Table 3.2-3 |

### 15.4.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 15.4.5 Step 5 – BACT Selection

BACT for VOC from the K1 compressors is a catalytic converter, natural gas and good operating practices. This control technology is consistent with recent RBLC determinations.

## 15.5 K1 Compressors Ammonia Emissions

Ammonia emissions are the result of combustion, and according to the EPA WebFIRE emission factors are extremely low (0.0031 lb/MMBtu) for natural gas combustion.

### 15.5.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for Ammonia emissions from a review of available information are listed in Table 3-1.

### 15.5.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for ammonia emissions are summarized in Table 15-9. The following sections provide additional detail.

**Table 15-9 Technical Feasibility of Ammonia Control Technologies for K1 Compressors**

| Technology | Technically Feasible? |
|---|---|
| Add-on Ammonia Control | No |
| Use of Natural Gas | Yes |
| Electric Motor | No |
| Good Operating Practices | Yes |

Due to the extremely low concentration of ammonia in the flue gas (0.0031 lb generated per MMBtu of heat input), any add on ammonia control is technically infeasible. For exhaust streams with higher concentrations, control technologies such as water-based strippers and thermal oxidation are typical add-on ammonia control technologies.

Although replacing the motor with an electric motor may be feasible for one of the compressors, such upgrades are not able to be designed, installed, and in operation prior to December 31, 2018. Therefore, an upgrade to the motor is considered technically infeasible.

### 15.5.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 15-10, according to their control effectiveness.

**Table 15-10 Control Effectiveness Ranking of Ammonia Control Technologies for K1 Compressors**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Natural Gas and Good Operating Practices | 0.0031 lb/MMBtu | EPA WebFIRE Database |

### 15.5.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 15.5.5 Step 5 – BACT Selection

BACT for ammonia from the K1 Compressors is using natural gas and good operating practices. There are no BACT determinations for ammonia generated from combustion. During unit startup or shutdown, good operating practices will be followed in order to minimize ammonia emissions.

# 16.0 BACT for Fixed Roof Tanks

## 16.1 Fixed Roof Tanks VOC Emissions

Fixed roof tanks are either vented with a gooseneck or have a pressure/vacuum vent. Emissions from fixed roof tanks are in the form of working losses and standing losses. Standing losses occur through tank temperature fluctuations, while working losses occur primarily from liquid level changes.

### 16.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 16.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 16-1. The following sections provide additional detail.

**Table 16-1 Technical Feasibility of VOC Control Technologies for Fixed Roof Tanks**

| Technology | Technically Feasible? |
|---|---|
| Vapor Recovery System | Tank 104 – Yes<br>All others - No |
| Vent to a Control Device | Tank 104 – Yes<br>All other - No |
| Retrofit to an IFR | No |
| Good design methods and operating procedures | Yes |

Although adding a vapor recovery system or venting to a control device may be feasible, it is not feasible to design, install, and begin operating either of these control technologies prior to December 31, 2018 (with the exception of existing vapor recovery and venting to a control device at Tank 104). Therefore, a vapor recovery system and venting to a control device is considered technically infeasible.

As a part of the 2015 update to MACT Subpart CC, referred to as the Refinery Sector Rule (RSR), it was required to determine whether any fixed roof tanks previously classified as Group 2 tanks must be reclassified as Group 1 tanks due to the change in definition. Any tanks classified as a Group 1 storage tank require that a closed vent system with a control device be installed or the tank be converted to an internal floating roof tank at the next opportunity where the tank is emptied and degassed, but no later than January 30, 2026. Four Group 1 fixed roof tanks are not scheduled to be emptied and degassed prior to December 31, 2018. Table 16-2 lists the four tanks to have their controls upgraded, and the anticipated timeframe the updates will occur.

All other fixed roof tanks are classified as Group 2 tanks and follow good design methods and operating procedures.

**Table 16-2 Fixed Roof Tanks to Be Updated to MACT CC Controls with Anticipated Upgrade Date**

| Tank | Anticipated Upgrade Date |
|---|---|
| TK612 | Between January 1, 2019 and January 30, 2026 |
| TK609A | Between January 1, 2019 and January 30, 2026 |
| TK609B | Between January 1, 2019 and January 30, 2026 |
| Tank 291 | Between January 1, 2019 and January 30, 2026 |

### 16.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 16-3, according to their control effectiveness.

**Table 16-3 Control Effectiveness Ranking of VOC Control Technologies for Fixed Roof Tanks**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Vapor recovery system and venting to control device (Tank 104 only) | 95% | NSPS Subpart Kb |
| 2 | Good design methods and operating procedures | Varies by tank | N/A |

### 16.1.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected for each tank.

### 16.1.5 Step 5 – BACT Selection

With the exception of Tank 104, BACT for VOC emissions from fixed roof tanks is good design methods and operating procedures, as additional control technology is not feasible.

BACT for VOC emissions from Tank 104 is a vapor recovery system and venting to a control device consistent with existing operations.

# 17.0 BACT for Internal Floating Roof Tanks

## 17.1 Internal Floating Roof Tanks VOC Emissions

An internal floating roof (IFR) tank has a permanent roof with a floating roof on the inside floating on the surface of the liquid. Emissions from a floating roof tank come from both withdrawal losses and standing losses. Withdrawal losses are generally due to liquid level fluctuations, and standing storage losses originate from the rim seal, deck fittings, and the deck seam. All internal floating roof Group 1 tanks currently meet the double seal standard from 40 CFR Part 60 Subpart Kb and 40 CFR Part 63 Subpart CC (Existing MACT CC).

Some of the IFR tanks have been upgraded to meet controls required by recent revisions to Subpart CC under RSR. Under RSR, a new section within 40 CFR 63 Subpart CC (MACT CC RSR) has been added at 40 CFR 63.660. This new section contains new and additional requirements for floating roof seals, deck fitting controls, inspections, recordkeeping, and reporting. The existing storage tank section under Subpart CC, 40 CFR 63.646, remained effective until the new compliance date of April 29, 2016. After the new compliance date, the requirements of 40 CFR 63.646 no longer apply and the compliance requirements of 40 CFR 63.660 are now effective.

RSR requires that the next time the vessel is emptied and degassed or by February, 1, 2026, whichever comes first, the tank is upgraded to meet the deck fitting controls of 40 CFR Subpart WW, which is the method of compliance under 40 CFR 63.660. The deck fitting control upgrades (or commonly referred to below as Upgrades to RSR Controls) for IFR tanks from 40 CFR 63.646 to 40 CFR 63.660 compliance include:

- IFR well covers must be gasketed (i.e. deck openings other than for vents, drains, or legs) 1/8" max gap criteria.
- IFR vents to be gasketed (vacuum breakers, rim vents) 1/8" max gap criteria.
- Deck openings other than for vents must project into liquid.
- Access hatches and gauge float well covers are required to be bolted and gasketed.
- Emergency roof drains must have seals covering at least 90% of the floating roof deck opening.
- IFR column wells must have gasketed cover or flexible fabric sleeve.
- Unslotted guidepoles required to have a pole wiper at the deck fitting and a gasketed cap at the top of the pole.
- Slotted guidepoles must have an external pole wiper and an internal pole float or equivalent.
- Each opening through a floating roof for a ladder having at least one slotted leg shall be equipped with one of the following configurations:
    - A pole float in the slotted leg and pole wipers for both legs. The wiper or seal of the pole float must be at or above the height of the pole wiper.
    - A ladder sleeve and pole wipers for both legs of the ladder.
    - A flexible enclosure device and either a gasketed or welded cap on the top of the slotted leg.

Additionally, tank degassing emissions are controlled by portable combustion units, as required by the Utah SIP Section IX.H Emission Limits and Operating Practices.

### 17.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 17.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 17-1. The following sections provide additional detail.

**Table 17-1 Technical Feasibility of VOC Control Technologies for Internal Floating Roof Tanks**

| Technology | Technically Feasible? |
|---|---|
| NSPS Kb Controls | Varies by tank |
| Existing MACT CC Controls | Varies by tank |
| RSR Controls | Varies by tank |
| Degassing controls when storage tanks are taken out of service | Yes |
| Installation of a vapor recovery system with vapor combustion | No |

Although the installation of a vapor recovery system may be feasible, it would not be able to be designed, installed, and operated prior to December 31, 2018.

The technical feasibility of meeting NSPS Kb controls and/or RSR controls (MACT Subpart CC) varies by storage tank. The following tanks have been upgraded to include the MACT CC required controls and or currently meet NSPS Subpart Kb controls:

- TK331 (Kb)
- TK414
- TK504 (Kb)
- TK503 (Kb)

Table 17-2 shows the list of remaining tanks which are to be upgraded to the RSR MACT CC controls and the anticipated timeframe of the upgrade. Tanks complying with NSPS Kb are already in compliance. Tank 297 will be demolished and taken out of service prior to December 31, 2018.

**Table 17-2 Internal Floating Roof Tanks to Be Updated to RSR Controls with Anticipated Upgrade Date**

| Tank | Anticipated Upgrade Date |
|---|---|
| TK244 | Before December 31, 2018 |
| TK413 | Between January 1, 2019 and January 30, 2026 |
| TK321 | Between January 1, 2019 and January 30, 2026 |
| TK402 | Between January 1, 2019 and January 30, 2026 |
| TK412 | Between January 1, 2019 and January 30, 2026 |

### 17.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 17-3, according to their control effectiveness.

**Table 17-3 Control Effectiveness Ranking of VOC Control Technologies for Internal Floating Roof Tanks**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | RSR Controls | Varies by tank | N/A |
| 1 | Degassing controls when storage tanks are taken out of service. | Varies by tank | N/A |
| 1 | NSPS Kb Controls | Varies by tank | N/A |

### 17.1.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 17.1.5 Step 5 – BACT Selection

BACT for VOC emissions from internal floating roof tanks is as follows:

- For tanks currently meeting NSPS Kb and TK244, meeting NSPS Kb is BACT.
- For tanks currently meeting RSR requirements, meeting RSR is BACT.
- For tanks that don't meet either NSPS Kb or RSR requirements, the existing MACT CC controls are BACT because upgrades are not feasible by 12/31/18.

This is consistent with recent RBLC determinations of using dual seals and welded decks. During tank shutdowns and degassing, a portable combustion unit will continue to be used to control emissions.

# 18.0 BACT for External Floating Roof Tanks

## 18.1 External Floating Roof Tanks VOC Emissions

An external floating roof (EFR) tank is an open topped tank with a roof floating on the surface of the liquid. Emissions from a floating roof tank come from both withdrawal losses and standing losses. Withdrawal losses are generally due to liquid level fluctuations, and standing storage losses originate from the rim seal and deck fittings. All external floating roofs currently meet the double seal standard from 40 CFR Part 60 Subpart Kb or 40 CFR Part 63 Subpart CC (Existing MACT CC).

Some of the tanks have been upgraded to meet RSR controls. Refer to Section 17.1 for additional background on compliance with RSR.

RSR requires that the next time the vessel is emptied and degasses or by February 1, 2026, whichever comes first, the tank is upgraded to meet the deck fitting controls of 40 CFR Subpart WW, which is the method of compliance under 40 CFR 63.660. The deck fitting control upgrades (or commonly referred to below as Upgrades to RSR Controls) for external floating roof tanks from 40 CFR 63.646 to 40 CFR 63.660 compliance include:

- EFR well covers must be gasketed (i.e. deck openings other than for vents, drains, or legs) 1/8" max gap criteria.
- EFR vents to be gasketed (vacuum breakers, rim vents) 1/8" max gap criteria.
- Deck openings other than for vents must project into liquid.
- Access hatches and gauge float well covers must be bolted and gasketed.
- Emergency roof drains must have seals covering at least 90% of the floating roof deck opening.
- Guidepole wells must have gasketed deck cover and a pole wiper.
- Unslotted guidepoles required to have a cap at the top of the pole.
- Slotted guidepoles must have an internal float or equivalent.

Additionally, tank degassing emissions are being now controlled by portable combustion units, as required by the Utah SIP Section IX.H Emission Limits and Operating Practices.

### 18.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 18.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 18-1. The following sections provide additional detail.

**Table 18-1 Technical Feasibility of VOC Control Technologies for External Floating Roof Tanks**

| Technology | Technically Feasible? |
|---|---|
| Dome Retrofit | No |
| Installation of a vapor recovery system with vapor combustion | No |
| Existing MACT CC Controls | Varies by tank |
| NSPS Kb Controls | Varies by tank |
| RSR Controls | Varies by tank |

Due to Tesoro being located in an earthquake zone, due to the snow load, and due to the age of most EFR tanks, the addition of a dome via retrofit to external floating roofs is technically infeasible. As a dome to capture emissions is technically infeasible, the installation of a vapor recovery system with vapor combustion is also technically infeasible.

The technical feasibility of meeting NSPS Kb controls and/or RSR controls (MACT Subpart CC) varies by storage tank. For several tanks, the upgrades are not technically feasible before December 31, 2018. Additional detail is provided below.

### 18.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 18-2, according to their control effectiveness.

**Table 18-2 Control Effectiveness Ranking of VOC Control Technologies for External Floating Roof Tanks**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Meets RSR Controls | Varies by tank | N/A |
| 1 | Degassing controls when storage tanks are taken out of service. | Varies by tank | N/A |
| 1 | NSPS Kb Controls | Varies by tank | N/A |

### 18.1.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected. The following tanks have been upgraded to include the MACT CC required controls and or currently meet NSPS Subpart Kb controls:

- TK298
- TK326
- TK327

- TK328
- TK423
- TK424

Table 18-3 shows the list of remaining tanks which are to be upgraded to the MACT CC controls and the anticipated timeframe of the upgrade. Tanks complying with NSPS Kb are required to be in compliance currently.

**Table 18-3 External Floating Roof Tanks to Be Updated to MACT CC Controls with Anticipated Upgrade Date**

| Tank | Anticipated Upgrade Date |
|---|---|
| TK144 | Before December 31, 2018 |
| TK245 | Before December 31, 2018 |
| TK432 | Before December 31, 2018 |
| TK431 | Before December 31, 2018 |
| TK243 | Between January 1, 2019 and January 30, 2026 |
| TK252 | Between January 1, 2019 and January 30, 2026 |
| TK325 | Between January 1, 2019 and January 30, 2026 |
| TK241 | Between January 1, 2019 and January 30, 2026 |
| TK405 | Between January 1, 2019 and January 30, 2026 |
| TK242 | Between January 1, 2019 and January 30, 2026 |
| TK307 | Between January 1, 2019 and January 30, 2026 |
| TK308 | Between January 1, 2019 and January 30, 2026 |
| TK324 | Between January 1, 2019 and January 30, 2026 |
| TK330 | Between January 1, 2019 and January 30, 2026 |
| TK421 | Between January 1, 2019 and January 30, 2026 |
| TK422 | Between January 1, 2019 and January 30, 2026 |

### 18.1.5 Step 5 – BACT Selection

BACT for VOC emissions from the external floating roof tanks is as follows:

- For tanks currently meeting NSPS Kb, meeting NSPS Kb is BACT.
- For tanks currently meeting RSR requirements and TK144, TK245, TK432, TK431, meeting RSR is BACT.
- For tanks that don't meet either NSPS Kb or RSR requirements, the existing MACT CC controls are BACT because upgrades are not feasible by 12/31/2018.

This is consistent with recent RBLC determinations of using slotted guidepole controls. During tank shutdowns and degassing, a portable combustion unit will continue to be used to control emissions.

# 19.0BACT for Emergency Engines

Tesoro operates four compression ignition emergency engines: one at the wastewater treatment plant, two fire water pumps, and one at the firehouse. These engines are designated as emergency engines, with usage limited to 500 hours per year. All engines are subject to the Part 63, Subpart ZZZZ standards. The Firehouse Engine was installed in 2011, and is therefore subject to Part 60, Subpart IIII standards.

## 19.1 Emergency Engine $PM_{2.5}$ Emissions

$PM_{2.5}$ emissions are the result of diesel combustion in the compression ignition engines.

### 19.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $PM_{2.5}$ emissions from a review of available information are listed in Table 3-1.

### 19.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $PM_{2.5}$ emissions are summarized in Table 19-1. The following sections provide additional detail.

**Table 19-1 Technical Feasibility of $PM_{2.5}$ Control Technologies for Emergency Engines**

| Technology | Technically Feasible? |
|---|---|
| Ultra-Low Sulfur Diesel Use | Yes |
| Good Combustion Practices | Yes |
| Comply with Emergency Engine requirements of MACT ZZZZ | Yes |
| Replace engine with Tier 4 Engine | No |

Although it may be feasible to replace the emergency engines with engines meeting EPA Tier 4 requirements, such a change would not be able to be engineered and implemented prior to December 31, 2018. Therefore, the replacements of the emergency engines are considered technically infeasible.

### 19.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 19-2, according to their control effectiveness.

**Table 19-2 Control Effectiveness Ranking of $PM_{2.5}$ Control Technologies for Emergency Engines**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Ultra-Low Sulfur Diesel Use | 0.0022 lb/hp-hr | AP-42 Table 3.3-1 |
| 1 | Good Combustion Practices | | |
| 1 | Comply with Emergency Engine requirements of MACT ZZZZ | | |

### 19.1.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected. All control options are considered equal for the purposes of this evaluation.

### 19.1.5 Step 5 – BACT Selection

BACT for $PM_{2.5}$ emissions from the emergency engines is using ultra-low sulfur diesel, good combustion practices, and compliance with MACT ZZZZ. This is consistent with recent RBLC determinations, listing good combustion practices and ultra-low sulfur diesel as BACT.

## 19.2 Emergency Engine $SO_2$ Emissions

$SO_2$ emissions from the emergency engines are from the combustion of sulfur in the diesel fuel.

### 19.2.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $SO_2$ emissions from a review of available information are listed in Table 3-1.

### 19.2.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $SO_2$ emissions are summarized in Table 19-3. The following sections provide additional detail.

**Table 19-3 Technical Feasibility of $SO_2$ Control Technologies for Emergency Engines**

| Technology | Technically Feasible? |
|---|---|
| Ultra-Low Sulfur Diesel | Yes |
| Good Combustion Practices | Yes |

All control technologies are technically feasible.

### 19.2.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 19-4, according to their control effectiveness.

**Table 19-4 Control Effectiveness Ranking of $SO_2$ Control Technologies for Emergency Engines**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Ultra-Low Sulfur Diesel | 1.2E-05 lb/hp-hr | AP-42 Table 3.4-1 (at 0.0015 wt% S) |
| 1 | Good Combustion Practices | | |

### 19.2.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 19.2.5 Step 5 – BACT Selection

BACT for $SO_2$ from the emergency engines is the use of ultra-low sulfur diesel and good combustion practices. This is consistent with recent RBLC determinations, listing the top control technology as ultra-low sulfur diesel.

## 19.3 Emergency Engine $NO_X$ Emissions

$NO_X$ emissions from the emergency engines result from the combustion of the diesel fuel.

### 19.3.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $NO_X$ emissions from a review of available information are listed in Table 3-1.

### 19.3.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $NO_X$ emissions are summarized in Table 19-5. The following sections provide additional detail.

**Table 19-5 Technical Feasibility of $NO_X$ Control Technologies for Emergency Engines**

| Technology | Technically Feasible? |
|---|---|
| Good Combustion Practices | Yes |
| Comply with Emergency Engine requirements of MACT ZZZZ | Yes |
| Replace engine with Tier 4 Engine | No |

Although it may be feasible to replace the emergency engines with engines meeting EPA Tier 4 requirements, such a change would not be able to be engineered and implemented prior to December 31, 2018. Therefore, the replacements of the emergency engines are considered technically infeasible.

### 19.3.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 19-6, according to their control effectiveness.

**Table 19-6 Control Effectiveness Ranking of $NO_X$ Control Technologies for Emergency Engines**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Good Combustion Practices | 0.031 lb/hp-hr | AP-42 Table 3.3-1 |
| 1 | Comply with Emergency Engine requirements of MACT ZZZZ | | |

### 19.3.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 19.3.5 Step 5 – BACT Selection

BACT for $NO_X$ emissions from the emergency engines is using good combustion practices, and compliance with MACT ZZZZ. *This is consistent with recent RBLC determinations.*

## 19.4 Emergency Engine VOC Emissions

VOC emissions from the emergency engines are the result of diesel combustion.

### 19.4.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for VOC emissions from a review of available information are listed in Table 3-1.

### 19.4.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for VOC emissions are summarized in Table 19-7. The following sections provide additional detail.

**Table 19-7 Technical Feasibility of VOC Control Technologies for Emergency Engines**

| Technology | Technically Feasible? |
|---|---|
| Good Combustion Practices | Yes |
| Comply with Emergency Engine requirements of MACT ZZZZ | Yes |
| Replace engine with Tier 4 Engine | No |

Although it may be feasible to replace the emergency engines with engines meeting EPA Tier 4 requirements, such a change would not be able to be engineered and implemented prior to December 31, 2018. Therefore, the replacements of the emergency engines are considered technically infeasible.

### 19.4.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 19-8, according to their control effectiveness.

**Table 19-8 Control Effectiveness Ranking of VOC Control Technologies for Emergency Engines**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| 1 | Good Combustion Practices | 2.47E-03 lb/hp-hr | AP-42 Table 3.3-1 |
| 1 | Comply with Emergency Engine requirements of MACT ZZZZ | | |

### 19.4.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required, as the top feasible control option is selected.

### 19.4.5 Step 5 – BACT Selection

BACT for VOC emissions from the emergency engines is using good combustion practices, and compliance with MACT ZZZZ. This is consistent with recent RBLC determinations.

## 19.5 Emergency Engine Ammonia Emissions

Ammonia emissions from the combustion of diesel fuel are negligible, and therefore a BACT evaluation is not completed for ammonia emissions from the emergency engines.

# 20.0BACT for Temporary Boilers

Tesoro generates steam used in the refinery in the heat recovery steam generators (HRSGs) at the Cogen Units and waste heat boilers located in the process units. Tesoro does not have any backup boilers on site, and rents package boilers to produce steam on a temporary basis for the refinery as needed when the HRSG or other waste heat steam producers are out of service and the online steam production capacity is insufficient to meet refinery steam demand. This practice produces less emissions than an unplanned or planned startup and shutdown of all or some process units. Once these units are back in service and operating in a stable manner, operation of the package boilers ceases. Situations requiring the use of temporary package boilers are relatively infrequent; so, it is more economical to use rental equipment than installing backup boilers which would rarely be used.

Temporary boiler emissions are limited by:

- The use of natural gas for fuel.
- The boilers are operated only on an as needed basis.
- Time on site is limited to 180 days or less per 40 CFR 60.41b.

The emissions from these Temporary Boilers are discussed in total in the sections which follow.

## 20.1Temporary Boilers $PM_{2.5}$ Emissions

According to the AP-42 emission factors, particulate matter emissions from combustion of gaseous fuels are typically low and consist of filterable and condensable fractions. Since the temporary boilers fire natural gas, $PM_{2.5}$ emissions from temporary boilers will be equivalent to $PM_{2.5}$ from the refinery's process heaters, and $PM_{2.5}$ BACT for temporary boilers is the same as the Process Heater BACT. See Section 5.1 for the Process Heater $PM_{2.5}$ BACT analysis.

## 20.2 Temporary Boilers $SO_2$ Emissions

$SO_2$ emissions from combustion arise from trace amounts of sulfur present in the fuel. Temporary boilers operate on natural gas, therefore $SO_2$ emissions from the temporary boiler are minimal. The use of natural gas and good combustion practices are BACT for $SO_2$ from the temporary boilers. See Section 15.2 for the K1 Compressor $SO_2$ BACT analysis for additional detail for natural gas-fired units.

## 20.3Temporary Boilers VOC Emissions

VOC emissions from the Temporary Boilers are a result of incomplete combustion. Temporary boilers operate on the same fuels as the refinery process heaters and combustion conditions in a temporary boiler are similar to those in Tesoro's process heaters.

The application of thermal oxidation or catalytic oxidation technology within a temporary package boiler is concluded to not be technically feasible. Thermal oxidation and catalytic oxidation has been shown to

be ineffective below VOC concentrations of 100 ppm. The concentration in a temporary boiler exhaust stream are estimated to be below 13 ppm, making thermal oxidation technically infeasible.

BACT for temporary boilers is the same as the Process Heater BACT. See Section 5.3 for the Process Heater VOC BACT analysis.

## 20.4 Temporary Boilers Ammonia Emissions

Ammonia emissions are the result of combustion, and according to the EPA WebFIRE emission factors are extremely low (0.0031 lb/MMBtu) for natural gas combustion.

Temporary boilers will use the same fuels as refinery process heaters; so, the ammonia BACT for temporary boilers is the same as the process heater ammonia BACT. See Section 5.4 for the Process Heater ammonia BACT analysis.

## 20.5 Temporary Boilers $NO_X$ Emissions

There are three mechanisms by which NOx production occurs during combustion including thermal, fuel, and prompt NOx formation. In the case of gaseous fuel combustion, the primary mechanism of NOx formation is through thermal NOx formation.

Temporary boilers are operated on gaseous fuels; thus, minimizing NOx emissions associated with fuel bound nitrogen.

### 20.5.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for $NO_X$ emissions from a review of available information is listed in Table 3-1.

### 20.5.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for $NO_X$ emissions are summarized in Table 20-1. The following sections provide additional detail.

**Table 20-1 Technical Feasibility of $NO_X$ Control Technologies for Temporary Boilers)**

| Technology | Technically Feasible? |
|---|---|
| ULNB | No |
| SCR + ULNB | No |
| SNCR + ULNB | No |
| Use of Gaseous Fuels | Yes |
| Operate boiler on temporary basis per 40 CFR 60.41b | Yes |

The NOx performance of rental boilers is limited by the availability boilers in the rental fleet at the time when the temporary boilers are needed onsite at the refiners.

NOx performance may also be limited by:

- When the boiler was purchased by the rental company.
- What technologies can be incorporated into a design which would fit on a truck trailer

### 20.5.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table 20-2, according to their control effectiveness.

**Table 20-2 Control Effectiveness Ranking of $NO_X$ Control Technologies for Temporary Boilers**

| Rank | Technology | Emission Control Effectiveness | Basis for Listed Performance |
|---|---|---|---|
| Temporary Boilers | Use of gaseous fuels | Varies by boiler | NOx performance is limited by rental boiler availability |
| | Operate boiler on temporary basis per 40 CFR 60.41b | | |

### 20.5.4 Step 4 – Evaluation of Feasible Control Technologies

The economic, environmental, and energy impacts of technically feasible control options are not required. The top technically feasible control for each heater based upon current control technology is selected.

### 20.5.5 Step 5 – BACT Selection

BACT for $NO_X$ from Temporary Boilers is:

- Use of natural gas.
- Limited use of temporary boilers while onsite and limit time on site to 180 days or less.

Tesoro will operate temporary boilers on gaseous fuels to minimize NOx from fuel bound nitrogen.

As noted above, the NOx performance of rental boilers is limited by the boilers in the rental company's fleet and the availability of boilers during the time when Tesoro needs them on site. So, the NOx performance of temporary boilers cannot be guaranteed at all times a temporary boiler is needed.

Tesoro will limit temporary boiler use time periods as they are needed to meet refinery steam demand when Cogen HRSGs and other waste heat steam generating capacity is out of service and during transition periods when operation of the boilers for plant reliability is required. Tesoro limits the time onsite for temporary boilers to 180 days or less per the requirements of 40 CFR 60.41b.

UTAH DEPARTMENT OF
ENVIRONMENTAL QUALITY
DEC 11 2017
DIVISION OF AIR QUALITY

December 8, 2017

Mr. Marty D. Gray
Manager, New Source Review Section UDAQ
195 N 1950 W
Salt Lake City, UT 84114Regional Administrator
U.S. Environmental Protection Agency

TESORO

Tesoro Refining & Marketing Company LLC
474 West 900 North
Salt Lake City, UT 84103

HAND DELIVERED

**RE: Best Available Control Technology (BACT) Assessment for Tesoro Refining & Marketing Company LLC and Tesoro Logistics Operations LLC Salt Lake City Utah**

Mr. Marty Gray,

Attached is the requested supplement to the BACT analysis submitted to UDAQ on May 5, 2017. We have included cost estimates and additional details on technical feasibility as requested by DAQ. This supplement should be referred to in conjunction with the May 5, 2017 submittal. The following are a few highlights that the information represents:

- In cases where Tesoro has concluded that the controls evaluated are technically and economically feasible and otherwise constitute BACT, additional technical and economic information has not been provided.
- Our BACT analysis addresses state of the art controls including the following: a wet gas scrubber on our FCC unit, flare gas recovery, tail gas treatment unit on the SRU, several other refinery-wide controls in accordance with EPA's recently adopted revisions to the Refinery sector rules MACT Subparts CC and UUU, ultralow NOx burners, catalytic converter, LDAR, and other design and operating practices.
- Several of the project and operating costs shown ($) and controls costs ($/ton) do not account for constraints that we will need to consider in any actual detailed engineering design such as limited or inadequate plot space, infrastructure requirements to steam or electrical systems, and others. Therefore, in cases where we noted these issues, the actual control cost may be substantially greater than the $/ton shown.
- As our original BACT analysis and this supplement make clear, there are significant technical and economic considerations that form the basis for eliminating SCR from being considered BACT. Additionally, even assuming that such limitations were not present, prior to concluding that SCR constituted BACT, a more extensive evaluation of collateral adverse environmental impacts resulting from the ammonia slip would need to be assessed. Currently we do not fully understand the ammonia inventory or how ammonia combines in the atmosphere to form ammonium PM2.5 species, evidenced by the very large amount of "ammonia injection" required for the CAMx model to perform properly. Yet these ammonium PM2.5 species comprise a very significant portion of the PM2.5 in the Salt Lake nonattainment area. Thus, while we do not have adequate information at this point in time to quantify the extent to which increases in ammonia emissions associated with SCRs would offset the secondary PM2.5 reductions achieved from NOx reductions, it is certain that it would have some definite countervailing

impact. Such an assessment would need to be concluded before SCR were determined to constitute BACT (again, assuming that SCR was not otherwise disqualified based on technical and economic feasibility considerations). The countervailing effect of ammonia slip would also have to be accounted for in the cost effectiveness estimates as the increase in secondary ammonia PM2.5 would effectively increase the $/ton control cost.

As you know, the SIP development has been on an accelerated schedule. We have made every attempt to be as complete and accurate as possible in view of these timeframes. While more detailed engineer design work could be undertaken in some cases, we believe that the level of detail contained in our submittals is sufficient to support the BACT conclusions reached.

Respectfully,

Amber Larsen

EH&S Manager, Tesoro Salt Lake City Refinery

# BACT Financial and Technical Analysis

| Emission | Emission Unit | Controls/Measures Evaluated | Technically Feasible | Technical Feasibility<br>Justification | Emission Reduction<br>tpy | Project Cost<br>Equipment/Install only | Yearly Operating cost<br>$/year (Based on EPA Air Pollution Control Cost Manual) | Control Cost<br>$/ton | BACT Conclusion |
|---|---|---|---|---|---|---|---|---|---|
| PM2.5, SO2, NOX, VOC, Ammonia | FCCU/CO Boiler | Electrostatic Precipitator (ESP) and Wet Gas Scrubber (WGS), Good Combustion practice | -- | -- | -- | -- | -- | -- | Electrostatic Precipitator (ESP) and Wet Gas Scrubber (WGS), Good Combustion practice constitute BACT |
| PM2.5, VOC, Ammonia | H-101 Crude Unit Furnace | Good Design Methods and Good Operating Practices | -- | -- | -- | -- | -- | -- | Good Design Methods and Good Operating Practices constitute BACT |
| PM2.5, VOC, Ammonia | F-1 UFU Furnace | | -- | -- | -- | -- | -- | -- | |
| PM2.5, VOC, Ammonia | F-15 UFU Regen Furnace | | -- | -- | -- | -- | -- | -- | |
| PM2.5, VOC, Ammonia | F-680 DDU Furnace | | -- | -- | -- | -- | -- | -- | |
| PM2.5, VOC, Ammonia | F-681 DDU Furnace | | -- | -- | -- | -- | -- | -- | |
| PM2.5, VOC, Ammonia | F-701 GHT Furnace | | -- | -- | -- | -- | -- | -- | |
| PM2.5, VOC, Ammonia | Cogen Units | | -- | -- | -- | -- | -- | -- | |
| PM2.5, NOX, VOC | SRU | | -- | -- | -- | -- | -- | -- | |
| PM2.5, NOX, VOC, Ammonia | Temporary Boilers | | -- | -- | -- | -- | -- | -- | |
| PM2.5, SO2, NOX, VOC, Ammonia | North and South Flares | Flare Gas Recover System, Flare Minimization Plan, Flare Caps, and Flare Combustion Efficiency. | -- | -- | -- | -- | -- | -- | Flare Gas Recover System, Flare Minimization Plan, Flare Caps, and Flare Combustion Efficiency constitute BACT |
| PM2.5, SO2, NOX | Emergency Engines | Ultra-Low Sulfur Diesel, Good Operating Practices, and Compliance with MACT ZZZZ | -- | -- | -- | -- | -- | -- | Ultra-Low Sulfur Diesel, Good Operating Practices, and Compliance with MACT ZZZZ constitute BACT |
| SO2 | Fuel Gas H2S (Furnace/Cogens/Pilot Gas to SRU Flare) | Amine Treat Fuel Gas | -- | -- | -- | -- | -- | -- | Amine Treat Fuel Gas constitute BACT |
| NOX | F-1 UFU Furnace | Ultra-Low Nox burners | -- | -- | -- | -- | -- | -- | Ultra-Low Nox burners constitute BACT |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| VOC | Cooling Towers | Compliance with 40 CFR 63 Subpart CC leak detection program requirements | -- | -- | -- | -- | -- | -- | | Compliance with a leak detection program that meets the requirements of 40 CFR 63 Subpart CC constitutes BACT. |
| VOC | Transport Loading Rack | Vapor Recovery Unit with Carbon Adsorption | -- | -- | -- | -- | -- | -- | | Vapor Recovery Unit with Carbon Adsorption constitutes BACT |
| VOC | K1 Compressors | Catalytic Converter | -- | -- | -- | -- | -- | -- | | Catalytic Converter constitutes BACT. |
| VOC | Fixed Roof Tanks | Good Design Methods and Good Operating Practices | -- | -- | -- | -- | -- | -- | | Good Design Methods and Good Operating Practices constitute BACT |
| VOC | Fugitive Equipment | An LDAR program compliant with Subpart GGGa | -- | -- | -- | -- | -- | -- | | An LDAR program compliant with Subpart GGGa constitutes BACT. |
| NOX, VOC, Ammonia | SRU Flare | Flare minimization plan | -- | -- | -- | -- | -- | -- | | Flare minimization plan constitutes BACT. |
| **PM2.5** | | | | | | | | | | |
| | K1 Compressors | Install electric motors. | Potentially | Requires upgrade to the refinery's electrical supply via 3rd party, infrastructure and civil work. The electrical infrastructure is to Rocky Mountain Power's and is not within the refinery's control and therefore we are not sure of additional technical and economic considerations. (Costs for these upgrades are not included in the project cost.) We are not sure of potential timing for project and if we could meet 2024 timeline. | 0.16 | $ 2,700,000 | $ 434,000 | $ 2,721,000 | | Not BACT based on economic and technical feasibility considerations. |
| | Cooling Tower UU3 | New drift eliminators | No | Not technically feasible with out all new equipment. Old equipment can not be retrofitted at this point. We do not have the real estate for new equipment. Install of new equipment would require an approximate 6 month outage to demo and rebuild cooling tower. Outage would have a significant but undefined impact on refinery operations, throughput, and profitability. | | | | | | Installing new drift eliminators is not technically feasible or cost effective based on 6 month outage. |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Cooling Tower UU2 | New drift eliminators | No | Not technically feasible with out all new equipment. Old equipment can not be retrofitted at this point. We do not have the real estate for new equipment. Install of new equipment would require an approximate 6 month outage to demo and rebuild cooling tower. Outage would have a significant but undefined impact on refinery operations, throughput, and profitability. | | | | | Installing new drift eliminators is not technically feasible or cost effective based on 6 month outage. |
| **NOX** | | | | | | | | | |
| | K1 Compressors | Install electric motors. | Potentially | Requires upgrade to the refinery's electrical supply via 3rd party, infrastructure and civil work. The electrical infrastructure is to Rocky Mountain Power's and is not within the refinery's control and therefore we are not sure of additional technical and economic considerations. (Costs for these upgrades are not included in the project cost.) We are not sure of potential timing for project and if we could meet 2024 timeline. | 7.75 | $ 2,700,000 | $ 434,000 | $ 56,000 | Not BACT based on economic and technical feasibility considerations. Additionally, available information does not allow for complete assessment of technical feasibility. Cost effectiveness is high and does not include cost of upgrades to Rocky Mountain Power infrastructure. |
| | F701 (ULNB) | Install ULNB | No | Not technically feasible due to flame impingement. A new furnace would need to be purchased. | | | | | Not technically feasible. |
| | F701 SCR | Install SCR | Potentially | Need to do additional feasibility/engineering study. Not sure if infrastructure can support an SCR. No infrastructure upgrades in estimate. If there is no plot space for an SCR we will need to build up which requires civil work. Also SCR's result in ammonia emissions that would offset some of the PM2.5 reduction resulting from the NOX reduction. | 1.92 | $ 3,006,000 | $ 371,000 | $ 193,229 | Partial cost estimates indicate high cost effectiveness. Preliminary evaluation |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | F15 UFU Regen Furnace | Install ULNB | No | Not technically feasible due to flame impingement. A new furnace would need to be purchased. | | | | | Not technically feasible. |
| | F15 UFU Regen Furnace | Install SCR | Potentially | Need to do a feasibility study. Not sure if infrastructure can support an SCR. No infrastructure upgrades in estimate. If there is no plot space for an SCR we will need to build up which requires civil work. Also SCR's do create an ammonia emission source that would offset some of the PM2.5 recustion resulting from the NOX reduction. | 3.3 | $ 4,419,000 | $ 545,000 | $ 165,152 | Not BACT based on economic and technical feasibility considerations. Additionally, available information does not allow for complete assessment of technical feasibility. |
| | F680/681 DDU Furnace | Install SCR | Potentially | Need to do a feasibility study. Not sure if infrastructure can support an SCR. No infrastructure upgrades in estimate. If there is no plot space for an SCR we will need to build up which requires civil work. Also SCR's do create an ammonia emission source that would offset some of the PM2.5 recustion resulting from the NOX reduction. | 5.52 | $ 8,701,500 | $ 932,000 | $ 168,841 | Not BACT based on economic and technical feasibility considerations. Additionally, available information does not allow for complete assessment of technical feasibility. |
| | Cogen | Install SCR | Potentially | Need to do a feasibility study. SCR's do create an ammonia emission source that would offset some of the PM2.5 reduction resulting from the NOX reduction. | 86.67 | $ 14,618,000 | $ 2,012,000 | $ 23,214 | |
| SO2 | | | | | | | | | |
| | SRU/TGU Wet Gas Scrubber | Install a wet gas scrubber on the SRU/TGU plant. | no | Not technically feasible at this time. Current WGS not designed for SRU/TGU treatment capacity nor do we have the steam/water/electrical etc. infrastructure for another WGS. Infrastructure upgrades would put us past 2024. Increase in steam infrastructure would lead to a potential offset of emissions reductins. | | | | | Not technically feasible. |
| | K1 Compressors | Install electric motors. | urrent technology meets BA | Currently on Natural Gas. No SO2 generation. | | | | | Current technology meets BACT. |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **VOC** | | | | | | | | | |
| | Refinery Waste Water | Install QQQ API Separators, vapor recovery or carbon canisters. | Potentially | Not sure if project can be executed by 2024. Major equipment components with long lead time. Intensive engineering review required. Existing waste water treatment plant cannot be upgraded. | 14.97 | $ 2,511,100 | $ 3,450,000 | $ 230,461 | More analysis is required to determine BACT conclusion. |
| | Uncontrolled Refinery Drains | Captured in Refinery Waste Water Project. | | | | | | | |
| | Internal Floating Roof Tanks | Upgrades to tanks are meeting Refinery Sector rule by 2028 | Partially | Not technically feasible to upgrade all tanks by 2024. All internal floating roof tanks are scheduled to meet Refinery Sector Rule upgrades (BACT) by 2028. | | | | | Not technically feasible to install controls on all internal floating roof tanks by 2028. |
| | External Floating Roof Tanks | Upgrades to tanks are meeting Refinery Sector rule by 2028 | Partially | Not technically feasible to upgrade all tanks by 2024. All external floating roof tanks are scheduled to meet Refinery Sector Rule upgrades (BACT) by 2028. | | | | | Not technically feasible to install controls on all external floating roof tanks by 2028. |

all these are south coast aqmd

DRAFT

BOARD MEETING DATE: December 2, 2016 AGENDA NO. ##

PROPOSAL: Amend BACT Guidelines and Approve Charter for BACT Scientific Review Committee

SYNOPSIS: Periodically, staff proposes updates to Parts A and C of the Policy and Procedures of the BACT Guidelines for major and non-major polluting facilities as well as reports new Lowest Achievable Emission Rate and BACT determinations added to Parts B and D for major and non-major polluting facilities. Additionally, for the first time, the BACT Guidelines need to incorporate policy and procedures and determinations for facilities subject to prevention of significant deterioration for greenhouse gases. These actions are to amend the BACT Guidelines to make them consistent with recent changes to SCAQMD rules and regulations as well as state and federal requirements and approve a charter for the BACT Scientific Review Committee.

COMMITTEE: Stationary Source, September 16 and November 18, 2016; Recommended for Approval

RECOMMENDED ACTIONS:

1. Determine that proposed amendments to the BACT Guidelines are exempt from the California Environmental Quality Act;
2. Approve Proposed Amendments to BACT Guidelines; and
3. Approve Proposed Charter for the SCAQMD BACT Scientific Review Committee detailing goals and objectives and membership of the BACT Scientific Review Committee.

Wayne Nastri
Acting Executive Officer

NMM:AHB:JA

I didn't print all this - it is 333 pages. If it has useful info, the web address is www.aqmd.gov/search?q=refinery bact (leave a space)

**Background**
SCAQMD's New Source Review (NSR) regulations require permit applicants to use Best Available Control Technology (BACT) for new sources, relocated sources and modifications to existing sources that may result in an emission increase of any nonattainment air contaminant, any ozone depleting compound (ODC) or ammonia. Regulation XIII–New Source Review also requires the Executive Officer to periodically publish BACT Guidelines that establish the procedures and the BACT requirements for commonly permitted equipment.

The BACT Guidelines are separated into parts for major polluting facilities and non-major polluting facilities. A facility is a major polluting facility if it emits, or has the potential to emit, a criteria air pollutant at a level that equals or exceeds the Regulation XXX Title V emission thresholds. Major polluting facilities that are subject to NSR are required by the Clean Air Act (CAA) to have the Lowest Achievable Emission Rate (LAER). The federal CAA requirement for LAER is implemented through BACT in the SCAQMD. The Part B BACT and LAER determinations for major polluting facilities are only examples of past determinations that help in determining LAER for new permit applications. The California Health & Safety Code (H&SC) Section 40405 defines state BACT similar to federal LAER and requires the application of BACT for all new and modified permitted sources subject to NSR. For non-major polluting facilities, minor source BACT (MSBACT) is as specified in Part D of the BACT Guidelines and determined in accordance with state law at the time an application is deemed complete. In updating Part D with new or more stringent MSBACT, SCAQMD must follow a more rigorous process than for major polluting facilities, including a cost-effectiveness analysis, notification of the public, presentation at a BACT Scientific Review Committee (BACT SRC) meeting and Board approval. SCAQMD also follows the criteria and process specified in H&SC Section 40440.11.

The BACT SRC was established as a standing committee by the Board on September 8, 1995. The BACT SRC was intended to enhance the public participation process with technical review and comments by a focused committee at periodic intervals, prior to the updates of the BACT Guidelines. Staff is proposing the establishment of a Charter that will provide BACT SRC members with an outline of the BACT SRC's mission, goals and objectives, and membership.

**Proposed Amendments to the BACT Guidelines**
The proposed amendments are to update the Overview, Parts A, B, C and D and to add Parts E and F of the BACT Guidelines to maintain consistency with recent changes to SCAQMD rules and state and federal requirements. The proposed amendments will not result in more stringent requirements than would otherwise occur. Therefore, it was not necessary for staff to evaluate the achieved-in-practice status nor cost effectiveness of the underlying technologies. The BACT SRC and other interested parties were provided with a detailed description of the proposed amended BACT Guidelines at

scheduled public meetings on May 11, 2016, September 27, 2016 and November 9, 2016. The proposed amendments to the Guidelines were posted on the SCAQMD website, and a 30-day public comment period commenced after the first two BACT SRC meetings. Comments by BACT SRC members and the general public along with staff responses are included in Attachment G.

**Overview**
The Overview consists of five chapters which provide an introduction to the BACT Guidelines and a summary of how BACT is implemented in the SCAQMD. The proposed amendments to the Overview section are primarily administrative in nature and intended to update and clarify content. A summary of the proposed Overview amendments is included in Attachment A with the complete proposed amended Overview included in Attachment B.

**Part A – Policy and Procedures for Major Polluting Facilities**
Part A describes the policy and procedures for major polluting facilities and explains what BACT is, why it is required, when it is required and how it is determined for major polluting facilities. The proposed amendments to Part A are to maintain consistency with existing and recent changes to SCAQMD rules and state and federal requirements. A summary of the proposed Part A amendments is included in Attachment A with the complete proposed amended Part A included in Attachment B.

**Part B - LAER/BACT Determinations for Major Polluting Facilities**
Part B consists of three sections: Section I contains listings of LAER/BACT determinations made by SCAQMD; Section II contains listings of LAER/BACT determinations for equipment in other air districts; and Section III contains listings of emerging control technologies. The proposed Part B LAER/BACT determinations of Section I are summarized below with the complete proposed determinations included in Attachment C. The other portions of Section I, and Sections II and III, are not included because they are not being updated.

Section I – SCAQMD LAER/BACT Determinations
Four new listings include "Flare, Oil and Gas Production" and three listings under "I.C. Engine-Emergency, Compression Ignition with PM Trap".

The new "Flare, Oil and Gas Production" listing is for a Flare Industries/Bekaert CEB enclosed ground flare with clean enclosed burner rated at 27 MMBtu per hour. This flare is operated by Linn Operating, Inc., for process gas disposal and is located in the City of Brea. The flare was permitted with NOx, VOC and CO emission levels of 15 ppm, 10 ppm and 10 ppm, respectively, all corrected to 3% $O_2$, which are below current BACT requirements for this type of flare. The flare commenced operation and was source tested in early 2013 and has operated since that time. The source test showed the flare complied with the NOx, VOC and CO emission limits. In addition, a similar 17

MMBtu per hour flare by the same manufacturer has been included in the CARB BACT Clearinghouse with the same emission limits.

The "I.C. Engine-Emergency, Compression Ignition with PM Trap" listings are for three separate engines rated at 374 horsepower (hp), 755 hp and 2220 hp, all equipped with a CARB-verified diesel particulate filter and certified to meet the applicable EPA tier emission standards. These engines were permitted between 2011 and 2014 and have operated since that time.

**Part C – Policy and Procedures for Non-Major Polluting Facilities**
Part C describes the policy and procedures for non-major polluting facilities and explains what BACT is, why it is required, when it is required and how it is determined for non-major polluting facilities. The proposed updates to Part C are to maintain consistency with recent changes to SCAQMD rules and state and federal requirements. A summary of the proposed Part C amendments is included in Attachment A with the complete proposed amended Part C included in Attachment B.

**Part D BACT Determinations for Non-Major Polluting Facilities**
Part D consists of BACT determinations for minor sources which are determined in accordance with state law at the time an application is deemed complete. The proposed amendments to Part D are intended to maintain consistency with recent changes to SCAQMD rules and state and federal requirements. The proposed amendments will not result in more stringent requirements than would otherwise occur through rule compliance. Therefore, it was not required for staff to evaluate the achieved-in-practice status nor cost effectiveness of the underlying technologies. The proposed amendments comply with the requirements of California H&SC Section 40440.11. The proposed Part D BACT determinations are summarized below with the complete proposed amended Part D included in Attachment D.

***Boilers***
Background
SCAQMD Rules 1146 and 1146.1, addressing emissions of oxides of nitrogen from industrial, institutional, and commercial boilers, steam generators, and process heaters, were most recently approved by the Board on November 1, 2013. These rules apply to most gaseous fuel-fired boilers, steam generators and process heaters rated at greater than 2,000,000 Btu per hour, with the exception of utility boilers, refinery boilers and process heaters rated at greater than 40,000,000 Btu per hour, thermal fluid heaters and sulfur plant reaction boilers.

Proposal
Updated NOx concentration emissions requirements and additional subcategories are being proposed to the Boiler BACT listing to maintain consistency with the requirements in Rules 1146 and 1146.1.

Staff is recommending incorporating these limits into the BACT Guidelines now that the compliance deadlines have passed and all NOx emission limits are now required by these rules. Subcategories for "Propane Fired, > 2 MMBtu/hr and < 20 MMBtu/hr," "Natural Gas or Propane Fired, ≥ 20 MMBtu/hr and < 75 MMBtu/hr," "Natural Gas or Propane Fired, ≥ 75 MMBtu/hr," "Atmospheric Unit, ≥ 2 and ≤ 10 MMBtu/hr," "Landfill Gas Fired, < 75 MMBtu/hr" and "Digester Gas Fired, < 75 MMBtu/hr" will be added to the listing to maintain consistency with the definitions in Rules 1146 and 1146.1.

***Portable Internal Combustion Engines***

Background

The BACT Guidelines for portable compression ignition I.C. engines reflect the federal emission standards for non-road engines. EPA has established a multiple-tiered system for the emission standards for non-road I.C. engines, which includes portable engines. The Tier 4 emission standards were introduced in 2004 and have been completely phased in for most non-road engines as of January 1, 2015. The current BACT Guidelines list the Tier 2 and Tier 3 requirements for Compression Ignition engines.

Proposal

Staff is proposing to update the BACT Guidelines for portable I.C. Engines to reflect the requirements of the current Tier 4 standards. CARB adopted the same Tier 4 emission standards and schedule on December 7, 2005. These standards are only applicable to the Compression Ignition subcategory of this listing and will not affect the Spark Ignition engine requirements. However, until further notice, CARB has extended the deadline of the Tier 4 Final requirements, which will now be subject to higher Tier 4 Interim emission levels and are being incorporated into the BACT Guidelines for Portable, Compression-Ignition Engines 75 ≤ HP < 175 and HP ≥ 750. Final Tier 4 requirements will be added to NOx, NMHC, "NOx+NMHC", CO and PM BACT emission standards for all the other listed ratings of Compression-Ignition portable I.C. Engines. These updates are all current requirements in 40 CFR Section 10301 Subpart B, 13 CCR Section 2420 et seq. and 17 CCR Section 93116.

Formatting changes in this BACT Listing were done to maintain consistency with the new standards. Most notably, the previous "NMHC+NOx" standard has been changed to separate NOx and NMHC standards for three of the four HP rating categories.

***Stationary, Emergency, Internal Combustion Engines***

Background

The BACT guidelines for the subcategories "Compression Ignition, Fire Pumps" as well as "Compression Ignition, Other" under the "I.C. Engine, Stationary, Emergency" listing reflect the federal emission standards for non-road engines as well as the CARB ATCM for Stationary Compression Engines 17 CCR Section 93115. As with the portable engines, EPA has established a tiered system for stationary I.C. engine

emission standards, which was adopted into the CARB ATCM. Currently, all I.C. engines rated greater than or equal to 50 HP and less than 750 HP are subject to the Tier 3 emission standards. Engines under these two subcategories that are rated greater than or equal to 750 HP are subject to the Tier 2 standards. In addition, these two subcategories are both subject to the requirements of SCAQMD Rule 1470 that was last amended on May 4, 2012. SCAQMD Rule 1470 sets emission standards for PM, primarily limited to new engines located at or near sensitive receptors, and NOx + NMHC and CO that are consistent with EPA and CARB's tiered-emission standards.

The "Spark Ignition" subcategory is subject to the New Source Performance Standards (NSPS) under 40 CFR 60 Subpart JJJJ. The current BACT listing applies to all ratings of spark ignition I.C. engines and limits VOC emissions to 1.5 grams VOC/bhp-hr. Subpart JJJJ requires emergency spark ignition engines rated at greater than or equal to 130 HP to meet an emission standard of 1.0 grams VOC per brake horsepower-hour (/bhp-hr).

Proposal

Staff is proposing to add "Compliance with Rule 1470" for NOx+NMHC and CO emission standards to the subcategories "Compression Ignition, Fire Pumps," and "Compression Ignition, Other". The current BACT listing already includes this requirement for the PM emission standard. In addition, staff is proposing to remove outdated diesel fuel standards from the SOx emission standards for these two subcategories. The current SOx standard required by SCAQMD Rule 431.2, which is also currently listed, will remain.

Staff is also proposing to remove the outdated Tier 2 references under the NOx+NMHC standard and leave the current Tier 3 standards for "Compression Ignition, Fire Pumps".

For the Spark Ignition subcategory, staff proposes to separate the listing into two ratings: $50 \leq HP < 130$ and $HP \geq 130$. Engines rated $50 \leq HP < 130$ will be subject to the same existing requirements. Engines rated $HP \geq 130$ will be subject to the NSPS standard of 1.0 gram VOC/bhp-hr.

Staff is also proposing to delete previous footnotes for situations that are no longer applicable to the current standards due to compliance dates that have passed or rule changes.

***Stationary, Non-Emergency, Non-Electrical Generators, Internal Combustion Engines***

Background

Currently, Part D of the BACT Guidelines has a listing for "I.C. Engine, Stationary, Non-Emergency." Due to recent amendments to SCAQMD Rule 1110.2, "Emissions from Gaseous- and Liquid-Fueled Engines," staff has recognized the need for two major

categories under this listing and will be proposing two separate listings, "I.C. Engine, Stationary, Non-Emergency, Non-Electrical Generators," and "I.C. Engine, Stationary, Non-Emergency, Electrical Generators." At this time, only the former category will be added to the guidelines since analysis for the latter category is still in progress. The existing listing for "I.C. Engine, Stationary, Non-Emergency," will remain until both new categories are implemented.

Qualifying engines under "I.C. Engine, Stationary, Non-Emergency" are subject to the requirements of Rule 1110.2. On February 1, 2008, the current NOx, VOC and CO concentration limits were adopted and fully implemented by 2010 for all engines, except landfill and digester gas (biogas) fired units. In 2012, a compliance deadline of January 1, 2016, was established for biogas-fired units to meet the same NOx, VOC and CO limits; however, the recent Rule 1110.2 amendment on December 4, 2015, extended the compliance date until January 1, 2017. In addition, an exemption was provided to biogas units with ongoing technology demonstration projects to extend the compliance date until January 1, 2018.

Proposal

Staff proposes to establish the category of "I.C. Engine, Stationary, Non-Emergency, Non-Electrical Generators." The category of "I.C. Engine, Stationary, Non-Emergency" will remain unchanged. The new listing will incorporate the existing Rule 1110.2 limits and requirements listed below for all engines rated greater than 50 bhp.

| ppmvd NOx @ 15% $O_2$ | ppmvd VOC[1] @ 15% $O_2$ | ppmvd CO @ 15% $O_2$ |
|---|---|---|
| 11 | 30 | 250 |

[1]measured as carbon

Due to the extension allowed for biogas engines, the existing BACT limits will still apply for NOx, VOC and CO. A footnote will be added to indicate the compliance deadlines for biogas-fueled engines to meet the SCAQMD Rule 1110.2 limits for these contaminants. In addition, the SOx category will continue to require compliance with Rule 431.1.

***Liquid Transfer and Handling***

Background

Part D of the BACT Guidelines for Liquid Transfer and Handling currently lists three different subcategories for Marine, Loading and Tank Truck and Railcar Bulk Loading Classes A, B and C. The listing does not include a subcategory for Gasoline Transfer and Dispensing beyond the Bulk Loading subcategories.

Proposal
Staff is proposing to add an additional subcategory to Part D of the BACT Guidelines for "Gasoline Transfer and Dispensing." The subcategory will only be subject to VOC emission requirements, which will specify "Compliance with SCAQMD Rule 461." These facilities are already subject to the requirements of this rule, last amended on April 6, 2012. This proposal will incorporate the existing rule requirements into the BACT Guidelines for minor sources.

***Non-Refinery Process Heater***
Background
SCAQMD Rules 1146 and 1146.1, both titled "Emissions of Oxides of Nitrogen from (Small) Industrial, Institutional , and Commercial Boilers, Steam Generators, and Process Heaters," were most recently approved by the Board on November 1, 2013. These rules apply to most gaseous fuel-fired boilers, steam generators and process heaters rated at greater than 2,000,000 Btu per hour, with the exception of utility boilers, refinery boilers and process heaters rated at greater than 40,000,000 Btu per hour, thermal fluid heaters and sulfur plant reaction boilers.

Proposal
To maintain consistency with the current requirements of Rules 1146 and 1146.1, staff is proposing to specify in the BACT listing for Process Heater–Non-Refinery under NOx "Compliance with SCAQMD Rules 1146 and 1146.1." This proposal will incorporate the existing rule requirements into the BACT Guidelines for minor sources.

***Oil and Gas Production***
Background
SCAQMD Rules 1148, Thermally Enhanced Oil Recovery Wells, and 1148.1, Oil and Gas Production Wells, apply to oil and gas production operations and specifically Rule 1148.1 was recently amended and approved by the Board on September 4, 2015.

Proposal
To maintain consistency with the current requirements of Rules 1148 and 1148.1, staff is proposing to specify in the BACT listing for Oil and Gas Production under VOC "Compliance with SCAQMD Rules 1148 and 1148.1." This proposal will incorporate the existing rule requirements into the BACT Guidelines for minor sources.

**Proposed New Part E–Policy and Procedures for Facilities Subject to Prevention of Significant Deterioration for Greenhouse Gases**
Background
For the first time, GHG emissions from the largest stationary sources are covered by the Prevention of Significant Deterioration (PSD) and Title V Operating Permit Programs beginning January 2, 2011. These permitting programs, required under the Clean Air Act, are proven tools for protecting air quality and the same tools will be used to reduce

GHG emissions. The SCAQMD is currently required to implement the GHG BACT requirements through its permitting program.

40 CFR 52.21, amended in both May 2010 and October 2015, established an approach to permit GHG emissions under PSD and Title V. Through this rule, permitting focused on the major industrial sources, which emit nearly 70 percent of the greenhouse gas pollution from stationary sources. At this time, lesser-emitting sources are not subject to these requirements.

The requirements of this rule apply only to GHG as defined by EPA as a total group of six GHG which are: carbon dioxide ($CO_2$), nitrous oxide ($N_2O$), methane ($CH_4$), hydrofluorocarbons (HFC), perfluorocarbons (PFC) and sulfur hexafluoride ($SF_6$). All other attainment air contaminants, as defined in SCAQMD Rule 1702 subdivision (a), shall be regulated for the purpose of PSD.

Proposal

To maintain consistency with current federal GHG permitting requirements, staff is proposing to add Part E to the BACT Guidelines. This part summarizes the requirements of GHG BACT regulations according to EPA, describes the Top-Down Process, explains how to calculate GHG emissions and explains PSD Applicability for GHGs for new and modified sources. 40 CFR 52.21 was recently revised to address the U.S. Supreme Court decision in Utility Air Regulatory Group v. Environmental Protection Agency, 134 S. Ct. 2427 (2014)19, regarding the applicability of PSD and GHG BACT. The guidance in this chapter is applicable to the EPA requirements in place as of the date of these guidelines, as well as SCAQMD Rule 1714, which incorporates most of 40 CFR 52.21 by reference. Proposed Part E is included in Attachment B.

**Proposed New Part F–BACT Determinations for Facilities Subject to Prevention of Significant Deterioration for Greenhouse Gases**

Background

Similar to Part B, proposed new Part F will consist of Section I with listings of GHG BACT determinations made by SCAQMD, Section II with listings of GHG BACT determinations for equipment in other air districts, and Section III with listings of emerging GHG BACT control technologies.

Proposal

Staff is proposing to add Part F and bring new GHG BACT determinations for Board approval as they become available for inclusion into Part F. At this time, there are no GHG BACT listings to be proposed; however, staff is in the process of identifying potential GHG BACT for future listings. Proposed Part F is included in Attachment B.

**Proposed Amendments to List of Abbreviations and Index of Equipment Categories**

Staff is proposing to update the List of Abbreviations by the addition of the following: California Air Resources Board (CARB), Carbon Capture and Sequestration (CCS), Carbon Dioxide ($CO_2$), Carbon Dioxide Equivalent ($CO_2e$), Greenhouse Gas (GHG), Global Warming Potential (GWP), Maximum Individual Cancer Risk (MICR), Lead (Pb), Particulate Matter less than 2.5 microns in diameter ($PM_{2.5}$), Prevention of Significant Deterioration (PSD), Potential to Emit (PTE), RECLAIM Trading Credit (RTC), South Coast Air Quality Management District (SCAQMD replaced AQMD) and Best Available Control Technology for Toxics (T-BACT).

To be consistent with the function of the Index of Equipment Categories, staff is proposing to rename it to List of Equipment Categories. The proposed amendments to this list are administrative in nature and consist of having the same equipment categories as those in Parts B, D and F and included in Attachment B.

**Proposed Charter for BACT Scientific Review Committee**

Staff is proposing the establishment of a Charter for the BACT SRC, which details the BACT SRC's goals and objective, the composition and selection of the BACT SRC membership, the desired qualifications of its membership and the operational guidelines for the BACT SRC. The proposed Charter for the BACT SRC is included in Attachment E.

**Presentation to BACT Scientific Review Committee**

The proposed amendments to the BACT Guidelines were presented to the BACT SRC at the publicly noticed May 11, 2016 meeting. A 30-day period was provided to the BACT SRC and general public to review and submit comments. At the September 16, 2016 Stationary Source Committee, staff was directed to hold a follow-up BACT SRC meeting; a meeting was held on September 27, 2016 to address additional comments on the Proposed Amended BACT Guidelines. At the request of BACT SRC members and the public an additional 30-day comment period was provided to review and submit comments. The proposed amended BACT Guidelines along with staff response to comments was, for the third time, presented to the BACT SRC at a publicly noticed meeting on November 9, 2016. Comments by BACT SRC members and the general public along with staff responses are included in Attachment G.

**California Environmental Quality Act (CEQA)**

SCAQMD staff has reviewed the proposed amendments to the BACT Guidelines, pursuant to CEQA Guidelines, pursuant to CEQA Guidelines Section 15002(k)(1) and Section 15061, and determined them to be exempt from CEQA pursuant to CEQA Guidelines Section 15061(b)(3). Since the proposed amendments are only updating the BACT Guidelines with current, already existing requirements, it can be seen with

certainty that the proposed project has no potential to adversely impact air quality or any other environmental topic area.

**Socioeconomic Analysis**
The proposed amendments of the BACT Guidelines are to maintain consistency with recent changes to SCAQMD rules and state and federal requirements. These proposed amendments are administrative in nature and will therefore not result in more stringent requirements than would otherwise occur and would not result in any adverse socioeconomic impacts.

**Benefits to SCAQMD**
Emission reductions realized through permitted sources that apply the latest BACT will benefit air quality, achieve emissions reductions needed to attain air quality standards and improve public health in the SCAQMD's jurisdiction. In addition, the successful implementation of BACT for permitted stationary sources will contribute towards achieving the air quality objectives of SCAQMD's Air Quality Management Plan.

**Resource Impacts**
Existing SCAQMD resources will be sufficient to implement the proposed changes to the BACT Guidelines.

**Recommendation**
This Board letter serves as staff's report to the Board on proposed amendments to the BACT Guidelines. The updated BACT Guidelines with these amendments are scheduled to be made available at SCAQMD's website at http://www.aqmd.gov/home/permits/bact, pending Board approval.

These actions are to determine that proposed amendments to the BACT Guidelines are exempt from the California Environmental Quality Act, approve proposed amendments to the BACT Guidelines, and approve the proposed Charter for the SCAQMD BACT Scientific Review Committee.

**Attachments**
A. Summary of Proposed Amendments to BACT Guidelines
B. Proposed Amended BACT Guidelines Overview, Parts A, C, E and F
C. Proposed Amended BACT Guidelines Part B
D. Proposed Amended BACT Guidelines Part D
E. Proposed Charter for BACT Scientific Review Committee
F. Notice of Exemption from the California Environmental Quality Act
G. Comments and Responses

Single underline/~~Single Strikeout~~ text shows new language added/deleted as of October 7, 2016 Board Package.

Double underline/ ~~Double Strikeout~~ text shows new language added/deleted subsequent to October 7, 2016 Board Package.

# PROPOSED BACT GUIDELINES

# ATTACHMENT A

# SUMMARY

Attachment **A**

## SUMMARY OF PROPOSED AMENDMENTS TO BACT GUIDELINES

The following summarizes the key proposed amendments to the BACT Guidelines:

Overview

Chapter 1 - Introduction
- Toxic BACT (T-BACT) reference
- Description for addition of Parts E and F to address Prevention of Significant Deterioration (PSD) requirements for GHG emissions established by U.S. EPA
- BACT Docket information updated
- Hyperlinks added for Web pages and email

Chapter 2 – Applicability Determination
- Added $PM_{2.5}$ and updated SOx threshold levels on Table 1
- Clarification of GHG BACT emission threshold applicability in Table 1
- Updated map of SCAQMD, Figure 1

Chapter 3 – When is BACT Required?
- Carbon monoxide attainment and BACT requirement
- Added reference to Lead Rules 1420.1 and 1420.2
- Chlorobromomethane added to Table 2 – Class I Substances (ODCs)
- Added $PM_{2.5}$ to Table 3

Chapter 4 – What is BACT?
- PSD Rules BACT applicability

Chapter 5 – Review of Staff BACT Determinations
- Background, goals and objectives and membership of the Scientific Review Committee

Part A

Chapter 1 – How is LAER Determined for Major Polluting Facilities?
- Added section on Federal $PM_{2.5}$ New Source Review and SCAQMD Rule 1325
- Super "Clean" Materials clarified as Super "Compliant" Materials to be consistent with SCAQMD Rule 109 definition
- Added section on Other Considerations for Pollution Prevention, Monitoring and Testing and Capture Efficiency

- Clean Fuels Policy clarified as also including electricity as a clean fuel, as well as zero and near-zero emission technologies ~~Industrial Electrification~~

Part B

The following LAER/BACT listings will be included in Part B:

- I.C Engines (3), Emergency, Compression Ignition with Diesel Particulate Filter
  - 374 BHP
  - 755 BHP
  - 2220 BHP
- Flare, Oil and Gas Operations

Part C

Chapter 1 – How is MSBACT Determined for Minor Polluting Facilities?

- Clarified that dates on Part D Determinations do not exempt equipment from complying with new requirements or limits implemented after that date
- Updated Maximum Cost Effectiveness Values
- Added section on BACT Top-Down Cost Methodology
- Clean Fuels Policy clarified as also including Industrial Electrification
- Updated Figure 2 flowchart: The Ongoing BACT Update Process

Chapter 2 – How to Use Part D of the MS BACT Guidelines?

- Super "Clean" Materials clarified as Super "Compliant" Materials to be consistent with definition
- Added section on Other Considerations for Pollution Prevention, Monitoring and Testing and Capture Efficiency

Part D

All of the following Part D listings are proposed to be updated to the current SCAQMD and state and federal requirements. In certain cases, new listings, categories and subcategories were created for consistency with the requirements.

- Boiler
- I.C. Engine, Portable
- I.C. Engine, Stationary Emergency

- I.C. Engine, Stationary, Non-Emergency, Non-Electrical Generators
- Liquid Transfer and Handling
- Oil and Gas Production
- Process Heater - Non-Refinery

Part E

Part E was added to address the policies and procedures set forth in EPA's GHG Program under 40 CFR 52.21, which is incorporated by reference under SCAQMD Rule 1714. The following sections were added under Part E:

- Background
- Permitting Guidance for GHG
- Federal PSD Applicability for GHG
- SCAQMD PSD Applicability for GHG
- Top-Down BACT Process
- GHG Control Measures White Papers

Part F

This section is reserved for future GHG BACT listings. There are currently no proposed GHG listings.

# PROPOSED BACT GUIDELINES

# ATTACHMENT B

# OVERVIEW, and PARTS A, C, E and F

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

# Best Available Control Technology Guidelines

**OVERVIEW**

**Part A: Policy and Procedures for Major Polluting Facilities**

**Part B: LAER/BACT Determinations for Major Polluting Facilities**

**Part C: Policy and Procedures for Non-Major Polluting Facilities**

**Part D: BACT Guidelines for Non-Major Polluting Facilities**

**Part E: Policy and Procedures for Facilities Subject to Prevention of Significant Deterioration for Greenhouse Gases**

**Part F: BACT Determinations for Facilities Subject to Prevention of Significant Deterioration for Greenhouse Gases**

August 17, 2000 (Revised June 6, 2003; December 5, 2003; July 9, 2004; July 14, 2006;, ~~October 7, 2016~~December 2, 2016)

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# Table of Contents

~~CHAPTER 5 - REVIEW OF STAFF BACT DETERMINATIONS ..... 12~~
~~*MEETING WITH AQMD MANAGEMENT* ..... 12~~
~~*THE BACT REVIEW COMMITTEE* ..... 12~~
~~*THE AQMD HEARING BOARD* ..... 12~~
~~*THE AQMD GOVERNING BOARD* ..... 13~~

~~*INITIALIZATION OF PART D OF THE MSBACT GUIDELINES* ..... 26~~
~~**INDEX OF EQUIPMENT CATEGORIES** ..... 39~~

**OVERVIEW** ..... 1

CHAPTER 1 - INTRODUCTION ..... 2
CHAPTER 2 – APPLICABILITY DETERMINATION ..... 5
*MAJOR POLLUTING FACILITY EMISSION THRESHOLDS* ..... 5
*POTENTIAL TO EMIT* ..... 8
*LIMITING POTENTIAL TO EMIT* ..... 8
CHAPTER 3 - WHEN IS BACT REQUIRED? ..... 9
*POLLUTANTS SUBJECT TO NSR, PSD AND BACT* ..... 9
*PERMIT ACTIONS SUBJECT TO NSR, PSD AND BACT* ..... 12
*CALCULATION PROCEDURES FOR EMISSION INCREASES* ..... 12
CHAPTER 4 - WHAT IS BACT? ..... 14
*NSR RULES* ..... 14
*PSD RULES* ..... 14
*DEFINITION OF BACT* ..... 14
*REQUIREMENTS OF HEALTH & SAFETY CODE SECTION 40440.11* ..... 15
*CLEAN FUEL GUIDELINES REQUIREMENTS* ..... 15
CHAPTER 5 - REVIEW OF STAFF BACT DETERMINATIONS ..... 16
*BACT SCIENTIFIC REVIEW COMMITTEE (BACT ~~SRC~~SRC)* ..... 16
*MEETING WITH SCAQMD MANAGEMENT* ..... 17
*THE BACT REVIEW COMMITTEE* ..... 17
*THE SCAQMD HEARING BOARD* ..... 17
*THE SCAQMD GOVERNING BOARD* ..... 18

**PART A - POLICY AND PROCEDURES FOR MAJOR POLLUTING FACILITIES** ..... 19

CHAPTER 1 - HOW IS LAER DETERMINED FOR MAJOR POLLUTING FACILITIES? ..... 20
*CRITERIA FOR DETERMINING LAER FOR MAJOR POLLUTING FACILITIES* ..... 20
*LAER APPLICATION CUT-OFF DATES* ..... 27
*LAER UPDATE PROCESS* ..... 27
*CLEAN FUEL GUIDELINES ~~REQUIREMENTS~~* ..... 28
CHAPTER 2 - HOW TO USE PART B OF THE BACT GUIDELINES ..... 29
*GENERAL* ..... 29
*HOW TO DETERMINE LAER* ..... 30

**PART B - LAER/BACT DETERMINATIONS FOR MAJOR POLLUTING FACILITIES ..... 3229**

**PART C - POLICY AND PROCEDURES FOR NON-MAJOR POLLUTING FACILITIES ..... 33**

CHAPTER 1 - HOW IS MSBACT DETERMINED FOR MINOR POLLUTING FACILITIES? ..... 34
*PART D OF THE MSBACT GUIDELINES ..... 34*
*CRITERIA FOR NEW MSBACT AND UPDATING PART D ..... 34*
*COST EFFECTIVENESS METHODOLOGY ..... 37*
*CLEAN FUEL GUIDELINES REQUIREMENTS ..... 40*
*BACT UPDATE PROCESS ..... 41*
CHAPTER 2 - HOW TO USE PART D OF THE MSBACT GUIDELINES ..... 434539
*GENERAL ..... 434539*
*SPECIAL PERMITTING CONSIDERATIONS ..... 434539*
*BACT APPLICATION CUT-OFF DATES ..... 4749*

**PART D - BACT GUIDELINES FOR NON-MAJOR POLLUTING FACILITIES ..... 4850**

**PART E – POLICIES AND PROCEDURES FOR FACILITIES SUBJECT TO PREVENTION OF SIGNIFICANT DETERIORATION FOR GREENHOUSE GASES 4951**

CHAPTER 1 - GHG BACT ..... 5052
*BACKGROUND ..... 5052*
*PERMITTING GUIDANCE FOR GHG ..... 5052*
*FEDERAL PSD APPLICABILITY FOR GHG ..... 5153*
*SCAQMD PSD APPLICABILITY FOR GHG ..... 5254*
*TOP-DOWN BACT PROCESS ..... 5355*
*GHG CONTROL MEASURES WHITE PAPERS ..... 5557*

**PART F – BACT DETERMINATIONS FOR FACILITIES SUBJECT TO PREVENTION OF SIGNIFICANT DETERIORATION FOR GREENHOUSE GASES ..... 5759**

**LIST OF ABBREVIATIONS ..... 5860**

**LIST OF EQUIPMENT CATEGORIES ..... 6062**

# OVERVIEW

# Chapter 1 - Introduction

The South Coast Air Quality Management District (SCAQMD) Regulation XIII – New Source Review (NSR) and Regulation XX – RECLAIM, require applicants to use Best Available Control Technology (BACT) for new sources, relocated sources, and ~~for~~ modifications to existing sources that may result in an emission increase of any nonattainment air contaminant, any ozone depleting compound (ODC), or ammonia. Regulation XIII requires the Executive Officer to periodically publish BACT Guidelines that establish the procedures and the BACT requirements for commonly permitted equipment. SCAQMD Regulation XIV – Toxics and Other Non-Criteria Pollutants, requires applicants to use Best Available Control Technology for Toxics (T-BACT) for new, relocated or modified permit units that result in a cumulative increase in Maximum Individual Cancer Risk (MICR) of greater than one in a million ($1.0 \times 10^{-6}$) at any receptor location. Additionally, Regulation XVII – Prevention of Significant Deterioration (PSD) also sets forth BACT requirements for new sources, relocated sources and modifications to existing sources that emit attainment air contaminants. ~~Regulation XIII requires the Executive Officer to periodically publish BACT Guidelines that establish the procedures and the BACT requirements for commonly permitted equipment.~~ PSD BACT is incorporated into these BACT Guidelines. As of the publication date of these guidelines, there is currently not a requirement for SCAQMD to publish T-BACT guidelines and T-BACT must be established during the permitting process. ~~The BACT Guidelines were first published in May 1983, and later revised in October 1988.~~

Historically, the BACT Guidelines were first published in May 1983, and later revised in October 1988. The Guidelines consisted of two parts: Part A – Policy and Procedures, and Part B – BACT Determinations. Part A provided an overview and general guidance while Part B contained specific BACT information by source category and pollutant. Since the October 1988 revision, Part A was amended once in 1995, and Part B was updated with six LAER determinations~~times~~ between 1997 and 1998.

On December 11, 1998, the Governing Board approved a new format for listing BACT determinations in Part B of the Guidelines. While the previous Ppart B of the BACT Guidelines specified BACT requirements and set out source category determinations which could be interpreted as definitive, the new format simply provides listings of recent BACT determinations by SCAQMD permitting staff and others as well as information on new and emerging technologies. Part B of the SCAQMD BACT Guidelines now follows the same outline as the permit listings in the California Air Resources Board State BACT Clearinghouse Ddatabase, which is managed under the direction of the California Air Pollution Control Officers Association's (CAPCOA) Engineering Managers Committee. ~~and coordinates the submittal of~~ In addition, BACT determinations made by ~~the districts~~SCAQMD are submitted to the U.S. Environmental Protection Agency (USEPA) RACT/BACT/LAER Clearinghouse by ARB staff.~~California Air Pollution Control Officer Association (CAPCOA) BACT Clearinghouse and the United States Environmental Protection Agency (USEPA) RACT/BACT/LAER Clearinghouse.~~ Further information on the ~~new~~ format of the Guidelines, including reasons for the change in direction, may be found in Board Letters presented at the October 1998

Board Meeting, Agenda No. 41, and the December 1998 Board Meeting, Agenda No. 28.

The public participation process ~~was also enhanced to~~ includes technical review and comments by a focused BACT Scientific Review Committee (BACT SRC) at periodic intervals, prior to the updates of the SCAQMD BACT Guidelines. ~~At the same time,~~ tThe Board established a 30-day notice period for the BACT SRC and interested persons to review and comment on SCAQMD BACT determinations that result in BACT requirements that are more stringent than previously imposed BACT.

As a result of amendments ~~being proposed~~ to SCAQMD's ~~New Source Review~~ (NSR) regulations in September 2000, the BACT Guidelines ~~waswere~~ill ~~be~~ separated into two sections: one for major polluting facilities and another for non-major (minor) polluting facilities. (See Chapter 2 in the Overview for how to determine if a facility is major or minor).

The BACT Guidelines for major polluting facilities include:

- Part A: Policy and Procedures for Major Polluting facilities~~,~~; and
- Part B: LAER/BACT Determinations for Major Polluting Facilities.

The BACT Guidelines for non-major polluting facilities include:

- Part C: Policy and Procedures for Non-Major Polluting Facilities~~,~~; and
- Part D: BACT Guidelines for Non-Major Polluting Facilities.

Both the format of the guidelines and the process for determining BACT are significantly different between major and non-major polluting facilities. Major polluting facilities that are subject to NSR are required by the Clean Air Act to have the Lowest Achievable Emission Rate (LAER). LAER is determined at the time the permit is issued, with little regard for cost, and pursuant to USEPA's LAER policy as to what is achieved in practice. The Part B BACT and LAER determinations for major polluting facilities are only examples of past determinations that help in determining LAER for new permit applications.

For non-major polluting facilities, BACT will be determined in accordance with state law at the time an application is deemed complete unless a more stringent rule requirement becomes applicable prior to permit issuance. For the most part, it will be as specified in Part D of the BACT Guidelines. Changes to Part D for minor source BACT (MSBACT) to make them more stringent will be subject to public review and SCAQMD Board approval, ~~in view of cost~~ for considerations of cost.

For the 2016 amendment to the Guidelines, additional parts have been added to address PSD requirements for greenhouse gas (GHG) emissions established by U.S. EPA in 40 CFR 52.21 in 2011. The requirements are incorporated by reference in SCAQMD Rule 1714. The BACT Guidelines for GHG requirements include:

- Part E: Policy and Procedures for Facilities Subject to Prevention of Significant Deterioration for Greenhouse Gases; and
- Part F: BACT Determinations for Facilities Subject to Prevention of Significant Deterioration for Greenhouse Gases.

In order to distinguish between BACT for ~~major sources and BACT for minor~~various sources, this document will use the following nomenclature for BACT:

LAER for BACT at major polluting facilities

MSBACT for BACT at non-major polluting facilities

PSD~~GHG~~ BACT for BACT at facilities subject to ~~PSD GHG~~ BACT requirements for criteria pollutants

Written comments about the BACT Guidelines are welcome at any time and will be evaluated by SCAQMD staff and included in the BACT Docket at the SCAQMD library. These comments should be addressed to:

South Coast Air Quality Management District
BACT Docket
Science and Technology Advancement
21865 Copley Dr.
Diamond Bar, CA 91765-0934

Comments may also be submitted via email to BACTTeam@aqmd.gov, and should include BACT Docket in the subject line.

The BACT Guidelines are available without charge from SCAQMD's web site at www.aqmd.gov/home/permits/bact. A hardcopy of t~~T~~he BACT Guidelines may be obtained for a fee by submitting a request to ~~contacting~~ Subscription Services at www.aqmd.gov/contact/subscription-services or ~~at the above address or~~by calling (909) 396-3720. Revisions to the ~~guidelines~~ Guidelines will be mailed to all persons that have purchased annual updates to the BACT Guidelines. ~~The BACT Guidelines are also available without charge from SCAQMD's Internet web site at http://www.aqmd.gov/home/permits/bact http://www.aqmd.gov/bact.~~

# Chapter 2 – Applicability Determination

This chapter explains how to determine whether a facility is a major or minor polluting facility, and how a facility can become a minor polluting facility.

## MAJOR POLLUTING FACILITY EMISSION THRESHOLDS

A facility is a major polluting facility (or a major stationary source as it is called in the federal Clean Air Act [CAA]) if it emits, or has the potential to emit (PTE), a criteria air pollutant at a level that equals or exceeds emission thresholds specified~~given~~ in the CAA[1] based on the attainment or nonattainment status. Table 1 presents~~shows~~ those emission thresholds for each criteria air pollutant for each air basin in SCAQMD. The map in Figure 1 shows the location of the three air basins in SCAQMD. If a threshold for any one criteria pollutant is equaled or exceeded, the facility is a major polluting facility, and will be subject to LAER for all pollutants subject to NSR. ~~Currently Although Table 1 is part of determining GHG BACT applicability,~~ Table 1 does not include emission thresholds that trigger GHG BACT for SCAQMD Rule 1714 and 40 CFR 52.21. ~~Subp~~Part E of the BACT Guidelines should be referenced for a detailed explanation of how GHG BACT emission thresholds are determined.

A facility includes all sources located within contiguous properties owned or operated by the same person, or persons under common control. Contiguous means in actual contact or separated only by a public roadway or other public right-of-way. However, on-shore crude oil and gas production facilities under the same ownership or use entitlement must be included with offshore crude oil and gas production facilities located in Southern California Coastal or Outer Continental Shelf waters.

The following mobile source emissions are also considered as part of the facility[2]:

1. Emissions from in-plant vehicles; and
2. All emissions from ships during the loading or unloading of cargo and while at berth where the cargo is loaded or unloaded; and
3. Non-propulsion ship emissions within Coastal Waters under SCAQMD jurisdiction.

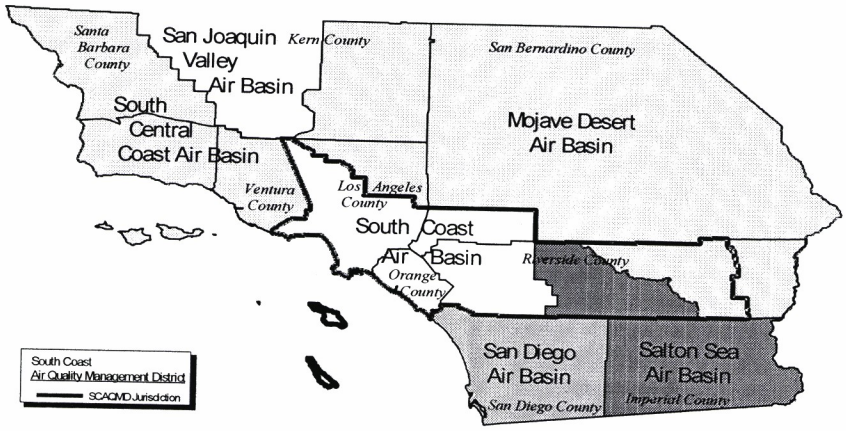
[1] The major source emission thresholds are higher for air basins that comply with the national ambient air quality standard and lower depending on how far an air basin is from compliance with the standard for a pollutant. The lowest thresholds apply to extreme non-attainment air basins, the only ~~example~~ ones ~~of~~ which are~~is~~ the South Coast Air Basin and San Joaquin Valley Air Basin for ozone (VOC and NOx).

[2] In accordance with Rule 1306(g).

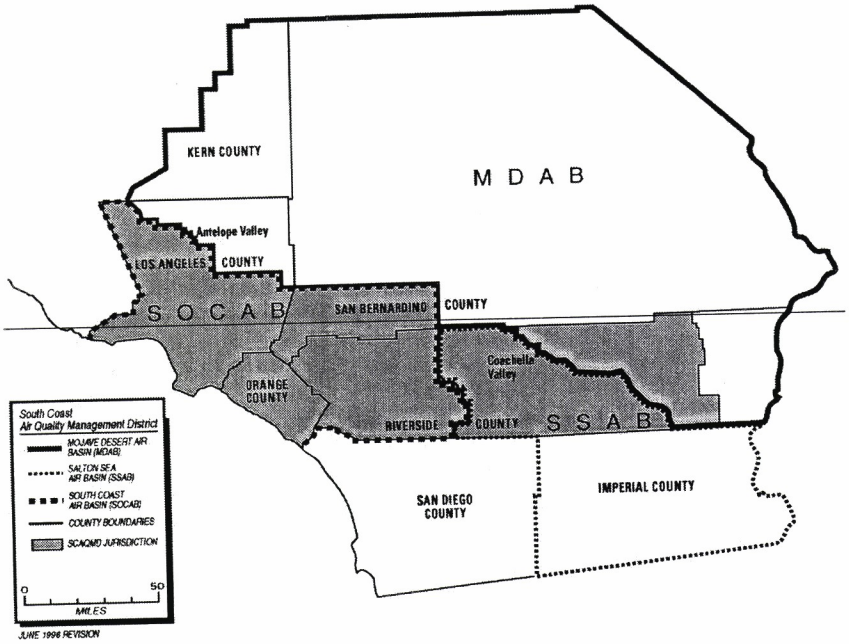
**Table 1**
**Actual or Potential Emission Threshold Levels (Tons per Year)**
**for Major Polluting Facilities**

| Pollutant | South Coast Air Basin | Riverside County Portion of Salton Sea Air Basin | Riverside County Portion of Mojave Desert Air Basin |
|---|---|---|---|
| VOC | 10 | 25 | 100 |
| NOx | 10 | 25 | 100 |
| [3]SOx | 70~~100~~ | 70~~100~~ | 100 |
| CO | 50 | 100 | 100 |
| $PM_{10}$ | 70 | 70 | 100 |
| $PM_{2.5}$ | 70~~100~~ | --- | --- |

**Figure 1: Map of SCAQMD**




[3] The threshold for SOx, as a precursor for PM, is 70 tons per year for serious $PM_{10}$ areas, which the SCAB previously was, and 70 tons per year for serious $PM_{2.5}$ areas, which the SCAB currently is. Rule 1302 previouslycurrently specifieds 100 tons per year, which wasis in error, and wasis ~~being~~ changedcorrected at the November 2016 Board Meeting.


KERN COUNTY
M D A B
Antelope Valley
LOS ANGELES COUNTY
S O C A B
SAN BERNARDINO COUNTY
Coachella Valley
ORANGE COUNTY
RIVERSIDE COUNTY
S S A B
SAN DIEGO COUNTY
IMPERIAL COUNTY
South Coast Air Quality Management District
MOJAVE DESERT AIR BASIN (MDAB)
SALTON SEA AIR BASIN (SSAB)
SOUTH COAST AIR BASIN (SOCAB)
COUNTY BOUNDARIES
SCAQMD JURISDICTION
0
50
MILES
JUNE 1996 REVISION

## POTENTIAL TO EMIT

Potential to emit ~~(PTE)~~ is based on permit conditions that limit emissions or throughput. If there are no such permit conditions, PTE is based on:

- the maximum rated capacity; and
- the maximum daily hours of operation; and
- physical characteristics of the materials processed.

The PTE must include fugitive emissions associated with the source. RECLAIM emission allocations are not considered emission limits because RECLAIM facilities may purchase RTCs and increase their emissions without modifying their permit. For PSD purposes, as well as Rule 1325 for $PM_{2.5}$, which incorporates federal requirements, fugitive emissions are included only for major source categories specifically identified in 40 CFR 52.21.

## LIMITING POTENTIAL TO EMIT

A facility's PTE can be capped by an enforceable permit condition that limits emissions. This condition will likely involve monitoring, recordkeeping and reporting to ensure that emissions remain below the permit limit.

# Chapter 3 - When is BACT Required?

This chapter explains when BACT is required by identifying the air pollutants subject to BACT, the permit actions that trigger BACT review, and the calculation procedures to determine emission increases.

## POLLUTANTS SUBJECT TO NSR, PSD AND BACT

The SCAQMD's New Source Review (NSR) programs include *Regulation XIII - New Source Review* and *Rule 2005 - New Source Review for RECLAIM.* Rule 2005 applies only to NOx and SOx emissions from RECLAIM facilities, while Regulation XIII applies to other non-attainment air pollutants from RECLAIM facilities, all non-attainment air pollutants from all other facilities, and ammonia and ozone-depleting compound (ODC) emissions from all facilities. ODCs are defined as Class I substances listed in 40 CFR, Part 82, Appendix A, Subpart A, and are listed in Table 2. Rule 1325 specifically applies to $PM_{2.5}$.

Although the SCAQMD is in attainment with the ambient air quality standards for $SO_2$ and $NO_2$, NOx is a precursor to ozone, and both SOx and NOx are precursors to $PM_{10}$ and $PM_{2.5}$, which are non-attainment air pollutants. Therefore, SOx and NOx are treated as non-attainment air pollutants as well~~, including ozone~~. The net result is that VOC, NOx, SOx, ~~and~~ $PM_{10}$ and $PM_{2.5}$~~,~~ are subject to NSR in all of SCAQMD.

~~, while CO is only subject to NSR in the South Coast Air Basin (SOCAB).~~

The South Coast Air Basin has historically been ~~had a persistent~~designated nonattainment for CO~~ problem~~. However, there has been considerable improvement in CO air quality in the Basin from 1976 to 2005. In 2001, the Basin met both the federal and state 8-hour CO standards for the first time at all monitoring stations. The 2003 AQMP revision to the CO plan served a dual purpose; it replaced the 1997 attainment demonstration that lapsed at the end of 2000, and it provided the basis for a CO maintenance plan in the future. The Basin was designated as attainment for CO in 2007. ~~Therefore, CO is no longer a nonattainment pollutant, since the state standard for CO is the same as the federal.~~Therefore, CO is in attainment with state and federal ambient air quality standards.

The SCAQMD's Regulation XVII – Prevention of Significant Deterioration sets forth BACT requirements for stationary sources that emit attainment air contaminants. The BACT requirement applies to any net emission increase of a criteria pollutant from a permit unit at any source. ~~Similar to the Regulation XIII NSR requirements, precursors to attainment air contaminants, would also be treated as attainment air contaminants, unless they also qualify as a nonattainment air contaminant, or nonattainment precursor as well.~~ As explained in the SCAQMD Staff Report for Regulation XVII dated September 28, 19988 for the October 7, 1988 Board meeting, the PSD BACT requirement is applicable to all permit units regardless if the source is classified as a minor or major facility.

Lead (Pb) is a criteria air pollutant and is subject to BACT in areas of non-attainment, or is subject to PSD in areas of attainment. ~~Although the SCAQMD complies with the ambient air quality standards for lead (Pb),~~ Pb can be a component of a source's $PM_{10}$ emissions and is therefore subject to BACT for $PM_{10}$. BACT for Pb will be BACT for $PM_{10}$ or compliance with Rules 1420~~ or~~, 1420.1 or 1420.2, whichever is more stringent. ~~In addition, non-attainment pollutants include inorganic gases such as hydrogen chloride (HCl) and hydrogen fluoride (HF), which are precursors to $PM_{10}$, and hydrogen sulfide ($H_2S$), a precursor to $SO_2$.~~

The applicability of the various pollutants to NSR in the various air basins is summarized in Table 3. See Figure 1 in the previous chapter for a map of SCAQMD that shows the location of the three air basins in SCAQMD.

**Table 2**
**Class I Substances (ODCs)***

| | |
|---|---|
| A. Group I:<br>$CFCl_3$ Trichlorofluoromethane (CFC-11)<br>$CF_2Cl_2$ dichlorodifluoromethane (CFC-12)<br>$C_2F_3Cl_3$ Trichlorotrifluoroethane (CFC-113)<br>$C_2F_4Cl_2$ Dichlorotetrafluoroethane (CFC-114<br>$C_2F_5Cl$ Monochloropentafluoroethane (CFC-115)<br>All isomers of the above chemicals<br><br>B. Group II:<br>$CF_2ClBr$ Bromochlorodifluoromethane (Halon-1211)<br>$CF_3Br$ Bromotrifluoromethane (Halon-1301)<br>$C_2F_4Br_2$ Dibromotetrafluoroethane (Halon-2402)<br>All isomers of the above chemicals<br><br>C. Group III:<br>$CF_3Cl$ Chlorotrifluoromethane (CFC-13)<br>$C_2FCl_5$ (CFC-111)<br>$C_2F_2Cl_4$ (CFC-112)<br>$C_3FCl_7$ (CFC-211)<br>$C_3F_2Cl_6$ (CFC-212)<br>$C_3F_3Cl_5$ (CFC-213)<br>$C_3F_4Cl_4$ (CFC-214)<br>$C_3F_5Cl_3$ (CFC-215)<br>$C_3F_6Cl_2$ (CFC-216)<br>$C_3F_7Cl$ (CFC-217)<br>All isomers of the above chemicals<br><br>D. Group IV:<br>$CCl_4$ Carbon Tetrachloride<br><br>E. Group V:<br>$C_2H_3Cl_3$ 1,1,1 Trichloroethane (Methyl chloroform)<br>All isomers of the above chemical except 1,1,2-trichloroethane<br><br>F. Group VI:<br>$CH_3Br$ Bromomethane (Methyl Bromide)<br><br>H. Group VIII:<br>$CH_2BrCl$ (Chlorobromomethane) | G. Group VII:<br>$CHFBr_2$<br>$CHF_2Br$ (HBFC-2201)<br>$CH_2FBr$<br>$C_2HFBr_4$<br>$C_2HF_2Br_3$<br>$C_2HF_3Br_2$<br>$C_2HF_4Br$<br>$C_2H_2FBr_3$<br>$C_2H_2F_2Br_2$<br>$C_2H_2F_3Br$<br>$C_2H_2FBr_2$<br>$C_2H_3F_2Br$<br>$C_2H_4FBr$<br>$C_3HFBr_6$<br>$C_3HF_2Br_5$<br>$C_3HF_3Br_4$<br>$C_3HF_4Br_3$<br>$C_3HF_5Br_2$<br>$C_3HF_6Br$<br>$C_3H_2FBr_5$<br>$C_3H_2F_2Br_4$<br>$C_3H_2F_3Br_3$<br>$C_3H_2F_4Br_2$<br>$C_3H_2F_5Br$<br>$C_3H_3FBr_4$<br>$C_3H_3F_2Br_3$<br>$C_3H_3F_3Br_2$<br>$C_3H_3F_4Br$<br>$C_3H_4FBr_3$<br>$C_3H_4F_2Br_2$<br>$C_3H_4F_3Br$<br>$C_3H_5FBr_2$<br>$C_3H_5F_2Br$<br>$C_3H_6FBr$<br><br>~~H. Group VIII:~~<br>~~$CH_2BrCl$~~<br>~~(Chlorobromomethane)~~ |

* 40 CFR, Part 82, Appendix A, Subpart A

**Table 3**
**Applicability of NSR ~~and BACT~~ to Various Pollutants in South Coast Air Basin (SOCAB), Salton Sea Air Basin (SSAB), and Mojave Desert Air Basin (MDAB)**

| Air Basin | VOC | NOx | SOx | CO | $PM_{10}$ | $PM_{2.5}$ | $NH_3$ | Pb | ODC |
|---|---|---|---|---|---|---|---|---|---|
| SOCAB | ☒ | ☒ | ☒ | ☒ | ☒ | ☒ | ☒ | ☒ | ☒ |
| SSAB | ☒ | ☒ | ☒ | | ☒ | | ☒ | ☒ | ☒ |
| MDAB | ☒ | ☒ | ☒ | | ☒ | | ☒ | ☒ | ☒ |

## PERMIT ACTIONS SUBJECT TO NSR, PSD AND BACT

SCAQMD's NSR and PSD regulations are preconstruction permit review programs that require the Executive Officer to deny a permit to construct unless the proposed equipment includes BACT when:

- ☒ new equipment is installed~~,~~;
- ☒ existing stationary permitted equipment is relocated~~,~~; or
- ☒ existing permitted equipment is modified such that there is an emission increase.

If the new equipment is to replace the same kind of equipment, NSR[4] still requires BACT unless it is an identical replacement, which does not require a new permit according to ~~paragraph (c)(3) of~~ *Rule 219 -Equipment Not Requiring a Written Permit Pursuant to Regulation II*~~, as amended May 19, 2000~~.

BACT is not required for a change of operator, provided the facility is a continuing operation at the same location, without modification or change in operating conditions.

In case of relocation of a non-major facility, the facility operator may opt out of installing MSBACT, provided that the owner/operator meets the conditions specified in Rule 1302 (ai) and Rule 1306 (d)(3).[5]

PSD applies to GHG if the source is otherwise subject to PSD for another regulated NSR pollutant and the source is new with ~~has~~ a GHG PTE ≥ 75,000 tons per year $CO_2e$, or an existing source with a modification resulting in a similar GHG emissions increase.

It is SCAQMD policy that BACT is required only for emission increases greater than or equal to one (1.0) pound per day.

## CALCULATION PROCEDURES FOR EMISSION INCREASES

The calculation procedures for determining whether there is an increase in emissions from an equipment modification that triggers BACT are different for NOx

[4] See Rules 1303(a) and 1304(a).
[5] USEPA has expressed concerns with this provision of the NSR Rules for minor polluting facilities as of September 2000. Staff will continue to work with USEPA to resolve this issue.

and SOx pollutants from RECLAIM facilities ~~and~~ than for all other cases. In general, the calculation procedures for RECLAIM facilities are less likely to result in an emission increase that requires BACT.

For NOx and SOx emissions from a source at a RECLAIM facility, there is an emission increase if the maximum hourly potential to emit is greater after the modification than it was before the modification.[6]

For modifications subject to Regulation XIII, there are two possible cases[7]:

1. If the equipment was previously subject to NSR, an emission increase occurs if the new potential to emit in one day is greater than the previous potential to emit in one day.
2. If the equipment was never previously subject to NSR, an emission increase occurs if the new potential to emit in one day exceeds the actual average daily emissions over the two-year period, or other appropriate period, prior to the permit application date. However, for the installation of air pollution controls on any source constructed prior to the adoption of the NSR on October 8, 1976 for the sole purpose of reducing emissions, Rule 1306(f) allows the emission change to be calculated as the post-modification potential to emit minus the pre-modification potential to emit.

The potential to emit is based on permit conditions that directly limit the emissions, or, if there are none, then the potential to emit is based on:

- ~~a)~~ maximum rated capacity; and
- ~~b)~~ the maximum daily hours of operation; and
- ~~c)~~ the physical characteristics of the materials processed.

[6] See Rule 2005(d).
[7] See Rule 1306(d)(2).

# Chapter 4 - What is BACT?

This chapter explains the definitions of BACT found in SCAQMD rules, state law and federal law.

## NSR RULES (REGULATION XIII)

New sources, relocations, and modifications of existing sources that increase nonattainment air contaminant emissions are subject to New Source Review (NSR) regulations which require BACT, among other requirements. Both federal and state laws require this strategy. The federal Clean Air Act (CAA) requirement for Lowest Achievable Emission Rate (LAER) is implemented through BACT in the SCAQMD. Federal LAER applies to major sources only. Although federal LAER applies to any emissions increase at a major stationary source of ozone precursors, SCAQMD has interpreted this provision as a 1.0 lb/day increase in emissions from all sources subject to NSR. According to SCAQMD's rules, BACT requirements may not be less stringent than federal LAER for major polluting facilities. The California Health & Safety Code (H&SC) Section 40405 defines state BACT similar to federal LAER and requires the application of BACT for all new and modified permitted sources subject to NSR.

## PSD RULES (REGULATION XVII)

New sources, relocations, and modifications of existing sources that emit attainment air contaminant emissions and certain other specified pollutants are subject to Prevention of Significant Deterioration (PSD) regulations, which require BACT. Pursuant to Rule 1701, the BACT requirement applies to a net emission increase from a permit unit located at minor and major stationary sources. The intention of the PSD requirement is to implement a similar requirement as Regulation XIII to maintain national ambient air quality standards for attainment air contaminants.

## DEFINITION OF BACT

Definitions of BACT are found in: Rule *1302 -Definitions* of *Regulation XIII - New Source Review*, which applies to all cases in general, except for *Rule 1702 – Definitions*, which applies only to attainment air contaminants, and *Rule 2000 - General*, which applies to NOx and SOx emissions from ~~nearly 400~~ RECLAIM facilities. While the definitions are not identical, they are essentially the same. Section (~~f~~h) of *Rule 1302 - Definitions* defines BACT as:

> *BEST AVAILABLE CONTROL TECHNOLOGY (BACT) means the most stringent emission limitation or control technique which:*
>
> *(1) has been achieved in practice for such category or class of source; or*
> *(2) is contained in any state implementation plan (SIP) approved by the United States Environmental Protection Agency (EPA) for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source*

*demonstrates to the satisfaction of the Executive Officer or designee that such limitation or control technique is not presently achievable; or*

*(3) is any other emission limitation or control technique, found by the Executive Officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board.*

The first two requirements in the BACT definition are required by federal law, as LAER for major sources. The third part of the definition is unique to SCAQMD and some other areas in California, and allows for more stringent controls than LAER.

Rule 1303(a)(2)~~, as proposed to adopted, will further~~ requires that economic and technical feasibility be considered in establishing the class or category of sources and the BACT requirements for non-major polluting facilities.

## REQUIREMENTS OF HEALTH & SAFETY CODE SECTION 40440.11

Senate Bill 456 (Kelley) was chaptered into state law in 1995 and became effective in 1996. H&SC Section 40440.11 specifies the criteria and process that must be followed by the SCAQMD to update its BACT Guidelines to establish more stringent BACT limits for listed source categories. After consultation with the affected industry, the CARB, and the U.S. EPA, and considerable legal review and analysis, staff concluded that the process specified in SB 456 to update the BACT Guidelines should be interpreted to apply only if the SCAQMD proposes to make BACT more stringent than LAER or to establish BACT for non-major sources. This is because the CAA requires the SCAQMD staff to apply current LAER for major polluting facilities, even if the proposed LAER determination has not gone through the SB456 process. Therefore, the SB 456 requirements do apply to BACT requirements for non-major polluting facilities, but do not apply to federal LAER determinations for major polluting facilities.

## CLEAN FUEL GUIDELINES~~REQUIREMENTS~~

In January 1988, the SCAQMD Governing Board adopted a Clean Fuels Policy that included a requirement to use clean fuels as part of BACT. The implementation of this policy is further described in Parts A and C of these guidelines.

# Chapter 5 - Review of Staff BACT Determinations

New BACT determinations and guideline updates proposed by SCAQMD staff are subject to public notification requirements. In addition to allowing the public to comment on these items, the SCAQMD has established a BACT Scientific Review Committee (BACT SRC) to review and comment on technical matters of the proposals.

The SCAQMD has included provisions for an applicant to request a review of particular circumstances regarding a permit application and reconsideration of the BACT determination. Additional avenues are available to permit applicants for further review of staff BACT determinations through SCAQMD management, BACT Review Committee, Hearing Board, and the Governing Board.

## BACT SCIENTIFIC REVIEW COMMITTEE (BACT SRC)

The BACT SRC was established as a standing committee by action of the SCAQMD Governing Board ~~o~~in September 8, 1995 to enhance the public participation process and include technical review and comments by a focused committee at periodic intervals, prior to the updates of the SCAQMD BACT Guidelines. A 30-day notice period applies for the BACT SRC and interested persons to review and comment on SCAQMD BACT determinations that result in BACT requirements that are more stringent than previously imposed. BACT SRC members, include but are not limited to, representatives from CARB, U.S. EPA, neighboring Air Pollution Control Districts (APCD), with the balance of the committee created by invitation of recognized experts from industry, public utilities, suppliers of air pollution control equipment and advocacy groups. Whenever a committee member resigns or is no longer able to serve, SCAQMD seeks out an appropriate replacement to join the committee. A list of current BACT SRC members can be accessed at~~:~~

www.aqmd.gov/home/permits/bact/scientific-review-committee/src-members.

The overall purpose of the BACT Scientific Review Committee ~~(SRC)~~ is to:

- Comment on proposed new ~~&~~and more stringent BACT determinations in permit applications under 30-day public review.
- Comment on proposed BACT listings for all parts of the BACT Guidelines.

Except for the above, the BACT SRC's purpose is not to comment on past permitting decisions or change them.

Specifically, the role of the BACT SRC ~~Role~~ is to review and comment in writing on the appropriateness of new BACT determinations under 30-Day public review. During this comment period, SCAQMD, State, and Federal required permit issuance timelines are still in effect. SCAQMD BACT staff will commit to sending the BACT

SRC newly proposed BACT listings at least seven days prior to the next scheduled BACT SRC meeting. Meetings will typically consist of a presentation by BACT Team (BACTTeam@aqmd.gov) staff of new BACT forms and technical data and a general discussion of the proposed BACT listings, as well as addressing any preliminary written comments received from the public and BACT SRC prior to the meeting. SCAQMD staff will respond in writing to preliminary comments about new BACT proposals within ~~two weeks~~thirty days of the subject BACT SRC meeting. New issues raised during the BACT SRC meetings regarding newly proposed BACT listings will be addressed at the subsequent BACT SRC meeting to allow time for SCAQMD staff to research the comments. SCAQMD Engineering ~~and Compliance~~ staff may also respond to specific issues raised at the following BACT SRC meeting.

In addition to newly proposed BACT listings, the BACT SRC will be tasked with reviewing and commenting on updates to the policy and procedure sections of the BACT Guidelines prior to the guidelines being presented to the SCAQMD Governing Board for approval.

## MEETING WITH SCAQMD MANAGEMENT

SCAQMD management, starting with the Senior ~~Engineering~~ Manager of the permitting team, can consider unique and site-specific characteristics of an individual permit. The ~~allowance~~ flexibility for considering site-specific characteristics has been taken into account in these guidelines ~~designed into the guidelines~~ and can be reviewed with the manager of the section processing the permit. It is also possible to request review at the next level, with the Assistant Deputy Executive Officer of Engineering ~~and Compliance~~. The Senior ~~Engineering~~ Managers and the Assistant Deputy Executive Officers are authorized~~empowered~~ to make case-by-case decisions on an individual permit. Further review can be obtained through a meeting with the Deputy Executive Officer (DEO) of Engineering ~~and Compliance~~. Ultimately, all permitting decisions are the responsibility of the Executive Officer.

## THE BACT REVIEW COMMITTEE

Beyond meetings with SCAQMD management, an applicant may also request, prior to permit issuance or denial, that the proposed BACT for an individual permit be reviewed by the BACT Review Committee (BRC). The BRC is composed of five senior-level SCAQMD officials - the DEO of Public Affairs; the DEO of Science and Technology Advancement; the DEO of Engineering ~~and Compliance~~; the DEO of Planning, Rule Development and Area Sources; and General Counsel. This committee can review pending individual applications and decide if the BACT determination is appropriate. The BRC can be accessed without any fee or legal representation, and will meet upon demand.

## THE SCAQMD HEARING BOARD

After the permit is issued or denied, the applicant can seek further independent review of an individual BACT determination through the SCAQMD Hearing Board. In order to access this venue, the permit applicant would need to submit a petition and fee to appeal the final BACT determination by SCAQMD (once the permit is denied

or issued)[8]. The Hearing Board is an independent, quasi-judicial body composed of five members, who can review a permitting decision by the Executive Officer. In this venue, legal counsel represents the SCAQMD. Although not required, many petitioners choose to have legal counsel to represent their position.

## T~~T~~HE SCAQMD GOVERNING BOARD

Any applicant may petition the SCAQMD Governing Board to review a pending application pursuant to SCAQMD Regulation XII and Health and Safety Code Section 40509. While t~~T~~he Governing Board has the authority to hear and consider any pending permit application, it has rarely done so. It is important to note that this action must be taken while the permit application is pending with staff. Once staff reaches its decision, the only avenue of appeal is through the Hearing Board and ultimately to court.

~~but this circumstance is extremely rare and cases has only agreed to consider two pending permit applications in the last sixteen years are typically handled during the prior stages of review.~~

[8] Applicants must file an appeal petition with the Hearing Board within thirty days of the receipt of the permit or the notification of permit denial. See Rule 216 - *Appeals*, Regulation V - *Procedure Before the Hearing Board*, and Rule 303 - *Hearing Board Fees* for more information.

# PART A - POLICY AND PROCEDURES FOR MAJOR POLLUTING FACILITIES

# Chapter 1 - How is LAER Determined for Major Polluting Facilities?

This chapter explains the criteria used for determining LAER[9] and the process for updating Part B of the BACT Guidelines for major polluting facilities.

## CRITERIA FOR DETERMINING LAER FOR MAJOR POLLUTING FACILITIES

SCAQMD staff determines LAER requirements on a permit-by-permit basis based on the definition of LAER. In essence, LAER is the most stringent emission limit or control technology that is:

- found in a state implementation plan (SIP), or
- achieved in practice (AIP), or
- is technologically feasible and cost effective.

For practical purposes, at this time, nearly all SCAQMD LAER determinations will be based on AIP LAER because it is generally more stringent than LAER based on SIP, and because state law constrains SCAQMD ~~from~~in using the third approach~~.~~, as such a determination must go through the SB456 process, which may take more time than allowed for the permit decision.

Based on Governing Board policy, LAER also includes a requirement for the use of clean fuels. Terms such as "achieved in practice" and "technologically feasible" have not been defined in the rule, so the purpose of this section is to explain the criteria SCAQMD permitting staff uses to make a LAER determination.

### LAER Based on a SIP

The most stringent emission limit found in an approved state implementation plan (SIP) might be the basis for LAER. This means that the most stringent emission limit adopted by any state as a rule, regulation or permit[10], and approved by USEPA, is eligible as a LAER requirement. No other parameters are required to be evaluated when this category is chosen. This does not include future emission limits that have not yet been implemented.

[9] In order to distinguish between BACT for major polluting facilities and BACT for minor polluting facilities, this document uses the term LAER when referring to BACT for major polluting facilities.

[10] Some states incorporate individual permits into their SIP as case-by-case Reasonably Available Control Technology requirements.

## Achieved in Practice LAER

### *Regulatory Documents*

An emission limit or control technology may be considered achieved in practice (AIP) for a category or class of source if it exists in any of the following regulatory documents or programs:

- SCAQMD BACT Guidelines
- CAPCOA BACT Clearinghouse
- USEPA RACT/BACT/LAER Clearinghouse
- Other districts' and states' BACT Guidelines
- BACT/LAER requirements in New Source Review permits issued by SCAQMD or other agencies

However, staff will check with the permitting authority (other than SCAQMD) on the status of the BACT or LAER requirement. If it is found that an emission limit is not being achieved or a control technology is not performing as expected in the equipment referenced in any of the above sources or in other equipment used as the basis for the BACT or LAER determination, then it will not be considered as AIP.

### *New Technologies/Emission Levels*

New technologies and innovations of existing technologies occasionally evolve without a regulatory requirement, but still deserve consideration. They may have been voluntarily installed to reduce emissions, and may or may not be subject to an air quality permit or an emission limit. -Therefore, in addition to the above means of being determined as AIP, a control technology or emission limit may also be considered as AIP if it meets all of the following criteria:

Commercial Availability:

At least one vendor must offer this equipment for regular or full-scale operation in the United States. A performance warranty or guaranty must be available with the purchase of the control technology, as well as parts and service.

Reliability:

All control technologies must have been installed and operated reliably for at least six months. If the operator did not require the basic equipment to operate daily, then the equipment must have at least 183 cumulative days of operation. During this period, the basic and/or control equipment must have operated: 1) at a minimum of 50% design capacity; or 2) in a manner that is typical of the equipment in order to provide an expectation of continued reliability of the control technology.

Effectiveness:

The control technology must be verified to perform effectively over the range of operation expected for that type of equipment. If the control technology will be allowed to operate at lesser effectiveness during certain modes of operation, then those modes of operation must be identified. The verification shall be based on a performance test or tests deemed to be acceptable by SCAQMD, when possible, or other performance data.

### *Technology Transfer*

LAER is based on what is AIP for a category or class of source. However, USEPA guidelines require that technology that is determined to be AIP for one category of source be considered for transfer to other source categories. There are two types of potentially transferable control technologies: 1) exhaust stream controls, and 2) process controls and modifications. For the first type, technology transfer must be considered between source categories that produce similar exhaust streams. For the second type, technology transfer must be considered between source categories with similar processes.

## Federal $PM_{2.5}$ New Source Review and SCAQMD Rule 1325

$PM_{2.5}$ NSR applies to a new major polluting facility, major modifications to a major polluting facility, and any modification to an existing facility that would constitute a major polluting facility. A major polluting facility would be a facility located in areas federally designated pursuant to 40 CFR 81.305 as non-attainment for $PM_{2.5}$ for the South Coast Air Basin (SOCAB) which has actual emissions of, or the potential to emit, ~~10~~70 tons or more per year of $PM_{2.5}$, or its precursors for serious areas. For major modifications, LAER applies on a pollutant-specific basis to emissions of $PM_{2.5}$ and its precursors, for which (1) the source is major, (2) the modification results in a significant increase, and (3) the modification results in a significant net emissions increase.

Significant means in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates[11]:

Nitrogen oxides: 40 tons per year

Sulfur dioxide: 40 tons per year

$PM_{2.5}$: 10 tons per year

Ammonia: 40 tons per year[12]

A facility subject to the Federal $PM_{2.5}$ NSR will be required to comply with the following:

- Lowest Achievable Emission Rate (LAER)
- Emission increases offset
- Certification of compliance with Clean Air Act; and
- Analysis conducted of benefits of the proposed project outweigh the environmental and social costs associated with that project.

Please refer to SCAQMD Rule 1325 for specific requirements.

[11] SCAQMD Rule 1325(b)(12), as amended on December 5, 2014

[12] Ammonia is being added to Rule 1325 as a precursor to $PM_{2.5}$ pursuant to EPA's 2016 $PM_{2.5}$ SIP implementation Rule. PAR 1325, scheduled for hearing in November 2016, would set a significance threshold of 40 tons per year for ammonia.

## Cost in LAER Determinations

USEPA guidelines do not allow for routine consideration of the cost of control in LAER determinations. However, USEPA guidelines say that LAER is not considered achievable if the cost of control is so great that a new source could not be built or operated with a particular control technology. If a facility in the same or comparable industry already uses the control technology, then such use constitutes evidence that the cost to the industry is not prohibitive.

State law (H&SC 40405) also defines BACT as the lowest achievable emission rate, which is the more stringent of either (i) the most stringent emission limitation contained in the SIP, or (ii) the most stringent emission limitation that is achieved in practice. There is no explicit reference or prohibition to cost considerations, and the applicability extends to all permitted sources. SCAQMD rules implement both state BACT and federal LAER requirements simultaneously, and furthermore specify that SCAQMD BACT must meet federal LAER requirements for major polluting facilities.

If a proposed LAER determination results in extraordinary costs to a facility, the applicant may bring the matter to SCAQMD management for consideration as described in Overview, Chapter 6.

## ~~Clean Fuel Requirements~~

~~In January 1988, the SCAQMD Governing Board adopted a Clean Fuels Policy that included a requirement to use clean fuels as part of BACT/LAER. A clean fuel is one that produces air emissions equivalent to or lower than natural gas for $NO_x$, $SO_x$, ROG, and fine respirable particulate matter ($PM_{10}$). Besides natural gas, other clean fuels are methanol, liquid petroleum gas (LPG), and hydrogen. The burning of landfill, digester, refinery and other by-product gases is not subject to the clean fuels requirement. However, the combustion of these fuels must comply with other SCAQMD rules, including the sulfur content of the fuel.~~

~~The requirement of a clean fuel is based on engineering feasibility. Engineering feasibility considers the availability of a clean fuel and safety concerns associated with that fuel. Some state and local safety requirements limit the types of fuel, which can be used for emergency standby purposes. Some fire departments or fire marshals do not allow the storage of LPG near occupied buildings. Fire officials have, in some cases, vetoed the use of methanol in hospitals. If special handling or safety considerations preclude the use of the clean fuel, the SCAQMD has allowed the use of fuel oil as a standby fuel in boilers and heaters, and for emergency standby generators. The use of these fuels must meet the requirements of SCAQMD rules limiting $NO_x$ and sulfur emissions.~~

## Special Permitting Considerations

Although the most stringent, AIP LAER for a source category will most likely be the required LAER, SCAQMD staff may consider special technical circumstances that apply to the proposed equipment which may allow deviation from that LAER. The permit applicant should bring any pertinent facts to the attention of the SCAQMD permitting engineer for consideration.

## *Case-Specific Situations*

SCAQMD staff may consider unusual equipment-specific and site-specific characteristics of the proposed project that would warrant a reconsideration of the LAER requirement for new equipment. Here are some examples of what may be considered.

**Technical ~~i~~Infeasibility of the control technology~~:~~**

A particular control technology may not be required as LAER if the applicant demonstrates that it is not technically feasible to install and operate it to meet a specific LAER emission limitation in a specific permitting situation.

**Operating schedule and project length~~:~~**

If the equipment will operate much fewer hours per year than what is typical, or for a much shorter project length, it can affect what is considered ~~"achieved in practice"~~AIP.

**Availability of fuel or electricity~~:~~**

Some LAER determinations may not be feasible if a project will be located in an area where natural gas or electricity is not available.

**Process requirements~~:~~**

Some LAER determinations specify a particular type of process equipment. SCAQMD staff may consider requirements of the proposed process equipment that would make the LAER determination not technically feasible.

## *Equivalency*

The permit applicant may propose alternative means to achieve the same emission reduction as required by LAER. For example, if LAER requires a certain emission limit or control efficiency to be achieved, the applicant may choose any control technology, process modification, or combination thereof that can meet the same emission limit or control efficiency.

## *Super ~~Clean~~ Compliant Materials*

SCAQMD will accept the use of super ~~clean~~ compliant materials in lieu of an add-on control device controlling volatile organic compound (VOC) emissions from coating operations. For example~~ at this time~~, if a permit applicant uses only surface coatings that ~~contain less than 5% VOC by weight~~meet the super compliant material definition in SCAQMD Rule 109, an add-on control device would not be required for VOC LAER. This policy does not preclude any other LAER requirements for other contaminants.

## *Equipment Modifications*

As a general rule, it is more difficult to retrofit existing equipment with LAER as a result of NSR modification when compared to a new source. The equipment being modified may not be compatible with some past LAER determinations that specify a particular process type. There may also be space restrictions that prevent installation of some add-on control technology.

## Other Considerations

Although multiple process and control options may be available during the LAER determination process, considerations should be made for options that reduce the formation of air contaminants from the process, as well as ensuring that emissions are properly handled. In addition to evaluating the efficiency of the control stage, these additional considerations are needed to ensure that the system is capable of reducing or eliminating emissions from the facility on a consistent basis during the operational life of the equipment.~~:~~

### *Pollution Prevention*

The Pollution Prevention Act of 1990 (42 U.S.C. §§13101-13109) established a national policy that pollution should be prevented or reduced at the source whenever feasible. In many cases, air pollution control is a process that evaluates contaminants at the exhaust of the system. Pollution prevention is the reduction or elimination of waste at the source by the modification of the production process. Pollution prevention measures may consist of the use of alternate or reformulated materials, a modification of technology or equipment, or improvement of energy efficiency changes that result in an emissions reduction. These measures should be considered as part of the LAER determination process if the measures will result in the elimination or reduction of emissions, but are not required to include projects which are considered to fundamentally redefine the source. New and different emissions created by a process or material change will also need to be considered as part of the LAER determination process, in contrast to the overall emissions reductions from the implementation of pollution prevention measures. U.S. EPA policy defined pollution prevention as source reduction and other practices that reduce or eliminate the creation of pollutants through increased efficiency in the use of raw materials, energy, water, or other resources, and protection of natural resources by conservation[13]. U.S. EPA further specifies that pollution prevention does not include recycling (except in-process recycling), energy recovery, treatment or disposal. For purposes of these BACT Guidelines, and to be consistent with federal definitions, source reduction and pollution prevention ~~shall~~ may include, but not be limited to, a consideration of the feasibility of:

- equipment or technology modifications,
- process or procedure modifications,
- reformulation or redesign of products,
- substitution of raw materials, or
- improvements in housekeeping, maintenance or inventory control,

that reduce the amount of air contaminants entering any waste stream or otherwise released into the environment, including fugitive emissions.

[13] U.S. EPA Pollution Prevention Law and Policies (www.epa.gov/p2/pollution-prevention-law-and-policies#define)

## *Monitoring and Testing*

In order to ensure that LAER determinations continue to meet their initial emission and efficiency standards, periodic or continuous parameter monitoring and testing requirements may be required~~implemented~~ during the permitting process. Equipment and processes may experience some change over time, due to aging or operational methods of the equipment, which may affect emission rates or control efficiencies. In addition to other rule requirements, additional monitoring and testing requirements may need to focus on aspects directly related to the BACT determination, and may be made enforceable by permit conditions. Monitoring and testing requirements should be specific to characterize operating conditions (e.g. temperatures, pressures, flows, production rates) and measurement techniques when LAER is established to ensure clarity and consistency with the standard.

## *Capture Efficiency*

An integral part of controlling air pollutants emitted from a process with add-on air pollution control equipment is capturing those emissions and directing them to the air pollution control device. Emissions which are designed to be collected by an exhaust system but are vented uncontrolled into the atmosphere can have a much greater impact than controlled emissions. When applicable, the evaluation of a process and its associated control equipment should address the qualification and quantification of capture efficiency. By addressing capture efficiency during LAER determinations, a standard can be established to evaluate the capture efficiency of other systems, as well as ensure that the capture efficiency is maintained consistently over time.

If applicable, LAER determinations may include the percentage capture efficiency and the methods and measurements (e.g. EPA Method 204, capture velocity measurements, design using ACGIH's Industrial Ventilation, static pressures) used to determine and verify it. For various circumstances, several SCAQMD rules (Table 4) already require an assessment of collection efficiency of an emission control system following EPA Method 204, EPA's "Guidelines for Determining Capture Efficiency", SCAQMD's "Protocol for Determination of Volatile Organic Compounds (VOC) Capture Efficiency," or other methods approved by the Executive Officer, and are appropriate to include as LAER requirements. The capture efficiency for any LAER Determination shall be no less stringent than any applicable rule requirement. Other considerations that may affect capture, such as cross-drafts, thermal drafts and the volume of combustion products, should also be addressed during this process.

**Table 4**

**SCAQMD Regulation XI and XIV Rules with Capture Efficiency Requirements or Considerations**

| | | | | |
|---|---|---|---|---|
| 1103 | 1125 | 1136 | 1162 | 1420.1 |
| 1104 | 1126 | 1141 | 1164 | 1420.2 |
| 1106 | 1128 | 1141.2 | 1171 | 1425 |
| 1107 | 1130 | 1144 | 1175 | 1469 |
| 1115 | 1130.1 | 1145 | 1178 | 1469.1 |
| 1122 | 1131 | 1155 | 1407 | |
| 1124 | 1132 | 1156 | 1420 | |

## LAER APPLICATION CUT-OFF DATES

For applications submitted by major polluting facilities, LAER requirements will be determined based on information available up to the date the permit to construct is issued. This requirement allows interested parties to comment on possible technologies that could provide lower emissions.

Applications for a Registration Permit for equipment issued a valid Certified Equipment Permit (CEP), which is valid for one year, will only be required to comply with LAER as determined at the time the CEP was issued. However, SCAQMD staff will reevaluate the LAER requirements for the CEP upon ~~annual~~ renewal of the Title V permit.~~CEP by the equipment manufacturer.~~

## LAER UPDATE PROCESS

SCAQMD will update Section I – SCAQMD LAER/BACT Determinations of Part B of the BACT Guidelines on an ongoing basis with actual LAER determinations for SCAQMD permits issued to major polluting facilities. The process will depend on whether or not the LAER requirement is more stringent than previous SCAQMD LAER determinations for the same equipment category.

When SCAQMD permitting staff makes a LAER determination that is no more stringent than previous SCAQMD LAER determinations, the permitting team will issue the permit and forward information regarding this LAER determination to the BACT/~~NSR~~ Team.[14] The BACT/~~NSR~~ Team will review this LAER determination with the BACT SRC prior to listing in the BACT Guidelines.

Whenever permitting staff makes a LAER determination that is more stringent than what SCAQMD has previously required as LAER, the permit to construct may be subject to a public review. In any event depending on Rule 212, ~~T~~the permitting team will forward the preliminary LAER determination to the BACT/~~NSR~~ Team, who will prepare and send a public notice of the preliminary determination to the BACT SRC, potentially interested persons, and anyone else requesting the information. Staff will consider all comments filed during the 30-day review period before making a permit decision. Staff will make every effort to conduct the public review consistent with the requirements of state law. However, if the 30-day review period conflicts with the deadline of the Permit Streamlining Act[15] for issuing the permit, the permit will be issued in accordance with state law. The 30-day public review may also be done in parallel with other public reviews mandated by *Rule 212 - Standards for Approving Permits and Issuing Public Notice* or *Regulation XXX - Title V Permits* in applicable cases.

On a ~~quarterly~~ periodic basis, the SCAQMD BACT/~~NSR~~ Team will provide standing status reports to the SCAQMD Governing Board's Stationary Source Committee and to the Governing Board.

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[14] To reduce the burden on SCAQMD of preparing hundreds of LAER Determination Forms each month, forms will not be prepared for routine LAER determinations after Part B, Section I of the guidelines has sufficient entries to demonstrate typical LAER requirements.

[15] The requirements of the Permit Streamlining Act are also found in SCAQMD's Rule 210.

In summary, as technology advances, many categories in the SCAQMD's BACT Guidelines will be updated with new listings. This on-going process will reflect new lower emitting technologies not previously identified in the Guidelines.

## CLEAN FUEL GUIDELINES~~REQUIREMENTS~~

In January 1988, the SCAQMD Governing Board adopted a Clean Fuels Policy that included a requirement to use clean fuels as part of BACT/LAER. A clean fuel is one that produces air emissions equivalent to or lower than natural gas for $NO_x$, $SO_x$, ROG, and fine respirable particulate matter ($PM_{10}$). Besides natural gas, other clean fuels are ~~methanol,~~ liquid petroleum gas (LPG), ~~and~~ hydrogen and electricity. ~~Industrial electrification (e.g., replacement of I.C. Engines, etc.) is~~ Utilization of zero and near-zero emission technologies are also integrated into the Clean Fuels Policy. The burning of landfill, digester, refinery and other by-product gases is not subject to the clean fuels requirement. However, the combustion of these fuels must comply with other SCAQMD rules, including the sulfur content of the fuel.

The requirement of a clean fuel is based on engineering feasibility. Engineering feasibility considers the availability of a clean fuel and safety concerns associated with that fuel. Some state and local safety requirements limit the types of fuel, which can be used for emergency standby purposes. Some fire departments or fire marshals do not allow the storage of LPG near occupied buildings. Fire officials have, in some cases, vetoed the use of methanol in hospitals. If special handling or safety considerations preclude the use of the clean fuel, the SCAQMD has allowed the use of fuel oil as a standby fuel in boilers and heaters, fire suppressant pump engines and for emergency standby generators. The use of these fuels must meet the requirements of SCAQMD rules limiting $NO_x$ and sulfur emissions.

# Chapter 2 - How to Use Part B of the BACT Guidelines

This chapter explains the LAER information found in Part B - LAER/BACT Determinations for Major Polluting Facilities. Part B is a listing of LAER/BACT determinations for major polluting facilities contained in SCAQMD and other air pollution control agencies' permits, and data on new and emerging technologies. These LAER/BACT determinations and data are guides and will be used, along with other information, to determine LAER as outlined in Chapter 1. For a listing of equipment types, refer to the ~~Index~~ List of Equipment Categories. LAER determination for equipment not found in Part B of the BACT Guidelines is done according to the process outlined in Chapter 1.

## GENERAL

Part B is divided into three sections. Section I – SCAQMD LAER/BACT Determinations, contains information on LAER/BACT determinations contained in permits issued by SCAQMD, with permit limits based on achieved in practice technology. Section II – Non-AQMD LAER/BACT Determinations, lists LAER/BACT determinations contained in other air pollution control agencies' permits or BACT Guidelines, with permit limits based on achieved in practice technology. Section III – Other Technologies, consists of information on technologies which have been achieved in practice but are not reflected in a permit limit, and information on emerging technologies or emission limits which have not yet been achieved in practice ~~(i.e., do not qualify as LAER)~~. All three sections are subdivided based on the attached ~~Index~~ List of Equipment Categories. Within each category, the LAER/BACT determinations will be listed in order of stringency.

Each listing includes the following information, in addition to other information detailing the description and operation of the equipment ~~subdivided into the following six sections~~:

- Basic Equipment[16]
  This provides information on the type, model, style, manufacturer, function, and cost of the basic equipment. It also lists applicable SCAQMD Regulation XI rules. Cost data are generally obtained from the SCAQMD application forms, manufacturer or owner/operator, and are not verified.

- Basic Equipment Rating/Size
  This identifies the size, dimensions, capacity, or rating of the basic equipment. It also provides additional information such as fuel type for combustion equipment, weight of parts cleaned per load for degreasers, and the number and size of blowers for spray booths.

- Company Information
  This identifies the contact person and owner/operator of the equipment, along with telephone numbers.

[16] Basic equipment is the process or equipment, which emits the air contaminant for which BACT is being determined.

- Permit Information
  This identifies the permitting agency and the name and telephone number of the agency's contact person. It also provides information on Permits to Construct/Operate. The SCAQMD is always the issuing agency for LAER determinations listed in Section I.

- Emission Information
  This identifies the actual permit limits and LAER/BACT requirements set forth by the issuing agency for the equipment being evaluated. It provides technical, performance, and cost data on the control technology used to achieve the permit limit and the LAER/BACT requirements.

- Comment
  This provides additional information relevant to basic equipment and control technology assessment, or further explains or clarifies the LAER/BACT determination.

The above ~~six sections~~information will enable permit applicants to assess the applicability of each LAER/BACT determination to their particular equipment.

The LAER requirements usually found in ~~section 5A of~~ the LAER Determination listings are in the form of:

- an emission limit;
- a control technology;
- equipment requirements; or
- a combination of the last ~~two~~.

If the requirement is an emission limit, the applicant may choose any control technology to achieve the emission limit. The SCAQMD prefers to set an emission limit as LAER because it allows an applicant the most flexibility in reducing emissions. If control technology and/or equipment requirements are the only specified LAER, then either emissions from the equipment are difficult to measure or it was not possible to specify an emission limit that applies to all equipment within the category. Where possible, an emission limit or control efficiency condition will be specified on the permit along with the control technology or equipment requirements to ensure that the equipment is properly operated with the lowest emissions achievable.

## HOW TO DETERMINE LAER

The Part B LAER determinations are only examples of LAER determinations for equipment that have been issued permits or that have been demonstrated in practice. As described in Chapter 1, LAER is determined on a case-by-case basis. To find out what LAER is likely to be for a particular equipment, the applicant should review the Part B LAER determinations found at the SCAQMD website www.aqmd.gov/home/permits/bact—~~http://www.aqmd.gov/bact~~. The CAPCOA Clearinghouse maintained by the California Air Resources Board and the USEPA RACT/BACT/LAER Clearinghouse should also be reviewed. These compendiums contain information from other districts, local agencies, and states that may not be included in the SCAQMD BACT Guidelines. Finally, the SCAQMD permitting staff may be contacted to discuss LAER prior to submitting a permit application.

As described in Chapter 1, the permit applicant should bring to the attention of the SCAQMD permitting engineer any special permitting considerations that may affect the LAER determination.

# PART B - LAER/BACT DETERMINATIONS FOR MAJOR POLLUTING FACILITIES

Part B of the BACT Guidelines is maintained on the SCAQMD Internet website at http://www.aqmd.gov/home/permits/bact/guidelines ~~http://www.aqmd.gov/bact~~.

# PART C - POLICY AND PROCEDURES FOR NON-MAJOR POLLUTING FACILITIES

# Chapter 1 - How Is MSBACT Determined for Minor Polluting Facilities?

This chapter explains the definitions of BACT for non-major polluting facilities (minor source BACT or MSBACT) found in SCAQMD rules and state law and how they are interpreted. It also explains the criteria used for initializing the Part D MSBACT Guidelines and the process for updating the MSBACT Guidelines.

## ~~INITIALIZATION OF~~ PART D OF THE MSBACT GUIDELINES

Part D of the MSBACT Guidelines specifies the MSBACT requirements for all of the commonly permitted categories of equipment. (See Chapter 2 for a full explanation of Part D).

~~The initial~~The initial listings in Part D of the MSBACT Guidelines reflected the current BACT determinations at the time for sources at non-major polluting facilities as of April 2000. ~~This~~ These ~~initialization does~~ did not represent new requirements but rather ~~memorializes~~ memorialized ~~current~~ BACT determinations and emission levels at that time. This initialization ~~is~~ was necessary to benchmark the transition from federal LAER to MSBACT for non-major polluting facilities. The control technologies and emission levels identified ~~initially will apply~~applied to any non-major source subject to NSR until the Guideline ~~is~~ was updated or ~~becomes~~ became out of date. The dates listed on the BACT determinations in Part D refer to the date of adoption of the determination. The dates listed do not grandfather the equipment from complying with any new requirements or limits that are implemented after the approval of a BACT determination[17].

## CRITERIA FOR NEW MSBACT AND UPDATING PART D

MSBACT requirements are determined for each source category based on the definition of MSBACT. In essence, MSBACT is the most stringent emission limit or control technology that is:

- found in a state implementation plan (SIP), or
- achieved in practice (AIP), or
- is technologically feasible and cost effective.

For practical purposes, nearly all SCAQMD MSBACT determinations will be based on AIP BACT because it is generally more stringent than MSBACT based on SIP, and because state law contains some constraints on SCAQMD from using the third approach. For minor polluting facilities, MSBACT will also take economic feasibility into account.

Based on Governing Board policy, MSBACT also includes a requirement for the use of clean fuels.

Terms such as "achieved in practice" and "technologically feasible" (including technology transfer) have not been defined in the rule, so one of the purposes of this

[17] SCAQMD Rule 1303(a)(3)

section is to explain the criteria SCAQMD permitting staff uses to make a MSBACT determination.

## MSBACT Based on a SIP

The most stringent emission limit found in an approved state implementation plan (SIP) might be the basis for MSBACT. This means that the most stringent emission limit adopted by any state as a rule, regulation or permit[18] and approved by USEPA is eligible as a MSBACT requirement. This does not include future emission limits that have not yet been implemented.

## Achieved in Practice MSBACT

MSBACT may also be based on the most stringent control technology or emission limit that has been achieved in practice (AIP) for a category or class of source. AIP control technology may be in operation in the United States or any other part of the world. SCAQMD permitting engineers will review the following sources to determine ~~what is~~ the most stringent AIP MSBACT:

- LAER/BACT determinations in Part B of the BACT Guidelines
- CAPCOA BACT Clearinghouse
- USEPA RACT/BACT/LAER Clearinghouse
- Other districts' and states' BACT Guidelines
- Permits to operate issued by SCAQMD or other agencies
- Any other source for which the requirements of AIP can be demonstrated

### *Achieved in Practice Criteria*

A control technology or emission limit found in any of the references above may be considered as AIP if it meets all of the following criteria:

Commercial Availability~~:~~

At least one vendor must offer this equipment for regular or full-scale operation in the United States. A performance warranty or guaranty must be available with the purchase of the control technology, as well as parts and service.

Reliability~~:~~

The control technology must have been installed and operated reliably for at least twelve months on a comparable commercial operation. If the operator did not require the basic equipment to operate continuously, such as only eight hours per day and 5 days per week, then the control technology must have operated whenever the basic equipment was in operation during the twelve months.

Effectiveness~~:~~

The control technology must be verified to perform effectively over the range of operation expected for that type of equipment. If the control technology will be allowed to operate at lesser effectiveness during certain modes of operation, then

[18] Some states incorporate individual permits into their SIP as case-by-case Reasonably Available Control Technology requirements.

those modes must be identified. The verification shall be based on a District-approved performance test or tests, when possible, or other performance data.

Cost Effectiveness:

The control technology or emission rate must be cost effective for a substantial number of sources within the class or category. Cost effectiveness criteria are described in detail in a later section. Cost criteria are not applicable to an individual permit but rather to a class or category of source.

### *Technology Transfer*

MSBACT is based on what is AIP for a category or class of source. However, technology transfer must also be considered across source categories, in view of the other AIP criteria. There are two types of potentially transferable control technologies: 1) exhaust stream controls, and 2) process controls and modifications. For the first type, technology transfer must be considered between source categories that produce similar exhaust streams. For the second type, process similarity governs the technology.

## Requirements of Health & Safety Code Section 40440.11

Senate Bill 456 (Kelley) was chartered into state law in 1995 and became effective in 1996. H&SC Section 40440.11 specifies the criteria and process that must be followed by the SCAQMD to establish new MSBACT limits for source categories listed in the MSBACT Guidelines. In general, the provisions require:

- Considering only control options or emission limits to be applied to the basic production or process equipment;
- Evaluating cost to control secondary pollutants;
- Determining the control technology is commercially available;
- Determining the control technology has been demonstrated for at least one year on a comparable commercial operation;
- Calculating total and incremental cost-effectiveness;
- Determining that the incremental cost-effectiveness is less than SCAQMD's established cost-effectiveness criteria;
- Putting BACT Guideline revisions on a regular meeting agenda of the SCAQMD Governing Board;
- Holding a Board public hearing prior to revising maximum incremental cost-effectiveness values;
- Keeping a BACT determination made for a particular application unchanged for at least one year from the application deemed complete date; and
- Considering a longer period for a major capital project (> $10,000,000)

After consultation with the affected industry, the CARB, and the U.S. EPA, and considerable legal review and analysis, staff concluded that the process specified in SB 456 to update the BACT Guidelines should be interpreted to apply only if the SCAQMD proposes to make BACT more stringent than LAER or where LAER is inapplicable (e.g. in establishing minor source BACT). Staff intends to incorporate

the spirit and intent of the SB 456 provisions into the MSBACT update process, as explained below, because non-major polluting facilities are no longer subject to federal LAER-, according to Regulation XIII. Therefore, MSBACT may consider cost as specified herein.

## COST EFFECTIVENESS METHODOLOGY

Cost effectiveness is measured in terms of control costs (dollars) per air emissions reduced (tons). If the cost per ton of emissions reduced is less than the maximum required cost effectiveness, then the control method is considered to be cost effective. This section also discusses the updated maximum cost effectiveness values, and those costs, which can be included in the cost effectiveness evaluation.

There are two types of cost effectiveness: average and incremental. Average cost effectiveness considers the difference in cost and emissions between a proposed MSBACT and an uncontrolled case. On the other hand, incremental cost effectiveness looks at the difference in cost and emissions between the proposed MSBACT and alternative control options.

Applicants may also conduct a cost effectiveness evaluation to support their case for the special permit considerations discussed in Chapter 2.

### Discounted Cash Flow Method

The discounted cash flow method (DCF) is used in the MSBACT Guidelines. This is also the method used in SCAQMD ~~the 1999~~ Air Quality Management Plan. The DCF method calculates the present value of the control costs over the life of the equipment by adding the capital cost to the present value of all annual costs and other periodic costs over the life of the equipment. A real interest rate[19][~~1~~] of four percent, and a 10-year equipment life is used. The cost effectiveness is determined by dividing the total present value of the control costs by the total emission reductions in tons over the same 10-year equipment life.

### Maximum Cost Effectiveness Values

The MSBACT maximum cost effectiveness values, shown in Table 45, are based on a DCF analysis with a 4% real interest rate.

**Table 45: Maximum Cost Effectiveness Criteria ~~(Second Quarter 2003)~~(1st2nd Quarter 2016)**

| Pollutant | Average (Maximum $ per Ton) | Incremental (Maximum $ per Ton) |
|---|---|---|
| ROG | 28,~~37046~~20,~~200~~ | 85,~~100~~38~~060~~,~~600~~ |
| NOx | 26,~~82~~091~~019~~,~~100~~ | 80,~~32~~059~~057~~,~~200~~ |
| SOx | 14,~~180~~23~~010~~,~~100~~ | 42,~~550~~69~~030~~,~~300~~ |

[19] The real interest rate is the difference between market interest rates and inflation, which typically remains constant at four percent.

[~~1~~] ~~The real interest rate is the difference between market interest rates and inflation, which typically remains constant at four percent.~~

| Pollutant | Average (Maximum $ per Ton) | Incremental (Maximum $ per Ton) |
|---|---|---|
| $PM_{10}$ | 6,32404,500 | 18,828013,400 |
| CO | 560400 | 1,6201,150 |

The cost criteria are based on those adopted by the SCAQMD Governing Board in the 1995 BACT Guidelines, adjusted to first second quarter 2016 2003 dollars using the Marshall and Swift Equipment Cost Index. Cost effectiveness analyses should use these figures adjusted to the latest Marshall and Swift Equipment Cost Index. Contact the BACT Team for current figures., which is published monthly in Chemical Engineering.

## Top-Down Cost Methodology

The SCAQMD uses the top-down approach for evaluating BACT and cost effectiveness. This means that the best control method, with the highest emission reduction, is first analyzed. If it is not cost effective, then the second-best control method is evaluated for cost effectiveness. The process continues until a control method is found to be cost-effective. This process provides a mechanism for all practical andly potential control technologies to be evaluated. As part of the permitting process, the applicant is responsible for preparing the BACT analysis, and submitting it to the District for review and approval.

The top-down process consists of five steps:

### *1. Identify all control technologies*

Identify all possible air pollution control options for the emissions unit. In addition to add-on control, control options may include production process methods and techniques. Innovative, transferable technologies, and LAER technologies should also be identified.

### *2. Eliminate technically infeasible options*

The technologies identified in Step 1 should be evaluated for technical feasibility. Elimination of any of the technologies identified in Step 1 should be well-documented and based on physical, chemical and engineering principles.

### *3. Rank remaining control technologies*

Based on overall control effectiveness, all remaining technically feasible control options should be ranked for the pollutants under review. A list should be generated for each pollutant subject to the BACT analysis. This list should include control efficiencies, emission rates, emission reductions, environmental impacts and energy impacts. Environmental impacts may include multimedia impacts and the impacts of the control option on toxic emissions.

### *4. Evaluation*

Evaluate the most effective controls and document the results. For each option, the applicant is responsible for objectively discussing each of the beneficial and adverse impacts. Typically, the analysis should focus on the direct impacts. Calculations for

both incremental and average cost effectiveness should be completed during this step. The MSBACT option must be cost effective for both analyses. In the event that the top option from Step 4 is ruled out after the impacts and cost effectiveness are evaluated, the decision and reasoning should be fully documented. The next most stringent alternative from Step 4, should then be evaluated.

### *5. Select BACT*

The most effective control option not eliminated in Step 4 is proposed as BACT for the pollutant and permit unit and presented to the District for review and approval.

~~The SCAQMD uses the top-down approach for evaluating cost effectiveness. This means that the best control method, with the highest emission reduction, is first analyzed. If it is not cost effective, then the second best control method is evaluated for cost effectiveness. The process continues until a control method is found to be cost effective.~~

~~AQMD staff will calculate both incremental and average cost effectiveness. The new MSBACT must be cost effective based on both analyses.~~

## Costs to Include in a Cost Effectiveness Analysis

Cost effectiveness evaluations consider both capital and operating costs. Capital cost includes not only the price of the equipment, but the cost for shipping, engineering and installation. Operating or annual costs include expenditures associated with utilities, labor and replacement costs. Finally, costs are reduced if any of the materials or energy created by the process result in cost savings. These cost items are shown in Table ~~5~~6. Methodologies for determining these values are given in documents prepared by USEPA through their Office of Air Quality Planning and Standards (~~OAQPS~~ EPA Air Pollution Control Cost Manual, ~~4th~~ Sixth Edition, 2002, ~~US~~EPA ~~450~~452/3B ~~900~~2-~~006~~ 001~~and Supplements~~).

The cost of land will not be considered because 1) add-on control equipment usually takes up very little space, 2) add-on control equipment does not usually require the purchase of additional land, and 3) land is non-depreciable and has value at the end of the project. In addition, the cost of controlling secondary emissions and cross-media pollutants caused by the primary MSBACT requirement should be included in any required cost effectiveness evaluation of the primary MSBACT requirement.

Table ~~5~~6: Cost Factors

**Total Capital Investment**

Purchased Equipment Cost
- Control Device
- Ancillary (including duct work)
- Instrumentation
- Taxes
- Freight

Direct Installation Cost
- Foundations and Supports
- Handling and Erection
- Electrical
- Piping
- Insulation
- Painting

Indirect Installation Costs
- Engineering
- Construction and Field Expenses
- Start-Up
- Performance Tests
- Contingencies

**Total Annual Cost**

Direct Costs
- Raw Materials
- Utilities
  - Electricity
  - Fuel
  - Steam
  - Water
  - Compressed Air
- Waste Treatment/Disposal
- Labor
  - Operating
  - Supervisory
  - Maintenance
- Maintenance Materials
- Replacement Parts

Indirect Costs
- Overhead
- Property Taxes
- Insurance
- Administrative Charges

Recovery Credits
- Materials
- Energy

## CLEAN FUEL GUIDELINES~~REQUIREMENTS~~

In January 1988, the SCAQMD Governing Board adopted a Clean Fuels Policy that included a requirement to use clean fuels as part of BACT. A clean fuel is one that produces air emissions equivalent to or lower than natural gas for $NO_X$, $SO_X$, ROG, and fine respirable particulate matter ($PM_{10}$). Besides natural gas, other clean fuels are ~~methanol,~~ liquid petroleum gas (LPG), ~~and~~ hydrogen and electricity. ~~Industrial electrification (e.g., replacement of I.C. Engines, etc.) is~~ Utilization of zero and near-zero emission technologies are also integrated into the Clean Fuels Policy. The burning of landfill, digester, refinery and other by-product gases is not subject to the

clean fuels requirement ~~as they are considered industry~~. However, the combustion of these fuels must comply with other SCAQMD rules, including the sulfur content of the fuel.

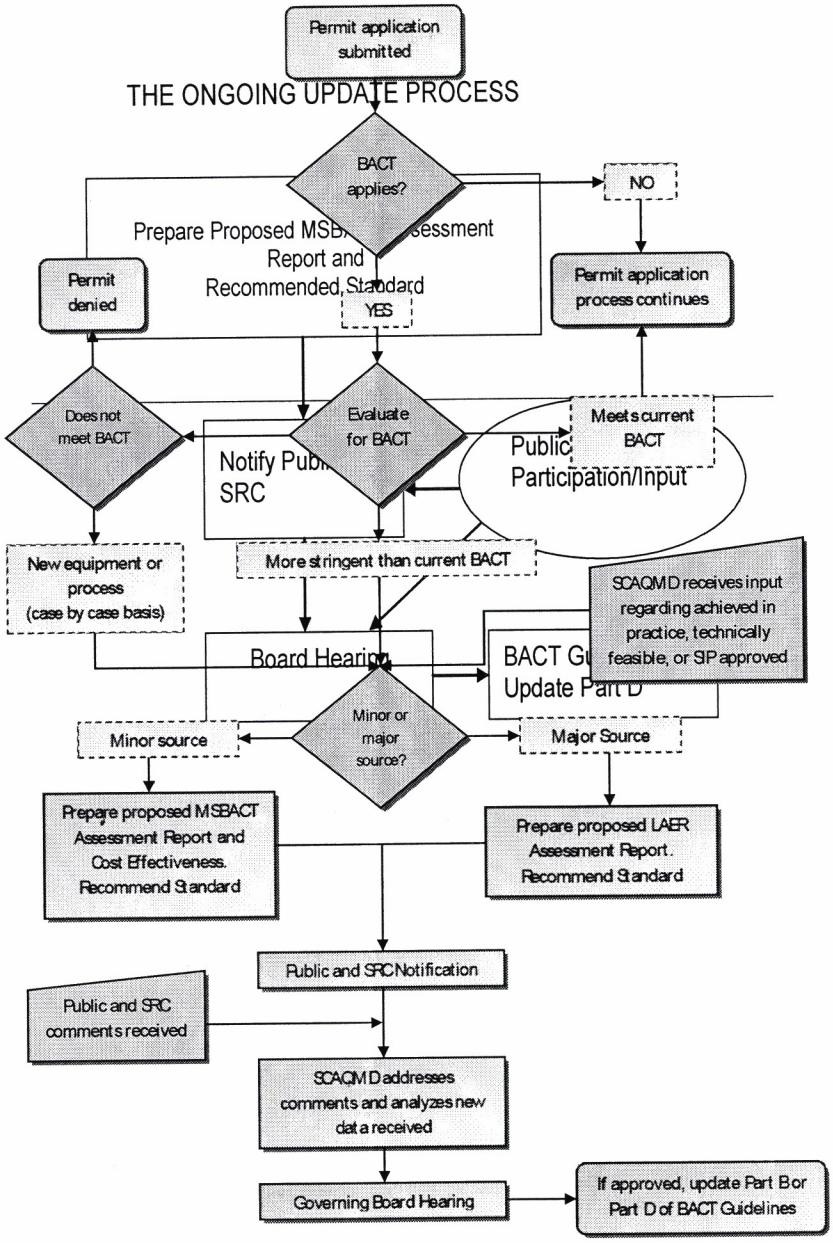
The requirement of a clean fuel is based on engineering feasibility. Engineering feasibility considers the availability of a clean fuel and safety concerns associated with that fuel. Some state and local safety requirements limit the types of fuel, which can be used for emergency standby purposes. Some fire departments or fire marshals do not allow the storage of LPG near occupied buildings. Fire officials have, in some cases, vetoed the use of methanol in hospitals. If special handling or safety considerations preclude the use of the clean fuel, the SCAQMD has allowed the use of fuel oil as a standby fuel in boilers and heaters, fire suppressant pump engines and for emergency standby generators. The use of these fuels must meet the requirements of SCAQMD rules limiting $NO_X$ and sulfur emissions. In addition, the Clean Fuel requirements for MSBACT are subject to the provisions of California Health and Safety Code Section 40440.11.

## BACT UPDATE PROCESS

As technology advances, the SCAQMD's MSBACT Part D Guidelines will be updated. Updates will include revisions to the guidelines for existing equipment categories, as well as new guidelines for new categories.

The MSBACT Guidelines will be revised based on the criteria outlined in the previous sections. Once a more stringent emission limit or control technology has been reviewed by staff and is determined to meet the criteria for MSBACT, it will be reviewed through a public process. The process is shown schematically in Figure 2. The public will be notified and the BACT Scientific Review Committee ~~(SRC)~~ will have an opportunity to comment. Following the public process and comment period, the guidelines will be presented to the Governing Board for approval at a public hearing, prior to updates of the MSBACT Guidelines, Part D.

**Figure 2: The Ongoing BACT Update Process**



# Chapter 2 - How to Use Part D of the MSBACT Guidelines

This chapter explains the MSBACT information found in Part D - MSBACT Guidelines. The Guidelines in Part D should be used to determine MSBACT for non-major polluting facilities. For a listing of equipment, refer to the Part D Table of Contents. Determination of MSBACT for equipment not found in Part D of the MSBACT Guidelines is also explained.

## GENERAL

Part D includes MSBACT Guidelines for more than 100 categories of equipment commonly processed by SCAQMD. Some guidelines are further subdivided by equipment size, rating, type or the material used, as appropriate.

The MSBACT requirements are in the form of:

1) an emission limit;
2) a control technology;
3) equipment requirements; or
4) a combination of the last two.

If the requirement is an emission limit, the applicant may choose any control technology to achieve the emission limit. The SCAQMD prefers to set an emission limit as MSBACT because it allows an applicant the most flexibility in reducing emissions.

If a control technology and/or equipment requirements are the only specified MSBACT, then either emissions from the equipment are difficult to measure or it was not possible to specify an emission limit that applies to all equipment within the category. Where possible, an emission limit or control efficiency condition will be specified in the permit along with the control technology or equipment requirements to ensure that the equipment is properly operated with the lowest emissions achievable. An applicant may still propose to use other ways to achieve the same or better emission reduction than the specified MSBACT.

MSBACT is the control technology or emission limit given in Part D for the basic equipment or process being evaluated, unless the guideline is out of date, or there are special permitting conditions, or the equipment is not identified in Part D. In those cases, the procedures described in the following sections will be used to determine MSBACT. Applicants or other interested parties are encouraged to contact the SCAQMD permitting staff if there are any questions about MSBACT.

## SPECIAL PERMITTING CONSIDERATIONS

Although the most stringent, AIP BACT for a source category will most likely be the required MSBACT, SCAQMD staff may consider special technical

circumstances that apply to the proposed equipment which may allow deviation from that MSBACT. The permit applicant should bring any pertinent facts to the attention of the SCAQMD permitting engineer for consideration.

## Case-Specific Situations

SCAQMD staff may consider unusual equipment-specific and site-specific characteristics of the proposed project that would warrant a reconsideration of the MSBACT requirement for new equipment.

**Technical ~~i~~Infeasibility of the control technology~~:~~**
~~–~~A particular control technology may not be required as MSBACT if the applicant demonstrates that it is not technically feasible to install and operate it to meet a specific MSBACT emission limitation in a specific permitting situation.

**Operating schedule and project length~~:~~**
If the equipment will operate much fewer hours per year than what is typical, or for a much shorter project length, it can affect what is considered ~~"~~AIP~~"~~.

**Availability of fuel or electricity~~:~~**
Some MSBACT determinations may not be feasible if a project will be located in an area where natural gas or electricity is not available.

**Process requirements~~:~~**
Some MSBACT determinations specify a particular type of process equipment. SCAQMD staff may consider requirements of the proposed process equipment that would make the MSBACT determination not technically feasible.

## Equivalency

The permit applicant may propose alternative means to achieve the same emission reduction as required by BACT. For example, if BACT requires a certain emission limit or control efficiency to be achieved, the applicant may choose any control technology, process modification, or combination thereof that can meet the same emission limit or control efficiency.

## Super ~~Clean~~ Compliant Materials

SCAQMD will accept the use of super ~~clean~~ compliant materials in lieu of an add-on control device controlling volatile organic compound (VOC) emissions from coating operations. For example~~ at this time~~, if a permit applicant uses only surface coatings that meet the super compliant material definition in SCAQMD Rule 109~~contain less than 5% VOC by weight~~, it may qualify as VOC MSBACT. This policy does not preclude any other MSBACT requirement for other contaminants.

## Equipment Modifications

As a general rule, it is more difficult to retrofit existing equipment with MSBACT as a result of NSR modification when compared to a new source. The equipment being modified may not be compatible with some past MSBACT

determinations that specify a particular process type. There may also be space restrictions that prevent installation of some add-on control technology.

## Other Considerations

Although multiple process and control options may be available during the MSBACT determination process, considerations should be made for options that reduce the formation of air contaminants from the process, as well as ensuring that emissions are properly handled. In addition to evaluating the efficiency of the control stage, these additional considerations are needed to ensure that the system is capable of reducing or eliminating emissions from the facility on a consistent basis during the operational life of the equipment. Measures listed in this section for MSBACT are subject to the requirements of California Health and Safety Code Section 40440.11.

### *Pollution Prevention*

The Pollution Prevention Act of 1990 (42 U.S.C. §§13101-13109) established a national policy that pollution should be prevented or reduced at the source whenever feasible. In many cases, air pollution control is a process that evaluates contaminants at the exhaust of the system. Pollution prevention is the reduction or elimination of waste at the source by the modification of the production process. Pollution prevention measures may consist of the use of alternate or reformulated materials, a modification of technology or equipment, or improvement of energy efficiency changes that result in an emissions reduction. These measures should be considered as part of the MSBACT determination process if the measures will result in the elimination or reduction of emissions, but are not required to include projects which are considered to fundamentally redefine the source. New and different emissions created by a process or material change will also need to be considered as part of the MSBACT determination process, in contrast to the overall emissions reductions from the implementation of pollution prevention measures. U.S. EPA policy defined pollution prevention as source reduction and other practices that reduce or eliminate the creation of pollutants through increased efficiency in the use of raw materials, energy, water, or other resources, and protection of natural resources by conservation[20]. U.S. EPA further specifies that pollution prevention does not include recycling (except in-process recycling), energy recovery, treatment or disposal. For purposes of these BACT Guidelines, and to be consistent with federal definitions, source reduction and pollution prevention shall may include, but not be limited to, consideration of the feasibility of:

- equipment or technology modifications,
- process or procedure modifications,
- reformulation or redesign of products,
- substitution of raw materials, or
- improvements in housekeeping, maintenance or inventory control,

[20] U.S. EPA Pollution Prevention Law and Policies (www.epa.gov/p2/pollution-prevention-law-and-policies#define)

that reduce the amount of air contaminants entering any waste stream or otherwise released into the environment, including fugitive emissions.

### *Monitoring and Testing*

In order to ensure that MSBACT determinations continue to meet their initial emission and efficiency standards, periodic or continuous parameter monitoring and testing requirements may be ~~implemented~~required during the permitting process. Equipment and processes may experience some change over time, due to aging or operational methods of the equipment, which may affect emission rates or control efficiencies. In addition to other rule requirements, additional monitoring and testing requirements may need to focus on aspects directly related to the MSBACT determination, and may be made enforceable by permit conditions. Monitoring and testing requirements should be specific to characterize operating conditions (e.g. temperatures, pressures, flows, production rates) and measurement techniques when MSBACT is established to ensure clarity and consistency with the standard.

### *Capture Efficiency*

An integral part of controlling air pollutants emitted from a process with add-on air pollution control equipment is capturing those emissions and directing them to the air pollution control device. Emissions which are designed to be collected by an exhaust system but are vented uncontrolled into the atmosphere can have a much greater impact than controlled emissions. When applicable, the evaluation of a process and its associated control equipment should address the qualification and quantification of capture efficiency. By addressing capture efficiency during MSBACT determinations, a standard can be established to evaluate the capture efficiency of other systems, as well as ensure that the capture efficiency is maintained consistently over time.

If applicable, MSBACT determinations may include the percentage capture efficiency and the methods and measurements (e.g. EPA Method 204, capture velocity measurements, design using ACGIH's Industrial Ventilation, static pressures) used to determine and verify it. For various circumstances, several SCAQMD rules (see Table 5, Part A, Chapter 1) already require an assessment of collection efficiency of an emission control system following EPA Method 204, EPA's "Guidelines for Determining Capture Efficiency", SCAQMD's "Protocol for Determination of Volatile Organic Compounds (VOC) Capture Efficiency," or other methods approved by the Executive Officer, and are appropriate to include as BACT requirements. The capture efficiency for any MSBACT Determination shall be no less stringent than any applicable rule requirement. Other considerations that may affect capture, such as cross-drafts, thermal drafts and the volume of combustion products, should also be addressed during this process.

## MSBACT Determinations Should the Guidelines Become Out of Date

Should the MSBACT Guideline Part D become out of date with state BACT requirements or permits issued for similar equipment in other parts of the state,

staff will evaluate permits consistent with the definition of BACT considering technical and economic criteria as required by Rule 1303 (a) and Health & Safety Code Section 40405. The technical and economic factors to be considered are those identified in Chapter 1.

## BACT APPLICATION CUT-OFF DATES

These guidelines apply to all non-major polluting facility applications deemed complete subsequent to SCAQMD Governing Board adoption of the Regulation XIII amendments in 2000.

Applications for a Registration Permit for equipment issued a valid Certified Equipment Permit (CEP), which is valid for one year, will only be required to comply with MSBACT as determined at the time the CEP was issued. However, SCAQMD staff will reevaluate the MSBACT requirements for the CEP upon annual renewal of the CEP by the equipment manufacturer.

# PART D - BACT GUIDELINES FOR NON-MAJOR POLLUTING FACILITIES

Part D of the BACT Guidelines is published as a separate document.

# PART E – POLICY AND PROCEDURES FOR FACILITIES SUBJECT TO PREVENTION OF SIGNIFICANT DETERIORATION FOR GREENHOUSE GASES

# Chapter 1 - GHG BACT

This chapter explains the requirements of greenhouse gases (GHG) BACT regulations according to EPA, describes the Top-Down Process, shows how to calculate GHG emissions and explains the Prevention of Significant Deterioration (PSD) Applicability for GHGs for new sources as well as modified sources. ~~Currently, the Tailoring Rule is undergoing a revision to address the U.S. Supreme Court decision in *Utility Air Regulatory Group v. Environmental Protection Agency, 134 S. Ct. 2427 (2014)*[21].~~ The guidance in this chapter is applicable to the EPA requirements in place as of the date of these guidelines, and takes into consideration the U.S. Supreme Court decision in *Utility Air Regulatory Group v. Environmental Protection Agency, 134 S. Ct. 2427 (2014)*[22] ~~as well as SCAQMD Rule 1714.~~

## BACKGROUND

EPA has found that GHG, made of up of six combined compounds, constitute air pollution that endanger public health and welfare. EPA's adopted requirements for GHG under 40 CFR 52.21 ~~Tailoring Rule was issued~~ in May 2010, which were revised in October 2015, to establish~~ing~~ a way to permit GHG emissions under PSD and Title V. Through this rule, permitting focused on the major industrial sources, which emit nearly 70 percent of the greenhouse gas pollution from stationary sources. At this time, smaller businesses and sources are not be subject to these requirements.

The requirements of this rule apply only to GHG as defined by EPA as a total group of six GHG which are: carbon dioxide ($CO_2$), nitrous oxide ($N_2O$), methane ($CH_4$), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride ($SF_6$). All other attainment air contaminants, as defined in SCAQMD Rule 1702 subdivision (a), shall be regulated for the purpose of PSD. ~~PSD is not applicable to air contaminants designated as nonattainment status.~~

## PERMITTING GUIDANCE FOR GHG

EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases" provides the basic information that permit writers and applicants need to address GHG emissions in permits. Although this guidance was issued prior to the revision of 40 CFR 52.21 in 2015, there are parts still applicable to the current requirements. The applicable parts of the guidance document are summarized in these Guidelines. The guidance:

- applies long-standing PSD and Title V permitting requirements and processes to GHG;
- reiterates that BACT determinations will continue to be a state, and project specific decision;

~~[21] The UARG v. EPA decision limited the scope originally envisioned by the Tailoring Rule, and now only "anyway sources" are subject to GHG BACT.~~

[22] The UARG v. EPA decision limited the scope originally envisioned by the Tailoring Rule, and now only "anyway sources" are subject to GHG BACT. On October 3, 2016, EPA proposed revising 40 CFR 52.21 to establish a Significant Emissions Rate for GHGs at the same threshold of 75,000 ton per year $CO_2e$ as Step 1 of the Tailoring Rule for "anyway" sources.

- does not prescribe GHG BACT for any source type;
- emphasizes the importance of BACT options that improve energy efficiency;
- points out that Carbon Capture and Sequestration (CCS) is a promising technology in the early stage of demonstration and commercialization (it should be identified as an available control measure in the first step of BACT, it is currently an expensive technology and unlikely to be selected as BACT in most cases);
- ~~clarifies that EPA does not intend to require GHG to be addressed in permits issued before January 2, 2011 that do not become effective until after this date;~~
- notes that biomass could be considered BACT after taking into account environmental, energy, and economic considerations and state and federal policies that promote biomass for energy-independence and environmental reasons. In its memorandum[23] dated November 19, 2014, EPA states that it is still assessing and monitoring biogenic feedstocks and will provide further guidance. Further updates can be found at EPA's webpage "CO2 Emissions Associated with Biomass Use at Stationary Sources."
- provides flow charts and examples that illustrate the key points of the traditional five-step process for determining BACT for GHG; and
- identifies technical resources related to GHG emissions and controls.

## FEDERAL PSD APPLICABILITY FOR GHG

Beginning January 2, 2011, ~~GHG are regulated as a NSR contaminant.~~ GHG BACT applies when a new or modified facility is subject to PSD requirements for GHG. The first step for PSD applicability determination for new or modified sources is listed in the Tables 7 and 8 below that address the ~~Tailoring Rule~~ requirements in 40 CFR 52.21. A second step for PSD applicability is contemporaneous netting. For detailed guidance on this topic, EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011) should be referenced, but should be used in accordance with EPA's clarifying documents regarding the U.S. Supreme Court decision in *Utility Air Regulatory Group v. Environmental Protection Agency*[24] and the current requirements under 40 CFR 52.21.

In determining PSD applicability, a differentiation between GHG $CO_2e$ and mass basis must be made. GHG mass basis is simply the sum of all six GHG compound mass emissions. However, to obtain GHG $CO_2e$, the mass emissions of each individual GHG compound must be multiplied by its 100-year Global Warming Potential (GWP). The individual GHG $CO_2e$ are then summed to obtain the total $CO_2e$ for the source. Current GWP factors should be obtained from EPA's website when performing these calculations.

[23] EPA Memo: "Addressing Biogenic Carbon Dioxide Emissions from Stationary Sources, (2014 November 9)

[24] EPA Memo: Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision, (2014, July 24)

**Table 7**
**GHG PSD Applicability for New Sources**

| PSD applies to GHG if: |
|---|
| 1. The source is otherwise subject to PSD for another regulated NSR pollutant, **AND** |
| 2. The source has a GHG PTE ≥ 75,000 tons per year (TPY) $CO_2e$; |

**Table 8**
**GHG PSD Applicability for Modified Sources**

| PSD applies to GHG if: |
|---|
| 1. The modification is otherwise subject to PSD for another regulated NSR pollutant, **AND** |
| 2. The modification results in a GHG emissions increase ~~or~~and net emissions increase: |
| a. ~~PTE ≥~~ 75,000 TPY $CO_2e$, **AND** |
| b. > zero TPY mass basis |

### Contemporaneous Netting

Contemporaneous netting is the process of considering all of the creditable emission increases and decreases that have occurred during the period beginning five years before the proposed construction of the modification through the date that the emission increase from the modification occurs. When calculating the net emissions increase in Table 8 above for PSD applicability, it must include all emission increases and decreases during this period.

## SCAQMD PSD APPLICABILITY FOR GHG

SCAQMD adopted Rule 1714 in 2010 to implement the PSD GHG requirements set forth by 40 CFR 52.21. SCAQMD Rule 1714 incorporates the provisions of 40 CFR 52.21 by reference, excluding the sections listed under SCAQMD Rule 1714 (c)(1). SCAQMD PSD applicability should be determined following the applicable sections of the Code of Federal Regulation identified in the rule.

## TOP-DOWN BACT PROCESS

EPA recommends that permitting authorities continue to use the EPA's five-step "Top-Down" BACT process to determine BACT for GHG (U.S. EPA, 2011)[25]. While this section summarizes the steps in the process, further details for each of the steps can be referenced in EPA's guidance document.

### BACT Step 1 – Identify All Available Control Options

The first step in the top-down BACT process is to identify all "available" control options. Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and the regulated pollutant under evaluation.

Permit applicants and permitting authorities should identify all "available" GHG control options that have the potential for practical application to the source under consideration.

The application of BACT to GHG does not affect the discretion of a permitting authority to exclude options that would fundamentally redefine a proposed source. GHG control technologies are likely to vary based on the type of facility, processes involved, and GHG being addressed. EPA has emphasized the importance of energy efficiency improvements. ~~The first category of energy efficiency improvement options includes technologies or processes that maximize the efficiency of the individual emissions unit. The second category of energy efficiency improvements includes the options that could reduce emissions from a new greenfield facility by improving utilization of thermal energy and electricity that is generated and used on site.~~

For the purposes of a BACT analysis for GHG, EPA classifies CCS as an add-on pollution control technology that is "available" for large $CO_2$-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity $CO_2$ streams (*e.g.*, hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).

### BACT Step 2 – Eliminate Technically Infeasible Options

Under the second step of the top-down BACT analysis, a potentially applicable control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. EPA generally considers a technology to be technically feasible if it has been successfully operated on the same type of source under review, or is available and applicable to the source under review.

Assuming CCS has been included in Step 1 of the top-down BACT process for such sources, it now must be evaluated for technical feasibility in Step 2. CCS is composed of three main components: $CO_2$ capture and/or compression, transport, and storage. CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for any~~each~~ of these three main components from what has already

[25] U.S. EPA (2011). PSD and Title V Permitting Guidance for Greenhouse Gases

been applied to a differing source type. For example, the temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review. CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations (*e.g.*, space for $CO_2$ capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options).

### BACT Step 3 – Ranking of Controls

After the list of all available controls is winnowed down to a list of the technically feasible control technologies in Step 2, Step 3 of the top-down BACT process calls for the remaining control technologies to be listed in order of overall control effectiveness for the regulated NSR pollutant under review. The most effective control alternative (*i.e.*, the option that achieves the lowest emissions level) should be listed at the top and the remaining technologies ranked in descending order of control effectiveness. The ranking of control options in Step 3 determines where to start the top-down BACT selection process in Step 4.

The options considered in a BACT analysis for GHG emissions will likely include, but not necessarily be limited to, control options that result in energy efficiency measures to achieve the lowest possible emission level. Where plant-wide measures to reduce emissions are being considered as GHG control techniques, the concept of overall control effectiveness will need to be refined to ensure the suite of measures with the lowest net emissions from the facility is the top-ranked measure. Ranking control options based on their net output-based emissions ensures that the thermal efficiency of the control option, as well as the power demand of that control measure, is fully considered when comparing options in Step 3 of the BACT analysis. Finally, to best reflect the impact on the environment, the ranking of control options should be based on the total $CO_2e$ rather than total mass or, mass for the individual GHG.

### BACT Step 4 – Economic, Energy, and Environmental Impacts

Under Step 4 of the top-down BACT analysis, permitting authorities must consider the economic, energy, and environmental impacts arising from each option remaining under consideration. Accordingly, after all available and technically feasible control options have been ranked in terms of control effectiveness (BACT Step 3), the permitting authority should consider any specific energy, environmental, and economic impacts identified with those technologies to either confirm that the top control alternative is appropriate or determine it to be inappropriate.

There are compelling public health and welfare reasons for BACT to require all GHG reductions that are achievable, considering economic impacts and the other listed statutory factors. As a key step in the process of making GHG a regulated pollutant, EPA has considered scientific literature on impacts of GHG emissions and has made a final determination that emissions of six GHG endanger both the public health and the public welfare of current and future

generations. Potential impacts that may be considered in this step based on the EPA's January 2010 Endangerment Finding[26] are detailed in EPA's guidance document. ~~Among the public health impacts and risks that EPA cited are anticipated increases in ambient ozone and serious ozone-related health effects, increased likelihood of heat waves affecting mortality and morbidity, risk of increased intensity of hurricanes and floods, and increased severity of coastal storm events due to rising sea levels. With respect to public welfare, EPA cited numerous and far-ranging risks to food production and agriculture, forestry, water resources, sea level rise and coastal areas, energy, infrastructure, and settlements, and ecosystems and wildlife. The potentially serious adverse impacts of extreme events such as wildfires, flooding, drought and extreme weather conditions also supported EPA's finding.~~

When conducting a BACT analysis for GHG, the environmental impact analysis should continue to concentrate on impacts other than the direct impacts due to emissions of the regulated pollutant in question. Where GHG control strategies affect emissions of other regulated pollutants, applicants and permitting authorities should consider the potential trade-offs of selecting particular GHG control strategies.

### BACT Step 5 – Selecting BACT

In Step 5 of the BACT determination process, the most effective control option not eliminated in Step 4 should be selected as BACT for the pollutant and emissions unit under review and included in the permit. For energy-producing sources, one way to incorporate the energy efficiency of a process unit into the BACT analysis is to compare control effectiveness in BACT Step 3 based on output-based emissions of each of the control options. Establishing an output-based BACT emissions limit, or a combination of output- and input-based limits, wherever feasible and appropriate to ensure that BACT is complied with at all levels of operation should be considered.

## GHG CONTROL MEASURES WHITE PAPERS

EPA has a series of technical "white papers" that summarize readily available information on control techniques and measures to reduce GHG emissions from specific industrial sectors. These papers provide basic technical information which may be useful in a BACT analysis, but they do not define BACT for each sector. The industrial sectors covered include:

- Electric Generating Units (PDF) (48pp, 805k)
  EPA Contact: Christian Fellner (919-541-4003 or fellner.christian@epa.gov)
- Large Industrial/Commercial/Institutional Boilers (PDF) (39pp, 337k)
  EPA Contact: Jim Eddinger (919-541-5426 or eddinger.jim@epa.gov)
- Pulp and Paper (PDF) (62pp, 421k)
  EPA Contact: Bill Schrock (919-541-5032 or schrock.bill@epa.gov)

[26] https://www3.epa.gov/climatechange/endangerment/

- Cement (PDF) (48pp, 220k)
  EPA Contact: Keith Barnett (919-541-5605 or barnett.keith@epa.gov)
- Iron and Steel Industry (PDF) (78pp, 620k)
  EPA Contact: Donna Lee Jones (919-541-5251 or jones.donnalee@epa.gov)
- Refineries (PDF) (42pp, 707k)
  EPA Contact: Brenda Shine (919-541-3608 or shine.brenda@epa.gov)
- Nitric Acid Plants (PDF) (31pp, 544k)
  EPA Contact: Nathan Topham (919-541-0483 or topham.nathan@epa.gov)
- Landfills (PDF) (28pp, 250k)
  EPA Contact: Hillary Ward (919-541-3154 or ward.hillary@epa.gov)

# PART F – BACT DETERMINATIONS FOR FACILITIES SUBJECT TO PREVENTION OF SIGNIFICANT DETERIORATION FOR GREENHOUSE GASES

(This section is currently under development)

# LIST OF ABBREVIATIONS

| | |
|---|---|
| AIP | Achieved in Practice |
| APCD | ~~Air Pollution Control District~~ Air Pollution Control District |
| ~~AQMD~~ | ~~South Coast Air Quality Management District~~ |
| AQMP | Air Quality Management Plan |
| BACT | Best available control technology |
| BRC | BACT Review Committee, SCAQMD |
| CAA | Clean Air Act |
| CAPCOA | California Air Pollution Control Officers Association |
| CARB | California Air Resources Board |
| CCS | Carbon Capture and Sequestration |
| CEP | Certified Equipment Permit |
| CFC | Chlorofluorocarbons |
| CFR | Code of Federal Regulations |
| CO | Carbon monoxide |
| $CO_2$ | Carbon dioxide |
| $CO_2e$ | Carbon dioxide equivalent |
| DCF | Discounted Cash Flow Method |
| DEO | Deputy Executive Officer |
| GHG | Greenhouse Gas(es) |
| GWP | Global Warming Potential |
| H&SC | Health and Safety Code, California State |
| LAER | Lowest achievable emission rate |
| LPG | Liquefied petroleum gas |
| MDAB | Mojave Desert Air Basin |
| MICR | Maximum Individual Cancer Risk |
| MSBACT | Minor Source BACT |
| $NO_2$ | Nitrogen dioxide |
| NOx | Oxides of nitrogen |
| NSR | New Source Review |
| ODC | Ozone depleting compounds |
| Pb | Lead |
| $PM_{10}$ | Particulate matter less than 10 microns in diameter |
| $PM_{2.5}$ | Particulate matter less than 2.5 microns in diameter |
| PSD | Prevention of Significant Deterioration |
| PTE | Potential to Emit |
| RACT | Reasonably available control technology |
| RECLAIM | Regional Clean Air Incentives Market |
| ROG | Reactive organic gas |
| RTC | RECLAIM trading credit |
| SCAQMD | South Coast Air Quality Management District |
| SIP | State Implementation Plan |
| SOCAB | South Coast Air Basin |

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT**
**Best Available Control Technology (BACT) Guideline**

**Source Category**

| | | | |
|---|---|---|---|
| **Source:** | **IC Engine – Compression Ignition, Stationary Prime; non-Agricultural** | **Revision:** | **6** |
| | | **Document #:** | **96.1.4** |
| **Class:** | **> 50 BHP Output** | **Date:** | ~~**04/13/2009**~~ REVISED 6/11/15 |

**Determination**

| Pollutant | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| **POC** | 1. 50% reduction of current tier[a,b] standard for POC.<br>2. Current tier[a,b] standard for POC at applicable horsepower rating. | 1. Catalytic oxidation combined with current POC certified engine.[a,b]<br>2. Current POC certified engine.[a,b] |
| **NOx** | 1. 85% reduction of current tier[a,b] standard for NOx.<br>2. Current tier[a,b] standard for NOx at applicable horsepower rating. | 1. Selective catalytic reduction (SCR) + current NOx certified engine.[a,b]<br>2. Current NOx certified engine.[a,b] |
| **$SO_2$** | 1. n/s<br>2. Fuel sulfur content not to exceed 0.0015% (wt) or 15 ppm. | 1. n/s<br>2. CARB Diesel Fuel (Ultra Low Sulfur Diesel). |
| **CO** | 1. 50% reduction of current tier[a,b] standard for CO.<br>2. 2.75 g/bhp-hr [319 ppmvd @ 15% $O_2$][d] | 1. Catalytic oxidation combined with current CO certified engine.[a,b]<br>2. Any engine demonstrated or certified to meet 2.75 g/bhp-hr. |
| **$PM_{10}$** | 1. n/s<br>2. 0.01 g/bhp-hr or equiv[c] technology.[e]<br>3. TBACT: 0.01 g/bhp-hr or equivalent[c] technology[e]. | 1. n/s<br>2. Any engine/technology verified or certified to achieve 0.01 g/bhp-hr.[c]<br>3. (See 2., above)[c] |
| **NPOC** | 1. n/s<br>2. n/s | 1. n/s<br>2. n/s |

**References**

| | |
|---|---|
| a. | Current tier standard: The current CARB or EPA off-road tier standard for the pollutant of concern within the appropriate horsepower range. Where NMHC + NOx is listed (with no individual standards for NOx or NMHC) as the standard, the portions may be considered 95% NOx and 5% NMHC. For the purposes of determining BACT NMHC = POC. Any engine which has been certified or demonstrated to meet the current year tier standard may be considered a current certified engine for that pollutant. |
| b. | An engine which does not meet the current EPA or CARB off-road tier standard may represent BACT2, providing 1) the engine met the most stringent EPA Tier Standard in effect prior to the Tier change for that horsepower rating, and 2) the permit application is submitted within 6 months of the effective date of the Tier change. [Source: California Health & Safety Code Section 93116.3(b)(7)] |
| c. | Compliance with 0.01 g/bhp-hr may be demonstrated by use of *Alternative Compliance Demonstration*, specified in California Health & Safety Code Section 93115.13(f) [Stationary CI Engine ATCM]. |
| d. | Previous BACT determination dated 01/11/02. |
| e. | Specified because not all BAAQMD-defined stationary engines are subject to the Stationary ATCM. |

John –
Before I print many of these, is this the information you need?
Thanks
Bill
6/12/17

# Overview of Off-Road Compression Ignition Engine Certification Standards in g/bhp-hr (g/kW-hr)[1]

| Engine | Tier 1[2] | | | | | Tier 2 | | | | Tier 3 | | | | Tier 4 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HP (KW) | HC | NOx | CO | PM | Years | NMHC + NOx | CO | PM | Years | NMHC + NOx | CO | PM | Years | NMHC + NOx | NMHC | NOx[3] | CO | PM | Years |
| 50 <75 (37<56) | | 6.9 (9.2) | | | 1998 - 2003 | 5.6 (7.5) | 3.7 (5.0) | 0.30 (0.40) | 2004 - 2007 | 3.5 (4.7) | 3.7 (5.0) | 0.22 (0.30) | 2008 - 2012 | 3.5 (4.7) | | | 3.7 (5.0) | 0.02 (0.03) | 2013+ |
| 75<100 (56<75) | | 6.9 (9.2) | | | 1998 - 2003 | 5.6 (7.5) | 3.7 (5.0) | 0.30 (0.40) | 2004 - 2007 | 3.5 (4.7) | 3.7 (5.0) | 0.30 (0.40) | 2008 - 2011 | 3.5 (4.7) | 0.14 (0.19) | 0.30-2.5 (0.40-3.4) | 3.7 (5.0) | 0.01 (0.02) | 2012 - 2013 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 0.30 (0.40) | 3.7 (5.0) | 0.01 (0.02) | 2014+ |
| 100<175 (75<130) | | 6.9 (9.2) | | | 1997 - 2002 | 4.9 (6.6) | 3.7 (5.0) | 0.22 (0.30) | 2003 - 2006 | 3.0 (4.0) | 3.7 (5.0) | 0.22 (0.30) | 2007 - 2011 | 3.0 (4.0) | 0.14 (0.19) | 0.30-2.5 (0.40-3.4) | 3.7 (5.0) | 0.01 (0.02) | 2012 - 2013 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 0.30 (0.40) | 3.7 (5.0) | 0.01 (0.02) | 2014+ |
| 175<300 (>130<225) | 0.97 (1.3) | 6.9 (9.2) | 8.5 (11.4) | 0.40 (0.54) | 1996 - 2002 | 4.9 (6.6) | 2.6 (3.5) | 0.15 (0.20) | 2003 - 2005 | 3.0 (4.0) | 2.6 (3.5) | 0.15 (0.20) | 2006 - 2010 | 3.0 (4.0) | 0.14 (0.19) | 0.30-1.5 (0.40-2.0) | 2.6 (3.5) | 0.01 (0.02) | 2011 - 2013 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 0.30 (0.40) | 2.6 (3.5) | 0.01 (0.02) | 2014+ |
| 300<600 (225<450) | 0.97 (1.3) | 6.9 (9.2) | 8.5 (11.4) | 0.40 (0.54) | 1996 - 2000 | 4.8 (6.4) | 2.6 (3.5) | 0.15 (0.20) | 2001 - 2005 | 3.0 (4.0) | 2.6 (3.5) | 0.15 (0.20) | 2006 - 2010 | 3.0 (4.0) | 0.14 (0.19) | 0.30-1.5 (0.40-2.0) | 2.6 (3.5) | 0.01 (0.02) | 2011 - 2013 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 0.3.0 (0.40) | 2.6 (3.5) | 0.01 (0.02) | 2014+ |
| 600<750 (450<560) | 0.97 (1.3) | 6.9 (9.2) | 8.5 (11.4) | 0.40 (0.54) | 1996 - 2001 | 4.8 (6.4) | 2.6 (3.5) | 0.15 (0.20) | 2002 - 2005 | 3.0 (4.0) | 2.6 (3.5) | 0.15 (0.20) | 2006 - 2010 | 3.0 (4.0) | 0.14 (0.19) | 0.30-1.5 (0.40-0.20) | 2.6 (3.5) | 0.01 (0.02) | 2011 - 2013 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 0.30 (0.40) | 2.6 (3.5) | 0.01 (0.02) | 2014+ |
| ≥750 (≥560 ) | 0.97 (1.3) | 6.9 (9.2) | 8.5 (11.4) | 0.40 (0.54) | 2000 - 2005 | 4.8 (6.4) | 2.6 (3.5) | 0.15 (0.20) | 2006 - 2010 | | | | | | 0.30 (0.40) | 2.6 (3.5) | 2.6 (3.5) | 0.075 (0.10) | 2011 - 2014 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 2.6 (3.5) | 2.6 (3.5) | 0.03 (0.04) | 2015+ |
| >750≤1200[4] (560≤900) Gen. Only | 0.97 (1.3) | 6.9 (9.2) | 8.5 (11.4) | 0.40 (0.54) | 2000 - 2005 | 4.8 (6.4) | 2.6 (3.5) | 0.15 (0.20) | 2006 - 2010 | | | | | | 0.30 (0.40) | 2.6 (3.5) | 2.6 (3.5) | 0.075 (0.10) | 2011 - 2014 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 0.50 (0.67) | 2.6 (3.5) | 0.02 (0.03) | 2015+ |
| >1200[4] (>900) Gen. Only | 0.97 (1.3) | 6.9 (9.2) | 8.5 (11.4) | 0.40 (0.54) | 2000 - 2005 | 4.8 (6.4) | 2.6 (3.5) | 0.15 (0.20) | 2006 - 2010 | | | | | | 0.30 (0.40) | 0.50 (0.67) | 2.6 (3.5) | 0.075 (0.10) | 2011 - 2014 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 0.5 (0.67) | 2.6 (3.5) | 0.02 (0.03) | 2015+ |

1 This table is intended as an overview. For California Exhaust Emission Standards and Test Procedures -Off-Road Compression-Ignition Engines, consult title 13, California Code of Regulations, section 2423. For federal Nonroad Compression Ignition Engine Certification Standards, consult title 40, United States Code of Federal Regulations, Chapter 1, Part 89, subpart B and Part 1039, Subpart B.

2 Engine manufacturers have several options for complying with NOx during the transitional implementation years of Tier 4, including a "phase-in--phase-out" or alternative NOx level approach.

San Joaquin Valley APCD

Back

## Best Available Control Technology (BACT) Guideline 1.8.2 D

| | | | |
|---|---|---|---|
| **Emissions Unit:** | Refinery Process Heater, Refinery Fuel Gas and/or Natural Gas | **Equipment Rating:** | 641 and 215 MM Btu/hr |
| **Facility:** | Big West of California LLC | **References:** | S-33-407-0 and '411-0 |
| **Location:** | Bakersfield | **Date of Determination:** | 9/1/2006 |

| **Pollutant** | **BACT** |
|---|---|
| CO | 10 ppmv @ 3% O2 (SCR and burner tuning) |
| NOx | 5 ppmv at 3% O2, (15 minute average) (Low NOx burners and SCR) |
| PM10 | Treated refinery gas and/or natural gas with no more than 100 ppmv total reduced sulfur (3-hour rolling average) |
| SOx | Treated refinery gas and/or natural gas with no more than 100 ppmv total reduced sulfur (3-hour rolling average) |
| VOC | Good combustion practices |

| **BACT Status** | **Comment** |
|---|---|
| Achieved in Practice | VOC, NOx, SOx and CO |
| Technologically Feasible BACT | PM10 |

## Best Available Control Technology (BACT) Guideline 1.8.2 C

| | | | |
|---|---|---|---|
| **Emissions Unit:** | Process Heater - Refinery | **Equipment Rating:** | All |
| **Facility:** | Equilon Enterprise | **References:** | ATC #: Withdrawn Project #: S-990010 |
| **Location:** | Bakersfield | **Date of Determination:** | 1/4/2001 |

| **Pollutant** | **BACT** |
|---|---|
| CO | BACT NOT TRIGGERED |

| Pollutant | BACT |
|---|---|
| NOx | BACT NOT TRIGGERED |
| PM10 | BACT NOT TRIGGERED |
| SOx | Natural gas or treated refinery gas @ 0.0621 grains H2S/dscf (100 ppmv H2S) |
| VOC | BACT NOT TRIGGERED |

| BACT Status | Comment |
|---|---|
| Achieved in Practice | |

**Best Available Control Technology (BACT) Guideline 1.8.2 B**

| | | | |
|---|---|---|---|
| **Emissions Unit:** | Process Heater - Refinery | **Equipment Rating:** | = or > 50.0 MMBtu/hr |
| **Facility:** | n/a | **References:** | District Proactive BACT Determination |
| **Location:** | n/a | **Date of Determination:** | 6/30/1999 |

| Pollutant | BACT |
|---|---|
| CO | BACT NOT TRIGGERED |
| NOx | 9.0 ppmvd @ 3% 02 (0.0108 lb/MMBtu) SCR |
| PM10 | BACT NOT TRIGGERED |
| SOx | BACT NOT TRIGGERED |
| VOC | BACT NOT TRIGGERED |

| BACT Status | Comment |
|---|---|
| Achieved in Practice | |

**Best Available Control Technology (BACT) Guideline 1.8.2 A**

| | | | |
|---|---|---|---|
| **Emissions Unit:** | Process Heater - Refinery | **Equipment Rating:** | 92 MMBtu/hr |
| **Facility:** | Equilon Enterprises LLC | **References:** | ATC #: S-33-17-7<br>Project #: S-981236 |

| **Location:** | Bakersfield | **Date of Determination:** | 6/11/1999 |
|---|---|---|---|

| **Pollutant** | **BACT** |
|---|---|
| CO | BACT NOT TRIGGERED |
| NOx | 30.0 ppmvd @ 3% 02 (0.036 lb/MMBtu) Ultra Low NOx burner with FGR. |
| PM10 | BACT NOT TRIGGERED |
| SOx | Treated Refinery gas with a sulfur content of 0.10 grains H2S/dscf (161 ppmv H2S) with natural gas as a supplemental fuel. |
| VOC | BACT NOT TRIGGERED |

| **BACT Status** | **Comment** |
|---|---|
| Achieved in Practice | |
| The following technologically feasible options were not cost effective | - Natural gas or treated refinery gas @ 100 ppmv H2S - Selective Catalytic Reduction |

## BACT Clearinghouse (Searchable)

INSTRUCTIONS: To filter, enter a search term in "Search Description" and press return, or select a "Main Category" and/or "Sub Category".

| Search Description | Main Category | Sub Category |
|---|---|---|
| | All | All |

| # | Description |
|---|---|
| 1.1.1 | Boiler: < or = 20.0 MMBtu/hr, Natural Gas or Propane Fired *RESCINDED* (10/26/2009) |
| 1.1.2 | Boiler: > 20.0 MMBtu/hr, Natural gas fired, base-loaded or with small load swings. *RESCINDED* (10/26/2009) |
| 1.1.3 | Boiler - > 20.0 MMBtu/hr, Natural gas fired, with highly variable loads or high turndown ratios. *RESCINDED* (10/26/2009) |
| 1.1.4 | Digester Gas Fired Boiler *RESCINDED* (10/26/2009) |
| 1.1.5 | Boiler-Dual Fuel for Facilities Requiring Liquid Backup Fuel *RESCINDED* (10/26/2009) |
| 1.1.6 | Boiler - Fired with a High-Ammonia Fuel *RESCINDED* (10/26/2009) |
| 1.1.7 | Limited Use Boiler - Natural Gas Fired, < 9 Billion Btu/yr *RESCINDED* (10/26/2009) |
| 1.1.8 | Biomass-fired Boiler - Grate Systems *RESCINDED* (10/26/2009) |
| 1.2.1 | Oilfield Steam Generator (> or =20 MMBtu/hr) (3/24/2014) |
| 1.2.2 | Steam Generator - >20.0 MMBtu/Hr Vertically Oriented w/Counterflow Heat Transfer *RESCINDED* (10/26/2009) |
| 1.2.3 | Oilfield Steam Generator/TEOR Gas Incinerator **RESCINDED - part of 5/04 update to guideline 1.2.1** (5/1/2004) |
| 1.3.1 | Fluidized-Bed Combustor => 272 MMBtu/hr, Cogeneration Operation, Fired with Delayed Petroleum Coke (DPC) (8/27/2005) |
| 1.3.2 | Fluidized Bubbling Bed Combustor (biomass-fired) *RESCINDED* (3/12/2012) |
| 1.4.1 | Waste Gas Flare - 15.3 MMBtu/hr, Serving a Tank Vapor Control System *RESCINDED* (11/7/2016) |
| 1.4.2 | Waste Gas Flare - Incinerating Produced Gas *RESCINDED* (11/7/2016) |
| 1.4.3 | Landfill Gas Vapor Collection System *RESCINDED* (11/7/2016) |
| 1.4.4 | Digester Gas-Fired Flare *RESCINDED* (11/7/2016) |
| 1.4.5 | Oilfield Waste Gas Incinerator *RESCINDED* (11/7/2016) |

This web site has BACT for San Joaquin Valley APCD. I can not print them. You will have to open the site, pick the equipment, and read the info.

If you do find a way to print the individual results, let me know & I'll go back to print the applicable ones

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 1.0 External Combustion

| BACT Code | Boilers | NOx | VOC |
|---|---|---|---|
| 1.1.1.a | Boiler: < or = 20.0 MMBtu/hr, Natural Gas or Propane Fired (> 30 Billion Btu/year) | 15 ppmvd @ 3% O2(0.018 lb/MMBtu) | Natural gas with LPG backup or propane fired |
| 1.1.1.b | Boiler: < or = 20.0 MMBtu/hr, Natural Gas or Propane Fired (< 30 Billion Btu/year) | 20.0 ppmvd @ 3% O2 (0.024 lb/MMBtu) | Natural gas with LPG backup or propane fired |
| 1.1.2 | Boiler: > 20.0 MMBtu/hr, Natural gas fired, base-loaded or with small load swings | 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) | Natural gas fuel with LPG backup |
| 1.1.3 | Boiler - > 20.0 MMBtu/hr, Natural gas fired, with highly variable loads or high turndown ratios | 15.0 ppmvd @ 3% O2 (0.018 lb/MMBtu) | Natural Gas Fired with LPG as a backup fuel |
| 1.1.4 | Digester Gas Fired Boiler - < 5 MMBtu/hr | Natural Gas as supplemental fuel | Natural Gas as supplemental fuel |
| 1.1.5 | Boiler-Dual Fuel for Facilities Requiring Liquid Backup Fuel | 15 ppmvd @ 3% O2 for the primary fuel | Natural gas as primary fuel with low sulfur #2 fuel oil (0.05% S by weight or less) as backup fuel |
| 1.1.6 | Boiler - Fired with a High-Ammonia Fuel | | gaseous fuel |
| 1.1.7 | Limited Use Boiler - > 20.0 MMBtu/hr, Natural Gas Fired, < 9 billion Btu/year | 30.0 ppmvd @ 3% O2 (0.036 lb/MMBtu) | Natural gas fuel with LPG backup |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 1.0 External Combustion

| BACT Code | Steam Generators | NOx | VOC |
|---|---|---|---|
| 1.2.1 | Steam Generator (> or = 5 MMBtu/hr, Oil Field) | 14 ppmvd @ 3% O2 | Gaseous fuel |
| 1.2.2.a | Steam Generator - >20.0 MMBtu/Hr Vertically Oriented w/Counterflow Heat Transfer (> 30 Billion Btu/year) | 15 ppmvd @ 3% O2(0.018 lb/MMBtu) | Natural Gas or LPG |
| 1.2.2.b | Steam Generator - >20.0 MMBtu/Hr Vertically Oriented w/Counterflow Heat Transfer (< 30 Billion Btu/year) | 30.0 ppmvd @ 3% O2 (0.036 lb/MMBtu) | Natural Gas or LPG |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 1.0 External Combustion

| BACT Code | Fluidized-bed Combustors | NOx | VOC |
|---|---|---|---|
| 1.3.1 | Fluidized-Bed Combustor => 272 MMBtu/hr, Cogeneration Operation, Fired with Delayed Petroleum Coke (DPC) | 28 ppmvd (as NO2 corrected to 3% O2), ammonia injection (less than 30 ppmvd ammonia slip) and natural gas and fuel oil as auxiliary fuel) | 0.008 lb/MMBtu, natural gas and fuel oil as auxiliary fuel |
| 1.3.2 | Fluidized Bubbling Bed Combustor (biomass-fired) | 0.10 lb/MMBtu, ammonia injection and natural gas auxiliary fuel | 0.02 lb/MMBtu, natural gas auxiliary fuel |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 1.0 External Combustion

| BACT Code | Flares | NOx | VOC |
|---|---|---|---|
| 1.4.1 | Waste Gas Flare - 15.3 MMBtu/hr, Serving a Tank Vapor Control System | Steam-assisted or air-assisted when steam unavailable | Steam-assisted or air-assisted when steam unavailable |
| 1.4.2 | Waste Gas Flare - Incinerating Produced Gas | Steam assisted or Air-assisted or Coanda effect burner, when steam unavailable | Steam assisted or Air-assisted or Coanda effect burner, when steam unavailable |
| 1.4.3 | Landfill Gas Vapor Collection System | 0.06 lb-NOx/MMBtu | Flare with a control efficiency of (= or >) 98% or a controlled VOC (measured as methane) of (= or <) 20 ppmv @ 3% O2 |
| 1.4.4 | Digester Gas-Fired Flare | enclosed flare and NOx emissions <= 0.06 lb/MMBtu | enclosed flare and VOC emissions =< 0.068 lb/MMBtu |
| 1.4.5 | Oilfield Waste Gas Incinerator | Natural gas auxiliary fuel | Natural gas auxiliary fuel |
| 1.4.7 | Waste Gas Flare - Oilfield Well Drilling and Testing Operation, < 50 MMscf/day | N/A | Elevated Flare with propane fueled pilot light |
| 1.4.8 | Refinery Flare | Engineered flare, with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases. | Engineered flare designed with a VOC destruction efficiency of ≥ 98%. Flare design shall include air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system non-emergency releases. |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 1.0 External Combustion

| BACT Code | Furnaces | NOx | VOC |
|---|---|---|---|
| 1.5.1 | Fiberglass Production Furnace, Natural gas fired | Natural gas firing, electric heat boost, Low excess air (< 5%), and use of cullet > 15% annually | Natural gas firing and use of cullet (scrap glass) > 15% annually |
| 1.5.2 | Flat Glass Production Float Furnace, Natural Gas Fired | Tier 1 limit in Rule 4354 specific to furnace | gaseous fuel |
| 1.5.4 | Metal Melting Crucible/Furnace | Natural gas | Natural gas |
| 1.5.5 | Glass Bottle Label Curing Lehr - < 10 MMBtu/hr, Natural Gas Fired | Natural Gas or LPG Fuel | Natural Gas or LPG Fuel |
| 1.5.6 | Natural Gas-Fired Metal Heating Furnace | 30 ppmv NOx @ 3% O2 at the final stack | 30 ppmv NOx @ 3% O2 at the final stack |
| 1.5.7 | Glass Furnace Forehearth | natural gas/propane-fired and good combustion practices | natural gas/propane-fired and good combustion practices |
| 1.5.8 | Container Glass Production - Container Glass Distributor | Natural gas-fired container glass distributor with good combustion practices, using LPG backup fuel, and NOx emissions of 0.10 lb/MMBtu | Natural gas with LPG backup |
| 1.5.9 | Container Glass Production - Furnace | NOx emissions of < or = 1.5 lb/ton of glass pulled | VOC emissions of < or = 0.2 lb/ton of glass pulled |
| 1.5.10 | Container Glass Production - Container Glass Lehr | 60 ppmv NOx @ 3% O2 or 0.073 lb-NOx/MMBtu | Natural gas with LPG backup |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 1.0 External Combustion

| BACT Code | Food & Ag Products Ovens, etc. | NOx | VOC |
|---|---|---|---|
| 1.6.1.a | Tomato Roaster | Operation of burner within manufacturer's specification to minimize Nox emissions | Gaseous fuel |
| 1.6.1.b | Vegetable Roasting Operation | Use of natural gas fuel and operating the burner within manufacturer's specification to minimize NOx emissions | Gaseous fuel |
| 1.6.2 | Oven - Tortilla, <= 5 MMBtu/hr | natural gas fired with optional LPG as backup fuel | natural gas fired with optional LPG as backup fuel |
| 1.6.4 | Oven - Snack Food | Natural gas and LPG as backup fuel | Natural gas and LPG as backup fuel |
| 1.6.7 | Pistachio Roasting Operation | Natural gas fuel | Natural gas fuel |
| 1.6.8 | Pistachio Nut Dryer | 0.083 lb/MMBtu and natural gas fuel | Natural gas fuel |
| 1.6.11 | Dryer - Milk Spray, > or = 20 MMBtu/hr | Low NOx burner fired on natural gas with LPG as backup fuel | Natural gas with LPG as backup fuel |
| 1.6.14 | Dehydrator Tunnel - Fruit, Natural Gas Fired | < 0.16 lb/MMBtu | Natural Gas or Propane-Fired Burner |
| 1.6.15 | Dryer - Milk Spray, < 20 MMBtu/hr | 20 ppmv @ 3% O2 | Natural gas or propane |
| 1.6.16 | Dryer - Seed Processing, < 20 MMBtu/hr | 20 ppmv | Natural gas with LPG backup |
| 1.6.17 | Food Preparation Oven, <800 degrees Fahrenheit, = or < 3.7 MMBtu/hr | 20 - 30 ppmv @ 3% O2 | Natural gas with LPG backup |
| 1.6.19 | Meat Smokehouse - Natural Gas-Fired,< or = 2 MMBtu/hr | Natural gas-fired oven/smokehouse with a natural gas-fired smoke generator | Natural gas-fired oven/smokehouse with a natural gas-fired smoke generator |
| 1.6.20 | Feather Meal Processing Rotary Dryer - Natural Gas Fired, High Ammonia Environment | Natural gas fired with LPG as a backup fuel | Natural gas fired with LPG as a backup fuel |
| 1.6.21 | Flake Cereal Dryer - < 20 MMBtu/hr, Conveyor-fed | 30 ppmv @ 3% O2 | Natural gas fuel |
| 1.6.22 | Wood Drying Kiln | natural gas | natural gas fuel |
| 1.6.23 | Pistachio, Almond, and Walnut Dryers (<10 MMBtu/hr and <2,160 hr/yr) | 0.06 lb/MMBtu | Natural gas with LPG as backup fuel |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 1.0 External Combustion

| BACT Code | Food & Ag Products Ovens, etc. | NOx | VOC |
|---|---|---|---|
| 1.6.24 | Commercial Bakery Oven | 30 ppmvd @ 3% O2 equivalent to 0.036 lb/MMBtu | VOC capture and 95% control efficiency |
| 1.6.25 | Blood Drying Operation | no determination | 95% overall capture and control efficiency |
| 1.6.27 | Direct-Fired Conveyorized Hotdog Cooking Oven | 70.0 ppmvd @ 3% O2 (0.085 lb/MMBtu) | Natural gas fuel |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 1.0 External Combustion

| BACT Code | Industrial Ovens | NOx | VOC |
|---|---|---|---|
| 1.7.1 | Oven - Polyethylene Curing, = or < 20 MMBtu/hr | Natural Gas or Propane Fuel | Natural Gas or Propane Fuel |
| 1.7.2 | Oven - Plastisol curing/fusing, = or < 2.5 MMBtu/hr | Natural gas fuel used in the fusing oven | Plastisol with 2% VOC by weight and natural gas fuel used in the fusing oven |
| 1.7.3 | Oven - Parts Cleaning, Burnoff or Burnout | Natural Gas Fuel | 99% by weight control |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

**Main Category: 1.0 External Combustion**

| BACT Code | Petroleum Product Combustion Devices | NOx | VOC |
|---|---|---|---|
| 1.8.1 | Process Heater - Refinery, = or < 50.0 MMBtu/hr | 30.0 ppmvd @ 3% 02 (0.036 lb/MMBtu) | good combustion practices |
| 1.8.2 | Process Heater - Refinery, > 50 MMBtu/hr | 9.0 ppmvd @ 3% 02 (0.0108 lb/MMBtu) | Good combustion practices |
| 1.8.3.a | Gas Dehydration - Glycol Reboiler (=> 5 MM scf/year) | Natural gas fired burner | collection and control |
| 1.8.3.b | Gas Dehydration - Glycol Reboiler (< 5 MM scf/year) | Natural gas fired burner | no determination |
| 1.8.4 | Heater Treater < 20 MMBtu/hr, Natural Gas Fired | 15 ppmv @ 3% O2 | gaseous fuel and good combustion practices |
| 1.8.5 | Process Heater (non-refinery, < or = 20 MMBtu/hr) | 12 ppmv @ 3% O2 | natural gas with LPG backup or propane fired |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 1.0 External Combustion

| BACT Code | Misc. Combustion Devices | NOx | VOC |
|---|---|---|---|
| 1.9.3 | Crematory - Natural Gas Fired | natural gas fuel | natural gas fuel and a secondary combustion chamber (afterburner) => 1600 degrees F |
| 1.9.4 | Dryer - Natural Gas Fired, Solvent-Laden Towels, = or < 950 lb towels/day | 0.061 lb NOx /MMBtu | Natural gas |
| 1.9.5 | Gas Absorption Chiller - Natural Gas Fired,< 20 MMBtu/hr | 0.036 lb NOx /MMBtu | Natural gas fuel |
| 1.9.6 | Asphalt-Surface-Repair Heater, Propane Fired, < 20 MMBtu/hr | 0.15 lb NOx /MMBtu | Gaseous fuel |
| 1.9.7 | Auxiliary Burner System, Dryer, Natural Gas Fired,< 20 MMBtu/hr | no determination | Natural gas fuel |
| 1.9.8 | Municipal-waste Incinerator - < 750 lb waste/hr feed rate | Natural gas fuel | Multichamber incinerator with afterburner, Starved Air Design (> 1500 degrees Fahrenheit afterburner) |
| 1.9.9 | Molded Paper Products Dryer - Natural Gas Fired,< 20 MMBtu/hr | 80 ppmv @ 3% O2 | Natural gas fuel |
| 1.9.10 | Mineral Products Spray Dryer - Natural Gas Fired,< or = 20 MMBtu/hr | 20 ppmv NOx @ 3% O2 | Natural gas fuel |
| 1.9.12 | Transportable Diesel-Fired Nitrogen Vaporizer | diesel fuel achieving 155 ppmv @ 3% O2 | 0.2 lb/100 gal |
| 1.9.13 | Blood Meal Processing Ring Dryer Burner | Natural gas fired with LPG as a backup fuel | Natural gas fired with LPG as a backup fuel |
| 1.9.14 | Natural Gas Fired Dryer with High Turndown Ratio | = < 8.9 ppmvd @ 19% O2 (0.1 lb/MMBtu) | Natural gas with LPG backup |
| 1.9.15 | Jet Aircraft Fire Training Facility | Use of Natural Gas or LPG/Propane Fuel | Use of Natural Gas or LPG/Propane Fuel |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 2.0 Remediation and Waste Disposal

| BACT Code | Soil Remediation | NOx | VOC |
|---|---|---|---|
| 2.1.1 | Soil Remediation Operation - Thermal Oxidizer | N/A | 95% or greater control efficiency |
| 2.1.2 | Soil Remediation Operation - I.C. Engine | LPG auxiliary fuel and 3 - way catalytic converter | 95% control efficiency |
| 2.1.3 | Soil Remediation Operation - Carbon Adsorption | N/A | 95% control efficiency |
| 2.1.4 | Extracted Soil Remediation using Steam Stripping/Flushingand 4-Stage Carbon Adsorption, > or = 40 tons/hr | N/A | 95% Control efficiency |
| 2.1.6 | Soil Remediation Operation - Boiler, = or < 4.2 MMBtu/hr | 0.036 lb/MMBtu (30 ppmv) when gas firing and 0.048 lb/MMBtu (40 ppmv)when firing diesel backup fuel | 95% control efficiency |
| 2.1.7 | Soil Remediation Operation - Thermal Soil Desorber | Low NOx burner and natural gas/LPG firing | 95% control efficiency |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 2.0 Remediation and Waste Disposal

| BACT Code | Waste Disposal | NOx | VOC |
|---|---|---|---|
| 2.2.1 | Non-hazardous Wastewater Receiving, Treatment, and Impoundment | N/A | Bays used to settle out solids and to skim oil from waste water. Recovered oil pumped to storage tank venting to carbon canisters or drums. Treated wastewater discharged to impoundments for evaporation. |
| 2.2.2 | Landfill - VOC-Contaminated Soil | N/A | Daily clean-fill cover (minimum one inch of compacted, District approved soil) onto the exposed VOC contaminated soil. |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 3.0 Internal Combustion Engines

| BACT Code | Emergency IC Engines | NOx | VOC |
|---|---|---|---|
| 3.1.1 | Emergency Diesel IC Engine, <175 hp | Certified emissions of 6.9 g/bhp-hr or less | Positive crankcase ventilation |
| 3.1.2 | Emergency Diesel I.C. Engine ( = or > 175 hp and < 400 hp) | Certified NOx emissions of 6.9 g/bhp-hr or less. | Positive crankcase ventilation |
| 3.1.3 | Emergency Diesel I.C. Engine = or > 400 hp | Certified emissions of 6.9 g/bhp-hr or less | Positive crankcase ventilation |
| 3.1.4 | Emergency Diesel I.C. Engine Driving a Fire Pump | Certified NOx emissions of 6.9 g/bhp-hr or less | Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification] |
| 3.1.5 | Emergency Gas Fired I.C. Engine - < 132 hp, Rich Burn | natural gas fuel | Positive crankcase ventilation (PCV) |
| 3.1.6 | Emergency Gas Fired I.C. Engine > or = 132 hp, Rich Burn | Natural gas, LPG or propane as fuel | Positive Crankcase Ventilation(PCV), and natural gas, LPG, or propane as fuel |
| 3.1.8 | Emergency Gas-Fired IC Engine - > or = 250 hp, Lean Burn | 1.5 g/bhp-hr | 1.0 g/bhp-hr |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 3.0 Internal Combustion Engines

| BACT Code | Limited/Special Use Engines | NOx | VOC |
|---|---|---|---|
| 3.2.1 | Diesel I.C. Engine - > 449 hp, used for testing of crankcase emission controls | NOx emissions of 7.2 grams/hp-hr or less OR Turbocharger with intercooler or aftercooler and timing retarded 4ø relative to standard timing | PCV or 90% crankcase control device |
| 3.2.2 | Limited Use (1,000 hr/yr max) Diesel-Fired IC Engine - Located at a Stationary Source, non-emergency, non-Transportable, and not used to drive an electrical generator | 6.9 grams/bhp-hr | Catalytic filter; thermal oxidizer, or equal |
| 3.2.4 | Transportable and Multi-location Diesel I.C. Engine | Certified NOx emissions of 6.9g/bhp-hr or less | Positive Crankcase Ventilation (PCV) or Crankcase Control Device that is at least 90% efficient |
| 3.2.5 | Diesel I.C. Engine - Used for starting a Gas Turbine | Certified NOx emissions of 6.9g/bhp-hr or less | Positive Crankcase Ventilation (PCV) or Crankcase Control Device that is at least 90% efficient |
| 3.2.7 | Diesel-Fired IC Engine - Low Use (= or < 1,000 hr/yr max) | Certified NOx emissions of 6.9g/bhp-hr or less. | Positive crankcase ventilation(PCV). |
| 3.2.8 | Limited Life (1,000 hr total max life) Diesel-Fired IC Engine - < 600 bhp, and Not Used to Drive an Electrical Generator | Certified NOx emissions of 7.2 g/bhp-hr or less OR Turbocharger with intercooler or aftercooler and timing retarded 4 deg relative to standard timing OR Turbocharger with intercooler or aftercooler and injection timing not to be greater than 16 deg BTDC (this option may be used if it is consistent with District policy GEAR 16-1, "Determination of Injection Timing Retard for Diesel IC Engines", dated 08/14/96) | Positive crankcase ventilation(PCV) |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 3.0 Internal Combustion Engines

| BACT Code | Fulltime IC Engines | NOx | VOC |
|---|---|---|---|
| 3.3.1 | Diesel Fired IC Engine - < 600 hp, Transportable Metal ContaminatedSoil Processing Operation | NOx emissions of 7.2 g/hp-hr or less | Positive crankcase ventilation or 90% crankcase control device(PCV) |
| 3.3.12 | Fossil Fuel Fired IC Engine > 50 hp | 9 ppmvd @ 15% O2, 0.15 g/bhp-hr, or 0.5 lb/MW/hr | 25 ppmvd @15% O2, 0.15 g/bhp-hr, or 0.5 lb/MW-hr |
| 3.3.13 | Waste Gas Fired IC Engine - > 50 hp | 50 ppmvd @ 15% O2, 0.6 g/bhp-hr, or 1.9 lb/MW- | 130 ppmvd @ 15% O2,0.6 g/bhp/hr, or 1.9 lb/MW-hr |
| 3.3.14 | Full-time Rich-burn IC Engine, Syngas-fueled | 9 ppmvd at 15% O2 | 25 ppmvd at 15% O2 |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 3.0 Internal Combustion Engines

| BACT Code | Gas Turbines | NOx | VOC |
|---|---|---|---|
| 3.4.1 | Gas Turbine - = or > 47 MMBtu/hr, Variable Load, Without Heat Recovery | 8 ppmvd @ 15% O2 (Steady State) and 12 ppmv @ 15% O2 (Transitional State) | 0.007 lb/MMBtu |
| 3.4.2 | Gas Turbine - = or > 50 MW, Uniform Load, with Heat Recovery | 2.5 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown) | 2.0 ppmv @ 15% O2 |
| 3.4.3 | Gas Turbine with Heat Recovery (= > 3 MW and = < 10 MW) | 2.5 ppmv @ 15% O2, based on a three-hour | 2.0 ppmv @ 15% O2, based on a three-hour average |
| 3.4.4 | Limited Use (< 877 hours per year) Gas Fired Turbine = or < 26 MW, without Heat Recovery | 25 ppmvd @ 15% O2 | PUC quality natural gas with fuel oil #2 as backup. |
| 3.4.6 | Gas Turbine - > 10 MW and < 50 MW, Uniform Load, with Heat Recovery | 2.5 ppmvd @ 15% O2, based on a three-hour rolling average | 2.0 ppmvd @ 15% O2 |
| 3.4.7 | Gas Turbine - = or > 50 MW , Uniform Load, without Heat Recovery | 5.0 ppmvd @ 15% O2, based on a three-hour average | 2.0 ppmvd @ 15% O2, based on a three-hour average |
| 3.4.8 | Gas Turbine - < 50 MW, Uniform Load, Without Heat Recovery | 5.0 ppmvd @ 15% O2, based on a three-hour average | 2.0 ppmvd @ 15% O2, based on a three-hour average |
| 3.4.9 | Gas Turbine - < 3 MW, Uniform Load, With or Without Heat Recovery | 9.0 ppmvd @ 15% O2, based on a three-hour average | 5.0 ppmvd @ 15% O2, based on a three-hour average |
| 3.4.10 | Oxy-Fuel Combustor Powering a Steam Turbine, Power Output < 3 MW, without Heat Recovery, Uniform and Variable Load, Research Facility | 5.3 ppmvd @ 15% O2, equivalent to 0.3 lb/MW-hr | 5.0 ppmv @ 15% O2, equivalent to 0.1 lb/MW-hr |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Dry Cleaners | NOx | VOC |
|---|---|---|---|
| 4.1.2 | Petroleum Solvent Dry Cleaning | N/A | dry-to-dry machine vented to vapor control device |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Motor Vehicle Coating | NOx | VOC |
|---|---|---|---|
| 4.2.1 | Automotive Spray Painting Operation, < 5.0 MMBtu/hr | Natural gas or LPG fired burner | HVLP spray guns, coatings, cleaning materials, and solvents compliant with District Rule 4612 |
| 4.2.2 | Group II Vehicles Spray Painting Operation - Vehicles requiring a Color Match | N/A | Use coatings with a VOC content of 3.5 lb/gal (less water and exempt compounds) or less, and Pretreatment Wash Primers with a VOC content of 6.0 lb/gal (less water and exempt compounds) or less, HVLP (or equivalent) spray equipment, and using an enclosed spray gun cleaning system |
| 4.2.3 | Mobile Equipment Coating Operation - Multiple Location, <= 20,000 lb-VOC/year | N/A | Coatings and cleaning materials, and solvents compliant with District Rule 4612, HVLP spray gun |
| 4.2.4 | Trailer Coating Operation | N/A | Using topcoats with a low VOC content (2.8 lb/gal les water and exempt compounds)and pretreatment wash primes with a low VOC content (6.0lb/gal less water and exempt compounds) |
| 4.2.5 | Limited Aircraft Coating Operation - Maintenance and Refinishing of Metal Parts on Aircraft, < 20 Gallons/day. | N/A | Use of Coating compliant with Rule 4605, HVLP application equipment, and an enclosed gun cleaner, or equal. |
| 4.2.6 | Aerospace Parts Coating Operation | N/A | The use of an enclosed gun cleaner and coatings with a VOC content (less water and exempt compounds) lower than the following:<br>Primers < 6.4 lb VOC/gal<br>Topcoats < 5.2 lb VOC/gal |
| 4.2.7 | Aerospace and Metal Parts Coating Operating - Solid FilmLubricant for computer, medical specialty, and aerospace metal parts and products | N/A | Solvent-based solid film lubricant coating with a VOC content of 6.44 lb/gal (less water and exempt compounds),or lower. |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Motor Vehicle Coating | NOx | VOC |
|---|---|---|---|
| 4.2.8 | Recreational Marine Vessel (Pleasure Craft) Coating | N/A | Use of materials with VOC contents (less water and exempt compounds) as indicated, or lower:<br>- antifouling coatings: aluminum substrate: 440 g/l,<br>- other substrates: 330 g/l,<br>- high gloss coatings: 340 g/l<br>- extreme high gloss coatings: 490 g/l<br>- pretreatment wash primers: 420 g/l<br>- primers: 340 g/l<br>- all other coatings: 340 g/l |
| 4.2.10 | Motor Vehicle Chassis Coating Operation -Electrodeposition with a Curing Oven. | N/A | 95 % control system serving coating tank and curing oven |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Metal Parts and Products Coating | NOx | VOC |
|---|---|---|---|
| 4.3.1 | Metal Parts and Products Coating - Air Dried (excluding specialty coating as defined in Rule 4603) | N/A | Coatings with a VOC content of 2.8 lb/gal or less; HVLP (or equivalent) spray equipment; and an enclosed spray gun cleaning system |
| 4.3.2 | Metal Parts and Products Coating - Heat Dried | N/A | HVLP guns, the use of an enclosed gun cleaner & coatings compliant with District Rule 4603 |
| 4.3.3 | Metal Product Coating - Metal Rod Dip Coating, Air-Dried, = or > 150 gallons/month coating | N/A | Dip coating with low VOC content of 3.5 lb/gallon (less water and exempt compounds),Dip tank covered when not in use |
| 4.3.5 | Metal Parts and Products Coating Operations (using specialtycoatings as defined by Rule 4603) | N/A | Using coatings with a VOC content of 3.5 lb/gal (less water and exempt compounds) or less, using HVLP spray equipment (or other application methods listed in Rule 4603), and using an enclosed spray gun cleaning system |
| 4.3.6 | Metal Products Coating - Shipping/Storage Containers | N/A | Coating with a VOC content of 2.8 lb/gal (less water and exempt compounds) or less; HVLP (or equivalent) spray equipment |
| 4.3.7 | Powder Coating Operation = or >1.5 MMBtu/hr | Natural gas fired fusing oven | Low-VOC Coating (< 1.5% VOC by weight) and Natural gas fired fusing oven |
| 4.3.8 | Metal Product Coating - Large Steel Structures, < 64 lbVOC/day, Outdoor Coating Operation | N/A | Use of coatings with a VOC content (less water and exempt compounds) as indicated, or lower:<br>- for General Coating: 2.5 lb/gal,<br>- for General Coating, when the ambient temperature is at or below 60 F: 2.8 lb/gal, and<br>- for Specialty Coatings - Extreme Performance or High-Gloss 3.5 lb/gal<br>and use of an HVLP spray gun or equivalent application method. |
| 4.3.9 | Metal Product Coating - Large Steel Structures, = or < 64 lb VOC/day, Indoor Operation | N/A | Coating with a low VOC content(2.5 lb/gal less water and exempt compounds) and HVLP spray gun or equivalent application method. |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Metal Parts and Products Coating | NOx | VOC |
|---|---|---|---|
| 4.3.10 | Metal Products Coating - Sheet Metal for Can Manufacturing, Major Source for VOC | 20 ppmv @ 3% O2 | VOC capture and thermal incineration |
| 4.3.11 | Metal Products Coating - Touch-up, 6.2 lb VOC/day | N/A | Coating with 1.9 lb VOC/gal (less water and exempt compounds), HVLP gun |
| 4.3.12 | Metal Products Coating - High Gloss, Air-Dried,= or < 30 lb/day Facility-wide VOC coating emissions | N/A | HVLP spray guns, coatings compliant with Rule 4603 and enclosed paint gun cleaners |
| 4.3.13 | Metal Products Coating - Metal Frames and Exterior Wooden Wall Panels for Modular Buildings | N/A | Metal frames: use of Rule 4603 compliant coatings Exterior wooden wallpanels: use of Rule 4606 compliant coatings (This control is Achieved in Practice only for facilities subject to Rule 4603/4606) |
| 4.3.14 | Side Seam Stripe Spray Coating Operation for 3-Piece Metal Can Manufacturing at a Facility-wide Can Manufacturing Rate of >= 180,000 Can/hr | N/A | VOC capture and control system at the side seam stripe coater with a fume hood (71% capture efficiency) and the curing tunnel exhaust stack all vented to a thermal or catalytic oxidizer (70% overall control efficiency). |
| 4.3.15 | Dip Coating of Steel Joists | N/A | Use of coatings with a maximum VOC content of 3.32 lb/gal for coatings with a viscosity, as applied, of less than or equal to 45.6 centistokes at 78 F and an average dry-film thickness of less than or equal to 2.0 mils, or 2.8 lb/gal for coatings with a viscosity, as applied, of more than 45.6 centistokes at 78 For an average dry-film thickness of greater than 2.0 mils with no additional control |
| 4.3.17 | "Bright Dip" Aluminum Surface Finishing Operation | 97% capture and 70% control | N/A |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Wood Parts and Products Coating | NOx | VOC |
|---|---|---|---|
| 4.4.1 | Wood Products Coating Operation - Non-Continuous Batch Coating | N/A | Utilizing HVLP or equivalent application equipment and using coatings compliant with District Rule 4606 |
| 4.4.2 | Wood Products Coating Operation - Continuously-fed Booth, = or < 5000 square feet material coated/day | N/A | Rule 4606 compliant coatings and application equipment |
| 4.4.3 | Wood Products Coating Operation - Custom Replica Furniture, < or = 400 lb VOC/day | N/A | Use of coating(s) with a VOC content (less water and exempt compounds) as indicated, or lower:<br>- For Sanding Sealers and Clear Topcoats: 5.7 lb/gal<br>- For High-solids Stain and Pigmented Coatings: 5.0 lb/gal<br>and use of HVLP application equipment, or equivalent method, and a enclosed spray gun cleaner if using a VOC containing solvent. |
| 4.4.4 | Wood Products Coating Operation - Exterior Wooden Wall Panels for Modular Buildings | N/A | Utilizing HVLP application equipment or other application methods listed in District Rule 4606 and using coatings compliant with District Rule 4606 (only for those facilities subject to Rule 4606) |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Misc. Coating | NOx | VOC |
|---|---|---|---|
| 4.5.1 | Paper Roll-Coating - Heatset | N/A | Use of coatings/inks with a VOC content compliant with Rule 4607 (Graphic Arts)[This control is achieved-in-practice only for facilities subject to District Rule 4607] |
| 4.5.3 | Coating Operation - Fiberglass Utility Poles, = or > 90 lb/day of VOC emissions | N/A | Low VOC coatings - 10% VOC by wt, HVLP application equipment, enclosed equipment cleanup or water based detergent |
| 4.5.4 | Plastic Parts and Products Coating | N/A | The use of HVLP spray guns, an enclosed gun cleaner, and low-VOC coatings (2.8 lb VOC/gal, as applied, less water and exempt solvents) |
| 4.5.5 | Coating Operation - Small Concrete Products | N/A | Use of material(s) with a VOC content (less water and exempt compounds) as indicated, or lower:<br>- For Glossy finish: 2.8 lb/gal<br>- For Matte Finish: 1.7 lb/gal<br>- For Waterproofing Sealer: 3.3 lb/gal<br>and use of HVLP application equipment, or equivalent |
| 4.5.6 | Coating Operation - Clay-based, Cat Litter, Heat Dried | N/A | Use of low VOC coating (0.69lb/gal (less water and exempt compounds) or less) |
| 4.5.8 | Weatherproofing Coating Application (Electronic Components) | N/A | Dip coating and the use of weather proofing coatings with VOC contents of 6.9 lb/gal or less (as applied, less water and exempt compounds) |
| 4.5.9 | Vinyl Window and Patio Door Assembly Glazing Table | N/A | utilize glazing material with VOC content, excluding water and exempt compounds, equal to or less than 15 g/l (0.125 lb/gal) |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Fuel Dispensing | NOx | VOC |
|---|---|---|---|
| 4.6.1 | Motor Vehicle Gasoline Storage and Dispensing Operation | N/A | CARB certified Phase I and Phase II vapor recovery systems |
| 4.6.3 | Motor Vehicle Gasoline Storage and Dispensing Operation - Bulk plants with Diesel fuel switch loading | N/A | CARB certified 95% effective Vapor Recovery |
| 4.6.4 | Non-Motor Vehicle Fuel Storage and Dispensing Operation | N/A | CARB certified Phase I Vapor Recovery System |
| 4.6.5 | Aviation Fuel Dispensing Facility | N/A | CARB certified Phase I vapor recovery system |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Printing & Graphic Arts | NOx | VOC |
|---|---|---|---|
| 4.7.1 | Offset Lithographic Printing - Publication Printing, High-end<br><br>Graphics, Heatset using with a Drying Oven | Natural gas fuel used in the drying oven | Using low VOC fountain solutions and inks compliant with District Rule 4607 (Graphic Arts) (This control is achieved in practice only for facilities subject to Rule 4607.) |
| 4.7.2 | Offset Lithographic Printing - Non-heat set Press | N/A | Using materials with the following VOC contents: less than 5% VOC by weight for inks (less water and exempt compounds) and less than 6% by volume for fountain solutions; for high end graphics, less than 30% VOC by weight for inks (less water and exempt compounds) and less than 8% by volume for fountain solutions |
| 4.7.3 | Flexographic Printer/Gluer - Corrugated Box | N/A | The use of inks with VOC content not exceeding 0.3 lb/gal (less water and exempts solvents) and the use of adhesives not exceeding 0.06 lb/gal (less water and exempt solvents) |
| 4.7.4 | Flexographic Printer - Corrugated Boxes, High-End Graphics and Metallic Inks for Porous Substrates | natural gas fuel | The use of inks with a VOC content not exceeding 1.1 lb/gal (less water & exempt compounds) for high-end graphics and use of inks with a VOC content not exceeding 2.5 lb/gal (less water & exempt compounds) for metallic inks |
| 4.7.5 | Flexographic printing - Heatset inks on low-porosityglossy paper and plastic film | N/A | Inks with a VOC content of = or < 2.5 lb/gal (less water and exempt compounds) |
| 4.7.6 | Screen Printer with natural gas-fired dryer | N/A | Use of inks with a VOC content compliant with Rule 4607 (Graphic Arts) [This control is achieved in practice only for facilities subject to District Rule 4607] |
| 4.7.7 | Screen Print - Ultraviolet (UV) Coating with Curing Lamp(s) | N/A | UV curing unit using inks with a VOC content not to exceed 3% by weight (less water and exempt compounds). |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Printing & Graphic Arts | NOx | VOC |
|---|---|---|---|
| 4.7.9 | Flexographic Printer - High-end graphics printing on Clay coatedPaper, = or < 23 tons VOC/year | N/A | Using materials with a VOC content, less water and exempt compounds, as indicated, or lower<br>• for metallic inks: 3.3 lb/gal<br>• for non-metallic inks: 1.0 lb/gal<br>• varnish: 0.63 lb/gal<br>and practicing evaporation minimization methods, which include keeping all solvents and solvent-laden cloths/papers, not in active use, in closed containers. |
| 4.7.10 | Printing Plate Manufacturing | N/A | Use of processor solvents with a VOC content, less water and exempt compounds, of 7.3 lb/gal, or lower, and Practicing evaporation minimization methods, which include keeping all solvents and solvent-laden cloths/papers, not in active use, in closed containers. |
| 4.7.11 | Rotogravure Printing Operation | N/A | Inks with a VOC content of < 2.5 lb/gal (Less water and exempt compounds) |
| 4.7.12 | Flexographic Printing - High-end graphics, Heat-setInks, on High-Porosity Material | N/A | Use of coating(s) with a VOC content (less water and exempt compounds) as indicated, or lower:<br>- Fluorescent Inks: 2.5 lb/gal.<br>- Thermal Inks: 0.3 lb/gal.<br>- Other Inks: 2.4 lb/gal. |
| 4.7.13 | Glass and Plastic Bottle Printing – Heat-dried | N/A | Using materials with a VOC content, less water and exempt compounds, as indicated, or lower<br>• High-end graphics, screen printing: 3.3 lb/gal<br>• High-end graphics, non-screen printing: 2.5 lb/gal<br>• Non-high-end graphics: 3% by weight (UV-cured inks).<br>And practicing evaporation minimization methods, which include keeping all solvents and solvent-laden cloths/papers, not in active use, in closed containers. |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Printing & Graphic Arts | NOx | VOC |
|---|---|---|---|
| 4.7.14 | Flexographic UV Printing - High End Printing of Labels, Tags, and Forms** | N/A | Use of coating with a VOC content (less water and exempt compounds) as indicated , or lower:<br>• For UV-cured Coatings: 1% VOC by Weight, and evaporative minimization methods, which include keeping all solvents and solvent-laden cloths/papers, not in active use, in close containers. |
| 4.7.15 | Flexographic Printing - Corrugated boxes, Low-endgraphics printing, = or < 50.4 lb VOC/day | N/A | Use of coating with a VOC content (less water and exempt compounds) as indicated, or lower:<br>- 0.3 lb/gal and evaporative minimization methods, which include keeping all solvents and solvent-laden cloths/papers, not in active use, in closed containers. |
| 4.7.16 | Rotogravure Printing Operation Low Porosity Substrate - High End Graphics | N/A | inks, coatings, and adhesives with a VOC content of <= 30% (less water and exempt compounds) |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Resin, Fiberglass & Plastic Products | NOx | VOC |
|---|---|---|---|
| 4.8.1 | Polyester Resin Products - Fiberglass Boat Manufacturing = < 120 gal resin/day | N/A | Low VOC resin (< or = 35% by wt), airless spray gun or hand layup or equivalent, non-VOC containing cleanup solvents |
| 4.8.5 | Polyester Resin Products - Chop Spray, Spray, and Hand Lay-Up, < or = 600 gallons resin/day | N/A | Low-VOC resin compliant with District Rule 4684 |
| 4.8.7 | Fiberglass Products Manufacturing - Fiberglass Mat Dryerand Curing Oven | Natural gas with LPG as a secondary fuel. | 98% control efficiency |
| 4.8.8 | Polyester Resin Application - Boat & Marine Vessel Repair Operations (Pleasure Crafts Only) | N/A | use of specialty resins and gel coats containing no more than 48% monomer by weight. |
| 4.8.9 | Fiberglass Products Manufacturing - Fiberglass Mat Forming | N/A | Low VOC Resin (containing less than 0.25% formaldehyde and less than 0.45% methanol)and White water (containing less than 0.1% VOC). |
| 4.8.10 | Expandable Polystyrene (EPS) Molding Operation -Pre-expander unit, = or < 20 Tons/day | N/A | Capture and Thermal Oxidation |
| 4.8.12 | Expanded Polystyrene (EPS) Products - Reclaim Extrusion Line | N/A | 95% control efficiency |
| 4.8.13 | Polyethylene Foam Extrusion Operation | N/A | 95% control efficiency |
| 4.8.14 | Expanded Polystyrene Products - Fluff Storage Silo, = or < 18 tons of foam/day | N/A | 90% capture and 95% destruction efficiency |
| 4.8.15 | Existing Polystyrene Foam Sheet Extrusion Operation – Using VOC Blowing Agents to Produce Food Service Products. | N/A | 95% destruction efficiency |
| 4.8.17 | Polyethylene Products Manufacturing - Rotational Molding | N/A | Mold Release Agents with VOC content not exceeding 6.5 lb/gal (less water and exempt compounds). |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Resin, Fiberglass & Plastic Products | NOx | VOC |
|---|---|---|---|
| 4.8.18 | Expanded Polystyrene Foam Products - Vertical Water-quenched extruder; Food-grade products. | N/A | Total emissions of 0.94lb VOC/100 lb of raw material processed. |
| 4.8.19 | Fiberglass-reinforced Composite Products – Pultruded, heat set resin products. | N/A | Use of polyester resins with 35% monomer by weight, or less, and Use of epoxy-based resins with 1% VOC by weight, or less, and Use of a covered, resin-product cooling bath. |
| 4.8.20 | Phenolic Urethane Products - No-Bake Mold Manufacturing | N/A | VOC content of the binder not to exceed 0.07 lb VOC/lb of binder. |
| 4.8.21 | Corrosion-Resistant Polyester Resin Application - Metal Products, < 75 gallons/day | N/A | Use of corrosion-resistant resin containing no more than 48% monomer by weight, mechanical non-atomizing resin application, enclosed gun cleaner |
| 4.8.22 | Polyisocyanurate Free Rise and Restrained Rise Lines | N/A | 90% capture and 95% control of manufacturing emissions |
| 4.8.23 | Finished Product Storage Area | N/A | uncontrolled |
| 4.8.24 | Fiberglass Mold Manufacturing (Tooling) Operation | N/A | non-atomizing application for polyester resins, gel coat application equipment compliant with District Rule 4684, and tooling resins ad gel coats with a monomer content not exceeding 48% |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Adhesives | NOx | VOC |
|---|---|---|---|
| 4.9.1 | Adhesives Application Operation - Tire Retreading | N/A | Use of adhesives with a VOC content of 5.2 lb/gal (less water and exempt compounds) or less |
| 4.9.2 | Adhesive Application Operation - Rubber Parts and Products,Brush Applied | N/A | Using adhesives with a VOC content of 7.0 lb/gal or less (less water and exempt compounds) |
| 4.9.3 | Adhesive Application Process - Foam Products | N/A | Adhesives with a VOC content of = or < 1.0lb/gallon (less water and exempt compounds) |
| 4.9.4 | Adhesive Application Process - Non-Porous Materials, Specialty Contact Adhesives, Spray Application | N/A | Using adhesives with a VOC content of 540 grams/liter or less (less water and exempt compounds) until July 1, 2000. Using adhesives with a VOC content of 400 grams/liter or less (less water and exempt compounds) after July 1, 2000. |
| 4.9.5 | Adhesive Application Process - Wooden case manufacturing | N/A | Use of adhesives with a VOC content compliant with Rule 4653(Adhesives) [This is achieved in practice only for those facilities subject to District Rule 4653.] |
| 4.9.6 | Paper Carton Manufacturing - Printing and Adhesive Application | N/A | Adhesive with a VOC content of = or < 5.7 lb/gal (excluding water and exempt compounds) and Inks with a VOC content of = or < 2.5 lb/gal (excluding water and exempt compounds) |
| 4.9.7 | Corrugated PVC Sheet Products - Special Contact Adhesive, Roller Applied | N/A | PVC welding adhesive compliant with District Rule 4653 |
| 4.9.8 | Adhesive Application Process – Wooden Door Assembly, Roller applied | N/A | Use of an adhesive with a VOC content of 5.0grams/liter (less water and exempt compounds), or less. |
| 4.9.9 | Adhesive Application Process - Vinyl Door and Window Assembly, Non-Spray Applied | N/A | Use of adhesive with VOC content of 3.0 g/l (less water and exempt compounds), or less for automated adhesive application and assembly processes 2) Use of adhesive with VOC content of 76.5 g/l (less water and exempt compounds), or less for manually applied adhesive operations when assembling custom window assemblies |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Adhesives | NOx | VOC |
|---|---|---|---|
| 4.9.10 | Adhesive Application for Multi-Wall Packaging Manufacturing | N/A | Adhesives with a VOC content of <= 0.2 lb/gal (excluding water and exempt compounds) for the adhesion of plastic film to porous material adhesives with a VOC content of <= 0.13 lb/gal (excluding water and exempt compounds) for the adhesion of porous materials |
| 4.9.11 | Adhesive Application Operation - Bonding of Fiberglass Boat Hulls and Decks, Non-Atomizing Application | N/A | Use of adhesives with VOC content of 80 grams/liter or less (less water and exempt compounds) |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Cleaning & Degreasing | NOx | VOC |
|---|---|---|---|
| 4.10.2 | Cold cleaner/degreaser - Metal Products, Batch Loaded, = or < 1 gal/day solvent usage | N/A | Drainage to Minimize Carryout Emissions, high freeboard ratio |
| 4.10.3 | Parts Cleaner - Rubber Parts and Products | N/A | Use of solvents with VOC content (less water and exempt compounds) as indicated, or lower:<br>- for Natural Rubber: 6.3 lb/gal,<br>- for Nitrile, SBR, or chlorobutyl Rubber: 6.71 lb/gal,<br>- for Neoprene Rubber: 7.25 lb/gal<br>and evaporative minimization methods, which include - use of controlled flow dispensers (e.g. squeeze bottles) and - keeping all cloth/papers and solvent, which are not in active use, stored in closed containers. |
| 4.10.5 | Medical Grade Silicon Products - Wipe Cleaning Operation | N/A | Use of solvents with VOC content (less water and exempt compounds) of 7.2 lb/gal, or lower, and evaporative minimization methods, which include - use of controlled flow dispensers (e.g. squeeze bottles) and - keeping all cloth/papers and solvent, which are not in active use, stored in closed containers. |
| 4.10.6 | Metal Parts, Open-top, Powder Coating Stripping Tank | N/A | Use of solvent with a VOC Content (less water and exempt compounds)of 0.75 lb/gal, or less. |
| 4.10.7 | Metal Parts and Products Cleaning - Open-top, Heated, Vapor Degreaser | N/A | 95% control (Open top degreaser w/refrigerated freeboard chiller, part movement < 2.2 ft/sec, and holding parts in degreaser until dry, or equal) |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Misc. Manufacturing | NOx | VOC |
|---|---|---|---|
| 4.11.3 | Cardboard Box Laminator | N/A | use of water-based adhesive with a VOC content (less water and exempt compounds) of 0.021 lb/gal or less |
| 4.11.4 | Organic Liquid Storage Tanks - Non-petroleum and non-petrochemical facilities, = or < 19,800 gallons capacity | N/A | Pressure/vacuum valve set within 10% of the maximum allowable tank working pressure. |
| 4.11.6 | Railcar Unloading - Transfer of Non-petroleum Organic Liquids into Delivery Vehicles | N/A | Bottom loading with vapor recovery system |
| 4.11.7 | Solvent-Laden Towel Cleaning - Counting Station,< 950 lb towels/day | N/A | Evaporative loss minimization (Store solvent-laden towels in closed containers). |
| 4.11.10 | Circuit Board Manufacturing – Flux Application for Wave Soldering Machine | N/A | Use of flux material(s) with a VOC content of 6.3 lb/gal(less water and exempt compounds), or lower. |
| 4.11.11 | Fructose Reclamation System - Process Vent | N/A | Proper operation and maintenance of the reclamation system as recommended by the equipment manufacturer(s) |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 4.0 Evaporative Loss Sources

| BACT Code | Chemical Processing | NOx | VOC |
|---|---|---|---|
| 4.12.1 | Chemical Plants - Valves & Connectors | N/A | Leak defined as a reading of methane, in excess of 100ppmv above background when measured at a distance of one(1) cm from the potential source and an Inspection and Maintenance Program pursuant to District Rule 4451 |
| 4.12.2 | Chemical Plants Pump and Compressor Seals | N/A | Leak defined as a reading of methane, in excess of 500ppmv above background when measured at a distance of one(1) cm from the potential source and an Inspection and Maintenance Program pursuant to District Rule 4452 |
| 4.12.4 | Ethanol Fermentation Process Tanks Including: Fermentation Tanks and Beerwell Storage Tanks | N/A | 99.5% VOC emissions control efficiency (fermentation wet scrubber vented to a CO12 recovery plant with a condenser and a high pressure scrubber; or equivalent) |
| 4.12.5 | Emission Units (Excluding Wet Cake Dryer) Involved in the Ethanol Distillation and Wet Cake Process | N/A | 95% VOC emissions control efficiency |
| 4.12.6 | Ethanol Manufacturing Facility Distillers Dried Grains with Solubles (DDGS) Dryer | 33 ppmv NOx @ 3% O2 (0.04 lb-NOx/MMBtu) | 98% by weight capture and control |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 5.0 Food and Agriculture Industry

| BACT Code | Nut & Grain Processing | NOx | VOC |
|---|---|---|---|
| 5.2.6 | Feed Mill - High Moisture Grain Pelletizing & Drying Operation | 64.2 ppmv @ 3% O2 (0.077lb/MMBtu/hr ) Natural gas burner | Natural Gas fuel |
| 5.2.8 | Propylene Oxide Fumigation - Fumigation Chamber | N/A | 98% Control Efficiency |
| 5.2.10 | Wet Corn Mill - High Moisture Gluten Dryer | N/A | VOC capture and control with carbon adsorption or biofiltration system |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 5.0 Food and Agriculture Industry

| BACT Code | Cotton & Fiber Processing | NOx | VOC |
|---|---|---|---|
| 5.3.2 | Cotton Gin - Natural Gas-Fired Dryer, = or < 8 MMBtu/hr Burner | Natural gas/LPG burner(0.1 lb/MMBtu) | Natural gas/LPG fuel |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 5.0 Food and Agriculture Industry

| BACT Code | Fruit, Vegetable, Seed Processing, & Equipment | NOx | VOC |
|---|---|---|---|
| 5.4.12 | Perishable Commodity Methyl Bromide Fumigation Chamber | N/A | minimize use of fumigant (i.e. use no more than product specifications recommend); and air-tight fumigation chamber |
| 5.4.13 | Wine Storage Tank | N/A | Insulation or Equivalent, Pressure Vacuum Relief Valve (PVRV) set within 10% of the maximum allowable working pressure of the tank; "gas-tight" tank operation; and continuous storage temperature not exceeding 75 degrees F, achieved within 60 days of completion of fermentation |
| 5.4.14 | Wine Fermentation Tank | N/A | Temperature-Controlled Open Top Tank with Maximum Average Fermentation Temperature of 95 deg F |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 5.0 Food and Agriculture Industry

| BACT Code | Snack Food Processing | NOx | VOC |
|---|---|---|---|
| 5.5.4 | Polishing Operation | N/A | 95% overall control |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 5.0 Food and Agriculture Industry

| BACT Code | Misc. Processes & Equip | NOx | VOC |
|---|---|---|---|
| 5.6.1 | Yeast Fermenter | N/A | Process controls limiting ethanol formation 75% - 90% control efficiency |
| 5.6.2 | Animal Feed Supplement Manufacturing - Palm Oil & Calcium Oxide Process | N/A | 70% control efficiency |
| 5.6.3 | Animal Feed Supplements - Steam-Heated Molasses Cooker | N/A | 95% control efficiency |
| 5.6.4 | Bakery Waste Products Dryer | no determination | thermal/catalytic incineration |
| 5.6.5 | Broiler House | N/A | 19% control |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 6.0 Mineral and Biomass Products

| BACT Code | Sand & Gravel Operations | NOx | VOC |
|---|---|---|---|
| 6.1.3 | Sand Dryer - Fluidized Bed | Natural gas fuel with LPG backup | Natural gas fuel with LPG backup |
| 6.1.5 | Rotary Aggregate Dryer - Remote Location Where Commercial Natural Gas is Not Available, (< or =) 15 tons aggregate/hr or (< o r=) 22.7 MMBtu/hr burner | LPG fuel | LPG fuel |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 6.0 Mineral and Biomass Products

| BACT Code | Portland Concrete | NOx | VOC |
|---|---|---|---|
| 6.2.5 | Portland Concrete Products Processing – Roof Tile Coating, Continuous Feed Booth | N/A | Use of coating(s) with a VOC content of 0.8lb/gal (less water and exempt compounds), or lower |
| 6.2.7 | Concrete Roofing Trim Tile Mold Releasing Oil Application Operation | N/A | use of mold releasing oils with a VOC content not exceeding 0.08 lb VOC/gal (less water and exempt compounds) |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 6.0 Mineral and Biomass Products

| BACT Code | Asphaltic Concrete | NOx | VOC |
|---|---|---|---|
| 6.3.1 | Asphaltic Concrete - Drum Mix Plant, = or > 2,000 ton/day or= or > 75.6 MMBtu/hr burner | 0.088 lb/MMBtu Low-NOx burner and either natural gas or LPG as the primary fuel. | Natural gas or LPG as a primary fuel; and enclosed hot mix silos and loadout operation vented to the rotary-dryer burner. |
| 6.3.2 | Asphalt Treating Unit | N/A | 98% by weight control efficiency |
| 6.3.3 | Asphaltic Concrete Plant - Batch Mix, = or > 75 MMBtu/hr and = or > 2,000 tons/day of Asphaltic Concrete | Natural gas or LPG fuel with a low Nox burner | Natural gas or LPG fired burner |
| 6.3.5 | Asphalt Roofing Shingle Mfg. - Process Heater, = or > 8 MMBtu/hr | 30 ppmv @ 3% O2, Natural gas with LPG as backup fuel | Natural gas with LPG as backup fuel |
| 6.3.6 | Asphalt Roofing Product Mfg. - Coating Operation, >100 tons/day | N/A | 80% capture and control |
| 6.3.7 | Asphalt-Based Roofing Products - Mixer | N/A | Operating practices to minimize fugitive VOC emissions (shut off blower when not charging mixer and close hatch when not adding materials) |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 6.0 Mineral and Biomass Products

| BACT Code | Composting & Biomass | NOx | VOC |
|---|---|---|---|
| 6.4.7 | Co-Composting with Biosolids | N/A | ACTIVE PHASE negatively aerated static piles with engineered, under pile, grid aeration system vent to control device with => 80% control efficiency |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 7.0 Petroleum/Gas Industry

| BACT Code | Petroleum Production | NOx | VOC |
|---|---|---|---|
| 7.1.1 | Thermally Enhanced Oil Recovery - Steam Drive Oil Wells | N/A | Vapor control system and inspection and maintenance program with either a) Non-condensables balanced casing vent system tied into tank vapor control system or b) Non-condensables incinerated at steam generator, incinerator, or equal |
| 7.1.2 | Thermally Enhanced Oil Recovery - Small Producer, Cyclic Injected Steam Enhanced Oil Well Pilot Test, < or = 10 Cyclic Wells, < or = 180 days of Total Operation | N/A | Closed casing vents and inspection and maintenance of stuffing boxes and polish rods |
| 7.1.3 | Petroleum Production - Small Producers, Cyclic Wells, < or = 4 Cyclic Wells | N/A | uncontrolled |
| 7.1.6 | Petroleum Production - Sand Removal Basin for Heavy Crude Oil | N/A | sunscreen tarp |
| 7.1.7 | Sludge Dewatering, Various Locations | N/A | gas-tight (as defined in Rule 4623) sludge tanks and processing equipment, vented to VOC control system served by carbon adsorption (at least two carbon canisters in series) |
| 7.1.8 | Petroleum Production - Mobile Degassing Operation for StorageTank with low H2S content, using an I.C. Engine as a control device | three way catalyst | three way catalyst |
| 7.1.9 | Petroleum Production - Mobile Degassing Operation for StorageTank with low H2S content, using a Thermal Oxidizer as a control device | N/A | VOC reduced by at least 98% by weight |
| 7.1.10 | Loading Rack/Switch Loading | natural gas or LPG fired pilot and air assist | bottom loading with dry break couplers and vapor collection vented to a thermal incinerator or flare with destruction efficiency => 99% |
| 7.1.13 | Petroleum Storage Tank and Pipeline De-Gassing - Mobile Operation | N/A | 98% by weight control |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 7.0 Petroleum/Gas Industry

| BACT Code | Petroleum Production | NOx | VOC |
|---|---|---|---|
| 7.1.14 | Light Crude Oil Unloading Rack | N/A | use of dry-break couplers or equivalent on unloading lines with an average disconnect loss of no greater than 10 ml liquid per disconnect, and fugitive components subject to Rules 4409 or 4455 as applicable |
| 7.1.15 | Biodiesel/Glycerol Production Operation | N/A | 100% capture and 98% control |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 7.0 Petroleum/Gas Industry

| BACT Code | Petroleum Refining | NOx | VOC |
|---|---|---|---|
| 7.2.2 | Petroleum Refining - Valves & Connectors | N/A | Leak defined as a reading of methane, in excess of 100 ppmv above background when measured at a distance of one(1) cm from the potential source and an Inspection and Maintenance Program pursuant to District Rule 4451 |
| 7.2.3 | Petroleum Refining - Pump and Compressor Seals | N/A | Leak defined as a reading of methane, in excess of 500ppmv above background when measured at a distance of one(1) cm from the potential source and an Inspection and Maintenance Program pursuant to District Rule 4452 |
| 7.2.4 | Petroleum Refineries and Chemical Plants - Swivel Joints Handling<br><br>Volatile Organic Compounds, > 20,000 gallons/day throughput | N/A | Inspection and Maintenance program consistent with District Rule 4451 (amended 12/17/92)- 2,300 ppmv, fugitive emission rate |
| 7.2.7 | Natural Gas Processing Plant - Valves, Connectors, and Compressor and Pump Seals (Subject to Rule 4403) < or = 100 Million SCF/Day | N/A | Leak defined as a dripping rate of more than three (3) drops per minute of liquid containing VOC or as a reading of methane, in excess of 10,000 ppmv above background when measured per EPA Method 21, for all components, and an Inspection and Maintenance Program pursuant to District Rule 4409 |
| 7.2.8 | Catalyst Regeneration - Fluid Catalytic Cracking Unit | 20 ppmv @ 0% O2 (365 day rolling average) and 40 ppmv @ 0% O2 (7 day rolling average). During startup/shutdown events, operator must comply with a District approved set of workplace practices. | Good combustion practices |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 7.0 Petroleum/Gas Industry

| BACT Code | Storage Tanks | NOx | VOC |
|---|---|---|---|
| 7.3.1 | Petroleum and Petrochemical Production - Fixed Roof OrganicLiquid Storage or Processing Tank, < 5,000 bbl Tank capacity ** | N/A | PV-vent set to within 10% of maximum allowable pressure |
| 7.3.2 | Petroleum and Petrochemical Production - Fixed Roof OrganicLiquid Storage or Processing Tank, = or > 5,000 bbl Tank capacity ** | N/A | 99% Control efficiency |
| 7.3.3 | Petroleum and Petrochemical Production - Floating Roof Organic Liquid Storage or Processing Tank, = or > 471 bbl Tank capacity, = or > 0.5 psia TVP | N/A | 95% control |

# San Joaquin Valley
# Unified Air Pollution Control District

## Rule 3170 Clean Unit 2006-2010 Achieved in Practice BACT Determinations

### Main Category: 8.0 Miscellaneous Sources

| BACT Code | Specialty Sources and Operations | NOx | VOC |
|---|---|---|---|
| 8.3.3 | Standby LPG Fuel Supply System - = or > 30 MMBtu/hr | 0.068 lb/MMBtu | 99.9% Control efficiency |
| 8.3.5 | Satellite thruster testing operation | Chemical packed scrubber serving nitrogen tetroxide transfer operation | N/A |
| 8.3.12 | Helicopter Engine Test Cell | Use of JP-8 fuel and good combustion practices. | Use of JP-8 fuel and good combustion practices. |
| 8.3.17 | Sulfur Powder Manufacturing (<= 4 MMBtu/hr Gas Generator) | 50 ppmv @ 11% O2 natural gas-fired inert gas pneumatic conveyance system | natural gas fuel |
| 8.3.20 | On-line Chemical Vapor Deposition Process | N/A | Use of thermal oxidizer |

BAY AREA AIR QUALITY MANAGEMENT DISTRICT (/)

A HEALTHY BREATHING ENVIRONMENT FOR EVERY BAY AREA RESIDENT



# BACT / TBACT Workbook

ew the BACT/TBACT Workbook, a resource for guiding permit applicants and Air District staff through one ep of the New Source Review permitting process.

e Air District's Best Available Control Technology and Best Available Control Technology for Toxics Workbook (PDF) is designed provide guidance on the BACT (/~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation efinition-of-bact-tbact.pdf?la=en) (83 Kb PDF, 2 pgs, revised 06/09/15) and TBACT (/~/media/files/engineering/bact-tbact-workshop act-tbact-policy-and-implementation/definition-of-bact-tbact.pdf?la=en) requirements for commonly permitted sources subject to w Source Review in the Bay Area. Each source subject to these requirements in analyzed on a "case by case" basis to termine compliance with these requirements and not all cases are covered by the guidance.

is workbook serves as a guide for permit applicants, Air District engineers, and others interested in understanding emissions its, control devices, and techniques needed to meet the BACT (/~/media/files/engineering/bact-tbact-workshop/bact-tbact-licy-and-implementation/definition-of-bact-tbact.pdf?la=en) (83 Kb PDF, 2 pgs, revised 06/09/15) New Source Review Rule (/rules-d-compliance/current-rules)and TBACT (/~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation efinition-of-bact-tbact.pdf?la=en) New Source Review of Toxic Air Contaminants Rule (/rules-and-compliance/current-rules).

# ection 1: BACT/TBACT Policy and Implementation

roduction (/~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation/introduction.pdf?la=en) (88 PDF, 3 pgs, revised 06/09/15)
finition of BACT and TBACT (/~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation/definition-bact-tbact.pdf?la=en) (83 Kb PDF, 2 pgs, revised 06/09/15)
licy and Implementation Procedure (/~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation olicy-and-implementation-procedure.pdf?la=en) (115 Kb PDF, 6 pgs, revised 06/09/15)
er's Guide to BACT/TBACT Workbook (/~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation ser-guide.pdf?la=en) (84 Kb PDF, 2 pgs, revised 06/09/15)
gure 1: Using the Workbook: Step A (/~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation gure_01.pdf?la=en) (86 Kb PDF, 1 pg, revised 06/09/15)
gure 2: Using the Workbook: Step B (/~/media/files/engineering/bact-tbact-workshop/bact-tbact-policy-and-implementation gure_02.pdf?la=en) (91 Kb PDF, 1 pg, revised 06/09/15)

# ection 2: Combustion Sources

## oilers, Commercial, Industrial, Institutional

iler, Rental: On-site < 6 consecutive months (/~/media/files/engineering/bact-tbact-workshop/combustion 3-1.pdf?la=en) (94 Kb PDF, 1 pg, revised 06/11/15)
iler: 5 to <33.5 MMBtu/hr (/~/media/files/engineering/bact-tbact-workshop/combustion/17-1-1.pdf?la=en) (19 Kb PDF, 2 pgs, ised 06/11/15)
iler: ≥33.5 to <50 MMBtu/hr (/~/media/files/engineering/bact-tbact-workshop/combustion/17-2-1.pdf?la=en) (19 Kb PDF, 2 pgs, ised 06/11/15)
iler: ≥50 MMBtu/hr (/~/media/files/engineering/bact-tbact-workshop/combustion/17-3-1.pdf?la=en) (21 Kb PDF, 2 pgs, revised 11/15)
iler, CO - Refinery (/~/media/files/engineering/bact-tbact-workshop/combustion/17-4-1.pdf?la=en) (95 Kb PDF, 1 pg, revised 11/15)
iler or Water Heater - Landfill or Digester Gas Fired (/~/media/files/engineering/bact-tbact-workshop/combustion 7-5-1.pdf?la=en) (95 Kb PDF, 1 pg, revised 05/24/16)
iler - Municipal Refuse Fired (/~/media/files/engineering/bact-tbact-workshop/combustion/17-8-1.pdf?la=en) (94 Kb PDF, 1 pg, ised 06/11/15)
iler - Wood Fired (/~/media/files/engineering/bact-tbact-workshop/combustion/17-9-1.pdf?la=en) (94 Kb PDF, 1 pg, revised 11/15)

## ternal Combustion Engines

C. Engine - Compression Ignition, Prime > 50 hp (/~/media/files/engineering/bact-tbact-workshop/combustion

# *BAY AREA AIR QUALITY MANAGEMENT DISTRICT*
## *Best Available Control Technology (BACT) Guideline*

### *Source Category*

| | | | |
|---|---|---|---|
| Source: | *Water Treating - Oil/Water Separator* | Revision: | *1* |
| | | Document #: | *177.1.1* |
| Class: | *<250 Gallons/min* | Date: | *10/04/91* |

### *Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *Vapor-tight fixed cover and vented to vapor recovery system w/ combined collection and destruction/recovery efficiency of ≥95%*[a]<br>2. *Vapor-tight fixed cover totally enclosing the separator tank liquid contents*[a] | 1. *BAAQMD Approved Design and Operation*[a]<br>2. *BAAQMD Approved Design and Operation*[a] |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |

### *References*

*a. BAAQMD*

# *BAY AREA AIR QUALITY MANAGEMENT DISTRICT*
## *Best Available Control Technology (BACT) Guideline*

### *Source Category*

| | | | |
|---|---|---|---|
| Source: | *Water Treating - Oil/Water Separator* | Revision: | *1* |
| | | Document #: | *177.2.1* |
| Class: | *≥250 Gallons/min* | Date: | *10/04/91* |

### *Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *n/d*<br>2. *Vapor-tight fixed cover and vented to vapor recovery system w/ combined collection and destruction/recovery efficiency of ≥95%*[a] | 1. *n/d*<br>2. *BAAQMD Approved Design and Operation*[a] |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |

### *References*

*a. BAAQMD*

# *BAY AREA AIR QUALITY MANAGEMENT DISTRICT*
## *Best Available Control Technology (BACT) Guideline*

### *Source Category*

| | | | |
|---|---|---|---|
| Source: | *Water Treating - Sour Water Stripping* | Revision: | *1* |
| | | Document #: | *178.1* |
| Class: | *All* | Date: | *01/10/92* |

### *Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/d*<br>2. *Steam strip, condense, and vent to sulfur recovery unit, w/ overall removal/recovery ≥95% of the $H_2S$ from the process water stream*[b] | 1. *n/d*<br>2. *BAAQMD Approved Design and Operation*[b] |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |

### *References*

*b. BAAQMD A #5258*

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT
## Best Available Control Technology (BACT) Guideline

### Source Category

| | | | |
|---|---|---|---|
| Source: | *Flare - Refinery* | Revision: | *2* |
| | | Document #: | *82.1* |
| Class: | *All* | Date: | *06/30/95* |

### Determination

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *Ground level flare, enclosed, steam- or air-assisted, w/ staged combustion; POC destruction efficiency ≥98.5% (≥0.6 sec. retention time at ≥1400°F); use of natural gas or LPG as pilot fuel. Flare to be operated only during periods of emergency plant upset or breakdown; routine venting of process gases to be routed to fuel gas recovery system*[b,T]<br>2. *Elevated flare, steam- or air-assisted, w/staged combustion; POC destruction efficiency ≥98%; use of natural gas or LPG as pilot fuel. Flare to be oprated only during periods of emergency plant upset or breakdown; routine venting of process gases to be routed to fuel gas recovery system*[a,b,T] | 1. *BAAQMD Approved Design and Operation*[a,T]<br>2. *BAAQMD Approved Design and Operation*[a,T] |
| NOx | 1. *n/d*<br>2. *Staged combustion as for POC above*[a,T] | 1. *n/d*<br>2. *BAAQMD Approved Design and Opration*[a] |
| $SO_2$ | 1. *n/d*<br>2. *n/d* | 1. *n/d*<br>2. *n/d* |
| CO | 1. *n/d*<br>2. *Same as for POC above*[a] | 1. *n/d*<br>2. *BAAQMD Approved Design and Operation*[a] |
| $PM_{10}$ | 1. *n/d*<br>2. *Same as for POC above*[a,T] | 1. *n/d*<br>2. *BAAQMD Approved Design and Operation*[a,T] |
| NPOC | 1. *n/a* | 1. *n/a* |

| | | |
|---|---|---|
| | 2. *n/a* | 2. *n/a* |

## *References*


*a. BAAQMD*
*b. CARB/CAPCOA Clearinghouse*
*T. TBACT*

# *BAY AREA AIR QUALITY MANAGEMENT DISTRICT*
## *Best Available Control Technology (BACT) Guideline*

### *Source Category*

| | | | |
|---|---|---|---|
| Source: | *Flanges* | Revision: | *3* |
| | | Document #: | *78.1* |
| Class: | *All* | Date: | *01/18/06* |

### *Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *n/d*<br>2. *100 ppm expressed as methane measured using EPA Reference Method 21*[a,T] | 1. *n/d*<br>2. *Graphitic Gaskets and BAAQMD Approved Inspection and Maintenance*[a,T] |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *n/d*<br>2. *100 ppm expressed as methane measured using EPA Reference Method 21*[a,T] | 1. *n/d*<br>2. *Graphitic Gaskets and BAAQMD Approved Inspection and Maintenance*[a,T] |

### *References*

*a. BAAQMD*
*T. TBACT*

# *BAY AREA AIR QUALITY MANAGEMENT DISTRICT*
## *Best Available Control Technology (BACT) Guideline*

### *Source Category*

| | | | |
|---|---|---|---|
| Source: | *Pressure Relief Valves, Emergency* | Revision: | *4* |
| | | Document #: | *135.1* |
| Class: | *All* | Date: | *06/30/95* |

### *Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *Rupture disk w/ vent to fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency ≥98%*[a,T]<br>2. *Vent to fuel gas recovery system, furnace, or flare with a recovery/destruction efficiency ≥98%*[a,T] | 1. *BAAQMD Approved Design and Operation*[a,T]<br>2. *BAAQMD Approved Design and Operation*[a,T] |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *Rupture disk w/ vent to carbon adsorption system or vapor recovery system with a capture/recovery efficiency ≥90%*[a,T]<br>2. *Vent to carbon adsorption system or vapor recovery system with a capture/recovery efficiency ≥90%*[a,T] | 1. *BAAQMD Approved Design and Operation*[a,T]<br>2. *BAAQMD Approved Design and Operation*[a,T] |

### *References*

*a. BAAQMD*
*T. TBACT*

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT**
**Best Available Control Technology (BACT) Guideline**

## Source Category

| | | | |
|---|---|---|---|
| Source: | *Process Valves* | Revision: | *3* |
| | | Document #: | *136.1* |
| Class: | *All* | Date: | *01/18/06* |

## Determination

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *n/d*<br>2. *100 ppm expressed as methane measured using EPA Reference Method 21*[a,T] | 1. *n/d*<br>2. *Bellows Valves; Diaphragm Valves; Quarter Turn Valves; Live Loaded Valves; or Other Low-Emission Valves; Each w/BAAQMD Approved Inspection and Maintenance*[a,T] |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *n/d*<br>2. *100 ppm expressed as methane measured using EPA Reference Method 21*[a,T] | 1. *n/d*<br>2. *Bellows Valves; Diaphragm Valves; Quarter Turn Valves; Live Loaded Valves; or Other Low-Emission Valves; Each w/BAAQMD Approved Inspection and Maintenance*[a,T] |

## References

*a. BAAQMD*
*T. TBACT*

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT
## Best Available Control Technology (BACT) Guideline

### Source Category

| | | | |
|---|---|---|---|
| Source: | *Pumps* | Revision: | *4* |
| | | Document #: | *137.1* |
| Class: | *All* | Date: | *01/18/06* |

### Determination

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *100 ppm expressed as methane measured using EPA Reference Method 21*[a,T]<br>2. *500 ppm expressed as methane measured using EPA Reference Method 21*[a,T] | 1. *Double Mechanical Seals w/ Barrier Fluid; Magnetically Coupled Pumps; Canned Pumps; Magnetic Fluid Sealing Technology; or Gas Seal System Vented to Thermal Oxidizer or Other BAAQMD Approved Control Device; all w/BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T]<br>2. *Double Mechanical Seals w/ Barrier Fluid, and BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T] |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *100 ppm expressed as methane measured using EPA Reference Method 21*[a,T]<br>2. *500 ppm expressed as methane measured using EPA Reference Method 21*[a,T] | 1. *Double Mechanical Seals w/ Barrier Fluid; Magnetically Coupled Pumps; Canned Pumps; or Magnetic Fluid Sealing Technology; all w/ BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T]<br>2. *Double Mechanical Seals w/ Barrier Fluid, and BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T] |

## *References*

*a. BAAQMD*
*b. EPA NSPS: 40 CFR 60 Subpart GGG (Petroleum Refineries) and 40 CFR 60 Subpart VV (Chemical Plants)*
*T. TBACT*

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT
## Best Available Control Technology (BACT) Guideline

### Source Category

| | | | |
|---|---|---|---|
| Source: | *Compressors* | Revision: | *4* |
| | | Document #: | *48B.1* |
| Class: | *All* | Date: | *01/18/06* |

### Determination

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *100 ppm expressed as methane measured using EPA Reference Method 21*[a,T]<br>2. *500 ppm expressed as methane measured using EPA Reference Method 21*[a,T] | 1. *Double Mechanical Seals w/ Barrier Fluid; or Gas Seal System Vented to a Thermal Oxidizer or Other BAAQMD Approved Control Device; all w/ BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T]<br>2. *Double Mechanical Seals w/ Barrier Fluid, and BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T] |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *100 ppm expressed as methane measured using EPA Reference Method 21*[a,T]<br>2. *500 ppm expressed as methane measured using EPA Reference Method 21*[a,T] | 1. *Double Mechanical Seals w/ Barrier Fluid; or Gas Seal System Vented to BAAQMD Approved Control Device; all w/ BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T]<br>2. *Double Mechanical Seals w/ Barrier Fluid, and BAAQMD Approved Quarterly Inspection and Maintenance Program*[a,b,T] |

### References

*a. BAAQMD*
*b. EPA NSPS: 40 CFR 60 Subpart GGG (Petroleum Refineries) and 40 CFR 60 Subpart VV (Chemical Plants)*
*T. TBACT*

# *BAY AREA AIR QUALITY MANAGEMENT DISTRICT*
## *Best Available Control Technology (BACT) Guideline*

### *Source Category*

| | | | |
|---|---|---|---|
| Source: | *Sulfur Recovery Plant* | Revision: | *1* |
| | | Document #: | *169.1* |
| Class: | *All* | Date: | *01/10/92* |

### *Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *Sulfur recovery unit w/ >95% conversion, two tail gas treating units (one standby) to treat gas to <10 ppm $H_2S$, and standby incinerator*[b]<br>2. *Sulfur recovery unit w/ >95% conversion, tail gas treating unit to treat gas to <10 ppm $H_2S$, and standby incinerator*[b] | 1. *BAAQMD Approved Design and Operation*[b]<br>2. *BAAQMD Approved Design and Operation*[b] |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |

### *References*

*b. BAAQMD A #5258*

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT**
**Best Available Control Technology (BACT) Guideline**

## Source Category

| | | | |
|---|---|---|---|
| Source: | ***Storage tank - External Floating Roof, Organic Liquids*** | Revision: | *2* |
| | | Document #: | *167.1.2* |
| Class: | ***All*** | Date: | ***09/19/2011*** |

## Determination

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *Vapor recovery system w/ an overall system efficiency ≥98%*[a,T]<br><br>2. *BAAQMD Approved roof w/ liquid mounted primary seal and zero gap secondary seal, all meeting design criteria of Reg. 8, Rule 5. Also, no ungasketed roof penetrations, no slotted pipe guide pole unless equipped with float and wiper seals, and no adjustable roof legs unless fitted w/ vapor seal boots or equivalent*[a,T]<br><br>*Additionally, a dome is required for tanks that meet all of the following: 1) capacity greater than or equal to 19,815 gallons 2) located at a facility with greater than 20 tpy VOC emissions since the year 2000 and 3) storing a material with a vapor pressure equal to or greater than 3 psia (except for crude oil tanks that are permitted to contain more than 97% by volume crude oil).*[b] | 1. *Thermal Incinerator; or Carbon Adsorber; or Refrigerated Condenser; or BAAQMD approved equivalent*[a,T]<br>2. *BAAQMD Approved Roof and Seal Design*[a,T] |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *Vapor recovery system w/ an overall system efficiency ≥98%*[a,T]<br><br>2. *Same as for POC above* | 1. *Carbon Adsorber; or Refrigerated Condenser; or BAAQMD approved equivalent*[a,T]<br>2. *BAAQMD Approved Roof and Seal Design*[a,T] |

## References


*a. BAAQMD*
*T. TBACT*
*b. BAAQMD Application 22722, SCAQMD Regulation 1178 (1/1/04)*

# *BAY AREA AIR QUALITY MANAGEMENT DISTRICT*
## *Best Available Control Technology (BACT) Guideline*

### *Source Category*

| | | | |
|---|---|---|---|
| Source: | ***Storage Tank - Fixed Roof, Organic Liquids*** | Revision: | *2* |
| | | Document #: | *167.2.1* |
| Class: | ***<20,000 Gallons*** | Date: | *03/03/95* |

### *Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *n/d*<br>2. *Vapor recovery system w/ an overall system efficiency ≥95%*[a,T] | 1. *n/d*<br>2. *Vapor Balance; or Carbon Adsorber; or Refrigerated Condenser; or Incinerator; or BAAQMD approved equivalent*[a,T] |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *n/d*<br>2. *Vapor recovery system w/ an overall system efficiency ≥95%*[a,T] | 1. *n/d*<br>2. *Vapor Balance; or Carbon Adsorber; or Refrigerated Condenser; or BAAQMD approved equivalent*[a,T] |

### *References*

*a. BAAQMD*
*T. TBACT*

# *BAY AREA AIR QUALITY MANAGEMENT DISTRICT*
## *Best Available Control Technology (BACT) Guideline*

### *Source Category*

| | | | |
|---|---|---|---|
| Source: | *Storage Tank - Fixed Roof, Organic Liquids* | Revision: | *2* |
| | | Document #: | *167.3.1* |
| Class: | *≥20,000 Gallons* | Date: | *03/03/95* |

### *Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *n/d*<br>2. *Vapor recovery system w/ an overall system efficiency ≥98%*[a,T] | 1. *n/d*<br>2. *Thermal Incinerator; or Carbon Adsorber; or Refrigerated Condenser; or BAAQMD approved equivalent*[a,T] |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *n/d*<br>2. *Vapor recovery system w/ an overall system efficiency ≥98%*[a,T] | 1. *n/d*<br>2. *Carbon Adsorber; or Refrigerated Condenser; or BAAQMD approved equivalent*[a,T] |

### *References*

*a. BAAQMD*
*T. TBACT*

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT
## Best Available Control Technology (BACT) Guideline

### Source Category

| | | | |
|---|---|---|---|
| Source: | *Storage Tank - Internal Floating Roof, Organic Liquids* | Revision: | *2* |
| | | Document #: | *167.4.1* |
| Class: | All | Date: | *03/03/95* |

### Determination

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *Vapor recovery system w/ an overall system efficiency ≥98%*[a,T]<br>2. *BAAQMD Approved roof w/ liquid mounted primary seal and zero gap secondary seal, all meeting design criteria of Reg. 8, Rule 5. Also, no ungasketed roof penetrations, no slotted pipe guide pole unless equipped with float and wiper seals, and no adjustable roof legs unless fitted w/ vapor seal boots or equivalent*[a,T] | 1. *Thermal Incinerator; or Carbon Adsorber; or Refrigerated Condenser; or BAAQMD approved equivalent*[a,T]<br>2. *BAAQMD Approved Roof and Seal Design*[a,T] |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *Vapor recovery system w/ an overall system efficiency ≥98%*[a,T]<br>2. *Same as for POC above* | 1. *Carbon Adsorber; or Refrigerated Condenser; or BAAQMD approved equivalent*[a,T]<br>2. *BAAQMD Approved Roof and Seal Design*[a,T] |

### References

*a. BAAQMD*
*T. TBACT*

# *BAY AREA AIR QUALITY MANAGEMENT DISTRICT*
## *Best Available Control Technology (BACT) Guideline*

### *Source Category*

| | | | |
|---|---|---|---|
| Source: | *Degreaser - Cold Solvent Cleaner* | Revision: | *2* |
| | | Document #: | *54.1* |
| Class: | *All* | Date: | *03/10/95* |

### *Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *Compliance w/ BAAQMD Reg. 8, Rule 16 for all solvents, and equipped with cover, freeboard ratio ≥ 1, and either: a) water layer (1 inch); or b) covering while in use*[a,b,T]<br>2. *Compliance w/ BAAQMD Reg. 8, Rule 16 for all solvents, and equipped with cover and freeboard ratio ≥0.75*[a,b,T] | 1. *BAAQMD Approved Design and Operation*[b,T]<br>2. *BAAQMD Approved Design and Operation*[b,T] |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *Same as for POC above*<br>2. *Same as for POC above* | 1. *Same as for POC above*<br>2. *Same as for POC above* |

### *References*


*a. BAAQMD*
*b. MACT Standard*
*c. TBACT*

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT**
**Best Available Control Technology (BACT) Guideline**

**Source Category**

| | | | |
|---|---|---|---|
| **Source:** | **Boiler** | **Revision:** | **4** |
| | | **Document #:** | **17.1.1** |
| **Class:** | **5 MMBtu/hr to < 33.5 MMBtu/hr Heat Input** | **Date:** | **08/04/10** |

**Determination**

| Pollutant | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| **POC** | 1. n/d<br>2. n/s | 1. n/d<br>2. Good Combustion Practice[a] |
| **NOx** | 1. n/d<br>2. n/d | 1. Low $NO_x$ Burners + Flue Gas Recirculation + Selective Catalytic Reduction[a]<br>2. Low $NO_x$ Burners + Flue Gas Recirculation[a] |
| **$SO_2$** | 1. Natural Gas or Treated Refinery Gas Fuel w/ ≤.50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur [a]<br>2. Natural Gas or Treated Refinery Gas Fuel w/ ≤100 ppmv Total Reduced Sulfur [a] | 1. Fuel Selection[Error! Reference source not found.]<br>2. Fuel Selection[Error! Reference source not found.] |
| **CO** | 1. 50 ppmv @ 3% $O_2$ Dry [a,e]<br>2. 50 ppmv @ 3% $O_2$ Dry, for Firetube Boilers[f] 100 ppmv @ 3% $O_2$ Dry, for Watertube Boilers [a,e] | 1. Good Combustion Practice [a]<br>2. Good Combustion Practice [a] |
| **$PM_{10}$** | 1. n/d<br>2. Natural Gas or Treated Refinery Gas Fuel [a] | 1. n/d<br>2. Fuel Selection[a] |
| **NPOC** | 1. n/a<br>2. n/a | 1. n/a<br>2. n/a |

## References

a. BAAQMD
d. $NO_x$ determination by BAAQMD source Test method ST-13A or B (average of three 30-minute sampling runs), or BAAQMD approved equivalent.
e. CO determination by BAAQMD Source Test Method ST-6 (average of three 30 minute sampling runs), or BAAQMD approved equivalent.
f. CO 100 ppmv allowance for firetube boilers meeting the 20 ppmv $NO_x$ standard.

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT**
**Best Available Control Technology (BACT) Guideline**

**Source Category**

| | | | |
|---|---|---|---|
| **Source:** | **Boiler** | **Revision:** | **4** |
| | | **Document #:** | **17.2.1** |
| **Class:** | **≥33.5 MMBtu/hr to <50 MMBtu/hr Heat Input** | **Date:** | **08/04/10** |

**Determination**

| Pollutant | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| **POC** | 1. n/d<br>2. n/s | 1. n/d<br>2. Good Combustion Practice[a] |
| **NOx** | 1. n/d<br>2. n/d | 1. Low $NO_x$ Burners + Flue Gas Recirculation + Selective Catalytic Reduction[a]<br>2. Low $NO_x$ Burners + Flue Gas Recirculation[a] |
| **$SO_2$** | 1. Natural Gas or Treated Refinery Gas Fuel w/ ≤.50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur [a]<br>2. Natural Gas or Treated Refinery Gas Fuel w/ ≤100 ppmv Total Reduced Sulfur [a] | 1. Fuel Selection[a]<br>2. Fuel Selection[a] |
| **CO** | 1. n/d<br>2. 100 ppmv @ 3% $O_2$ Dry[a,d] | 1. n/d<br>2. Good Combustion Practice[a] |
| **$PM_{10}$** | 1. n/d<br>2. Natural Gas or Treated Refinery Gas Fuel [a] | 1. n/d<br>2. Fuel Selection[a] |
| **NPOC** | 1. n/a<br>2. n/a | 1. n/a<br>2. n/a |

**References**

| | |
|---|---|
| a. | BAAQMD |
| c. | $NO_x$ determination by BAAQMD Source Test Method ST-13A or B (average of three 30-minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent. |
| d. | CO determination by BAAQMD Source Test Method ST-6 (average of three 30 minute sampling runs); or Continuous Emission Monitor (3-hour average), or BAAQMD approved equivalent. |

**BAY AREA AIR QUALITY MANAGEMENT DISTRICT**
**Best Available Control Technology (BACT) Guideline**

**Source Category**

| | | | |
|---|---|---|---|
| **Source:** | **Boiler** | **Revision:** | **5** |
| | | **Document #:** | **17.3.1** |
| **Class:** | **≥ 50 MMBtu/hr Heat Input** | **Date:** | **08/04/10** |

**Determination**

| Pollutant | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| **POC** | 1. n/d<br>2. n/s | 1. n/d[f]<br>2. Good Combustion Practice[a] |
| **NOx** | 1. n/d[b, c, d]<br>2. n.d[a, c, d] | 1. Selective Catalytic Reduction (SCR) + Low $NO_x$ Burners (LNB) + Flue Gas Recirculation (FGR) [b, c, d]<br>2. Ultra Low $NO_x$ Burners (ULNB) + FGR [a, c, d] |
| **$SO_2$** | 1. Natural Gas or Treated Refinery Gas Fuel w/ <.50 ppmv Hydrogen Sulfide and <100 ppmv Total Reduced Sulfur [a,c]<br>2. Natural Gas or Treated Refinery Gas Fuel w/ <100 ppmv Total Reduced Sulfur [a,c] | 1. Fuel Selection[a,c]<br>2. Fuel Selection[a,c] |
| **CO** | 1. 10 ppmv @ 3% $O_2$ Dry [f]<br>2. 50 ppmv @ 3% $O_2$ Dry [a, c, e] | 1. Oxidation Catalyst [f]<br>2. Good Combustion Practice in Conjunction with SCR System or Ultra Low $NO_x$ Burners and FGR [a, c, e] |
| **$PM_{10}$** | 1. n/d<br>2. Natural Gas or Treated Refinery Gas Fuel [a,c] | 1. n/d<br>2. Fuel Selection[a,c] |
| **NPOC** | 1. n/a<br>2. n/a | 1. n/a<br>2. n/a |

**References**

| | |
|---|---|
| a. | BAAQMD |
| b. | SCAQMD. Cost effectiveness evaluations shall be based on emissions from firing primary fuels but not emergency backup fuels. |
| c. | BACT limits apply to all fuels except for emergency backup fuel oil used during natural gas curtailment. For emergency backup fuel oil:<br>BACT(1) for NOx and CO (achieved using LNB+FGR+SCR and GCP) is 25 ppmvd NOx @3%O2, 100 ppmvd CO @3%O2, and 5 ppmvd NH3 @ 3%O2<br>BACT(2) for NOx and CO (achieved using ULNB+FGR and GCP) is 40 ppmvd $NO_x$ @3%O2 and 100 ppmvd CO @#%O2<br>BACT(2) for SO2 and PM10 is the use of low sulfur fuel with < 0.05 wt% S<br>BACT(2) for POC is GCP |
| d. | NOx determination by Continuous Emission Monitor (3-hr average), or BAAQMD approved equivalent. |
| e. | CO determination by Continuous Emission Monitor (3-hr average), or BAAQMD approved equivalent. |
| f. | The BACT(1) CO limit does not apply to boilers smaller than 250 MMBTU/hr unless an oxidation catalyst is found to be cost effective for TBACT or POC Control. |

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT
## Best Available Control Technology (BACT) Guideline

**Source Category**

| | | | |
|---|---|---|---|
| **Source:** | **IC Engine – Compression Ignition, Stationary Prime; non-Agricultural** | **Revision:** | **6** |
| | | **Document #:** | **96.1.4** |
| **Class:** | **> 50 BHP Output** | **Date:** | **04/13/2009** |

**Determination**

| Pollutant | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| **POC** | 1. 50% reduction of current tier[a,b] standard for POC.<br>2. Current tier[a,b] standard for POC at applicable horsepower rating. | 1. Catalytic oxidation combined with current POC certified engine.[a,b]<br>2. Current POC certified engine.[a,b] |
| **NOx** | 1. 85% reduction of current tier[a,b] standard for NOx.<br>2. Current tier[a,b] standard for NOx at applicable horsepower rating. | 1. Selective catalytic reduction (SCR) + current NOx certified engine.[a,b]<br>2. Current NOx certified engine.[a,b] |
| **$SO_2$** | 1. n/s<br>2. Fuel sulfur content not to exceed 0.0015% (wt) or 15 ppm. | 1. n/s<br>2. CARB Diesel Fuel (Ultra Low Sulfur Diesel). |
| **CO** | 1. 50% reduction of current tier[a,b] standard for CO.<br>2. 2.75 g/bhp-hr [319 ppmvd @ 15% $O_2$][d] | 1. Catalytic oxidation combined with current CO certified engine.[a,b]<br>2. Any engine demonstrated or certified to meet 2.75 g/bhp-hr. |
| **$PM_{10}$** | 1. n/s<br>2. 0.01 g/bhp-hr or equiv[c] technology.[e]<br>3. TBACT: 0.01 g/bhp-hr or equivalent[c] technology[e]. | 1. n/s<br>2. Any engine/technology verified or certified to achieve 0.01 g/bhp-hr.[c]<br>3. (See 2., above)[c] |
| **NPOC** | 1. n/s<br>2. n/s | 1. n/s<br>2. n/s |

**References**

a. Current tier standard: The current CARB or EPA off-road tier standard for the pollutant of concern within the appropriate horsepower range. Where NMHC + NOx is listed (with no individual standards for NOx or NMHC) as the standard, the portions may be considered 95% NOx and 5% NMHC. For the purposes of determining BACT NMHC = POC. Any engine which has been certified or demonstrated to meet the current year tier standard may be considered a current certified engine for that pollutant.

b. An engine which does not meet the current EPA or CARB off-road tier standard may represent BACT2, providing 1) the engine met the most stringent EPA Tier Standard in effect prior to the Tier change for that horsepower rating, and 2) the permit application is submitted within 6 months of the effective date of the Tier change. [Source: California Health & Safety Code Section 93116.3(b)(7)]

c. Compliance with 0.01 g/bhp-hr may be demonstrated by use of *Alternative Compliance Demonstration*, specified in California Health & Safety Code Section 93115.13(f) [Stationary CI Engine ATCM].

d. Previous BACT determination dated 01/11/02.

e. Specified because not all BAAQMD-defined stationary engines are subject to the Stationary ATCM.

## Overview of Off-Road Compression Ignition Engine Certification Standards in g/bhp-hr (g/kW-hr)[1]

| Engine | Tier 1[2] | | | | | Tier 2 | | | | Tier 3 | | | | Tier 4 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HP (KW) | HC | NOx | CO | PM | Years | NMHC + NOx | CO | PM | Years | NMHC + NOx | CO | PM | Years | NMHC + NOx | NMHC | NOx[3] | CO | PM | Years |
| 50 <75 (37<56) | | 6.9 (9.2) | | | 1998 - 2003 | 5.6 (7.5) | 3.7 (5.0) | 0.30 (0.40) | 2004 - 2007 | 3.5 (4.7) | 3.7 (5.0) | 0.22 (0.30) | 2008 - 2012 | 3.5 (4.7) | | | 3.7 (5.0) | 0.02 (0.03) | 2013+ |
| 75<100 (56<75) | | 6.9 (9.2) | | | 1998 - 2003 | 5.6 (7.5) | 3.7 (5.0) | 0.30 (0.40) | 2004 - 2007 | 3.5 (4.7) | 3.7 (5.0) | 0.30 (0.40) | 2008 - 2011 | 3.5 (4.7) | 0.14 (0.19) | 0.30-2.5 (0.40-3.4) | 3.7 (5.0) | 0.01 (0.02) | 2012 - 2013 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 0.30 (0.40) | 3.7 (5.0) | 0.01 (0.02) | 2014+ |
| 100<175 (75<130) | | 6.9 (9.2) | | | 1997 - 2002 | 4.9 (6.6) | 3.7 (5.0) | 0.22 (0.30) | 2003 - 2006 | 3.0 (4.0) | 3.7 (5.0) | 0.22 (0.30) | 2007 - 2011 | 3.0 (4.0) | 0.14 (0.19) | 0.30-2.5 (0.40-3.4) | 3.7 (5.0) | 0.01 (0.02) | 2012 - 2013 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 0.30 (0.40) | 3.7 (5.0) | 0.01 (0.02) | 2014+ |
| 175<300 (>130<225) | 0.97 (1.3) | 6.9 (9.2) | 8.5 (11.4) | 0.40 (0.54) | 1996 - 2002 | 4.9 (6.6) | 2.6 (3.5) | 0.15 (0.20) | 2003 - 2005 | 3.0 (4.0) | 2.6 (3.5) | 0.15 (0.20) | 2006 - 2010 | 3.0 (4.0) | 0.14 (0.19) | 0.30-1.5 (0.40-2.0) | 2.6 (3.5) | 0.01 (0.02) | 2011 - 2013 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 0.30 (0.40) | 2.6 (3.5) | 0.01 (0.02) | 2014+ |
| 300<600 (225<450) | 0.97 (1.3) | 6.9 (9.2) | 8.5 (11.4) | 0.40 (0.54) | 1996 - 2000 | 4.8 (6.4) | 2.6 (3.5) | 0.15 (0.20) | 2001 - 2005 | 3.0 (4.0) | 2.6 (3.5) | 0.15 (0.20) | 2006 - 2010 | 3.0 (4.0) | 0.14 (0.19) | 0.30-1.5 (0.40-2.0) | 2.6 (3.5) | 0.01 (0.02) | 2011 - 2013 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 0.3.0 (0.40) | 2.6 (3.5) | 0.01 (0.02) | 2014+ |
| 600<750 (450<560) | 0.97 (1.3) | 6.9 (9.2) | 8.5 (11.4) | 0.40 (0.54) | 1996 - 2001 | 4.8 (6.4) | 2.6 (3.5) | 0.15 (0.20) | 2002 - 2005 | 3.0 (4.0) | 2.6 (3.5) | 0.15 (0.20) | 2006 - 2010 | 3.0 (4.0) | 0.14 (0.19) | 0.30-1.5 (0.40-0.20) | 2.6 (3.5) | 0.01 (0.02) | 2011 - 2013 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 0.30 (0.40) | 2.6 (3.5) | 0.01 (0.02) | 2014+ |
| ≥750 (≥560 ) | 0.97 (1.3) | 6.9 (9.2) | 8.5 (11.4) | 0.40 (0.54) | 2000 - 2005 | 4.8 (6.4) | 2.6 (3.5) | 0.15 (0.20) | 2006 - 2010 | | | | | | 0.30 (0.40) | 2.6 (3.5) | 2.6 (3.5) | 0.075 (0.10) | 2011 - 2014 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 2.6 (3.5) | 2.6 (3.5) | 0.03 (0.04) | 2015+ |
| >750≤1200[4] (560≤900) Gen. Only | 0.97 (1.3) | 6.9 (9.2) | 8.5 (11.4) | 0.40 (0.54) | 2000 - 2005 | 4.8 (6.4) | 2.6 (3.5) | 0.15 (0.20) | 2006 - 2010 | | | | | | 0.30 (0.40) | 2.6 (3.5) | 2.6 (3.5) | 0.075 (0.10) | 2011 - 2014 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 0.50 (0.67) | 2.6 (3.5) | 0.02 (0.03) | 2015+ |
| >1200[4] (>900) Gen. Only | 0.97 (1.3) | 6.9 (9.2) | 8.5 (11.4) | 0.40 (0.54) | 2000 - 2005 | 4.8 (6.4) | 2.6 (3.5) | 0.15 (0.20) | 2006 - 2010 | | | | | | 0.30 (0.40) | 0.50 (0.67) | 2.6 (3.5) | 0.075 (0.10) | 2011 - 2014 |
| | | | | | | | | | | | | | | | 0.14 (0.19) | 0.5 (0.67) | 2.6 (3.5) | 0.02 (0.03) | 2015+ |

1 This table is intended as an overview. For California Exhaust Emission Standards and Test Procedures -Off-Road Compression-Ignition Engines, consult title 13, California Code of Regulations, section 2423. For federal Nonroad Compression Ignition Engine Certification Standards, consult title 40, United States Code of Federal Regulations, Chapter 1, Part 89, subpart B and Part 1039, Subpart B.

2 Engine manufacturers have several options for complying with NOx during the transitional implementation years of Tier 4, including a "phase-in--phase-out" or alternative NOx level approach.

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT
## Best Available Control Technology (BACT) Guideline

**Source Category**

| | | | |
|---|---|---|---|
| **Source:** | **IC Engine-Compression Ignition: Stationary Emergency, non-Agricultural, non-direct drive fire pump** | **Revision:** | **7** |
| | | **Document #:** | **96.1.3** |
| **Class:** | **≥ 50 BHP Output** | **Date:** | **12/22/2010** |

**Determination**

| Pollutant | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice<br>3. TBACT | TYPICAL TECHNOLOGY |
|---|---|---|
| **POC (NMHC)** | 1. n/s[c]<br>2. CARB ATCM standard[a] for POC at applicable horsepower rating (see attached Table 1). | 1. n/s[c]<br>2. Any engine certified or verified to achieve the applicable standard. [a] |
| **NOx** | 1. n/s[c]<br>2. CARB ATCM standard[a] for NOx at applicable horsepower rating (see attached Table 1). | 1. n/s[c]<br>2. Any engine certified or verified to achieve the applicable standard. [a] |
| **$SO_2$** | 1. n/s[c]<br>2. Fuel sulfur content not to exceed 0.0015% (wt) or 15 ppm (wt). | 1. n/s[c]<br>2. CARB Diesel Fuel (Ultra Low Sulfur Diesel) |
| **CO** | 1. n/s[c]<br>2. CARB ATCM standard[a] for CO at the applicable horsepower rating (see attached Table 1). | 1. n/s[c]<br>2. Any engine certified or verified to achieve the applicable standard. [a] |
| **$PM_{10}$** | 1. n/s[c]<br>2. 0.15 g/bhp-hr<br>3. 0.15 g/bhp-hr | 1. n/s[c]<br>2. Any engine or technology demonstrated, certified or verified to achieve the applicable standard.<br>3. Any engine or technology demonstrated, certified or verified to achieve the applicable standard. |
| **NPOC** | 1. n/s<br>2. n/s | 1. n/s<br>2. n/s |

**References**

a. ATCM standard (listed below): Where NMHC + NOx is listed (with no individual standards for NOx or NMHC) as the standard, the portions may be considered 95% NOx and 5% NMHC. For the purposes of determining BACT NMHC = POC. Any engine which has been certified or demonstrated to meet the current year tier standard may be considered compliant with the certified emission standard for that pollutant.

b. Deleted (no longer applies).

c. Cost effectiveness analysis must be based on lesser of 50 hr/yr or non-emergency operation as limited by District health risk screen analysis.

Table 1: BACT 2 Emission Limits based on CARB ATCM

| **Emissions Standards for Stationary Emergency Standby Diesel-Fueled CI Engines ≥50 BHP g/Kw-hr (g/bhp-hr)** | | | |
|---|---|---|---|
| **Maximum Engine Power** | **PM** | **NMHC+NOx** | **CO** |
| 37 ≤ KW < 56 (50 ≤ HP < 75) | 0.20 (0.15) | 4.7 (3.5) | 5.0 (3.7) |
| 56 ≤ KW < 75 (75 ≤ HP < 100) | 0.20 (0.15) | 4.7 (3.5) | 5.0 (3.7) |
| 75 ≤ KW < 130 (100 ≤ HP < 175) | 0.20 (0.15) | 4.0 (3.0) | 5.0 (3.7) |
| 130 ≤ KW < 225 (175 ≤ HP < 300) | 0.20 (0.15) | 4.0 (3.0) | 3.5 (2.6) |
| 225 ≤ KW < 450 (300 ≤ HP < 600) | 0.20 (0.15) | 4.0 (3.0) | 3.5 (2.6) |
| 450 ≤ KW ≤ 560 (600 ≤ HP ≤ 750) | 0.20 (0.15) | 4.0 (3.0) | 3.5 (2.6) |
| KW > 560 (HP > 750) | 0.20 (0.15) | 6.4 (4.8) | 3.5 (2.6) |

***Source Category***

| | | | |
|---|---|---|---|
| Source: | ***IC Engine – Spark Ignition, Natural Gas Fired Rich Burn Engine*** | Revision: | *1* |
| | | Document #: | *96.3.2* |
| Class: | *>= 50 HP* | Date: | *5/7/03* |

***Determination***

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *0.069 g/bhp-hr*[a] *(12 ppmvd @ 15% oxygen)*<br>2. *0.15 g/bhp-hr*[b] *(25 ppmvd @ 15% oxygen)* | 1. *3-way catalyst + air/fuel ratio controller*[a]<br>2. *NSCR, 3-way catalyst*[b] |
| NOx | 1. *0.071 g/bhp-hr*[a] *(4 ppmvd @ 15% oxygen)*<br>2. *0.15 g/bhp-hr*[b] *(9 ppmvd @ 15% oxygen)* | 1. *3-way catalyst + air/fuel ratio controller*[a]<br>2. *NSCR, 3-way catalyst*[b] |
| $SO_2$ | 1.*n/d*<br>2.*n/s* | 1. *n/d*<br>2. *natural gas*[b] |
| CO | 1. *n/d*<br>2. *0.60 g/bhp-hr*[b] *(56 ppmvd @ 15% oxygen)* | 1. *n/d*<br>2. *3-way catalyst*[b] |
| $PM_{10}$ | 1. *n/d*<br>2. *n/s* | 1. *n/d*<br>2. *natural gas*[b] |
| NPOC | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |

***References***

*a. San Joaquin Valley Air Pollution Control District (SJVUAPCD): Aera Energy Oilfield*
*b. CARB "Guidance for the Permitting of Electrical Generation Technologies", September 2001*

***Source Category***

| | | | |
|---|---|---|---|
| Source: | ***IC Engine – Spark Ignition, Natural Gas Fired Lean Burn Engine*** | Revision: | *1* |
| | | Document #: | *96.3.3* |
| Class: | *>= 50 HP* | Date: | *5/7/03* |

***Determination***

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *n/d*<br>2. *0.15 g/bhp-hr*[b]<br>*(32 ppmvd @ 15% oxygen)* | 1. *n/d*<br>2. *oxidation catalyst*[b] |
| NOx | 1. *0.07 g/bhp-hr*[a]<br>*(6 ppmvd @ 15% oxygen)*<br>2. *0.15 g/bhp-hr*[b]<br>*(12 ppmvd @ 15% oxygen)* | 1. *SCR*[a]<br>2. *SCR*[b] |
| $SO_2$ | 1.*n/d*<br>2.*n/s* | 1. *n/d*<br>2. *natural gas*[b] |
| CO | 1. *0.10 g/bhp-hr*[a]<br>*(12 ppmvd @ 15% oxygen)*<br>2. *0.60 g/bhp-hr*[b]<br>*(74 ppmvd @ 15% oxygen)* | 1. *oxidation catalyst*[a]<br>2. *oxidation catalyst*[b] |
| $PM_{10}$ | 1. *n/d*<br>2. *n/s* | 1. *n/d*<br>2. *natural gas*[b] |
| NPOC | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |

***References***

*a. Tehama County Air Pollution Control District: NEO California Power, LLC – Red Bluff, California (ammonia slip limited to 10 ppmvd @ 15% oxygen)*
*b. CARB "Guidance for the Permitting of Electrical Generation Technologies", September 2001*

***Source Category***

| | | | |
|---|---|---|---|
| Source: | ***IC Engine – Spark Ignition, Natural Gas Fired Emergency Engine*** | Revision: | *1* |
| | | Document #: | ***96.3.4*** |
| Class: | >= ***50 HP*** | Date: | ***5/7/03*** |

***Determination***

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *n/d*<br>2. *1.0 g/bhp-hr*[a] | 1. *n/d*<br>2. *lean burn technology*[a] |
| NOx | 1. *n/d*<br>2. *1.0 g/bhp-hr*[a] | 1. n/d<br>2. *lean burn technology*[a] |
| $SO_2$ | 1.*n/a*<br>2.*n/s* | 1. *n/a*<br>2. *natural gas*[a] |
| CO | 1. *n/d*<br>*2. 2.75 g/bhp-hr*[a] | 1. *n/d*<br>2. *lean burn technology*[a] |
| $PM_{10}$ | 1. *n/d*<br>2. *n/s* | 1. *n/d*<br>2. *natural gas*[a] |
| NPOC | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |

***References***

*a. 1993 BACT 2 levels for IC Engine-Spark Ignition, Nat. Gas >_ 250 HP (3/19/93) without the need for post-combustion controls (not considered to be cost effective for emergency only applications).*

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT
## Best Available Control Technology (BACT) Guideline

### Source Category

| | | | |
|---|---|---|---|
| Source: | *Heater - Refinery Process, Natural or Induced Draft* | Revision: | *3* |
| | | Document #: | *94.1.1* |
| Class: | *5 MMBtu/hr to <50 MMBtu/hr Heat Input* | Date: | *08/12/94* |

### Determination

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *n/d*<br>2. *n/s* | 1. *n/d*<br>2. *Good Combustion Practice*[a] |
| NOx | 1. *10 ppmv @ 3% $O_2$ Dry*[a,b,c,e]<br>2. *25 ppmv @ 3% $O_2$ Dry*[a,b,e] | 1. *Selective Catalytic Reduction (SCR) + Low $NO_x$ Burners*[a,b,c]<br>2. *Low $NO_x$ Burners; or Low $NO_x$ Burners + Selective Non-Catalytic Reduction (SNCR)*[a,d] |
| $SO_2$ | 1. *Natural Gas or Treated Refinery Gas Fuel w/ ≤50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur*[a]<br>2. *Natural Gas or Treated` Refinery Gas Fuel w/ ≤100 ppmv Total Reduced Sulfur*[a] | 1. *Fuel Selection*[a]<br>2. *Fuel Selection*[a] |
| CO | 1. *n/d*<br>2. *50 ppmv @ 3% $O_2$ Dry*[a,f] | 1. *n/d*<br>2. *Good Combustion Practice*[a] |
| $PM_{10}$ | 1. *n/d*<br>2. *Natural Gas or Treated Refinery Gas Fuel*[a,b] | 1. *n/d*<br>2. *Fuel Selection*[a,b] |
| NPOC | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |

### References


*a. BAAQMD*
*b. BAAQMD A #30783*
*c. BAAQMD A #3318*
*d. BAAQMD A #8407*
*e. $NO_x$ determination by BAAQMD Source Test Method ST-13A or B (average of three 30-minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.*

*f. CO determination by BAAQMD Source Test Method ST-6 (average of three 30 minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.*

# *BAY AREA AIR QUALITY MANAGEMENT DISTRICT*
## *Best Available Control Technology (BACT) Guideline*

### *Source Category*

| | | | |
|---|---|---|---|
| Source: | *Heater - Refinery Process, Forced Draft* | Revision: | *3* |
| | | Document #: | *94.2.1* |
| Class: | *5 MMBtu/hr to <50 MMBtu/hr Heat Input* | Date: | *08/12/94* |

### *Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *n/d*<br>2. *n/s* | 1. *n/d*<br>2. *Good Combustion Practice*[a] |
| NOx | 1. *10 ppmv @ 3% $O_2$ Dry*[a,b,c,e]<br>2. *20 ppmv @ 3% $O_2$ Dry*[a,b,e] | 1. *Selective Catalytic Reduction (SCR) + Low $NO_x$ Burners*[a,b,c]<br>2. *Low $NO_x$ Burners; + Flue Gas Recirculation; or Low $NO_x$ Burners + Selective Non-Catalytic Reduction (SNCR); or Selective Catalytic Reduction(SCR)*[a,d] |
| $SO_2$ | 1. *Natural Gas or Treated Refinery Gas Fuel w/ ≤50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur*[a]<br>2. *Natural Gas or Treated` Refinery Gas Fuel w/ ≤100 ppmv Total Reduced Sulfur*[a] | 1. *Fuel Selection*[a]<br>2. *Fuel Selection*[a] |
| CO | 1. *n/d*<br>2. *50 ppmv @ 3% $O_2$ Dry*[a,f] | 1. *n/d*<br>2. *Good Combustion Practice*[a] |
| $PM_{10}$ | 1. *n/d*<br>2. *Natural Gas or Treated Refinery Gas Fuel*[a,b] | 1. *n/d*<br>2. *Fuel Selection*[a,b] |
| NPOC | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |

### *References*


*a. BAAQMD*
*b. BAAQMD A #30783*
*c. BAAQMD A #3318*
*d. BAAQMD A #8407*

*e. $NO_x$ determination by BAAQMD Source Test Method ST-13A or B (average of three 30-minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.*
*f. CO determination by BAAQMD Source Test Method ST-6 (average of three 30 minute sampling runs); or Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.*

*BAY AREA AIR QUALITY MANAGEMENT DISTRICT*

*Best Available Control Technology (BACT) Guideline*

*Source Category*

| | | | |
|---|---|---|---|
| **Source:** | **Heater - Refinery Process** | **Revision:** | *4* |
| | | **Document #:** | *94.3.1* |
| **Class:** | *≥50 MMBtu/hr Heat Input* | **Date:** | *1/14/08* |

*Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| **POC** | 1. n/d<br>2. n/s | 1. n/d<br>2. Good Combustion Practice[a] |
| **NOx** | 1. *n/d*<br>2. 5 ppmv @ 3% $O_2$ Dry[c,d,e] | 1. *n/d*<br>2. Selective Catalytic Reduction (SCR) + Low $NO_x$ Burners[c,d] |
| **$SO_2$** | 1. Natural Gas or Treated Refinery Gas Fuel w/ ≤50 ppmv Hydrogen Sulfide and ≤100 ppmv Total Reduced Sulfur[a]<br>2. Natural Gas or Treated` Refinery Gas Fuel w/ ≤100 ppmv Total Reduced Sulfur[a] | 1. *Fuel Selection*[a]<br>2. Fuel Selection[a] |
| **CO** | 1. n/d<br>2. 10 ppmv @ 3% $O_2$ Dry[c,d,f] | 1. n/d<br>2. Good Combustion Practice in Conjunction w/ Selective Catalytic Reduction (SCR) System[c,d] |
| **$PM_{10}$** | 1. n/d<br>2. Natural Gas or Treated Refinery Gas Fuel[a,b] | 1. n/d<br>2. Fuel Selection[a,b] |
| **NPOC** | 1. n/a<br>2. n/a | 1. *n/a*<br>2. n/a |

*References*

a. BAAQMD A #8407
b. BAAQMD A #30783
c. ARB BACT Clearinghouse, based on several South Coast AQMD projects. Recommend ammonia slip limit of 10 ppmv at 3% $O_2$.
d. Authority to Construct issued for BAAQMD applications 13424 & 13678 for CononcoPhillips Clean Fuels Expansion Project. For 85 MM BTU/hr furnace, the CO limit only applies at firing rates greater than 30 MM BTU/hr.
e. $NO_x$ determination by Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.
f. CO determination by Continuous Emission Monitor (3-hour average); or BAAQMD approved equivalent.

# *BAY AREA AIR QUALITY MANAGEMENT DISTRICT*
## *Best Available Control Technology (BACT) Guideline*

### *Source Category*

| | | | |
|---|---|---|---|
| Source: | *Liquid Transfer & Handling - Tank Truck & Rail Car Bulk Loading* | Revision: | *2* |
| | | Document #: | *109.1* |
| Class: | *All (except Gasoline Bulk Terminals)* | Date: | *06/28/00* |

### *Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *n/d*<br>2. *Submerged pipe fill and vapor collection system vented to a thermal incinerator w/ a destruction efficiency ≥98.5%* [b] | 1. *n/d*<br>2. *BAAQMD Approved Design and Operation* [b] |
| NOx | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *n/d*<br>2. *Submerged pipe fill and vapor recovery system w/ an overall system efficiency ≥95%* [b] | 1. *n/d*<br>2. *Refrigerated Condenser; or Carbon Adsorber; or BAAQMD Approved Equivalent* [b] |

### *References*

*b. BAAQMD*

# BAY AREA AIR QUALITY MANAGEMENT DISTRICT
## Best Available Control Technology (BACT) Guideline

### Source Category

| | | | |
|---|---|---|---|
| Source: | ***Liquid Transfer & Handling - Tank Truck & Rail Car Bulk Loading*** | Revision: | *1* |
| | | Document #: | *109.2* |
| Class: | ***Gasoline Bulk Terminals*** | Date: | ***06/28/00*** |

### Determination

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *n/d*<br>2. *0.02 pounds/1000 gallons loaded*[a,b] | 1. *n/d*<br>2. *Submerged Loading with Vapor Collection System vented to a Thermal Oxidizer, Carbon Adsorber with vapor tank, or BAAQMD Approved Equivalent*[a,b] |
| NOx | 1. *n/a*<br>2. *0.10 pounds/1000 gallons loaded*[a,b] | 1. *n/a*<br>2. *Low-NOx combustion system* [a,b] |
| $SO_2$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| CO | 1. *n/a*<br>2. *0.05 lb CO/1000 gallons loaded*[a,b] | 1. *n/a*<br>2. *Good Combustion Practice* [a,b] |
| $PM_{10}$ | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |
| NPOC | 1. *n/d*<br>2. *0.02 pounds/1000 gallons loaded*[a,b] | 1. *n/d*<br>2. *Submerged Loading with Vapor Collection System vented to a Carbon Adsorber with vapor tank, or BAAQMD Approved Equivalent*[a,b] |

### References


*a. BAAQMD Application #100.*
*b. BAAQMD Interoffice memorandum dated 6/9/2000 from B. Young to Bill deBoisblanc, Director of Permit Services, titled "BACT Revision for Gasoline Bulk Terminals".*

# *BAY AREA AIR QUALITY MANAGEMENT DISTRICT*
## *Best Available Control Technology (BACT) Guideline*

### *Source Category*

| | | | |
|---|---|---|---|
| Source: | *Boiler, CO - Refinery* | Revision: | *2* |
| | | Document #: | *17.4.1* |
| Class: | *All* | Date: | *04/21/93* |

### *Determination*

| POLLUTANT | BACT<br>1. Technologically Feasible/ Cost Effective<br>2. Achieved in Practice | TYPICAL TECHNOLOGY |
|---|---|---|
| POC | 1. *n/d*<br>2. *n/s* | 1. *n/d*<br>2. *Minimum Furnace Gas bypassing + Good Comb ustion Practice* [c,d] |
| NOx | 1. *n/s*<br>2. *80 ppm @ 3% $O_2$, Dry* [a] | 1. *Selective Catalytic Reduction (SCR) + Flue Gas Recirculation + Technologies listed below* [c]<br>2. *Low NOx Burners + Reduced Air Preheat + Natural Gas or Treated Refinery Gas as Supplemental Fuel* [c,d] |
| $SO_2$ | 1. *Natural gas or Treated Refinery Gas Fuel w/ ≤50 ppm as hydrogen Sulfide as Supplemental Fuel* [c,d]<br>2. *Natural gas or Treated Refinery Gas Fuel w/ ≤100 PPm as hydrogen Sulfide as Supplemental Fuel* [c,d] | 1. *Fuel Selection* [a,d]<br>2. *Fuel Selection* [a,d] |
| CO | 1. *n/d*<br>2. *100 ppm @ 3% $O_2$, Dry* [c] | 1. *n/d*<br>2. *Minimum Furnace Gas Bypassing + Good Combustion Practice* [a,d] |
| $PM_{10}$ | 1. *n/d*<br>2. *n/s* | 1. *n/d*<br>2. *Electrostatic Precipitator* [a] |
| NPOC | 1. *n/a*<br>2. *n/a* | 1. *n/a*<br>2. *n/a* |

### *References*

*a. SOHIO Refinery; Toledo, Ohio*

*c. BAAQMD*
*d. See also Catalyst Regeneration - Fluidized Catalytic Cracking Unit*

# BACT Clearinghouse Database Lookup Results

## 8 Match(s) for Code 48.B

## Compressors

| Project Name & Description | A/C Issue Date & ARB File No. | Pollutant |
|---|---|---|
| Torch Operating Company<br>Nuevo - Platform 'B"<br><br>Rotary sliding-vane type gas compressor driven by rotating shaft into 1740 scfm compressor and used to move gas from oilfield to onshore processing facility<br><br>(Detailed Information) | 9/4/94<br>(P/O no. 9111)<br><br>A350-844-98<br><br>District Contact:<br>Steve Sterner<br>Santa Barbara County APCD<br>(805) 961-8886<br>sterners@sbcapcd.org | **VOC/HC**<br>(Detailed Control Information)<br>A-C Compressor Company Double Bellows-type Mechanical Sealing System with barrier fluid pressurized to 10 psig for rotary sliding-vane type gas compressor<br><br>100 ppmv THC as methane per Method 21<br>---------- |
| Mobil Exploration and Producing U.S., Inc.<br>Lost Hills Two Lease Compressor Station<br><br>280 bhp Ajax model no. DPC 280 lean-burn, natural gas-fired IC engine dring compressor unit and having LPG backup fuel<br><br>(Detailed Information) | 7/2/96<br><br>(A/C no. S-1512-458-0)<br><br>A330-724-96<br><br>District Contact:<br>George Heinen<br>San Joaquin Valley Unified Air Pollution Control District<br>(559) 230-5909 | **NOx**<br>(Detailed Control Information)<br>Air/fuel ratio controller and Ajax CleanBurn Combustion Technology<br><br>1.5 g/bhp-hr<br>22.32 lbm/day<br>----------<br>**PM** |

| | | |
|---|---|---|
| | | (Detailed Control Information)<br>Natural gas/LPG firing, air/fuel ratio controller, and Ajax CleanBurn Combustion Technology<br><br>0.18 g/bhp-hr<br>2.19 lbm/day<br>---<br>**VOC/HC**<br>(Detailed Control Information)<br>Air/fuel ratio controller and Ajax CleanBurn Combustion Technology with weekly monitoring<br><br>1.5 g/bhp-hr<br>22.32 lbm/day<br>--- |
| Exxon<br>(Platform Heritage<br><br>18.75 MMscfd gas compressor skid unit<br><br>(Detailed Information) | 12/18/96<br><br>(A/C no. 9634)<br><br>A350-715-96<br><br>District Contact:<br>Ray McCaffrey<br>Santa Barbara Co. APCD<br>(805) 961-8826 | **VOC/HC**<br>(Detailed Control Information)<br>or (Performance Information)<br>Flanges w/ graphitic gaskets rated at 150% of actual process temp. and pres.; seals and relief valves routed to vapor recovery system or flare; repair timelines; fugitive I&M program |

| | | |
|---|---|---|
| | | 100 ppm;<br>100% control for relief valves and compressor seals<br>---------- |
| Exxon<br>(Platform Harmony)<br><br>18.75 MMscfd gas compressor skid unit<br><br>(Detailed Information) | 12/18/96<br><br>(A/C no. 9640)<br><br>A350-714-96<br><br>District Contact:<br>Ray McCaffrey<br>Santa Barbara Co. APCD<br>(805) 961-8826 | **VOC/HC**<br>(Detailed Control Information)<br>or (Performance Information)<br>Flanges w/ graphitic gaskets rated at 150% of actual process temp. and pres.; seals and relief valves routed to vapor recovery system or flare; repair timelines; fugitive I&M program<br><br>100 ppm;<br>100% control for relief valves and compressor seals<br>---------- |
| Texaco Exploration and Production, Inc.<br><br>15 hp Ingersoll-Rand type 30 gas compressor for fixed roof storage tank vapor recovery system<br><br>(Detailed Information) | 6/2/92<br><br>(A/C no. 4003956A)<br><br>A330-548-92<br><br>District Contact:<br>Tom Goff<br>San Joaquin Valley Unified APCD<br>(805) 862-5200 | **VOC/HC**<br>(Detailed Control Information)<br>Crankcase breather vented to compressor suction inlet with vacuum gauge<br><br>No limit<br>(Expected control efficiency of 99%)<br>---------- |
| Kern Oil Refining Company<br>(Refining Waste Gas Recovery) | 3/19/84 | **VOC/HC**<br>(Detailed Control |

| | | |
|---|---|---|
| 720,000 scf/day vapor compressor, values, and flanges<br><br>(Detailed Information) | (A/C # 2018008A, 2018046A, 2018012B, and 2018062)<br><br>A350-038-84<br><br>District Contact:<br>Tom Paxson<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(805) 861-3682 | Information)<br>Inspection of maintenance to minimize fugtive emissions<br><br>65% control efficiency<br>---------- |
| TOSCO H2 Plant Compressors<br><br>Three 3500 hp each Worthington compressor seals<br><br>(Detailed Information) | 9/17/82<br><br>(A/C # 28790)<br><br>A350-018-82<br><br>District Contact:<br>Jim Karas<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>TOSCO mechanical seals vented to a flare<br><br>No limit<br>---------- |
| Cheveron USA Lube Oil Project<br><br>Nine 20 to 1000 hp VOC gas compressors<br><br>(Detailed Information) | 4/8/82<br><br>(A/C # 27797)<br><br>A350-011-82<br><br>District Contact:<br>Ellen Linder<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Mechanical seals vented to a flare or vapor recovery system<br><br>99% control efficiency<br>---------- |

Click here to return the CAPCOA BACT Search Page

# BACT Clearinghouse Database Lookup Results

## Displaying 68 of 68 Match(s) for Bay Area AQMD

| Project Name & Description | A/C Issue Date & ARB File No. | Pollutant |
|---|---|---|
| Pacific Refinery Modification<br><br>2.75 MMBtu/hr refinery hydrogen reformer furnace, H-4011<br><br>(Detailed Information) | 9/28/83<br><br>(A/C # 29180)<br><br>A310-022-80<br><br>District Contact:<br>Leonard Clayton<br>Bay Area AQMD<br>(415) 771-6000 | **NOx**<br>(Detailed Control Information)<br>Ammonia injection and selective catalytic reduction unit<br><br>20 ppm @ 3% O2<br>85% control efficiency<br>---------- |
| Pacific Refinery Modifications<br><br>Refinery fuel gas system<br><br>(Detailed Information) | 9/28/83<br><br>(A/C # 29180)<br><br>A350-021-83<br><br>District Contact:<br>Leonard Clayton<br>Bay Area AQMD<br>(415) 771-6000 | **SOx**<br>(Detailed Control Information)<br>Diglycolamine absorbing system for H2S removal<br><br>50 ppm H2S in fuel gas<br>---------- |
| TOSCO H2 Plant Compressors<br><br>Three 3500 hp each Worthington compressor seals<br><br>(Detailed Information) | 9/17/82<br><br>(A/C # 28790)<br><br>A350-018-82<br><br>District Contact:<br>Jim Karas<br>Bay Area AQMD | **VOC/HC**<br>(Detailed Control Information)<br>TOSCO mechanical seals vented to a flare<br><br>No limit<br>---------- |

| | | |
|---|---|---|
| | (415) 771-6000 | |
| Paul Masson Vineyards Cogeneration<br><br>1200 rpm, 526 hp natural gas-fired Waukesha model F2900G reciprocating engine, 300 KW<br><br>(Detailed Information) | 3/27/81<br><br>(A/C # 27796)<br><br>A330-016-81<br><br>District Contact:<br>Doug Wolf<br>Bay Area AQMD<br>(415) 771-6000 | **NOx**<br>(Detailed Control Information)<br>Emissions Control Systems, Inc. TDRVEX supported model 43N catalytic converter<br><br>30 ppm<br>---------- |
| Stecher - Travng - Schmidt<br><br>Varnisher drying oven, dry-sys, on varnisher 261<br><br>(Detailed Information) | 10/8/82<br><br>(A/C #28246)<br><br>A340-015-82<br><br>District Contact:<br>Ellen Linder<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Hirt model FLX-7M fume incinerator<br><br>90 % overall control efficiency<br>97% (in-out of incinerator)<br>---------- |
| FMC Corp - San Jose Ordnance<br><br>Binks paint spray booth<br><br>(Detailed Information) | 6/22/82<br><br>(A/C # 28310)<br><br>A340-012-82<br><br>District Contact:<br>Brain Bateman<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Binks airless-electrostatic spring of 40% solid paint, spraying by automated robots, and in-line heaters to reduce paint viscosity<br><br>190 lbs/day<br>---------- |
| Cheveron USA Lube Oil Project | 4/8/82<br><br>(A/C # 27797) | **VOC/HC**<br>(Detailed Control Information) |

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| Nine 20 to 1000 hp VOC gas compressors<br><br>(Detailed Information) | A350-011-82<br><br>District Contact:<br>Ellen Linder<br>Bay Area AQMD<br>(415) 771-6000 | Mechanical seals vented to a flare or vapor recovery system<br><br>99% control efficiency<br>---------- |
| Exxon Co. USA - Benicia<br><br>Refinery Process Furnace<br><br>(Detailed Information) | 12/10/80<br><br>(A/C # 27599)<br><br>A310-010-80<br><br>District Contact:<br>Leonard Clayton<br>Bay Area AQMD<br>(415) 771-6000 | **NOx**<br>(Detailed Control Information)<br>Low-Nox burners and thermal de-NOx<br><br>40 ppmvd @ 3% O2<br>70% control efficiency<br>---------- |
| Chevron FCC Precipitator<br><br>61000 bpd fluid catalytic cracking unit<br><br>(Detailed Information) | 10/6/81<br><br>(A/C # 27803)<br><br>A350-009-82<br><br>District Contact:<br>John Swanson<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Two parallel electrostatic precipitator units<br><br>10 lb/hr<br>94% control efficiency<br>---------- |
| H.S. Crocker Co. Printing<br><br>6 COLDR 64" Printing Press<br><br>(Detailed Information) | 3/21/83<br><br>(A/C # 28709)<br><br>A340-008-83<br><br>District Contact:<br>Mohamad Mdazed<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Limit on VOC centent of inks<br><br>2.5 lb VOC/day<br>---------- |

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| Gazette Press Printing<br><br>Two 12950 cfm Tec Printing System drying ovens<br><br>(Detailed Information) | 12/20/82<br><br>(A/C # 28925)<br><br>A340-007-82<br><br>District Contact:<br>Mohamad Mdazed<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Katec, TVA-812 fume incinerator<br><br>95% control efficiency<br>---------- |
| American Metal Decorating Co.<br><br>Paint coating line for metal parts<br><br>(Detailed Information) | 3/7/80<br><br>(A/C # 27361)<br><br>A340-006-80<br><br>District Contact:<br>John Phillips<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>CE Air Preheater Cor-Pak fume incinerator<br><br>87% control efficiency<br>---------- |
| Louisiana-Pacific Boiler<br><br>Babcock & Wilcox 4.77 MMBtu/hr waste wood-fired boiler<br><br>(Detailed Information) | 10/23/80<br><br>(A/C # 27440)<br><br>A310-005-80<br><br>District Contact:<br>Lew Potter<br>Bay Area AQMD<br>(415) 771-6000 | **PM**<br>(Detailed Control Information)<br>Zurn multiple cyclone, MTSA-240-11.5 & a United McGill electrostatic precipitator, 4-350-2<br><br>99.7% control efficiency<br>0.017 gr/scf<br>17 lb/hr<br>---------- |
| Time Oil Co. (Loading Rack)<br><br>One million gallons per day gasoline bulk loading rack<br><br>(Detailed Information) | 12/23/80<br><br>(A/C # 27611)<br><br>A350-004-82 | **VOC/HC**<br>(Detailed Control Information)<br>McGill activated carbon adsorption system with two |

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| | District Contact:<br>Dave Dixon<br>Bay Area AQMD<br>(415) 771-6000 | beds. Automatically timed desorption cycle<br><br>98.6% control efficiency<br>---------- |
| TOSCO Corp. Hydrotreating Unit<br><br>5 hp or larger centerifugal pump seals<br><br>(Detailed Information) | 2/19/82<br><br>(A/C # 27769)<br><br>A350-003-82<br><br>District Contact:<br>Jim Karas<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Double mechanical seals with a oil seal<br><br>500 ppm<br>---------- |
| Crown-Zellerbach Cogeneration<br><br>32 MW gas turbine generator (has a duct fired steam generator)<br><br>(Detailed Information) | 3/1/82<br><br>(A/C # 28179)<br><br>A330-002-82<br><br>District Contact:<br>Doug Wolf<br>Bay Area AQMD<br>(415) 771-6000 | **NOx**<br>(Detailed Control Information)<br>Steam/water injection and lo-NOx burners<br><br>No limit<br>---------- |
| Chevron Lube Oil Project<br><br>Four refinery process furnaces manifolded to common exhaust stack F-7, F-8, F-9, F-10<br><br>(Detailed Information) | 4/8/82<br><br>(A/C # 27797)<br><br>A310-002-82)<br><br>District Contact:<br>John Sawnson<br>Bay Area AQMD<br>(415) 771-6000 | **NOx**<br>(Detailed Control Information)<br>One selective catalytic reduction unit for four furnaces and lo-NOx burners<br><br>No limit<br>---------- |

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# BACT Clearinghouse Database Lookup Results

## 4 Match(s) for Code 94.2

## Heaters - Refinery, > 18 MMBtu/hr through < 86.2 MMBtu/hr heat input

| Project Name & Description | A/C Issue Date & ARB File No. | Pollutant |
|---|---|---|
| CENCO Refining Company<br><br>50 MMBtu/hr Tulsa Heaters Inc. natural gas-fired horizontal cabin coker charge heater for a delayed coking unit at the refinery<br><br>(Detailed Information) | n.d.<br><br>(A/C # 352869)<br><br>A350-987-00<br><br>District Contact:<br>Emmaunel E. Ruiviar<br>South Coast AQMD<br>(909) 396-2509<br>eruiviar@aqmd.gov | **NOx**<br>(Detailed Control Information)<br>John Zink low-NOx burners, Technip USA selective catalytic reduction with ammonia injection of the flue gas<br><br>7 ppmvd @ 3% O2, 1-hr average<br>---<br>**CO**<br>(Detailed Control Information)<br>John Zink low-NOx burners<br><br>10 ppmvd @ 3% O2, 1-hr average<br>---<br>**Other Pollutant**<br>(Detailed Control Information)<br>No control<br><br>5 ppmvd @ 3% O2, |

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| | | 1-hr average<br>---------- |
| San Joaquin Refining Company, Inc.<br><br>Refinery process heaters rated between 8.4 and 47.1 MMBtu/hr<br><br>(Detailed Information) | 3/22/96<br><br>(A/C no. S-36-51-1)<br><br>A310-681-96<br><br>District Contact:<br>George Heinen<br>San Joaquin Valley Unified APCD<br>(559) 230-5909 | **NOx**<br>(Detailed Control Information)<br>Natural gas and/or LPG firing with low-NOx burners and internal flue-gas recirculation<br><br>30 ppmvd at 3% oxygen<br>(Equipvalent to 0.036 lbm/MMBtu)<br>----------<br>**PM**<br>(Detailed Control Information)<br>Natural gas and/or LPG firing<br><br>0.137 lbm/MMBtu<br>----------<br>**VOC/HC**<br>(Detailed Control Information)<br>Natural gas and /or LPG firing<br><br>0.004 lbm/MMBtu<br>---------- |
| Fletcher Oil and Refinining Company<br><br>65 MMBtu/hr vacuum heater heating gas oil before vacuum distillation; unit is fired on refinery gas<br><br>(Detailed Information) | 7/3/91<br><br>(App. no. 170819)<br><br>A350-613-94<br><br>District Contact:<br>Sawsan Andrawis<br>South Coast AQMD | **NOx**<br>(Detailed Control Information)<br>Joy Technology selective catalytic reduction unit<br><br>12 ppm<br>---------- |

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| | (919) 396-2607<br>sandrawis@aqmd.gov | |
| Chevron Lube Oil Project<br><br>Four refinery process furnaces manifolded to common exhaust stack F-7, F-8, F-9, F-10<br><br>(Detailed Information) | 4/8/82<br><br>(A/C # 27797)<br><br>A310-002-82)<br><br>District Contact:<br>John Sawnson<br>Bay Area AQMD<br>(415) 771-6000 | **NOx**<br>(Detailed Control Information)<br>One selective catalytic reduction unit for four furnaces and lo-NOx burners<br><br>No limit<br>---------- |

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# BACT Clearinghouse Database Lookup Results

## 3 Match(s) for Code 169

# Sulfur Recovery Plant

| Project Name & Description | A/C Issue Date & ARB File No. | Pollutant |
|---|---|---|
| Pacific Offshore Pipeline Co.<br><br>Sulfur recovery unit at oil-field natural gas processing plant with 60 MMscfd gas output to sulfur recovery unit at 2.67 hydrogen sulfide<br><br>(Detailed Information) | 2/4/97<br><br>(A/C no. 9047)<br><br>A350-745-97<br><br>District Contact:<br>Steve Sterner<br>Santa Barbara Co. APCD<br>(805) 961-8886<br>sterners@sbcapcd.org | **SOx**<br>(Detailed Control Information)<br>Three-stage conversion process of hydrogen sulfide in acid gas from a sulfinol amine system to elemental sulfur<br><br>99.9% H2S removal by mass across the sulfur recovery unit<br>100 ppmv residual H2S Stretford tail gas prior to incineration<br>---------- |
| Texaco Refining and Marketing - Bakersfield<br><br>Three-stage Claus sulfur recovery unit with a capacity of 90 long tons/day liquid sulfur at a refinery<br><br>(Detailed Information) | 4/18/91<br><br>(A/C no. 200T245)<br><br>A350-477-91<br><br>District Contact:<br>Tom Goff<br>Kern Co. APCD<br>(now the San Joaquin Valley Unified APCD) | **SOx**<br>(Detailed Control Information)<br>Amine-based, tail-gas treating unit<br><br>10 ppmvd<br>(Expected control efficiency of 99.9%)<br>---------- |

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| | (805) 862-5200 | |
| Chevron-Gaviota<br><br>Four 7.5 MMscf/day sulfur recovery units<br><br>(Detailed Information) | 2/6/86<br><br>(A/C no. 5704)<br><br>A350-126-86<br><br>District Contact:<br>Bill Master<br>Santa Barbara Co. APCD<br>(805) 961-8800 | **NOx**<br>(Detailed Control Information)<br>Pipeline quality gas in tail-gas incinerator; proper burner operation<br><br>200 ppmvd at 3% oxygen<br>15.2 lbm/hr total<br>---<br>**SOx**<br>(Detailed Control Information)<br>Recycle selection process combined with tail-gas incinerator and caustic scrubber<br><br>90 ppmvd at 3% oxygen<br>99.9% control<br>---<br>**PM**<br>(Detailed Control Information)<br>Use of pipeline quality gas in tail-gas incinerator; caustic scrubber with mist eliminator<br><br>3.66 lbm/hr total<br>80% control<br>---<br>**VOC/HC**<br>(Detailed Control Information)<br>Pipeline quality gas |

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| | | in tail-gas incinerator; proper burner operation<br><br>3.64 lbm/hr total<br>---<br>**CO**<br>(Detailed Control Information)<br>Pipeline quality gas in tail-gas incinerator; proper burner operation<br><br>6.16 lbm/hr total<br>--- |

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# BACT Clearinghouse Database Lookup Results

## 5 Match(s) for Code 82

# Flares - Refinery

| Project Name & Description | A/C Issue Date & ARB File No. | Pollutant |
|---|---|---|
| California Department of Corrections, Corcoran II Facility<br><br>(1) standby LPG fuel supply system, (3) 30,000 gal storage tanks, vaporizer, air blender and a flare that operates during natural gas interruptions or calibration<br><br>(Detailed Information) | 3/7/97<br><br>(A/C no. C-214-22-0)<br><br>A350-805-97<br><br>District Contact:<br>George Heinen<br>San Joaquin Valley Unified APCD<br>(559) 230-5909 | **VOC/HC**<br>(Detailed Control Information)<br>No Control<br><br>13.16 lbm/1,000 gal<br>---------- |
| Fortune Petroleum Co.<br><br>4.395 MMBtu/hr produced gas flare<br><br>(Detailed Information) | 5/29/92<br><br>(A/C no. 4278001)<br><br>A350-550-92<br><br>District Contact:<br>Tom Goff<br>San Joaquin Valley Unified APCD<br>(805) 862-5200 | **NOx**<br>(Detailed Control Information)<br>Burner management<br><br>No limit<br>----------<br>**SOx**<br>(Detailed Control Information)<br>Low sulfur gas of less than 0.2 gr/100 dscf<br><br>No limit<br>----------<br>**PM**<br>(Detailed Control Information) |

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| | | Smokeless combustion using air assist<br><br>No limit<br>---<br>**VOC/HC**<br>(Detailed Control Information)<br>Burner management<br><br>No limit<br>---<br>**CO**<br>(Detailed Control Information)<br>Burner management<br><br>No limit<br>--- |
| Union Oil Co.<br>(Lompoc Dehydration)<br><br>Flare limited to a maximum purge and pilot gas flow of 45 scf/hr<br><br>(Detailed Information) | 6/20/86<br><br>(A/C no. 6708)<br><br>A350-331-89<br><br>District Contact:<br>Bill Master<br>Santa Barbara Co. APCD<br>(805) 961-8800 | **NOx**<br>(Detailed Control Information)<br>Proper burner management; use of pipeline-quality fuel as pilot fuel<br><br>No limit<br>---<br>**VOC/HC**<br>(Detailed Control Information)<br>Proper burner management; use of pipeline-quality gas as pilot fuel<br><br>No limit<br>--- |
| Gaviota Terminal Co. | 5/13/87 | **NOx** |

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| Backup flare preceded by a vapor control system on a 100,000 bbl/day tanker loading system at a gas and oil marine terminal<br><br>(Detailed Information) | (A/C no. 6408)<br><br>A350-328-89<br><br>District Contact:<br>Sanjib Mukherji<br>Santa Barbara Co. APCD<br>(805) 961-8800 | (Detailed Control Information)<br>Proper burner management and use of pipeline-quality natural gas<br><br>6.92 lbm/hr |
| Chevron-Gaviota<br><br>Flare<br><br>(Detailed Information) | 2/6/86<br><br>(A/C no. 5704)<br><br>A350-130-86<br><br>District Contact:<br>Bill Master<br>Santa Barbara Co. APCD<br>(805) 961-8800 | **NOx**<br>(Detailed Control Information)<br>Proper burner management and monitoring; gas-fired pilots; emissions equiv. of thermal oxidizer<br><br>0.05 lbm/hr<br>---<br>**SOx**<br>(Detailed Control Information)<br>Gas-fired pilots; pilot fuel with 4 ppmv H2S max.<br><br>0.02 lbm/hr<br>---<br>**PM**<br>(Detailed Control Information)<br>Gas-fired pilots; steam injection for smokeless operation<br><br>0.02 lbm/hr<br>---<br>**VOC/HC**<br>(Detailed Control Information) |

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| | | Proper burner management and monitoring; gas-fired pilots<br><br>0.13 lbm/hr<br>---<br>**CO**<br>(Detailed Control Information)<br>Gas-fired pilots; proper burner management and monitoring<br><br>0.02 lbm/hr<br>--- |

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# BACT Clearinghouse Database Lookup Results

## Displaying 50 of 68 Match(s) for Bay Area AQMD

| Project Name & Description | A/C Issue Date & ARB File No. | Pollutant |
|---|---|---|
| U.S.S. Posco Industries<br><br>95.7 MMBtu/hr Mitsubishi - Custom Kawasaki annealing furnance<br><br>(Detailed Information) | 12/14/87<br><br>(A/C no. 32211)<br><br>A310-881-99<br><br>District Contact:<br>Don Van Buren<br>Bay Area AQMD<br>(415) 749-4746<br>dvanburen@baaqmd.gov | **NOx**<br>(Detailed Control Information)<br>Mitsubishi Selective Catalytic Reduction unit<br><br>50 lb/day<br>---------- |
| Genxon Power Systems LLC<br><br>1550 KW natural gas-fired Kawasaki MIA-13A combustion gas turbine equipped with a gearbox connected to a 1500 KW generator.<br><br>(Detailed Information) | 7/7/98<br><br>(A/C no. 18547)<br><br>A330-878-99<br><br>District Contact:<br>Greg Solomon<br>Bay Area AQMD<br>(415) 749-4715<br>gsolomonm@baaqmd.gov | **NOx**<br>(Detailed Control Information)<br>or (Performance Information)<br>Catalytica Combustion Systems, Inc Xonon catalytic combustor<br><br>5 ppmvd @ 15% O2, average over 3 hours<br>----------<br>**VOC/HC**<br>(Detailed Control Information)<br>or (Performance Information)<br>Catalytica Combustion Systems, Inc Xonon catalytic |

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| | | combustor<br><br>10 ppmvd @ 15% O2, average over 3 hours<br>---<br>**CO**<br>(Detailed Control Information)<br>or (Performance Information)<br>Catalytica Combustion Systems, Inc Xonon catalytic combustor<br><br>5 ppmvd @ 15% O2, average over 3 hours<br>--- |
| Crockett Cogeneration (C&H Sugar)<br><br>1780 MMBtu/hr G E model PG7221(FA), i.e., Frame 7FA, with heat recovery steam generator having low NOx duct burners with a total rated capacity of 349 MMBtu/hr producing 240 MW (combined cycle and cogeneration).<br><br>(Detailed Information) | 10/5/93<br><br>(A/C no. S-201)<br><br>A330-859-98<br><br>District Contact:<br>Carol Allen<br>Bay Area AQMD<br>(415) 749-4702<br>callen@baaqmd.gov | **NOx**<br>(Detailed Control Information)<br>or (Performance Information)<br>Dry low-NOx combusters and a Mitsubishi Heavy Industries America selective catalytic reduction<br><br>5 ppmvd @ 15% O2<br>---<br>**VOC/HC**<br>(Detailed Control Information)<br>or (Performance Information)<br>Engelhard oxidation catalyst<br><br>352.6 lbm/day (Approximately 50% |

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| | | control)<br>---<br>**CO**<br>(Detailed Control Information)<br>or (Performance Information)<br>Engelhard oxidation catalyst<br><br>5.9 ppmvd @ 15% O2 (Approximately 90% control)<br>--- |
| Shell Martinez Refining Company<br><br>Refinery fuel gas system for various combustion sources (furnaces, boilers, CO boilers)<br><br>(Detailed Information) | 7/28/98<br><br>(A/C no. 18185)<br><br>A350-856-98<br><br>District Contact:<br>Greg Stone<br>Bay Area AQMD<br>(415) 749-4745<br>gstone@baaqmd.gov | **SOx**<br>(Detailed Control Information)<br>H2S and total reduced sulfur (TRS) in refinery fuel gas system reduced by Diethanolamine (DEA) absorber, Claus Sulfur Plant, and SCOT unit.<br><br>24 hr average H2S content limit of 50 ppm<br>Annual average TRS limit of 70 ppm<br>--- |
| Performance Information | | |
| Siliconix, Inc.<br><br>Photoresist applicators<br><br>(Detailed Information) | 2/18/93<br><br>(App. no. 9321)<br><br>A410-627-94<br><br>District Contact:<br>Karen Dzienkowski | **VOC/HC**<br>(Detailed Control Information)<br>Munters Zeol model IZS-D1900-TH abatement system with two zeolite rotor concentration in |

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| | Bay Area AQMD<br>(415) 749-5141<br>kdzienkowski@baaqmd.gov | series followed by 500,000 Btu/hr thermal oxidizer<br><br>No limit<br>(Control level equivalent to 98.5% destruction)<br>---------- |
| Performance Information | | |
| Granite Construction Company<br><br>150 MMBtu/hr BMG model 45R30P asphalt drum mixer fired on fuel oil no. 2. This is a portable unit to be operated at remote sites where electricity or natural gas may not be available.<br><br>(Detailed Information) | 5/14/91<br><br>(A/C no. 5841)<br><br>A390-626-94<br><br>District Contact:<br>R. Ted Hull<br>Bay Area AQMD<br>(415) 749-4919 | **NOx**<br>(Detailed Control Information)<br>Low-NOx burners<br><br>145 lbm/day for plant and IC engine (Initial source test indicated emissions of 165 ppmvd at 3% oxygen from drum mixer.)<br>---------- |
| Performance Information | | |
| Criterion Catalyst Co.<br><br>Micro-Pulverizer Model 60 ACM catalyst grinder with rated input of 2000 lbm/hr and storage silos (inlet PM is 95% PM10)<br><br>(Detailed Information) | 11/4/92<br><br>(A/C no. 9450)<br><br>A410-584-93<br><br>District Contact:<br>Thu Bui<br>Bay Area AQMD<br>(415) 749-5119<br>tbui@baaqmd.gov | **PM**<br>(Detailed Control Information)<br>or (Performance Information)<br>Four Micro-Pulsaire baghouses with 3000 acfm flow rates<br><br>0.006 gr./dscf<br>---------- |
| West Coast Lithographers, Inc.<br><br>Komori Lithrone sheet-feed lithographic printing presses with integral dryers | 10/15/92<br><br>(A/C no. 8582)<br><br>A340-583-93 | **VOC/HC**<br>(Detailed Control Information)<br>Kerosene-like oil-based inks, no |

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| (Detailed Information) | District Contact:<br>Thu Bui<br>Bay Area AQMD<br>(415) 749-5119<br>tbui@baaqmd.gov | more than 10% by vol. VOC fountain solution, and no more than 30% by vol. VOC clean-up solvents (or 7.71 lbm/gal VOC and VOC vapor pressure less than 25 mm Hg)<br><br>No limit<br>---------- |
| Performance Information | | |
| Everett Graphics Co.<br><br>Heidelberg model 1025-LE color lithographic press with an output capacity of 13,000 sheets/hr<br><br>(Detailed Information) | 7/30/92<br><br>(A/C no. 7765)<br><br>A340-582-93<br><br>District Contact:<br>Weyman Lee<br>Bay Area AQMD<br>(415) 749-4708<br>wlee@baaqmd.gov | **VOC/HC**<br>(Detailed Control Information)<br>Soy-based inks with no more than 8.5% VOC by wt., fountain solutions with no more than 4% VOC by wt., clean-up solvent with no more than 4 lbm VOC/gal, clear coat with no VOC<br><br>No limit<br>---------- |
| Performance Information | | |
| Napa Sanitation District<br><br>913 hp Waukesha model 5900GL IC engine fired on digester gas with supplementary natural gas<br><br>(Detailed Information) | 3/26/93<br><br>(A/C no. 9006)<br><br>A330-579-93<br><br>District Contact:<br>Ted Hull<br>Bay Area AQMD<br>(415) 749-4919 | **NOx**<br>(Detailed Control Information)<br>Lean-burn combustion control<br><br>1.25 g/bhp-hr<br>----------<br>**SOx**<br>(Detailed Control |

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| | | Information)<br>Addition of iron salts to the digester sludge to reduce H2S concentrations of digester gas to less than 300 ppmv<br><br>0.30 g/bhp-hr<br>---------- |
| Performance Information | | |
| Aratex Services, Inc.<br><br>33.5 gas-fired Cleaver Brooks model CB200- 800-150 firetube boiler rated at 800 hp output with distillate oil emergency backup fuel<br><br>(Detailed Information) | 2/3/93<br><br>(A/C no. 9840)<br><br>A310-578-93<br><br>District Contact:<br>Karen Dzienkowski<br>Bay Area AQMD<br>(415) 749-5141<br>kdzienkowski@baaqmd.gov | **NOx**<br>(Detailed Control Information)<br>or (Performance Information)<br>Cleaver Brooks low NOx burners and flue-gas recirculation<br><br>25 ppmvd at 3% oxygen<br>---------- |
| Lucas Film, Ltd<br><br>Lipsner Smith Co. model no. CF-3000-MKV film cleaning system using 180 gal of methyl cloroform per year and processing<br>8000 feet of film per gallon of solvent<br><br>(Detailed Information) | 4/29/93<br><br>(A/C no. 9942)<br><br>A340-577-93<br><br>District Contact:<br>Craig Ullery<br>Bay Area AQMD<br>(415) 749-4718<br>cullery@baaqmd.gov | **VOC/HC**<br>(Detailed Control Information)<br>Enclosed film cleaning system with refrigerated chiller operating at no more than 35 F<br><br>2000 lbm/yr<br>(Estimated control efficiency of 90%)<br>---------- |
| Performance Information | | |
| Mark West Quarry | 4/2/93 | **PM**<br>(Detailed Control |

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| 45 ton/hr secondary cone crusher and mineral screeners (addition to existing aggregate crushing operation)<br><br>(Detailed Information) | (A/C no. 10641)<br><br>A390-576-93<br><br>District Contact:<br>Ted Hull<br>Bay Area AQMD<br>(415) 749-4919 | Information)<br>Enclosures, curtains, and high 50 micron water mist foggers<br><br>Visible emission opacity of Ringleman 0.5<br>---------- |
| Performance Information | | |
| Conner Peripherals<br><br>38-gallon dip coat/luber<br><br>(Detailed Information) | 4/29/92<br><br>(A/C no. 8564)<br><br>A420-541-92<br><br>District Contact:<br>Carol Lee<br>Bay Area AQMD<br>(415) 749-4689<br>clee@baaqmd.gov | **VOC/HC**<br>(Detailed Control Information)<br>Sub-zero chiller at 10 degrees F and finned coils<br><br>No limit<br>---------- |
| Performance Information | | |
| GSS Array Technology, Inc.<br><br>204 gallon Detrex PCBD-18B51-2ER-W conveyorized solvent cleaner (Conditioned to terminate operation 3.5 years after issuance of authority to construct)<br><br>(Detailed Information) | 5/19/92<br><br>(A/C no. 8312)<br><br>A340-540-92<br><br>District Contact:<br>Barry Young<br>Bay Area AQMD<br>(415) 749-4721<br>byoung@baaqmd.gov | **VOC/HC**<br>(Detailed Control Information)<br>Secondary refrigerated freeboard chillers, freeboard tunnel extensions, metal baffles, and freeboard ratio of at least 1.0<br><br>No limit<br>---------- |
| Performance Information | | |
| Airco Coating Technology | 4/28/92 | **VOC/HC**<br>(Detailed Control |

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| Custom wipe cleaning operation with 100 gal/yr maximum solvent usage<br><br>(Detailed Information) | (A/C no. 8650)<br><br>A340-539-92<br><br>District Contact:<br>Alex Saschin<br>Bay Area AQMD<br>(415) 749-4713 | Information)<br>Solvent to be stored in closed containers<br><br>No limit<br>---------- |
| Performance Information | | |
| Wickland Oil Company MTBE tank farm<br><br>Thirteen fixed roof storage tanks with<br>10,000 bbl/hr throughput<br><br>(Detailed Information) | 7/19/91<br><br>(A/C no. 6719)<br><br>A350-538-92<br><br>District Contact:<br>Greg Solomon<br>Bay Area AQMD<br>(415) 749-4715<br>gsolomon@baaqd.gov | **VOC/HC**<br>(Detailed Control Information)<br>John Zink carbon adsorption/absorption system<br><br>1 lbm/1000 bbl<br>(Expected control efficiency of greater than 99%)<br>---------- |
| Performance Information | | |
| Midwestern Pipeline Services<br><br>Pipe coating, including spraybooth and 7.5 MMBtu/hr oven-fired on natural gas; coatings applied to inside of 40"X40' sections of steel pipe<br><br>(Detailed Information) | 4/16/91<br><br>(A/C no. 5948)<br><br>A340-537-92<br><br>District Contact:<br>Greg Solomon<br>Bay Area AQMD<br>(415) 749-4715<br>gsolomon@baaqd.gov | **VOC/HC**<br>(Detailed Control Information)<br>or (Performance Information)<br>5000 cfm B&G Automated Systems afterburner from spray operation and oven<br><br>98.5% destruction efficiency<br>---------- |
| The Dot Printer<br><br>Flexographic Printing Presses | 3/27/92<br><br>(A/C no. 7571) | **VOC/HC**<br>(Detailed Control Information) |

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| (Detailed Information) | A340-536-92<br><br>District Contact:<br>Alex Saschin<br>Bay Area AQMD<br>(415) 771-6000 | Low VOC inks (< 1.5 lbm/gal), and low VOC fountain solution (<13% VOC)<br><br>No limit<br>---------- |
| Performance Information | | |
| Huntway Refining Company, asphalt oxidation plant<br><br>28 ton/hr asphalt oxidation still and seven asphalt storage tanks, six having 85,000 gal capacity and one with 50,000 gal capacity with volatiles routed to control unit<br><br>(Detailed Information) | 4/3/92<br><br>(A/C no. 7311)<br><br>A350-535-92<br><br>District Contact:<br>Dharam Singh<br>Bay Area AQMD<br>(415)749-4714<br>dsign@baaqmd.gov | **PM**<br>(Detailed Control Information)<br>4.1 MMBtu/hr gas-fired asphalt heater-cum- thermal oxidizer ducting 5000 cfm<br><br>0.08932 lbm/ton<br>----------<br>**VOC/HC**<br>(Detailed Control Information)<br>4.1 MMBtu/hr gas-fired asphalt heater-cumthermal oxidizer ducting 5000 cfm<br><br>98% control efficiency<br>0.0023 lbm/ton<br>---------- |
| Performance Information | | |
| Consolidated Publications<br><br>Hantscho two-web lithographic printing press with 5 MMBtu/hr natural-gas, two-web drying oven and having an output capacity 38,000 impressions/hr | 1/22/92<br><br>(A/C no. 7920)<br><br>A340-534-92<br><br>District Contact:<br>Julian Elliot | **VOC/HC**<br>(Detailed Control Information)<br>TEC Systems Phoenix 2000 1.5 MMBtu/hr thermal oxidizer operating at 1100i F; Less than |

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| (Detailed Information) | Bay Area AQMD<br>(415) 749-4705<br>jelliot@baaqmd.gov | 12% VOC fountain solution; Less than 10 mm Hg cleanup solvents at 20 degrees C<br><br>95% POC destruction efficiency by thermal oxidizer<br>---------- |
| Performance Information | | |
| National Semiconductor<br><br>Semiconductor fabrication area with photo-resist maskant and developer operations<br><br>(Detailed Information) | 4/10/92<br><br>(A/C no. 7129)<br><br>A410-533-92<br><br>District Contact:<br>Craig Ullery<br>Bay Area AQMD<br>(415) 749-4718<br>cullery@baaqmd.gov | **VOC/HC**<br>(Detailed Control Information)<br>or (Performance Information)<br>REECO Fume incinerator<br><br>10 ppmv<br>0.985<br>---------- |
| Unocal Chemicals Division, Oakland Distribution Facility<br><br>Soil vapor extraction system with two 1267 scfm New York Blower Co. vacuum extraction blowers<br><br>(Detailed Information) | 4/1/92<br><br>(A/C no. 8447)<br><br>A430-532-92<br><br>District Contact:<br>Ted Hull<br>Bay Area AQMD<br>(415) 749-4919 | **VOC/HC**<br>(Detailed Control Information)<br>ARI Model CT-1000-SAB-G-50TE catalytic oxidation unit<br><br>97% control efficiency<br>---------- |
| Performance Information | | |
| Solectron Corporation<br><br>Relocation of wave solder systems with foam fluxers having 3.35 gal flux capacity and a net solvent usage of 6000 | 4/2/92<br><br>(App. no. 8337)<br><br>A410-531-92 | **VOC/HC**<br>(Detailed Control Information)<br>Calgon Vapor Pac-10 carbon absorption unit |

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| gal/yr<br><br>(Detailed Information) | District Contact:<br>Carol Allen<br>Bay Area AQMD<br>(415) 749-4702<br>callen@baaqmd.gov | 10 ppmv at 10,000 cfm<br>90% control efficiency<br>---------- |
| Performance Information | | |
| Western Steel & Tinplate, Inc.<br><br>6000 sheet/hr sheetmetal coating lines and 5 MMBtu/hr natural gas ovens<br><br>(Detailed Information) | 4/10/89<br><br>(App. no. 1931)<br><br>A340-341-89<br><br>District Contact:<br>Alex Saschin<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Direct-flame afterburner<br><br>90% capture efficiency with 98.5 percent afterburner control efficiency<br>---------- |
| International Paper<br><br>7000 sheet/hr lithographic single-sheet printing press<br><br>(Detailed Information) | 3/23/89<br><br>(A/C no. 1338)<br><br>A340-340-89<br><br>District Contact:<br>Doug Hall<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Low-solvent inks with no more than 10% VOC by volume; chilled fountain solution (no more than<br>45 degrees F)<br><br>15.7 tons/yr<br>---------- |
| Westinghouse Electric Corporation<br><br>380 MMBtu/hr gas-fired steam generator producing 300,000 lbm steam/hr<br><br>(Detailed Information) | 8/17/88<br><br>(A/C no. 883)<br><br>A310-297-88<br><br>District Contact:<br>Hari Doss<br>Bay Area AQMD<br>(415) 771-6000 | **NOx**<br>(Detailed Control Information)<br>Low-NOx burners, flue gas recirculation, and SCR<br><br>12 ppmvd at 3% oxygen<br>---------- |

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| GWF Power Systems<br><br>202 MMBtu/hr circulating fluidized bed combustor producing 19 MW and fired on petroleum coke, bituminous coal, or distillate fuel oil<br><br>(Detailed Information) | 2/11/88<br><br>(A/C nos. 31130, thru 31133, and 30686)<br><br>A310-278-88<br><br>District Contract:<br>Sandra Lopez<br>Bay Area AQMD<br>(415) 771-6000 | **NOx**<br>(Detailed Control Information)<br>Ammonia injection<br><br>50 ppmvd at 3% oxygen<br>0.074 lbm/MMBtu<br>360 lbm/day<br>---<br>**SOx**<br>(Detailed Control Information)<br>Sorbent injection system & 0.05% S content for fuel oil<br><br>54 ppmvd at 3% oxygen<br>0.109 lbm/MMBtu<br>528 lbm/day<br>---<br>**PM**<br>(Detailed Control Information)<br>Baghouse<br><br>0.005 gr/dscf<br>--- |
| Chevron USA, Inc.<br><br>Two 531 MMBtu/hr Brown Boveri Type 8 gas turbines with 250 MMBtu/hr duct burners producing 99 MW total (cogeneration)<br><br>(Detailed Information) | 9/4/87<br><br>(A/C no. 30331)<br><br>A330-277-88<br><br>District Contact:<br>Ellen Linder<br>Bay Area AQMD<br>(415) 771-6000 | **NOx**<br>(Detailed Control Information)<br>Steam injection and selective catalytic reduction<br><br>10 ppmvd at 15% oxygen<br>--- |
| Naval Station<br>Treasure Island | 12/19/86 | **NOx**<br>(Detailed Control |

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| Two 50 MMBtu/hr Cleaver Brooks steam boilers fired on natural gas<br><br>(Detailed Information) | (A/C no. 30543)<br><br>A310-167-87<br><br>District Contact:<br>Bob Nishimura<br>Bay Area AQMD<br>(415) 771-6000 | Information)<br>Flue gas recirculation and low-NOx burners<br><br>40 ppmvd at 3% oxygen<br>0.05 lbm/MMBtu<br>---------- |
| City of Santa Clara<br><br>29.4 MW General Electric Frame 5 gas turbine (simple-cycle peaking unit)<br><br>(Detailed Information) | 1/5/87<br><br>(A/C no. 31527)<br><br>A330-166-87<br><br>District Contact:<br>Ellen Linder<br>Bay Area AQMD<br>(415) 771-6000 | **NOx**<br>(Detailed Control Information)<br>Water injection<br><br>42 ppmvd at 15% oxygen<br>---------- |
| SF Southeast Treatment Plant<br><br>7300 hp reciprocating engine fired on sewage sludge gas (cogeneration)<br><br>(Detailed Information) | 5/86<br><br>(A/C no. 30456)<br><br>A330-150-86<br><br>District Contact:<br>Steve Hill<br>Bay Area AQMD<br>(415) 771-6000 | **NOx**<br>(Detailed Control Information)<br>Clean-burn engine<br><br>2.0 g/bhp-hr<br>---------- |
| Diamond A Ranch Quarry<br><br>350 ton/hr asphaltic concrete plant<br><br>(Detailed Information) | 6/2/86<br><br>(A/C no. 30724)<br><br>A390-144-86<br><br>District Contact:<br>Greg Stone<br>Bay Area AQMD<br>(415) 771-6000 | **PM**<br>(Detailed Control Information)<br>Venturi scrubber<br><br>0.02 gr/dscf<br>99.7% control<br>---------- |
| Diamond A Ranch Quarry | 6/2/86 | **PM**<br>(Detailed Control |

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| 300 ton/hr concrete batch plant<br><br>(Detailed Information) | (A/C no. 30724)<br><br>A390-143-86<br><br>District Contact:<br>Greg Stone<br>Bay Area AQMD<br>(415) 771-6000 | Information)<br>Water spray and fabric filter<br><br>99% control<br>10% opacity<br>---------- |
| Diamond A Ranch Quarry<br>(Oliver de Silva)<br><br>300 ton/hr rock crushing plant<br><br>(Detailed Information) | 6/2/86<br><br>(A/C no. 30724)<br><br>A390-142-86<br><br>District Contact:<br>Greg Stone<br>Bay Area AQMD<br>(415) 771-6000 | **PM**<br>(Detailed Control Information)<br>Water spray and baghouse<br><br>0.02 gr/decf<br>99.7% control<br>10% opacity<br>---------- |
| Wickland Oil<br><br>Marine loading with capacity of 10,000 barrels per day<br><br>(Detailed Information) | 6/86<br><br>(A/C no. 30472)<br><br>A340-141-86<br><br>District Contact:<br>Steve Hill<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>No controls<br>---------- |
| Scientific Games<br><br>Rotogravure press<br><br>(Detailed Information) | 4/5/85<br><br>(A/C no. 31248)<br><br>A340-140-86<br><br>District Contact:<br>Ellen Linder<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Incinerator<br><br>96% control<br>---------- |
| Union Cogeneration | 1/17/86 | **NOx**<br>(Detailed Control |

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| Three Westinghouse C191 gas turbines each with 175 MMBtu/hr duct burners and producing 16.5 MWe per turbine<br><br>(Detailed Information) | (A/C no. 30810)<br><br>A330-114-86<br><br>District Contact:<br>Steve Hill<br>Bay Area AQMD<br>(415) 771-6000 | Information)<br>Water injection and selective catalytic reduction<br><br>25 ppmvd at 15% oxygen<br>---<br>**VOC/HC**<br>(Detailed Control Information)<br>Oxidation catalyst<br><br>8 lbm/hr<br>(equal to 7%)<br>---<br>**CO**<br>(Detailed Control Information)<br>Oxidation catalyst<br><br>39 lbm/hr<br>(equal to 80%)<br>--- |
| Tri-Cities Resource Recovery<br><br>Waste to energy, MSW<br><br>(Detailed Information) | 12/3/85<br><br>(A/C no. 29795)<br><br>A320-113-86<br><br>District Contact:<br>B. Bateman<br>Bay Area AQMD<br>(415) 771-6000 | **NOx**<br>(Detailed Control Information)<br>Flue gas recirculation, combustion modification<br><br>200 ppmv at 12% CO2<br>---<br>**SOx**<br>(Detailed Control Information)<br>Dry scrubber<br><br>30 ppmv at 12% CO2<br>--- |

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| | | **PM**<br>(Detailed Control Information)<br>Dry scrubber, baghouse<br><br>0.01 gr/dscf<br>----------<br>**VOC/HC**<br>(Detailed Control Information)<br>Combustion modification<br><br>50 ppmv at 12% CO2<br>----------<br>**CO**<br>(Detailed Control Information)<br>Combustion modification<br><br>100 ppmv at 12% CO2<br>---------- |
| Crown Cork & Seal Co., Inc.<br><br>Aluminum can manufacturing<br><br>(Detailed Information) | 12/31/85<br><br>(A/C no. 30862)<br><br>A340-112-86<br><br>District Contact:<br>Judy Cutino<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Incineration<br><br>95% control<br>---------- |
| Stecher-Traung-Schmidt<br><br>Lithographic color printing press<br><br>(Detailed Information) | 11/5/85<br><br>(A/C no. 30733)<br><br>A340-111-86 | **VOC/HC**<br>(Detailed Control Information)<br>Low VOC solutions, refrigeration and alcohol reclaim, low |

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| | District Contact:<br>Ellen Linder<br>Bay Area AQMD<br>(415) 771-6000 | VOC ink<br><br>15% VOC content<br>---------- |
| Container Corp. of America<br><br>Two rotogravure print lines<br><br>(Detailed Information) | 1/2/86<br><br>(A/C no. 30834)<br><br>A340-110-86<br><br>District Contact:<br>Joe Slamovich<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Low solvent coatings<br><br>73.6 tpy,<br>2.5% VOC content<br>---------- |
| Genstar Gas Recovery Systems<br><br>Two 2650 hp Cooper-Superior lean burn IC engines fired on landfill gas<br><br>(Detailed Information) | 12/2/85<br><br>(A/C no. 30970)<br><br>A330-109-86<br><br>District Contact:<br>Craig Ullery<br>Bay Area AQMD<br>(415) 771-6000<br>cullery@baaqmd.gov | **NOx**<br>(Detailed Control Information)<br>Stratified charge combustion<br><br>1.5 g/hp-hr<br>---------- |
| Genstar Gas Recovery Systems<br><br>Two 1100 hp Cooper-Superior lean burn IC engines fired on landfill gas<br><br>(Detailed Information) | 8/29/85<br><br>(A/C no. 30893)<br><br>A330-108-86<br><br>District Contact:<br>Craig Ullery<br>Bay Area AQMD<br>(415) 771-6000<br>cullery@baaqmd.gov | **NOx**<br>(Detailed Control Information)<br>Stratified charge combustion<br><br>1.5 g/hp-hr<br>---------- |
| Eimac/Varian Fab Center<br><br>Detrex VS-8DOE vapor degreaser using 1,1,1 | 7/12/85<br><br>(A/C # 30832) | **VOC/HC**<br>(Detailed Control Information)<br>Use of freeboard |

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| trichloroethane<br><br>(Detailed Information) | A340-083-85<br><br>District Contact:<br>Craig Ullery<br>Bay Area AQMD<br>(415) 771-6000<br>cullery@aqmd.gov | chiller (above cooling coils) to provide blanket of cool air to reduce emission of TCE<br><br>33% control efficiency<br>---------- |
| Continental Can Company<br><br>2-piece aluminum can lines<br><br>(Detailed Information) | 3/15/85<br><br>(A/C # 30129)<br><br>A340-074-85<br><br>District Contact:<br>Judy Cutino<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Direct flame afterburner controlling pin ovens, inside bake oven and fugitive emissions from spray machines<br><br>26 tons/yr<br>95% control efficiency (afterburner)<br>---------- |
| Pacific Lighting Energy Systems<br><br>2650 hp Cooper model 165GTA superior landfill gas-fired clean burn IC engine<br><br>(Detailed Information) | 3/1/85<br><br>(A/C # 30336)<br><br>A/C # 330-075-85<br><br>District Contact:<br>Craig Ullery<br>Bay Area AQMD<br>(415) 771-6000<br>cullery@baaqmd.gov | **NOx**<br>(Detailed Control Information)<br>Cooper pre-chamber ignition lean burn or stratified charged turbo-chared engine<br><br>1.5g/hp-hr<br>---------- |
| PG&E - Los Medanos Comprssor<br><br>4130 hp Cooper Energy Systems natural gas-fired clean burn engine<br><br>(Detailed Information) | 1/8/81<br><br>(A/C # 27512)<br><br>A330-053-84<br><br>District Contact:<br>Bob Nishimura | |

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| | Bay Area AQMD<br>(415) 771-6000 | |
| IBM Cogeneration Project<br><br>49 MW United Technology Twin Pack gas trubine and 14.4 MW steam trubine generator system<br><br>(Detailed Information) | 12/21/84<br><br>(A/C # 30066)<br><br>A330-052-84<br><br>District Contact:<br>Victor Reyes<br>Bay Area AQMD<br>(415) 711-6000 | **NOx**<br>(Detailed Control Information)<br>Water injection and selective catalytic reduction<br><br>25 ppm @ 15% O2<br>---<br>**CO**<br>(Detailed Control Information)<br>Johnson Matthey CO catalyst<br><br>550 lb/day<br>--- |
| General Motors - Toyota Joint Venture<br><br>Automobile undercoating spray booth<br><br>(Detailed Information) | 2/22/84<br><br>(A/C # 29614)<br><br>A410-051-84<br><br>District Contact:<br>Jim Tomich<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>High solids coating, airless spray, incineration<br><br>35% control efficiency<br>--- |

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# BACT Clearinghouse Database Lookup Results

## Displaying 373 of 373 Match(s) for San Joaquin Valley Unified APCD

| Project Name & Description | A/C Issue Date & ARB File No. | Pollutant |
|---|---|---|
| Blackwell Land Company, Inc.<br><br>2,500 lbm/hr Pistachio Finishing Operation inlcuding a needle separator with fines discharge airleg<br><br>(Detailed Information) | 12/26/84<br><br>(A/C # 3004006)<br><br>A370-061-85<br><br>District Contact:<br>Tom Paxson<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(805) 861-3682 | **PM**<br>(Detailed Control Information)<br>RL Enterprises high efficiency cyclone discharging to two sock filters in parallel<br><br>0.63 lbm/hr<br>---------- |
| HOPCO<br><br>Crude oil storage tank<br><br>(Detailed Information) | 12/4/84<br><br>(A/C # 4099105 to 4099124)<br><br>A350-60-84<br><br>District Contact:<br>Tom Paxon<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(805) 861-3682 | **VOC/HC**<br>(Detailed Control Information)<br>Vapor collection and incineration<br><br>99-6% control efficiency<br>---------- |
| HOPCO<br>62.5 MMBtu/hr Thermotics crude oil production steam generators<br><br>(Detailed Information) | 12/4/84<br><br>(A/C # 4099002 to 4099013)<br><br>A310-059-84<br><br>District Contact: | **SOx**<br>(Detailed Control Information)<br>Wet scrubber<br><br>97% destruction efficiency |

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| | Tom Paxson<br>Kern County APCD<br>(Now the San Joaquin Valley Unified APCD)<br>(805) 861-3682 | 2.1 lbm/hr<br>---<br>**PM**<br>(Detailed Control Information)<br>Wet scrubber<br><br>70% destruction efficiency<br>1.7 lbm/hr<br>--- |
| Cheveron USA, Inc. (Add 2 Tanks to Battery)<br><br>Two 5000 and 2000 bbl cone roof tanks<br><br>(Detailed Information) | 11/21/84<br><br>(A/C # 4008407B)<br><br>A350-058-84<br><br>District Contact:<br>Tom Paxon<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(805) 861-3682 | **VOC/HC**<br>(Detailed Control Information)<br>Engersol Rand vapor recovery to gas plant intake by a compressor<br><br>15.1 lbm/day<br>--- |
| Pacific Energy Resources, Inc.<br><br>2650 hp Cooper Energy Service Superior model 16 SGTA land-fill gas-fired clean burn internal combustion engine<br><br>(Detailed Information) | 11/14/84<br><br>(A/C # 0083001)<br><br>A330-057-84<br><br>District Contact:<br>Tuan Ngo<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(805) 861-3682 | **NOx**<br>(Detailed Control Information)<br>Clean burn operating mode: two combustion chambers: pre-ignition chamber, fuel rich and main combustion chamber<br><br>8.25 lb/hr<br>1.5 g/bhp-hr<br>--- |
| Frito-Lay Corn Chip Line # 2<br><br>2,500 lbm/hr Frito-Lay corn chip fryer | 11/9/84<br><br>(A/C # 3082013) | **PM**<br>(Detailed Control Information)<br>Mist entroinment |

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| (Detailed Information) | A370-055-84<br><br>District Contact:<br>Tom Paxson<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(805) 861-3682 | separator<br><br>0.5 lb/hr<br>---------- |
| Frito-Lay Cogeneration<br><br>53 MMBtu/hr Allison/Coen gas-fired turbine engine with dual fuel-fired 40 MMBtu/hr duct burner serving boiler<br><br>(Detailed Information) | 11/9/84<br><br>(A/C # 3082014)<br><br>A330-054-84<br><br>District Contact:<br><br>Tom Paxon<br><br>San Joaquin Valley APCD<br>(former Kern County APCD)<br>(805) 861-3682 | **NOx**<br>(Detailed Control Information)<br>Allison/Coen water/steam injection<br><br>13.7 lbm/hr turbine and duct burner<br>----------<br>**SOx**<br>(Detailed Control Information)<br>Low sulfur fuel (natural gas) with 0.25% S fuel oil as standby for duct burner only during N.G. curtailment<br><br>0.03 lbm/hr (turbine)<br>10.1 lbm/hr (duct burner(oil))<br>----------<br>**PM**<br>(Detailed Control Information)<br>Complete combustion with low sulfur fuels, gaseous fuel except during curtailment<br><br>0.83 lbm/hr<br>---------- |

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| Moblie Oil<br><br>Two well vent vapor control systems<br><br>(Detailed Information) | 9/1/84<br><br>(A/C # 4011216 and 4011217)<br><br>A350-046-84<br><br>District Contact:<br>Tom Paxon<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(805) 861-3682 | **VOC/HC**<br>(Detailed Control Information)<br>McGill Inc.<br>incinerate well head non-condensible gases for HC control<br><br>99% control efficiency<br>---------- |
| Kern Pistachio Coop.<br><br>Pistachio precleaning/ hulling /drying<br><br>(Detailed Information) | 7/25/84<br><br>(A/C # 3068002A)<br><br>A370-045-84<br><br>District Contact:<br>Tuan Ngo<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(805) 861-3682 | **PM**<br>(Detailed Control Information)<br>High frequency cyclones and fabric collector<br><br>0.24 gr/scf (cyclone)<br>0.0084 gr/scf (fabric collector)<br>---------- |
| Mineral Spirits Internal Floating Roof Tank<br><br>3,300 bbl interal floating roof tank<br><br>(Detailed Information) | 6/18/84<br><br>(A/C # 2018063)<br><br>A350-044-84<br><br>District Contact:<br>Tom Paxon<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(805) 861-3682 | **VOC/HC**<br>(Detailed Control Information)<br>Altech Industries Co.<br>single-seal internal floating roof with no-gap seal retained by 10 pound force or greater<br><br>98% control efficiency<br>---------- |
| Gabriel Power Co.<br><br>Biomass Burner | 8/18/84<br><br>(A/C # 40102610101-144) | **SOx**<br>(Detailed Control Information)<br>Red Crown baghouse |

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|---|---|---|
| (Detailed Information) | A320-043-84<br><br>District Contact:<br>George Heinen<br>San Joaquin Valley Unified APCD<br>(599) 230-5909<br>george.heinen@valleyair.org | and scrubber<br><br>0.0247 lb/meg btu input<br>---------- |
| Shell California Production, Inc. (North Belnidye Dehy Facility)<br><br>3,000 bbl/day crude oil dehydration and storage with truck loading rack<br><br>(Detailed Information) | 5/25/84<br><br>(A/C # 4012304A)<br><br>A350-42-84<br><br>District Contact:<br>Tom Paxon<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(805) 861-3682 | **VOC/HC**<br>(Detailed Control Information)<br>Vapor control system connedted to process, storage and truck loading equipment<br><br>177.2 lbm/day<br>---------- |
| Shell California Production Inc. - Kern Ridge<br><br>168 hp Waukesha natural-gas fired compressor engine<br><br>(Detailed Information) | 5/29/84<br><br>(A/C # 2028022 and 2028023)<br>A330-041-84<br><br>District Contact:<br>Tuan Ngo<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(805) 861-3682 | **NOx**<br>(Detailed Control Information)<br>Riley-Beaird maxium MCSR rich burn catalytic converter<br><br>1.09 gm/bhp-hr<br>---------- |
| Getty Oil - Lost Hills Cogeneration<br><br>5000 hp Renske gas turbine followed by waste heat recovery steam generator for TEOR operation<br><br>(Detailed Information) | 5/9/84(A/C # 4003571-573)<br><br>A330-40-84<br><br>District Contact:<br>George Heinen<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(559) 230-5909 | **NOx**<br>(Detailed Control Information)<br>Water injection of 0.8:1 water to fuel gas (by weight) ratio<br><br>7.6 lb/hr<br>---------- |

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|---|---|---|
| | george.heinen@valleyair.org | |
| Kern Oil Refining Company (Refining Waste Gas Recovery)<br><br>720,000 scf/day vapor compressor, values, and flanges<br><br>(Detailed Information) | 3/19/84<br><br>(A/C # 2018008A, 2018046A, 2018012B, and 2018062)<br><br>A350-038-84<br><br>District Contact:<br>Tom Paxson<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(805) 861-3682 | **VOC/HC**<br>(Detailed Control Information)<br>Inspection of maintenance to minimize fugtive emissions<br><br>65% control efficiency<br>---------- |
| Cannery - Stanislaus Food<br><br>125,000 lb/hr Ward-Schmid Nebraska model NS-G-101 steam boiler<br><br>(Detailed Information) | 3/8/84<br><br>(A/C # 3-019-04)<br><br>A310-037-84<br><br>District Contact:<br>Mark Boese<br>San Joaquin Valley Unified APCD<br>(Stanislaus County APCD)<br><br>(209) 571-6908 | **NOx**<br>(Detailed Control Information)<br>Oxygen trim control, Hague International MJ-900-D burner with flue gas recirculation and staged combustion<br><br>65 ppm @ 3% O2<br>---------- |
| University Cogeneration LTD - 1983<br><br>8563 KW Solar Mars natural gas-fired turbine with water injection and waste heat unfired boiler<br><br>(Detailed Information) | 3/21/84<br><br>(A/C # 4133001)<br><br>A330-036-84<br><br>District Contact:<br>Tom Paxson<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(805) 861-3682 | **NOx**<br>(Detailed Control Information)<br>Water injection, 0.9/1.0 w/f<br><br>714 lb/day<br>---------- |

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| Salyer Grain & Milling Company<br><br>800 bales/day Lummus 5-158 Saw cotton gin<br><br>(Detailed Information) | 7/20/83<br><br>(A/C # 8323)<br><br>A370-034-83<br><br>District Contact:<br><br>George Heinen<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(599) 230-5909<br>george.heinen@valleyair.com | **PM**<br>(Detailed Control Information)<br>Lummus Industries, Inc. 1D-3D cyclones vented to dual rotary drum filtration units<br><br>17 lb/hr<br>---------- |
| Tankage change of service and vapor control system modification<br><br>Rerun charge and heavy naptha storage tanks<br><br>(Detailed Information) | 1/4/84<br><br>(A/C # 218009C, 059-61)<br><br>A350-032-84<br><br>District Contact:<br>Tom Paxson<br>San Joaquin Valley Unfied APCD<br>(former Kern County APCD)<br>(805) 861-3682 | **VOC/HC**<br>(Detailed Control Information)<br>Incineration of vapors in existing refinery fuel gas system<br><br>95% control efficiency<br>---------- |
| Angus Petrotech<br><br>62.5 MMBtu/hr oil-filled steam generator w/scrubber & "low NOx" burner<br><br>(Detailed Information) | 11/29/83<br><br>(A/C # 4132002-004)<br><br>A310-23-83<br><br>District Contact:<br>Tom Paxson<br>Kern County APCD<br>(Now the San Joaquin Valley Unified APCD)<br>(805) 861-3682 | **SOx**<br>(Detailed Control Information)<br>Diglycolamine absorbing system for hydrogen sulfide removal<br><br>95% control efficiency<br>61.4 lb/day<br>---------- |
| Warren Petroleum (Natural Gas Processing Orern) | 10/19/83<br><br>(A/C # 2023008, 2023009, | **NOx**<br>(Detailed Control Information) |

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| 2133 hp Waukesha natural gas-fired internal combustion engine<br><br>(Detailed Information) | and 2023016)<br><br>A330-020-83<br><br>District Contact:<br>Tuan Ngo<br>San Joaquin Valley Unified APCD<br>(former Kern County APCD)<br>(805) 861-3682 | Johnson Metthey, Inc. JMI "rich burn" catalytic converter<br><br>1.5 gr/bhp-hr<br>---------- |
| Snack Foods Plant<br><br>72 MMBtu/hr fuel oil or natural gas-fired process boiler; 507 gal/hr fuel oil or 72,000 scf/hr for natural gas<br><br>(Detailed Information) | 11/11/83<br><br>(A/C # 3082001)<br><br>A310-014-83<br><br>District Contact:<br>Tom Paxson<br>Kern County APCD<br>(Now the San Joaquin Valley Unified APCD)<br>(805) 861-3682 | **NOx**<br>(Detailed Control Information)<br>Low NOx burners & low sulfur fuel oil (.25% by weight) to be used only during periods of gaseous fuel unavailability<br><br>75 ppmv @ 3% O2<br>6.8 lbm/hr<br>----------<br>**SOx**<br>(Detailed Control Information)<br>Low sulfur fuel oil (.25% by weight) to be used only during periods of gaseous fuel unavailability<br><br>18.2 lbm/hr<br>----------<br>**PM**<br>(Detailed Control Information)<br>Low sulfur fuel oil (0.25% by weight) to be used only during periods of gaseous fuel unavailability |

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| | | 1 lb/hr<br>---------- |

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# BACT Clearinghouse Database Lookup Results

## Displaying 166 of 166 Match(s) for Code 200

## Miscellaneous

| Project Name & Description | A/C Issue Date & ARB File No. | Pollutant |
|---|---|---|
| Cannery - Stanislaus Food<br><br>125,000 lb/hr Ward-Schmid Nebraska model NS-G-101 steam boiler<br><br>(Detailed Information) | 3/8/84<br><br>(A/C # 3-019-04)<br><br>A310-037-84<br><br>District Contact:<br>Mark Boese<br>San Joaquin Valley Unified APCD<br>(Stanislaus County APCD)<br><br>(209) 571-6908 | **NOx**<br>(Detailed Control Information)<br>Oxygen trim control, Hague International MJ-900-D burner with flue gas recirculation and staged combustion<br><br>65 ppm @ 3% O2<br>---------- |
| Ultrasystems-Blue Lake<br><br>162 MMBtu/hr wood-waste fueled steam/electric generation plant with cascade type fuel dryer<br><br>(Detailed Information) | 1/12/84<br><br>A/C # HAC-129)<br><br>A320-029-84<br><br>District Contact:<br>Chuck Sassenrath<br>North Coast Unified AQMD<br>(707) 443-3093<br>ncuaqmd@northcoast.com | **PM**<br>(Detailed Control Information)<br>Multiclones and granular bed electro-scrubber for particulate//furnace combustion design for CO, NOx, and HC<br><br>0.045 lb/MMBtu<br>---------- |
| Aeroject Strategic Propulsion<br><br>Chemical Process | 4/1/83<br><br>(A/C # 7542) | **VOC/HC**<br>(Detailed Control Information)<br>VIC regenerative |

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| (Detailed Information) | A430-028-83<br><br>District Contact:<br>Robert Knight<br>Sacarmento Metropolitan AQMD<br>(916) 874-4800 | carbon adsorber<br><br>45 lb/day |
| American Lignite Cogeneration<br><br>240 MMBtu/hr Recirculating fluid bed combustion boiler with baghouse<br><br>(Detailed Information) | 12/21/83<br><br>(A/C # No A/C)<br><br>A310-025-83<br><br>District Contact:<br>Earl Withycombe<br>Amador County APCD<br>(209) 274-2407 | **NOx**<br>(Detailed Control Information)<br>Low bed temp, staged combustion<br><br>61.40 lbm/hr<br>247.97 tons/yr<br>---<br>**SOx**<br>(Detailed Control Information)<br>Limestone injection into fluid bed<br><br>65.34 lbm/hr<br>262.43 tons/yr<br>---<br>**PM**<br>(Detailed Control Information)<br>Multiclone/Baghouse<br><br>7.88 lbm/hr<br>31.77 tons/yr |
| Hayfork Cogeneration Project<br><br>236 MMBtu/hr wood waste-fired steam/electric generation plant<br><br>(Detailed Information) | 12/14/83<br><br>(A/C # TAC-012<br><br>A320-024-83<br><br>District Contact:<br>Chuck Sassenrath | **NOx**<br>(Detailed Control Information)<br>Furnace combustion design<br><br>0.15 lb/MMBtu |

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|---|---|---|
| | (707) 443-3093<br>ncuaqmd@northcoast.com | **SOx**<br>(Detailed Control Information)<br>Furnace combustion modification<br><br>0.35 lb/MMBtu<br>---<br>**PM**<br>(Detailed Control Information)<br>Multiclones and ESP<br><br>0.04 lb/MMBtu<br>---<br>**VOC/HC**<br>(Detailed Control Information)<br>Furnace combustion design<br><br>0.07 lb/MMBtu<br>--- |
| Pacific Refinery Modification<br><br>2.75 MMBtu/hr refinery hydrogen reformer furnace, H-4011<br><br>(Detailed Information) | 9/28/83<br><br>(A/C # 29180)<br><br>A310-022-80<br><br>District Contact:<br>Leonard Clayton<br>Bay Area AQMD<br>(415) 771-6000 | **NOx**<br>(Detailed Control Information)<br>Ammonia injection and selective catalytic reduction unit<br><br>20 ppm @ 3% O2<br>85% control efficiency<br>--- |
| Pacific Refinery Modifications<br><br>Refinery fuel gas system<br><br>(Detailed Information) | 9/28/83<br><br>(A/C # 29180)<br><br>A350-021-83 | **SOx**<br>(Detailed Control Information)<br>Diglycolamine absorbing system for H2S removal |

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|---|---|---|
| | District Contact:<br>Leonard Clayton<br>Bay Area AQMD<br>(415) 771-6000 | 50 ppm H2S in fuel gas<br>---------- |
| Stecher - Travng - Schmidt<br><br>Varnisher drying oven, dry-sys, on varnisher 261<br><br>(Detailed Information) | 10/8/82<br><br>(A/C #28246)<br><br>A340-015-82<br><br>District Contact:<br>Ellen Linder<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Hirt model FLX-7M fume incinerator<br><br>90 % overall control efficiency<br>97% (in-out of incinerator)<br>---------- |
| Mr. Spa's, Inc.<br><br>Gel coat & polyester resin application- manufacture of fiberglass spas<br><br>(Detailed Information) | 9/8/83<br><br>(A/C # 1240-1)<br><br>A340-013-83<br><br>District Contact<br><br>Keith Doval<br>Ventura County APCD<br>(805) 654-2664 | **VOC/HC**<br>(Detailed Control Information)<br>Increase styrene content in gel coat (to 41%)//Use of filler material in resin//vapor suppressant agents in resin<br><br>63% reduction<br>---------- |
| Exxon Co. USA - Benicia<br><br>Refinery Process Furnace<br><br>(Detailed Information) | 12/10/80<br><br>(A/C # 27599)<br><br>A310-010-80<br><br>District Contact:<br>Leonard Clayton<br>Bay Area AQMD<br>(415) 771-6000 | **NOx**<br>(Detailed Control Information)<br>Low-Nox burners and thermal de-NOx<br><br>40 ppmvd @ 3% O2<br>70% control efficiency<br>---------- |
| H.S. Crocker Co. Printing | 3/21/83 | **VOC/HC**<br>(Detailed Control |

| | | |
|---|---|---|
| 6 COLDR 64" Printing Press<br><br>(Detailed Information) | (A/C # 28709)<br><br>A340-008-83<br><br>District Contact:<br>Mohamad Mdazed<br>Bay Area AQMD<br>(415) 771-6000 | Information)<br>Limit on VOC centent of inks<br><br>2.5 lb VOC/day<br>---------- |
| Gazette Press Printing<br><br>Two 12950 cfm Tec Printing System drying ovens<br><br>(Detailed Information) | 12/20/82<br><br>(A/C # 28925)<br><br>A340-007-82<br><br>District Contact:<br>Mohamad Mdazed<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Katec, TVA-812 fume incinerator<br><br>95% control efficiency<br>---------- |
| American Metal Decorating Co.<br><br>Paint coating line for metal parts<br><br>(Detailed Information) | 3/7/80<br><br>(A/C # 27361)<br><br>A340-006-80<br><br>District Contact:<br>John Phillips<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>CE Air Preheater Cor-Pak fume incinerator<br><br>87% control efficiency<br>---------- |
| Time Oil Co. (Loading Rack)<br><br>One million gallons per day gasoline bulk loading rack<br><br>(Detailed Information) | 12/23/80<br><br>(A/C # 27611)<br><br>A350-004-82<br><br>District Contact:<br>Dave Dixon<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>McGill activated carbon adsorption system with two beds. Automatically timed desorption cycle<br><br>98.6% control efficiency<br>---------- |

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| TOSCO Corp. Hydrotreating Unit<br><br>5 hp or larger centerifugal pump seals<br><br>(Detailed Information) | 2/19/82<br><br>(A/C # 27769)<br><br>A350-003-82<br><br>District Contact:<br>Jim Karas<br>Bay Area AQMD<br>(415) 771-6000 | **VOC/HC**<br>(Detailed Control Information)<br>Double mechanical seals with a oil seal<br><br>500 ppm<br>---------- |

Click here to return the CAPCOA BACT Search Page

2003

# APPENDIX H

BAAQMD REFINERIES PROPOSED CARFG2 MODIFICATIONS
WITH BACT DETERMINATIONS

# CHEVRON'S PROPOSED CARFG2 OPERATIONAL PHASE EMISSIONS SOURCES WITH BACT DETERMINATIONS

New Sources

S-4355 DIB/ Butamer Plant
S-4356 Tertiary Amyl Methly Ether (TAME) Plant
S-3205 Tank, Methanol
S-3206 Tank, Whole Alkylate
S-3207 Tank, FCC Heavy GAsoline
S-3208 Sphere, Butane
S-3209 Sphere, Propane
S-3210 Sphere, Isopropane

Modified Sources

S-4291 Alkylation Plant
S-4357 C4 Treating Plant
S-6053 Alky/TAME Cooling Water Tower Bay
S-6016 FCC Flare
S-6019 Alky/Poly Flare
S-4285 Fluid Catalytic Cracker Unit (FCCU)
S-4353 #3 Naptha Hydrotreater
S-4032 #3 Naptha Hydrotreater, F101
S-4033 #3 Naptha Hydrotreater, F102
S-4346 Gas Recovery Unit
S-4348 $H_2$ Recovery Plant
S-4282 Aromatics Saturation Plant

Best Available Control Technology (BACT) – Regulation 2-2-301 states that BACT must be applied to sources emitting POC, NPOC, NOx, SOx, TSP, PM10, or CO in excess of 5 pounds per highest day or 365 pounds per year. The following are the units triggering this Regulation and their methods of compliance with BACT unless otherwise noted.

Flanges

| Application | Condition | BACT |
|---|---|---|
| All flanges | All new flanges inspected quarterly. Leaks of POC defined as 100ppmv. | Use graphite-based gaskets or equivalents for this level of POC control. |

Valves

| Application | Condition | BACT |
|---|---|---|
| All valves | Valves inspected quarterly. Leaks of POC defined as greater than 100ppmv. | Use bellows valves, lived loaded valves, graphitic packing, or equivalent. All other valves will utilize upgraded packing for this level of POC control. |

Pumps

| Application | Condition | BACT |
|---|---|---|
| All pumps | Pumps inspected quarterly. Leaks of POC defined as greater than 500ppmv. | Use double mechanical seals and barrier fluid or equivalent. Will use double mechanical seals with heavy liquid barrier fluid and/or Chevron's seal vapor recovery system at all light liquid service pumps for this level of POC control. |

Compressors

| Application | Condition | BACT |
|---|---|---|
| All compressors | Compressors inspected quarterly. Leaks of POC defined as greater than 500ppm. | Use double mechanical seals and barrier fluid or equivalent. Use wet enclosed seals and/or Chevron's seal vapor recovery system for this level of POC control. |

Relief Valves

| Application | Condition | BACT |
|---|---|---|
| All relief valves | All pressure relief valves will be vented to a flare gas recovery system, furnace, or flare for POC control. | |

Process Drains

| Application | Condition | BACT |
|---|---|---|
| All process drains | Use p-trap or equivalent method. All new process units will have new process drains with p-traps installed for POC control. | |

## Alkylation Plant

Only new emission from this source is fugitive POC. Will comply with all BACT conditions as stated in tables above with exception of sulfuric acid services.
Sulfuric acid degrades graphitic packing and gaskets, therefore, use Teflon gaskets for flanges and Teflon/graphitic based packing for valves.

## Deisobutanizer/ Butamer Plant

Only new emission from this source is fugitive POC. Will comply with all BACT conditions as stated in tables above.

## C4 Treating Plant

Only new emission from this source is fugitive POC. Will comply with all BACT conditions as stated in tables above.

## TAME Plant

Only new emission from this source is fugitive POC. Will comply with all BACT conditions as stated in tables above.

## Hydrogen Recovery Plant

Only new emission from this source is fugitive POC. Will comply with all BACT conditions as stated in tables above.

## Aromatics Saturation Unit

Only new emission from this source is fugitive POC. Will comply with all BACT conditions as stated in tables above. Valves which are 2 inches or less and are on process streams with greater than 2 wt% benzene shall wherever feasible (but no less than 95% of these valves) be Bellows-sealed valves or District approved technology. Fugitive sources with greater than 10 wt% benzene shall be inspected monthly.

## Alkylation/ TAME Cooling Water Tower Bay

For particulate control, will equip S-6053 Cooling Tower with a high efficiency drift eliminator to reduce drift loss. BACT for POC emissions from this source consists of good operating practice and minimizing POC leaks from process equipment into the cooling water system.

## Flare

BACT is not triggered because incremental increase in emissions from S-6016 and S-6019 are less than 1 pound per day.

## Storage Tanks

All non-LPG tanks equipped with external floating roof tanks. Design criteria will meet but not be limited to dual seals with zero gap secondary seal. All roof penetrations are gasketed, adjustable roof legs fitted with vapor seal boots, and with no slots above liquid level on guide poles. Guide poles with organic liquid inside will have a float fitted with wiper seals.

## FCCU Gasoline Hydrotreater

Only new emission from this source is fugitive POC. Will comply with all BACT conditions as stated in tables above.

## FCC Unit

| Application | Condition | BACT |
|---|---|---|
| POC | Will comply with all BACT conditions as stated in tables above for POC control. Compliance shall be based on annual source tests that demonstrate Chevron will not exceed 6.1 tons POC emissions per year. | |
| NOx | 24hr operating day avg: 220ppmv NOx, 3% $O_2$, dry<br>Rolling 30 day avg: 180ppmv NOx, 3% $O_2$, dry<br>Calendar year avg: 150ppmv NOx, 3% $O_2$, dry | |
| SOx | 24 hr day avg: 330ppmv $SO_2$, 3% $O_2$, dry | |
| CO | Rolling 30 day avg: 67ppmv CO, 3% $O_2$, dry<br>Calendar year avg: 50ppmv CO, 3% $O_2$, dry | |
| PM10 | Compliance shall be based on source tests that demonstrate Chevron will not exceed 21 lb/hr average of 4 source tests per calendar year. | |

## SHELL'S PROPOSED CARFG2 OPERATIONAL PHASE EMISSIONS SOURCES WITH BACT DETERMINATIONS

UNIT DESCRIPTION

A-4002 Delayed Coking Unit SCR
A-4005 Delayed Coking Unit Coke Barn Particulate Fabric Filter
A-4006 Delayed Coking Unit Railcar Loading Particulate Fabric Filter
A-4161 Hydrogen Plant – 3 SCR
A-4180 Sulfur Recovery Unit #4 SCOT Unit
A-4181 Sulfur Recovery Unit #4 Tailgas Thermal Oxidizer
A-4190 Boiler 6 Selective Catalytic Reduction
A-4191 Boiler 6 Catalytic Oxidation
A-4192 Boiler 6 Selective Catalytic Reduction
A-4193 Boiler 6 Catalytic Oxidation
A-4201 Flare Gas Recovery System
S-4001 Delayed Coker Unit
S-4002 Delayed Coker Unit – Furnace No. 1
S-4003 Delayed Coker Unit – Furnace No. 2
S-4004 Delayed Coker Unit – Furnace No. 3
S-4005 Delayed Coker Unit – Coke Handling
S-4010 Coker Gasoline Splitter Column
S-4020 Distillate Hydrotreater
S-4021 DHT Recycle Gas Heater
S-4022 DHT Fractionator Reboiler Heater
S-4023 DHT Heater SCR
S-4030 Cracked Gasoline Bottoming Column
S-4031 Cracked Gasoline Bottoming Column Reboiler Heater
S-4040 Distillate Saturation Unit – 2
S-4041 Distillate Saturation Unit – 2 Feed Heater
S-4042 Distillate Saturation Unit – 2 Reboiler Heater

UNIT DESCRIPTION

S-4050 Light Cracked Gasoline Treater
S-4080 C5/C6 Isomerization Unit
S-4090 Alkylation Unit
S-4100 Light Cracked Gaosline Hydrotreater
S-4101 LGHT Feed Heater
S-4130 Catalytic Reformate Bottoming Column
S-4140 Heavy Cracked Gasoline Hydrotreater
S-4141 HGHT Feed Heater
S-4150 Butane Isomerization Unit
S-4160 Hydrogen Plant – 3
S-4161 Hydrogen Plant – 3 SMR Furnace
S-4170 Lube Hydrotreater – 2
S-4171 Lube Hydrotreater (LHT-2)Feed Heater
S-4180 Sulfur Recovery Unit #4
S-4182 Sour Water Stripper
S-4183 Sour Water Stripper
S-4190 Boiler 6 Gas Turbine #1
S-4191 Boiler 6 Supplmt Steam Generator #1
S-4192 Boiler 6 Gas Turbine #2
S-4193 Boiler 6 Supplemental Steam Generator #2
S-4201 Flare
S-4210 Cooling Tower
S-4211 Maintenance Drop Out Vessel
S-4212 Maintenance Drop Out Vessel
S-4338 Pentane Loading Facility
S-4347 Sulfur Pit
S-4350 Process Wastewater Tank
S-4356 Process Wastewater Tank

NEW TANKS

S-4301 Spent Sulfuric Acid Tank; abated by A-33, Flare Gas Recovery System
S-4307 MDEA Make-up Tank
S-4308 DEA Tank #2
S-4309 DEA Tank #1
S-4310 Sour Water Tank
S-4311 Perchloroethylene Tank (pressurized)
S-4312 Perchloroethylene Tank (pressurized)
S-4319 Recovered Oil Tank; abated by A-56, Vapor Recovery
S-4321 DCU Feed Tank
S-4325 Isom Feed Tank
S-4329 Pentane Tank (pressurized); abated by A-4330, Pentane Vapor Recompression
S-4330 Pentane Tank (pressurized); abated by A-4330, Pentane Vapor Recompression
S-4333 Dimate Tank
S-4334 Alkylate Tank; by A-25, Vapor Recover
S-4335 Crude Oil Tank #1
S-4336 Crude Oil Tank #2
S-4346 Sulfuric Acid Tank
S-4349 Pentane Tank (pressurized); abated by A-4330, Pentane Vapor Recompression
S-4351 Process Wastewater Tank; abated by A-56, Vapor Recovery
S-4350 Olefin Storage (pressurized)
S-4354 Crude Oil Tank #3
S-4355 Crude Oil Tank #4
S-4356 Process Wastewater Tank; abated by A-56, Vapor Recovery

EXISTING TANKS

S-1129 Gaso Interim Tank (Tank 1129)
S-1130 Gaso Interim Tank (Tank 1130)
S-1131 Gaso Interim Tank (Tank 1131)

The following is a breakdown of BACT determinations:

Furnaces

| Application | Condition | BACT |
|---|---|---|
| All furnaces with a design firing rate greater than or equal to 50 MMBTU/hr | 10ppmv corrected to 3% $O_2$, avg. over 3 hrs | Use combination of low NOx burners & selective catalytic reduction (SCR) for this level of NOx control. |
| All natural draft furnaces with a design firing rate less than 50 MMBTU/hr | 25ppmv corrected to 3% $O_2$, avg. over 3 hrs | Use low NOx burners for this level of NOx control. |
| All forced draft furnaces with a design firing rate less than 50 MMBTU/hr | 20ppmv corrected to 3% $O_2$, avg. over 3 hrs | Use combination of low NOx burners and/or flue gas recirculation for this level of NOx control. |
| All furnaces, except hydrogen plant furnace (S-4161) | Combustion of refinery fuel gas or other gaseous fuel that does not exceed 50ppmv $H_2S$, avg. over 24 hrs | Use fuel gas amine treating system for this level of $SO_2$ control. |
| All furnaces, except S-4161 | 50ppm at 3% $O_2$, averaged over 8 hrs | Use an air to fuel ratio controller on each furnace for this level of CO control. |
| Hydrogen plant furnace S-4161 | Combustion of refinery fuel gas and pressure swing absorber (PSA) gas. Refinery fuel gas will not exceed 50ppmv $H_2S$, avg. over 24 hrs. Total reduced sulfur in the refinery fuel gas will not exceed 100ppm, annual avg. The PSA gas will not exceed 3.6ppm $H_2S$ avg. over 24 hrs. For $SO_2$ control. | |
| Hydrogen plant furnace S-4161 | Due to its large firing rate, limit of 25ppm at 3% $O_2$, averaged over 8hrs | |

Gas Turbines & Cogeneration plant

| Application | Condition | BACT |
|---|---|---|
| Cogeneration Plant | 5ppmv corrected to 15% , avg. over 3 hrs | Use steam injection & SCR for this level of NOx control. |
| Gas Turbines | Combustion of refinery fuel gas that does not exceed 50ppmv $H_2S$, avg. over 24 hrs | Use fuel gas amine treating system for this level of $SO_2$ control. |
| Gas Turbines | Limit of 6.5ppm at 15% $O_2$, avg over 8hrs or 90% overall reduction on a mass basis | Use non-selective catalytic oxidizer for this level of CO control. |
| Gas Turbine | Precursor Organic Compounds (POC) emissions | Use non-selective catalytic oxidizer for POC control. |

Flares

| Application | Condition | BACT |
|---|---|---|
| Flare | Steam assisted ground level flare with staged combustion. Pilots will be fueled with natural gas or LPG. The flare will be operated only during period of emergency upset or breakdown. Routine venting of process gases will go to the flare gas recovery system. For $SO_2$, CO, and PM control. | |
| Flare | Steam assisted ground level flare with staged combustion. The hydrocarbon destruction efficiency will be at least 98.5% on a mass basis. Pilots will be fueled with natural gas or equivalent. The flare will be operated only during period of emergency upset or breakdown. Routine venting of process gases will go to the flare gas recovery system. For POC control. | |

Sulfur Recovery System

| Application | Condition | BACT |
|---|---|---|
| Sulfur Recovery System #4 (SRU) | Exhaust from feed to tailgas incinerator will be limited to contain no more than 100ppm total reduced sulfur at 0% $O_2$. $SO_2$ and $H_2S$ emissions from the tailgas oxidizer will not exceed 50 and 2.5ppm at 0% $O_2$. The sulfur pit will be enclosed and vented to the tailgas oxidizer. Sour $H_2O$ strippers will remove 95% wt of the $H_2S$ and $NH_3$ from the sour $H_2O$ stream. The SRU and SCOT will achieve at least a 99.9% wt conversion of to elemental $H_2S$ sulfur. | Use SCOT (Shell Claus Offgas Treatment) unit and a tailgas thermal oxidizer for this level of $SO_2$ control. |
| SRU #4 | CO limit of 100ppm in the exhaust from the Thermal Oxidizer. | Meet limit by using good combustion practices. |

Pumps

| Application | Condition | BACT |
|---|---|---|
| Pumps in light liquid hydrocarbon service | Pumps inspected quarterly. Leaks of POC defined as greater than 500ppm. | Use double mechanical seals with a barrier fluid. The barrier fluid shall be either: 1) vented to a control device with a 95% efficiency; or 2) at a higher pressure than the process stream pressure. |

Compressors

| Application | Condition | BACT |
|---|---|---|
| Compressors in hydrocarbon service | Pumps inspected quarterly. Leaks of POC defined as greater than 500ppm. | Use double mechanical seals with a barrier fluid. The barrier fluid shall be either: 1) vented to a control device with a 95% efficiency; or 2) at a higher pressure than the process stream pressure. |

Valves

| Application | Condition | BACT |
|---|---|---|
| Valves in gaseous, light liquid, or toxic services | Valves inspected quarterly. Leaks of POC defined as greater than 100ppm. | Valves will be bellows sealed, lived loaded, graphitic packed, Teflon packed, or equivalent. Control valves will be live loaded with graphite packing and polished stems. |

Flanges

| Application | Condition | BACT |
|---|---|---|
| All flanges | Equipped with graphitic or Teflon gaskets, or equivalent for POC control. | |

Pressure Relief Valves

| Application | Condition | BACT |
|---|---|---|
| All pressure relief valves in hydrocarbon service | All pressure relief valves will be vented to the flare gas recovery system for POC control. | |

Tanks

| Application | Condition | BACT |
|---|---|---|
| Pressurized Tanks (6) | Vapor recompression or operate under a minimum pressure of 15 psig for POC control. | |
| New Storage Tanks (4) | Use existing vapor recovery systems for POC control. | |
| Remaining Tanks | Use external floating roof tanks. External floating roof tanks will have zero-gap secondary seals and with the exception of adjustable roof legs, the lowest emitting roof fittings, including: no ungasketted roof penetrations, and no slotted guide poles. Adjustable roof legs will be controlled by vapor seal boots. For POC control. | |

Wastewater

| Application | Condition | BACT |
|---|---|---|
| Maintenance Drop Out vessels | Enclosure and venting to the flare gas recovery system for POC control. | |

Cooling Tower

| Application | Condition | BACT |
|---|---|---|
| Cooling Tower | Installation of a hydrocarbon monitor to enhance the detection of hydrocarbon leaks to the cooling water system for POC control. | |

Railcar Loading (Pentane)

| Application | Condition | BACT |
|---|---|---|
| Pentane railcar loading operation | Use existing LPG flare (S-1470) for POC control. | |

Coke Handling

| Application | Condition | BACT |
|---|---|---|
| Coke handling operations | 1) Coke moisture content of at least 8% wt; 2) water supression at the crusher and coke barn piles; 3) an enclosed conveying system; 4) an enclosed coke barn controlled by a particulate filter; 5) a shrouded railcar loading operation controlled by a particulate filter; and 6) a vehicle wash-off area inside of the coke barn. | |

# PACIFIC'S PROPOSED CARFG2 OPERATIONAL PHASE EMISSIONS SOURCES WITH BACT DETERMINATIONS

| Unit | Description |
|---|---|
| A-109 | Catalytic Converter abating S-270 |
| A-110 | SCR system abating S-271 |
| [illegible] | [illegible] |
| A-270 | SCR system abating S-270 |
| A-275 | SCR system abating S-275 |
| A-276 | Offgas Scrubber |
| A-278 | SCR system abating S-278 |
| A-279 | SCR system abating S-279 |
| A-281 | North Vapor Recovery System abating S-281 & S-282 |
| A-283 | South Vapor Recovery System abating S-283, S-285, S-286, S-287, & S-288 |
| A-368 | Electrostatic Precipitator abating S-268 |
| A-378 | Oxidizing Catalysts abating S-278 |
| A-379 | Catalytic Converter abating S-279 |
| A-468 | Wet Gas Scrubber abating S-268 |
| S-250 | Crude / Vacuum Unit |
| S-252 | Unifiner Heater 2-H-102 |
| S-253 | Unifiner Reboiler 2-H-102 |
| S-254 | Fluid Catalytic Cracking Unit |
| S-255 | Feed Heater 3-H-201 |
| S-256 | Alkylation Unit |
| S-257 | Diesel Hydrotreater |
| S-258 | Feed Heater 7-H-101 |
| S-259 | Feed Heater 7-S-102 |
| S-273 | Isomerization Unit |
| S-274 | Gas Oil Hydrotreater |
| S-275 | Feed Heater 19-H-101 |
| S-276 | Sulfuric Acid Regeneration Plant |
| S-277 | Sulfuric Acid Combustor Furnace |
| S-278 | Gas Turbine 79-T-101 |
| S-279 | Gas Turbine 79-T-102 |
| S-281 | Crude Storage Tank 80-TK-101A |
| S-282 | Crude Storage Tank 80-TK-101B |
| S-283 | Naptha Storage Tank 80-TK-102 |
| S-285 | FCCU Feed Tank 82-TK-101A |
| S-286 | FCCU Feed Tank 82-TK-101B |
| S-287 | Diesel Hydrotreater Feed Tank 82-TK-102A |
| S-288 | Diesel Hydrotreater Feed Tank 82-TK-102B |
| S-296 | Cooling Tower |
| S-79 | Unifiner/ Platformer |

Crude/ Vacuum Unit (S-250)

| Application | Condition | BACT |
|---|---|---|
| All Flanges | All new flanges inspected monthly. Leaks of POC defined as 100ppmv. | Use flanges with graphite-based gaskets or equivalent. |
| Valves (general) | Valves inspected monthly. Leaks defined as greater than 100ppmv. | Use bellows valves, live-loaded valves, graphite-based packing, or equivalent. |
| New valves in light liquid & gas service 2" and < | Valves inspected monthly. Leaks defined as greater than 100ppmv. | Use bellows valves. |
| All other valves | Valves inspected monthly. Leaks defined as greater than 100ppmv. | Use upgraded packing for all other valves. |
| Pumps | Pumps inspected monthly. Leaks defined as 100ppmv or greater. | Use double mechanical seals with heavy liquid barrier fluid, or canned or mag drive pumps. |
| Compressors | Compressors inspected monthly. Leaks defined as 100mmpv. | Use double mechanical seals and barrier fluid or equivalent. |
| Relief Valves | Recovery system, furnace or flare must have recovery/destruction efficiency of at least 98%. | Use rupture disks and vent to a fuel gas recovery system, furnace or flare. |

| | | |
|---|---|---|
| Process drains | BACT must achieve approximately 80% control. | Use of p-trap or equivalent method. |
| Sample connections | N/A | Consists of closed loop sampling systems with an inert purge gas and venting to a control device. Septum sealed jars used for sampling. |

Naptha Hydrotreater (S-252 & S-253; heater rated capacity of 24.55 & 23.25 MMBtu/hr)

| Application | Condition | BACT |
|---|---|---|
| $NO_x$ | Emissions limit of 10ppm $NO_x$ corrected to 3% $O_2$, dry. | Use low $NO_x$ burners and SCR (A-252) on S-252 & S-253. Will abate approx. 90% of $NO_x$. |
| POC | BACT is not determined | Good combustion practices and efficient operation for POC control. |
| $SO_2$ | Gas used will not have $H_2S$ level greater than 50ppm. | Use natural gas or treated refinery gas fuel for this level of $SO_2$ control. |
| PM | BACT 1 is not determined. BACT 2 is triggered. | BACT 2 specifies the use of natural gas or treated refinery fuel gas for PM control. |

Isomerization Unit (S-273)

| Application | Condition | BACT |
|---|---|---|
| POC | Unit emits only fugitive POC. | BACT for control of fugitive POC emissions same as for Crude Unit (S-250) above. |

Diesel Hydrotreater (S-257)

| Application | Condition | BACT |
|---|---|---|
| POC | Unit emits only fugitive POC. | BACT for control of fugitive POC emissions same as for Crude Unit (S-250) above. |

Diesel Hydrotreater (S-258 & S-259; heater rated capacity of 28.57 & 32.47 MMBtu/hr)

| Application | Condition | BACT |
|---|---|---|
| $NO_x$ | Emissions limit of 10ppm $NO_x$ corrected to 3% $O_2$, dry. | Use low $NO_x$ burners and SCR (A-258) on S-258 & S-259. Will abate approx. 90% of $NO_x$. |
| POC | BACT is not determined | Good combustion practices and efficient operation for POC control. |
| $SO_2$ | Gas used will not have $H_2S$ level greater than 50ppm. | Use natural gas or treated refinery gas fuel for this level of $SO_2$ control. |
| PM | BACT 1 is not determined. BACT 2 is triggered. | BACT 2 specifies the use of natural gas or treated refinery fuel gas for PM control. |

Gas Oil Hydrotreater (S-274)

| Application | Condition | BACT |
|---|---|---|
| POC | Unit emits only fugitive POC. | BACT for control of fugitive POC emissions same as for Crude Unit (S-250) above. |

Gas Oil Hydrotreater (S-275; heater rated capacity of 59.2 MMBtu/hr)

| Application | Condition | BACT |
|---|---|---|
| $NO_x$ | Emissions limit of 10ppm $NO_x$ corrected to 3% $O_2$, dry. | Use low $NO_x$ burners and SCR (A-275) on S-275. Will abate approx. 90% of $NO_x$. |
| POC | BACT is not determined | Good combustion practices and efficient operation for POC control. |
| $SO_2$ | Gas used will not have $H_2S$ level greater than 50ppm. | Use natural gas or treated refinery gas fuel for this level of $SO_2$ control. |
| PM | BACT 1 is not determined. BACT 2 is triggered. | BACT 2 specifies the use of natural gas or treated refinery fuel gas for PM control. |

Hydrogen Plant (S-269)

| Application | Condition | BACT |
|---|---|---|
| POC | Unit emits only fugitive POC. | BACT for control of fugitive POC emissions same as for Crude Unit (S-250) above. |

Hydrogen Plants (S-270, S-271, S-272; heater rated capacity of 125 MMBtu/hr)

| Application | Condition | BACT |
|---|---|---|
| $NO_x$ | BACT 1 is not determined. BACT 2 is an emissions limit of 10ppm $NO_x$ corrected to 3% $O_2$, dry. | Use low $NO_x$ burners and SCR (A-270, A-110, A-112, respectively) on S-270, S-271, S-272. Will abate approx. 90% of $NO_x$. |
| POC | BACT is not determined. POC emissions limited to no more than 6.4 lb/day / heater | Use oxidizing catalysts for all three heaters for this level of POC control. |
| $SO_2$ | Gas used will not have $H_2S$ level greater than 50ppm. | Use natural gas or treated refinery gas fuel for this level of $SO_2$ control. |
| PM | BACT 1 is not determined. BACT 2 is triggered. | BACT 2 specifies the use of natural gas or treated refinery fuel gas for PM control. |

Fluidized Catalytic Cracking Unit (S-254 & S-266)

| Application | Condition | BACT |
|---|---|---|
| POC | Unit emits only fugitive POC. | BACT for control of fugitive POC emissions same as for Crude Unit (S-250) above. |

Fluidized Catalytic Cracking Unit (S-255; heater rated capacity of 24 MMBtu/hr)

| Application | Condition | BACT |
|---|---|---|
| $NO_x$ | Emissions limit of 10ppm $NO_x$ corrected to 3% $O_2$, dry. | Use low $NO_x$ burners and SCR (A-255) on S-275. Will abate approx. 90% of $NO_x$. |
| POC | BACT is not determined | Good combustion practices and efficient operation for POC control. |
| $SO_2$ | Gas used will not have $H_2S$ level greater than 50ppm. | Use natural gas or treated refinery gas fuel for this level of $SO_2$ control. |
| PM | BACT 1 is not determined. BACT 2 is triggered. | BACT 2 specifies the use of natural gas or treated refinery fuel gas for PM control. |

Fluidized Catalytic Cracking Unit (S-268; heater rated capacity of 35.9 MMBtu/hr)

| Application | Condition | BACT |
|---|---|---|
| $NO_x$ | BACT 1 not specified. Emissions limit of 10ppm $NO_x$ corrected to 3% $O_2$, dry. | Use SCR, flue gas recirculation, low-$NO_x$ burners and reduced-air preheat. Use low $NO_x$ burners and SCR (A-268) on S-268. |
| POC | BACT is not determined | Good combustion practices and efficient operation for POC control. |
| $SO_2$ | Gas used will not have $H_2S$ level greater than 50ppm. | Use natural gas or treated refinery gas fuel for this level of $SO_2$ control. S-268 will be equipped with a wet gas scrubber (A-468) that removes $SO_2$ from the flue gas. The controlled $SO_2$ level in the flue gas is estimated to be 10ppm corrected to 3% $O_2$. |
| PM | BACT 1 is not determined. BACT 2 is triggered. | BACT 2 specifies the use of an electrostatic precipitator (ESP). S-268 will be equipped with an ESP (A-368). |

Alkylation Unit (S-256)

| Application | Condition | BACT |
|---|---|---|
| POC | Unit emits only fugitive POC. | BACT for control of fugitive POC emissions same as for Crude Unit (S-250) above. |

Sulfuric Acid Regeneration Plant (S-276)

| Application | Condition | BACT |
|---|---|---|
| POC | Unit emits only fugitive POC. | BACT for control of fugitive POC emissions same as for Crude Unit (S-250) above. |
| $NO_x$ & $SO_x$ | Will remove over 94% of the $NO_x$ & $SO_x$ from the plant. | S-276 will be equipped with a "Trimer" tail gas scrubber (A-276) for $SO_2$ and NOx control. |

Storage Tanks – Internal Floating Roof (S-281, S-282, S-283, S-287, S-288)

| Application | Condition | BACT |
|---|---|---|
| POC | Vapor recovery system overall efficiency of at least 95%. Satisfies BACT 1 (technologically feasible/ cost effective). | Internal floating roof tanks hooked up to one of two vapor recovery systems (A-281 & A-283), each leading to an incinerator. Tanks are also equipped with a nitrogen padding control system to maintain tank pressure. |

Storage Tanks – Fixed Roof (S-285, S-286)

| Application | Condition | BACT |
|---|---|---|
| POC | Vapor recovery system overall efficiency of at least 95%. Satisfies BACT 2 (achieved in practice). BACT 1 not determined. | Fixed roof tanks equipped with a nitrogen padding control system and steam coils. Tanks are hooked up to the A-283 vapor recovery system. |

Cogeneration Plants (S-278, S-279; heater rated capacity of 193.5 MMBtu/hr)

| Application | Condition | BACT |
|---|---|---|
| $NO_x$ | Emissions limit of 5ppm $NO_x$ corrected to 15% $O_2$, dry. | Use steam injection and SCR (A-278 & A-279) on S-278 & S-279 for this level of $NO_x$ control. |
| POC | Abatement of at least 50%. | Both turbines will be equipped with oxidation catalysts (A-378 & A-379) which will achieve approximately 90% reduction. |
| $SO_2$ & $PM_{10}$ | 50ppm $H_2S$ maximum, 29ppm avg. | Use natural gas as primary fuel, and refinery fuel gas and butane as supplemental fuels. |

Cooling Tower (S-296)

| Application | Condition | BACT |
|---|---|---|
| POC | | Good operating practice and minimizing POC leaks from process equipment into the cooling water system. |
| PM | | Equip cooling tower with drift eliminator to reduce drift loss to 0.01%. |

# EXXON'S PROPOSED CARFG2 OPERATIONAL PHASE EMISSIONS SOURCES WITH BACT DETERMINATIONS

| New Sources | | Modified Sources | |
|---|---|---|---|
| S-1020 | Heartcut Tower | S-1003 | Hydrocracking Unit |
| S-1021 | Heartcut Saturation Unit | S-1007 | Alkylation Unit |
| S-1022 | Catalytic $T_{90}$ Reformer | S-1011 | Heavy Catalytic Naptha Hydrotreater |
| S-1023 | Catalytic Naptha $T_{90}$ Reformer | S-1014 | Virgin Light End Unit |
| S-1024 | Light Catalytic Naptha Hydrofiner | S-151 | Waste Water Treatment Plant |
| S-1025 | C5/C6 Splitter | S-21 | Hydrogen Furnace F-301 |
| S-220 | Hot Oil Furnace | S-22 | Hydrogen Furnace F-351 |
| S-227 | Pentane (C5) Fixed Storage Tank | | |
| S-228 | C5 Fixed Storage Tank | | |
| S-229 | C5 Fixed Storage Tank | | |
| S-230 | Hot Oil Fixed Storage Tank | | |
| S-231 | Aqueous Ammonia Fixed Roof Storage Tank | | |

Furnaces

| Application | Condition | BACT |
|---|---|---|
| All furnaces with a design firing rate greater than or equal to 50 MMBTU/hr (S-220) | 10ppmv corrected to 3% $O_2$, avg. over 3 hrs | Use a combination of low NOx burners and selective catalytic reduction (SCR) for this level of NOx control. |
| Hydrogen furnaces (S-21 & S-22) | Due to a field test in Jan 1992 not triggering BACT for NOx, a BARCT NOx level of 28ppmv is being proposed. ('92 test of furnace determined uncontrolled NOx level of 99.5ppm at 3% $O_2$) | Use a combination of low NOx burners and/or thermal deNOx to meet a 35ppm NOx level. |
| All furnaces (S-21, S-22, S-220) | Combustion of refinery fuel gas and/or LPG/pentane gases with a total reduced sulfur concentration not to exceed 65 ppmv, annualized 24hr avg based on BACT cost effectiveness discussion*. Daily limit for these furnaces not to exceed $H_2S$ concentration of 100ppmv, avg. over 24hrs | Based on BACT #1 level being non-cost effective, BACT #2 is to modify the existing MEA scrubbing system to enhance scrubbing capabilities for the removal of $H_2S$** and this level of $SO_2$ control. |
| All furnaces (S-21, S-22, S-220) | 28ppmv at 3% $O_2$, avg. over 8hrs | Best combustion practices as guaranteed by John Zink burner manufacturer for this level of CO control. |

* Note: There is no annualized state average. SO2 BACT determination discussion and explanation from Exxon BAAQMD A/C dated 12/2/93, Application #10392 ppg 9-11

** BACT#2 level determination discussion and explanation from Application #10392 as mentioned above.

Pumps

| Application | Condition | BACT |
|---|---|---|
| Pumps in light liquid hydrocarbon service | Pumps inspected in accordance with Regulation 8, Rule 25. Leaks of POC defined as greater than 500ppm. | Use double mechanical seals with a barrier fluid. The barrier fluid shall be either: 1) vented to a control device with at least 99.5% efficiency; or 2) held at a higher pressure than the process stream pressure for this level of POC control. |

Compressors

| Application | Condition | BACT |
|---|---|---|
| Compressors in hydrocarbon service | Compressors inspected quarterly. Leaks of POC defined as greater than 500ppm. | Use "wet" dual mechanical seals with a heavy liquid barrier fluid or dual gas mechanical seals buffered with inert gases. All reciprocating compressors shall be vented to at least a 99.5% efficient control device for this level of POC control. |

Valves

| Application | Condition | BACT |
|---|---|---|
| All hydrocarbon valves | Accessible valves inspected quarterly and inaccessible valves inspected annually. Leaks of POC defined as greater than 100ppm. | Valves will be lived loaded, bellows, graphitic packed, Teflon packed, or equivalent. All hydrocarbon control valves will be live loaded with graphite packing and polished stems or equivalent for this level of POC control. |

Flanges

| Application | Condition | BACT |
|---|---|---|
| All flanges | Leaks of POC defined as greater than 500ppm. | Equipped with graphitic gaskets, except in services that are not compatible with graphitic material for this level of POC control. |

Pressure Relief Valves

| Application | Condition | BACT |
|---|---|---|
| All pressure relief valves in hydrocarbon service | All pressure relief valves will be vented to the flaring system or fuel gas recovery system for POC control. | |

Tanks

| Application | Condition | BACT |
|---|---|---|
| New pentane storage tanks (S-227, S-228, S-229) | At least 99.5% control | Use existing vapor recovery systems (A-46, A-47, A-48, A-49). Prior to venting to units A-46 through A-49, these storage tanks will have an auto refrigeration vapor recovery system for this level of POC control. |

CARB

Attachment C

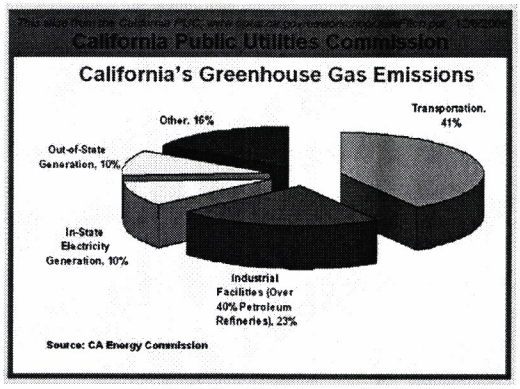
**Oil Refinery Sector Recommendations**

# Summary: **Reduce California Refinery GHG & Other Emissions, Reduce Product Demand**

| | DIRECT GHG REDUCTION METHODS | BENEFITS & BARRIERS |
|---|---|---|
| **1. Require Oil Refineries to become more efficient**<br><br>*→NO TRADING: Reductions generated through cleaning up oil refineries are necessary for local, regional, and global public health* | • **Energy Efficiency Audit for every refinery →require BACT first for biggest sources** Up front BACT for already-known big energy users (don't wait to finish audits) for Hydrogen Plants, Hydrotreaters, Hydrocrackers, Cracking, Coking, including Boilers & Heaters. [Many have grandfathered exemptions from modernized emission standards.]<br>• Cogeneration from Waste Heat, audit efficiency & indirect impacts, require BACT<br>• **Remove all Methane Exemptions in smog regulations for refineries and all sources**<br>• No dumping and burning of "waste" gases: Flare BACT/LAER (beyond BAAQMD & SCAQMD requirements) -- Apply Shell Martinez BACT model – far lower flaring than other refineries, Pressure Relief Devices: Ban venting to atmosphere<br>• **Set goal for reduction in Refinery Emissions & Product Demand (e.g. 25% by 2020)** | • Local pollution down, Jobs Up<br>• **Direct Controls avoid pollution trading pitfalls** (failure to address local health impacts, creating toxic hotspots by trading for clean-up elsewhere, major accounting errors due to poor baselines lack of monitoring, toxic co-pollutant inequalities, lack of public input)<br>• Refiner cost up in short term, probably mid term savings |
| **2. Stop refinery expansions & the switch to dirty crude oil** | • Crude Oil carbon input standard to stop the switch to dirtier crude oils in the state<br>• No new fossil fueled Hydrogen Plants, Hydrocrackers, Cokers, etc. associated with switch to high carbon, dirty crude, and refinery expansions<br>• Carbon tax & windfall profit taxes to fund clean alternative energy and jobs transition<br>• Low Carbon Fuel Standard must have full cradle-to-grave analysis of heavy crude impact on gas & diesel carbon content & must not undermine refinery regulation. LCFS must be designed not to hide high-carbon gasoline by adding corn ethanol to make the total seem lower carbon (while avoiding full cradle-to-grave ethanol carbon analysis, & smog & water pollution impacts analysis.) | • Local criteria & toxics go down<br>• Increase in sustainable jobs when done with demand reduction -- need for green jobs transition & worker protections while reducing demand for fossil fuels, but jobs are also created in 1, 3, and 4<br>• Higher crude oil cost, but no need for high cost of adding new energy-intensive hydrogen, coking, etc. |
| **3. Switch refinery grid electricity use to clean energy** | • Refineries are current large users of fossil fuel grid electricity & should be required to switch to clean alternative energy electricity, frequently buildable on refinery land | • Local pollution down & Jobs go up (alternatives create more jobs)<br>• Refiner costs up |
| **4. Reduce demand for California Oil Refinery Products** | **CARS -- Fund urban core transit systems equitably for EJ, transit system rebuilding and conservation,** CAFÉ standards, plug-in hybrids, alternative fuels<br>**POWER PLANTS** -- Alternatives, efficiency, low carbon inputs<br>**TRUCKS & SHIPPING** – Efficiency, electrification **ALL SOURCES** – CARBON TAX | • Many savings, solve smog<br>• Cleaner cars -- Political barriers<br>• Public transit - high initial costs<br>• Shipping costs • More and different jobs from public transit, and alternatives |

## Background on CBE Oil Refinery Recommendations for AB32 Scoping Plan

**"Refineries are the largest energy using industry in California and the most energy intensive industry in the United States. . . .** After Texas and Louisiana, California has the largest petroleum refining industry in the country."[1] Oil Refineries are not only a major source of Greenhouse Gases (GHGs) but also the largest point sources of smog precursors. The California Energy Commission found **"California ranks 1st in the U.S. in gasoline consumption and 2nd in jet fuel consumption."**[2] The California Public Utilities Commission found that industrial facilities in California represent about 23% of California's greenhouse gases, and that about 40% of this comes from refineries. **This means that oil refineries cause about 10% of the state's total GHG emissions:**




Focus on direct refinery emissions alone fundamentally understates the impact of oil refining on climate. Refineries make the transportation fuels, which when used as directed, cause an additional 40% of GHGs, they make a major portion of the fossil fuels used to generate electricity (another 20% of GHGs in California), as well as agricultural chemicals . **Efficiency and Best Available Control Technology at oil refineries are essential in reducing local and global pollution from refineries now, but we must also reduce the demand for the inherently polluting refinery fossil fuel products with a planned transition.**

Currently California is going in the wrong direction by building into the oil refinery infrastructure much more energy-intensive refining processes (such as large fossil-fueled hydrogen plants for making more gasoline and diesel, more cokers, more cracking, etc.) to allow the switch to energy intensive high-carbon, high-sulfur crude oil. The state needs to stop this trend and set standards implementing readily available controls, and must identify a specific goal to reduce oil refinery fossil fuel production by a date certain. Cleaning up this inherently polluting industry represents a challenge but it is also a major opportunity to clean up local smog and toxics while making a major reduction in Greenhouse Gas (GHG) emissions.

### Key Elements in Reducing GHGs, Smog Precursors, and Toxics from Oil Refineries

1. Require Refinery Energy Efficiency and BACT (Best Available Control Technology)
2. Stop refinery expansions and their switch to dirtier crude oil
3. Switch oil refinery electricity use off the grid to clean alternative electricity
4. Reduce demand for California oil refinery products

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[1] Profile of the Petroleum Refining Industry in California, California Industries of the Future Program, Lawrence Berkeley The Lawrence Berkeley National Laboratory, LBNL-55450, page iii., *Ernst Worrell and Christina Galitsky,* Environmental Energy Technologies Division, March 2004, http://ies.lbl.gov/iespubs/55450.pdf

[2] http://www.energy.ca.gov/oil/index.html

## 1. Require Refinery Efficiency and Best Available Control Technology (BACT)

- Energy Efficiency Audits for each refinery →require BACT for largest polluters first
- BACT for Hydrogen Plants, Distillation, Cracking, Coking, Hydrotreaters, Boilers & Heaters
- Cogeneration from Waste Heat
- No dumping of "waste gases" (through venting or flaring)

**Energy Efficiency Audits and BACT for known large energy users**

Oil refineries' huge emissions stem from combustion of fossil fuels, evaporation through leaks, and direct dumping to atmosphere. These emissions include practices that use energy (and many practices which waste energy) causing GHG and other emissions that impact public health. At the same time these processes are the single largest stationary source of smog precursors. Refineries emit large amounts of chemicals known to harm breathing, known carcinogens, etc. Progress towards reducing criteria emissions at refineries through smog regulation has slowed. In order to make the necessary progress both on drastically reducing GHGs and local smog and toxic pollution, readily available methods should be applied to rigorously audit and identify the biggest energy users within each refinery and to set stringent standards.

Energy efficiency audits for each refinery in California can identify uneven practices between refineries, such as use of old, inefficient equipment, new intensive energy users, but also best practices that should be more widespread. For example, many refineries have decades-old equipment exempt from current standards (such as large and very old boilers); some refineries have more routine dumping to atmosphere through flaring, Pressure Relief Devices, uncontrolled blowdown systems, and vessel depressurization; and many refineries are in the process of building large fossil-fueled hydrogen plants.

Furthermore, audits on individual refineries that have been carried out in the past have frequently been kept private from the public, and refineries are likely to fight to keep such information out of public scrutiny. The California Air Resources Board (ARB) should both begin by setting standards for known large energy users, but should also carry out its own audits for every refinery in the state and publish the results, since this energy use is an inherent cause of emissions.

While audits to rigorously evaluate each refinery should be required, Best Available Control Technology (BACT) should also be put in place as soon as possible for known large energy users. This should not wait for completion of refinery audits, because it is crucial for greenhouse gas emissions reductions to make expeditious progress.

An audit on the overall oil refining industry in California by the Lawrence Berkeley National Laboratory[3] summarized the largest energy users as follows:

[3] Ibid, page 31

*Table 4. Estimated energy consumption of petroleum refineries in California (2001).*

| Process | Capacity b/cd | Fuel TBtu | Steam TBtu | Electr. GWh | Final TBtu | Primary TBtu |
|---|---|---|---|---|---|---|
| Desalter | 1978132 | 0 | 0 | 32 | 0 | 0 |
| CDU | 1978132 | 46 | 27 | 322 | 83 | 84 |
| VDU | 1156155 | 18 | 20 | 132 | 44 | 45 |
| Thermal Cracking | 381468 | 11 | -2 | 546 | 10 | 13 |
| FCC | 650588 | 12 | 0 | 787 | 15 | 18 |
| Hydrocracker | 476334 | 21 | 11 | 1794 | 42 | 49 |
| Reforming | 409173 | 33 | 6 | 390 | 42 | 43 |
| Hydrotreater | 1576697 | 35 | 22 | 1282 | 67 | 72 |
| Deasphalting | 47767 | 2 | 0 | 30 | 2 | 2 |
| Alkylates | 150944 | 2 | 14 | 226 | 20 | 21 |
| Aromatics | 1433 | 0 | 0 | 1 | 0 | 0 |
| Asphalt | 73354 | 5 | 0 | 62 | 5 | 5 |
| Isomers | 81682 | 12 | 5 | 52 | 19 | 19 |
| Lubes | 30953 | 11 | 0 | 161 | 12 | 13 |
| Hydrogen | 6417226 | 94 | 0 | 313 | 95 | 96 |
| Sulfur | 4037 | 0 | -12 | 16 | -15 | -15 |
| Other | 0 | 13 | 7 | 950 | 25 | 29 |
| Total | 0 | 315 | 98 | 7094 | 467 | 496 |

Resorting the above processes in descending order of primary energy use and grouping similar processes together, identifies the largest process unit totals for the refining industry, aggregated, in California. The top five categories include Hydrogen Plants, Distillation Units, Cracking Units, Hydrotreaters, and Reforming, which make up about 85% of the total. The report also found: "Hydrocracking and hydrogen production are growing energy consumers in the refining industry."

| **Process** | **Final TBtu** |
|---|---|
| Hydrogen | 96 |
| **Distillation Units** | **129** |
| CDU (Crude Distillation Unit) | 84 |
| VDU (Vacuum Distillation Unit) | 45 |
| **Cracking Units:** | **80** |
| Hydrocracker | 49 |
| FCC | 18 |
| Thermal Cracking | 13 |
| **Other Large Units:** | **115** |
| Hydrotreater | 72 |
| Reforming | 43 |
| **Remaining Units:** | **74** |
| Other | 29 |
| Alkylates | 21 |
| Isomers | 19 |
| Lubes | 13 |
| Asphalt | 5 |
| Deasphalting | 2 |
| Desalter | 0 |
| Aromatics | 0 |
| Sulfur | -15 |

This list forms a preliminary order of priority for beginning immediately to set energy efficiency requirements for the top units within refineries. (Coking may be included under thermal cracking, or may be a large hidden energy user.) However, overall audits for individual oil refineries in California should also be carried out to identify problem areas where individual refineries perform poorly compared to other refinery averages.

**Fossil-fueled refinery hydrogen plants represent huge sources of GHG emissions, and these sources are expanding drastically in the state** (and nationally) in order to process higher carbon, higher sulfur inputs (dirty crude oil) at refineries. We provided the following partial list of refinery hydrogen plants during testimony to the state in 2007 during a public hearing on GHG controls. Although only partial and probably underestimated, it showed almost 6 million metric tons per year CO2 refinery emissions from hydrogen plants alone, and these are only the new or relatively new plants. To put this in perspective, CARB included about 30 million metric tons per year of GHGs, and the CEC estimated closer to 40 million metric tons per year for the total from refineries in the state. Thus the GHGs from just this partial list of only one process within refineries represents an added 15-20% in GHGs. More refineries are planning and building new fossil fueled hydrogen plants and increased plant capacity throughout the state. Without addressing such major increases in refinery GHGs in the state, we will not be able to make progress in reducing GHG emissions. The information below should be updated and evaluated for all refineries:

| **Examples of CA Refinery Hydrogen Plant Expansions since 1999** (not comprehensive) (million standard cubic feet) | **Approximate CO2 Emissions Increases for these sources** (metric tons per year) |
|---|---|
| 2007 ConocoPhillips Rodeo --120 MMscf | at least 1,250,000 |
| 2007 Chevron Richmond -- 100 MMscf | at least 900,000 |
| 2007 Valero Benicia – unknown MMscf | ≈ 860,000 ** |
| 2003 Chevron El Segundo -- 90MMscf | ≈ 940,000* |
| 1999 Air Products Wilmington for area refineries -- 96 MMscf | ≈ 1,000,000* |
| 1996 Air Products for Ultramar, Wilmington --83 MMscf | ≈ 860,000* |
| **493 MMscf** (million standard cubic feet) | ≈ at least **5.8 million metric tons** per year |

** CO2 emissions not yet available, estimated based on plant hydrogen capacity and assumption that emissions are approximately proportional to ConocoPhillips CO2 from Final EIR. This may underestimate emissions. For example, Chevron may be oversizing hydrogen plant for exporting, and not including these CO2 emissions in total. ConocoPhillips may be as well.*

*** Planned Valero Benicia facility's size is currently unknown – used the smallest size above as approximation*

**Refinery Boilers and Heaters are major sources of the energy use within refinery processing units that should be a first priority for requiring BACT**. There is a wide variation in the efficiency and emissions of Boilers and Heaters at refineries in California. Many boilers and heaters in California refineries are extremely old and have "grandfathered" permitting requirements exempting them from meeting more modernized NOx emissions standards. If refineries were required to meet strong NOx standards across the board, they would also have reduced CO2 emissions because these units are so inefficient. Furthermore, if BACT standards for heaters and boilers were required, further major

reductions could be achieved. Boilers and heaters are such large sources because they fuel the refining process and operate continuously, not intermittently.

**Cogeneration to capture refinery waste heat**

Oil refineries are a large source of cogeneration in the state, but there is still a great additional potential for capturing waste heat and other waste at oil refineries in order to increase efficiency.

> **5.10 Power Generation**
>
> The petroleum refining industry is one of the largest users of cogeneration or Combined Heat and Power production (CHP) in the country. **The petroleum refining industry is also identified as one of the industries with the largest potential for increased application of CHP. We estimate installed CHP capacity in Californian refineries at at least 1400 MWe.**[4]

Cogeneration has the potential to capture waste energy and increase refinery efficiency, but since it introduces complex interactions with electric Power Plants, care is needed in evaluating the relative efficiency of refinery cogeneration compared to other sources, as well as any environmental impacts associated with cogeneration at refineries. The key is to capture waste energy without introducing new sources of combustion at the refinery or otherwise increasing environmental impacts. BACT standards must be in place.

Reducing the need at refineries for grid electricity can increase reliability of electric power available to the refinery, which reduces risk of power outages causing emergency refinery shutdowns. Power plant outages and emergency shutdowns at refineries have caused major flaring, resulting in GHG emissions and major local impacts from hydrocarbon, SOx emissions, and very large plumes of black smoke (particulate matter). These impacts were exacerbated when several refineries shutdown simultaneously in the South Coast region, with neighbors reporting respiratory impacts and sickness for days following one event.

The South Coast Air Quality Management District (SCAQMD) presented the following table during a flare working group meeting in 2006. This table showed which refineries in the South Coast had high, medium, and low risk of power outage and increased risk of flaring. It also listed quantities of fossil-fuel based grid electricity used by these oil refineries:[5]

[4]Ibid, page 45, Units MWe are electrical megawatts, as opposed to thermal megawatts
[5] South Coast Air Quality Management District, Rule 1118 Working Group Meeting, October 26, 2006

## REFINERIES AND ROTATING POWER OUTAGE RISKS*

| Company | Location | Operating Crude Oil Atm Dist Capacity (MBPSD) | Electric Utility Service Area | Estimated Electricity Demand (MW) | Cogen Capacity (MW) | Number of Cogen Units | Cogen vs Demand - Cogen Coverage (%) |
|---|---|---|---|---|---|---|---|
| **HIGH RISK** | | | | | | | |
| ExxonMobil | Torrance | 160 | SCE | 94 | 42 | 1 | 44.8% |
| Conoco-Phillips | Carson | 137 | SCE | 26 | 0 | 0 | N/A |
| **MODERATE RISK** | | | | | | | |
| Chevron | El Segundo | 273 | SCE | 108 | 138 | 2 | 127.8% |
| Shell | Wilmington | 100 | SCE | 58 | 60 | 2 | 103.4% |
| **LOW RISK** | | | | | | | |
| BP | Carson | 260 | SCE | 82 | 331 | 1 | 403.5% |
| Ultramar | Wilmington | 79 | LADWP | 37 | 0 | 0 | N/A |
| Conoco-Phillips | Wilmington | 0 | LADWP | 47 | 59 | 1 | 124.5% |
| **UNDEFINED RISK** | | | | | | | |
| Paramount | Paramount | 48 | | | | | |

http://www.eia.doe.gov/emeu/steo/pub/special/california/june01article/carefinery.html

In this presentation, SCAQMD concluded that: *"Commercial power usage increased 67% from 79,691 megawatt-hours in 1990 to 117,573 megawatt-hours in 2004."* This indicates that not only are refineries responsible for more fossil fuel emissions (from power plants), but also that they are becoming more vulnerable to power outages. (Also see additional comments on flaring later in this comment letter.)

### <u>Remove all methane exemptions from smog regulations</u>

As an Early Action Measure under AB32, CBE proposed the removal of methane exemptions in smog regulations, which are currently allowed by Air Quality agencies throughout the state (and also throughout the nation). While the ARB did not accept removing the exemptions as an Early Action Measure, staff did recommend in the Final Report that removing the exemptions was feasible and should be considered as part of the Scoping Plan process under AB32.

The definition of VOCs (Volatile Organic Compounds) in smog precursor control regulations exempts methane in most cases. The following examples of regulations in different regions in the state include the SCAQMD, the BAAQMD, and the SJVAPD.

<u>SCAQMD:</u>[6]

**VOLATILE ORGANIC COMPOUND (VOC) is any volatile compound of carbon, excluding methane,** carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, ammonium carbonate, and exempt compounds.

ORGANIC MATERIAL means a chemical compound of carbon excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides, metallic carbonates and ammonium carbonate.

<u>BAAQMD:</u>[7]

**1-233 Organic Compound: Any compound of carbon, excluding methane**, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates and ammonium carbonate.

<u>SJVUAPCD:</u>[8]

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[6] *SCAQMD Regulation 1, General Provisions, Rule 102, Definition of Terms (Amended Dec 3, 2004)*
[7] *BAAQMD Regulation 1 General Provisions and Definitions (Adopted March 17, 1982)*

3.53 **Volatile Organic Compound (VOC):** any compound containing at least one (1) atom of carbon **except for the following exempt compounds:**

- **Methane** . . . . *(Many other compounds which are non-smog precursors are also listed as exempt.)*

The methane exemption can no longer be justified for oil refineries, other stationary sources, or any pollution source in the state. Methane is not only a highly potent greenhouse gas (23 times more potent than CO2), it is also a key smog precursor (for ground-level ozone), and its reduction is highly effective in reducing smog. A Harvard study, *Linking ozone pollution and climate change: The case for controlling methane*[9] found:

> **"Methane (CH4) emission controls are found to be a powerful lever for reducing both global warming and air pollution via decreases in background tropospheric ozone (O3) "**

This study was summarized as follows in Environmental Science and Technolgy[10]:

> "Aggressive efforts to improve urban air quality could be undermined by rising levels of methane, a compound more closely linked to global warming than air pollution. Using a global model of tropospheric chemistry, researchers at Harvard University, Argonne National Laboratory, and the **U.S. EPA determined that higher methane levels could increase ozone background levels worldwide, lead to a greater frequency of days with high ozone levels in the summer, and produce a longer "season of ozone pollution days."**
>
> "It is already known that methane is a major source of worldwide tropospheric ozone background concentrations, and this study supports that finding. However, **the surprise is that a 50% reduction in anthropogenic methane in their scenario is as effective as a 50% drop in anthropogenic NOx concentrations at lowering summer afternoon ozone levels over the United States."** (page 452A)

NOAA (National Oceanic and Atmospheric Administration) also found:[11]

> **Linking climate and air pollution:**
> **Methane emission controls yield a double dividend**
>
> An important area of research at GFDL is investigating the contribution of methane to surface ozone pollution, and quantifying the potential benefits to air quality and climate from controls on methane emissions. **Methane is both a greenhouse gas and an important contributor to background levels of ozone. Tropospheric ozone, a significant greenhouse gas and the primary constituent of photochemical smog, provides an obvious link between air quality and climate.**

There is no longer any reason for exempting this pollutant from smog regulations. Excluding accounting of methane from smog precursor emissions also makes VOC controls look less cost-effective than they actually are in reducing smog.

To begin to quantify methane as identified in regional air quality plans in criteria pollutant emissions categories, an excerpt of California's 2002 statewide criteria inventory summary table from ARB is excerpted below. This table includes organic compound emissions in both TOG (Total Organic Gases) and VOCs (Volatile Organic Compounds). The year 2002 was chosen because it is the latest year that included both TOG and VOCs. Later inventory years did not provide TOG, but just VOCs.

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[8] *SJVUAPCD Rule 1020, Definitions,*, 6/17/99
[9] Fiore, et al. 2002. Harvard University. http://www.agu.org/pubs/crossref/2002/2002GL015601.shtml
[10] Environmental Science & Technology. December 2002, http://pubs.acs.org/subscribe/journals/esthag-w/2002/oct/science/an_methanelink.html
[11] http://www.research.noaa.gov/spotlite/2006/spot_methane.html

**2002 Statewide Inventory: Table 2-1 Summary (tons per day)[12]**

| Division<br>Major Category | TOG | ROG |
|---|---|---|
| **Stationary Sources** | 2535 | 538 |
| Fuel Combustion | 215 | 49 |
| Waste Disposal | 1447 | 23 |
| Cleaning And Surface Coatings | 344 | 237 |
| Petroleum Production And Marketing | 450 | 164 |
| Industrial Processes | 79 | 65 |
| **Area-Wide Sources** | 2027 | 698 |
| Solvent Evaporation | 521 | 463 |
| Miscellaneous Processes | 1506 | 235 |
| **Mobile Sources** | 1530 | 1406 |
| On-Road Motor Vehicles | 1019 | 938 |
| Other Mobile Sources | 511 | 467 |
| **Natural Sources**** | 106 | 38 |
| ***Total Statewide - All Sources*** | ***6198*** | ***2680*** |

For example, three categories of Stationary Sources listed above (Fuel Combustion, Petroleum Production and Marketing, and Industrial Processes) add up to 744 ton per day (tpd) TOG and 278 tpd VOC, and the difference between these two is 466 tons per day (about 170,000 tons per year). The difference between TOG and VOCs includes exempt organic gases, and in this category, the difference is likely to be made up mostly of methane. If the difference is entirely methane, this is equivalent to almost 4 million US tons per year CO2Eq just for these categories. (This number is likely underestimated since exempt methane emissions receive less scrutiny.) This category of stationary source methane emissions is a significant source of GHGs, but also a huge source of unregulated smog precursors from only these three categories.

To capture the dual benefit of eliminating or greatly reducing these emissions, the organic compound definitions in the state for all smog regulations need to be modified to remove the exemption for methane. The state should require all regional air quality agencies in California to immediately begin reopening all smog regulations to remove methane exemptions, and to complete this by the most expeditious date. **Furthermore, all new smog regulatory proceedings in the state should be immediately required to include evaluation of removal of methane for each of these regulations.** In the case of such rules that are already in the process of modification, there is no need for any delay evaluating how to remove the methane exemptions. We understand that the state and regional Air Quality Management agencies are now beginning to discuss removing this exemption.

[12] *The 2003 California Almanac of Emissions and Air Quality*, (page 49), http://www.arb.ca.gov/aqd/almanac/almanac03/chap203.htm

**No dumping of waste gases through venting or flaring should be allowed**

Control Pressure Relief Devices (PRDs) and other venting to atmosphere

While PRDs are necessary for safety to ensure that pressure inside vessels does not get too high, most PRDs do not need to vent to the atmosphere. PRDs can be controlled to vent to refinery gas recovery systems where the gases are recycled as fuel in the refinery.

PRDs are designed to release large volumes of gases within minutes, increasing smog, GHGs, and representing a local health hazard and public nuisance especially because of H2S emissions. Some refineries have most of their PRDs connected to gas recovery systems. Other refineries have half or more PRDs vented to atmosphere. Better practices have been carried out by some refineries, demonstrating their feasibility for all refineries.

The SCAQMD found a large difference in refineries in the number of PRDs designed to vent directly to atmosphere (shown in this excerpt from an SCAQMD presentation).[13] BP had 592 out of the 770 total of PRDs dumping to atmosphere in the District, far more than the other South Coast refineries. At last count, roughly ***half*** of Bay Area refiners' PRDs were uncontrolled, although retrofits are distributed unevenly between these refineries as well, as should be expected, since an uncontrolled PRD is antiquated technology.

Atmospheric PRD Inventory

| Facility | No. of Atmospheric PRDs (as of 2005) |
|---|---|
| BP | 592 |
| Chevron | 49 |
| ConocoPhillips, Carson | 15 |
| ConocoPhillips, Wilmington | 8 |
| Edgington | 14 |
| ExxonMobil | 35 |
| Lunday Thagard | 9 |
| Shell Equilon | 40 |
| Valero | 8 |
| TOTAL | 770 |

5

PRD monitoring has historically been very poor. (Many refineries have admitted that they detected PRD releases by sound rather than through actual monitoring!) Because of this, annual inventories of emissions are very incomplete, but new regulations in the Bay Area and South Coast are beginning to improve monitoring. Dumping to the atmosphere should be considered a bad engineering practice and banned, and companies should not be allowed to avoid control through pay-to-pollute schemes allowed in the South Coast. Requiring controls and electronic monitoring will not only reduce GHG emissions but also reduce large episodic emissions of smog precursors and harmful toxics.

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[13] *Proposed Amended Rule 1173, Control of VOC Leaks and Releases from Components at Petroleum Facilities and Chemical Plants*, Working Group Meeting, March 13, 2007, SCAQMD slideshow

Although PRDs do not vent continually, one PRD can vent over 100 tons of VOCs in one day (even in minutes) including emissions of methane, other VOCs, and H2S. While these emissions are episodic, the potential to emit is large because there are over a thousand of them at oil refineries in the state. Venting of these devices has been poorly tracked in the past, and emissions very likely underestimated. PRD emissions can cause large spikes in smog precursor emissions on days when they vent; they are a source of direct dumping of methane to the atmosphere. Both for purposes of controlling GHGs and especially to protect public health, these devices should be required to vent to gas recovery systems throughout the state. There is a potential for increased emissions from these sources as refineries ramp up production, and do more intensive refining of heavy crude, increasing the risk of frequent upsets. Requiring all refineries to meet the same BACT standards for PRDs will reduce public health risks, smog precursors, and GHG emissions together.

Evaluate other venting to atmosphere

Refinery energy audits should include not only the refinery's steady state emissions, but should also evaluate:

- Frequency of upsets (which can increase emissions and hazards to neighbors and workers)
- Startup/shutdown and maintenance emissions
- Vessel Depressurization, when some part of gases in vessels are uncontrolled and vent to atmosphere
- Unusual operations (one refinery had uncontrolled blowdown systems with no attached flare, and these dumped directly to atmosphere)
- Tank cleaning that could cause large evaporation on an episodic basis
- Other direct dumping either during emergency conditions or on a regular basis should be identified and prevented
- Best Practices for preventing dumping to atmosphere
- Corrosion and other increased process intensity and decreased process stability impacts of refining lower quality crude and intermediate products

Apply BACT/LAER to Refinery Flares (beyond existing regulations)

Flaring should be limited true emergencies. Planned flaring, and repeated malfunctions that cause flaring from preventable emergencies should trigger enforcement that will prevent flaring from these causes. Flares emit CO2, methane, other VOCs, sulfur compounds that are known to exacerbate asthma and other breathing impacts, and toxics. While California flare controls have improved substantially due to regulations adopted in the Bay Area and South Coast following strong public pressure, there remain major differences in flaring emissions between different refineries in the state. ARB should require statewide flare standards that meet at least the Shell Martinez BACT/LAER (Best Available Control Technology / Lowest Achievable Emissions Rate) performance standard.

The Shell refinery in Martinez, California has demonstrated sustained and drastically lower emissions compared to other refineries in the state through methods including dedicated backup compressors, a rigorous Flare Minimization Plan, and methodical follow-up after any flaring event through root cause analysis and action to ensure that the cause for each flaring event will not recur. While other refineries in California have prepared Flare Minimization Plans and root cause analysis, they have not been carried out to the degree that Shell has achieved in Martinez, as demonstrated through flare monitoring data.

Flaring levels achieved by Shell in practice should be the considered the minimum BACT/LAER for flaring, and further reductions may be achievable. Since Shell has demonstrated in practice much lower flaring levels, these should be required for all refineries in the state. This will further reduce flaring in the Bay Area and the South Coast, and also will capture emissions from the remaining refineries in the state outside these regions. (See Shell's flaring emissions, available at BAAQMD website for current and previous years.[14]) In addition, Hydrocarbon Processing has published an account of very low or zero flaring at a refinery in Texas.[15] Performance standards at this facility should also be evaluated to determine whether this facility represents BACT/LAER, and represents an improvement over the Shell Martinez performance.

Flaring is not the largest source of GHGs at oil refineries, but it is a significant source of GHGs and a large source of VOCs and SOx emissions that represent local and regional health risks. Despite the newer flare regulations, flaring emissions in the state have a great potential for increasing. This is because of increased risk of upset due to refinery expansions and more intensive refining to handle dirtier crude oil. Heavier, dirtier, more intensive refining means increasing volumes and concentrations of toxic, corrosive gases such as sulfur compounds in refineries; it means increasing process instability and upsets, and it and also means dirtier flaring events.

The expansion of refineries and introduction of heavy, high-sulfur crude oil increases the risk of flaring and the quantities of SOx, VOCs, NOx, CO, PM2.5, and toxic emissions. See CBE report *Flaring Prevention Measures.*[16] This report evaluated in great detail BAAQMD flare data reported by the refineries and Flare Minimization Plans, and found that refinery processes required for heavier crude slates caused more flaring and caused dirtier flaring than other refinery processes. The report found:

> Dirty crude refining can increase flare pollution in similar ways. It produces more gases from the expanded catalytic cracking, hydrocracking and coking that make vehicle fuels from the increased volumes of gas oil and heavy ends. This is because of the increased volumes cracked in these processes and because cracking reactions produce gases as well as fuel-sized hydrocarbons. Dirty crude may also produce more gases from distillation. See Figure 4. The bigger gas volumes will have higher concentrations of sulfur and other pollutants. See Table 13. Dirtier processes will flare more, and dirtier, unless more gases are recovered and reused. (page 17)

In addition to being a significant source of GHGs, flaring in the South Coast represented **more than half of the refinery SOx emissions**, making flaring a severe source of emissions of compounds associated with local health impacts including asthma and other respiratory diseases. Statewide

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[14] http://www.baaqmd.gov/enf/flares/

[15] *Minimize facility flaring, Flares are safety devices that prevent the release of unburned gases to atmosphere*, J. Peterson, Flint Hills Resources, et al, Hydrocarbon Processing, http://www.johnzink.com/products/flares/pdfs/flare_hydro_proc_june_2007.pdf

[16] *Flaring Prevention Measures*, Communities for a Better Environment (CBE), Greg Karras, April 2007, attached

requirements that flaring meet BACT/LAER performance standards at least as stringent as Shell Martinez will secure further improvements in reducing local SOx and VOC emissions, reduce GHG emissions, and prevent increases due to expansions and heavy crude introduction.

## 2. Stop refinery expansions & the switch to dirty crude oil

- No new fossil fueled Hydrogen Plants, cokers, etc.
  (only possible without heavy, dirty crude oil inputs)
- Low Carbon Fuel Standard for Refineries
- Limit on heavy, contaminated crude and pre-processed unconventional oil input
- Carbon tax on refineries
- Windfall profit tax to fund clean alternative energy

Heavy crude oil means long hydrocarbon chains which require more cracking and coking, and this high carbon crude oil is typically associated with higher sulfur content. (Also see earlier section on refinery energy use.) This means that refineries switching to heavier crude stocks must build new hydrogen plants, additional cracking capacity to crack the long hydrocarbon chains into gasoline, more coking and bottom of the barrel processing, more hydrotreating to remove sulfur compounds to meet low sulfur gasoline and diesel standards, and more sulfur recovery units. All of these operations require greatly increased energy use by the refineries. (See list page five showing the biggest energy users at refineries, which include these types of units). This much greater energy use means much greater CO2 emissions. **Unfortunately, we are going strongly in the wrong direction in this state as far as GHG emissions from oil refineries.** The increased sulfur at the refineries also increases the risk to neighbors of upsets that cause asthma attacks and other respiratory impacts.

Given that the state is in the process of adopting a Low Carbon Fuel Standard, this move towards higher carbon inputs to refineries must not be allowed. It is true that lighter crude oils are becoming more expensive, and use of heavy crude oils represents much cheaper inputs. Carrying this to an extreme, use of the heaviest crude oils (Canada Tar Sands) is increasing drastically at U.S. refineries, and refiners also want to introduce this dirty crude source into California. This trend is a clear and present threat to climate protection given that the billions of dollars in proposed refinery equipment tooled for unconventional oil would be locked in place for decades once built.

**The state needs to perform a statewide evaluation on the alternatives to use of dirty, high carbon crude oil in the state, including a step-by-step reduction in the demand for refinery products through rigorous fuel efficiency and alternative fuels programs.** A windfall profits tax for oil refineries could help fund such a switch, so that instead of expanding refineries and increasing their energy intensity, we develop a detailed planning for reducing their output and impact over time. A few decades ago, an economic analysis for power plants found that they could actually make more money by investing in conservation instead of building more plants. Companies like Dow Chemical and Dupont actually made windfall profits from phasing out ozone depleting chemicals. We need a detailed, comprehensive plan that specifically calls for reducing the need for and the outputs of oil refineries in California. This is achievable through available means, as discussion in a later section of this comment, and can be funded through a carbon tax and windfall profits tax on the oil industry.

The California Low Carbon Fuel Standard requirement in development requires:

> "The California Executive Order S-1-07(issued on January 18, 2007), calls for a reduction of at least 10 percent in the carbon intensity of California's transportation fuels by 2020. . . . In response, ARB identified the LCFS as an Early Action Measure with a regulation to be adopted and implemented by 2010.
>
> The LCFS requires a reduction of 10 percent or greater in the average fuel carbon intensity (the "*AFCI*") *[Average Fuel Carbon Intensity]* of transportation fuels in 2020 compared to the baseline year of 2006, with a phase-in period from 2010 through 2019."[17]

The LCFS needs to be defined and adopted so as to rigorously evaluate the modifications being made to refineries which enable the use of high carbon, heavy crude oil in refineries. It appears from the recently-released partial draft proposal that LCFS will use averages allowing refineries with increasingly heavier crude oil inputs to average carbon intensity and thus underestimate actual carbon intensity. Furthermore facilities with lower carbon intensity inputs appear to be allowed to bank credits if they overcomply. This leads to an inaccurate assessment which makes it appear that the state's refinery fuel products have lower carbon intensity when in reality they are much higher in intensity. Care must also be taken in assessing baselines so as not to build in an inflated baseline assuming high carbon crude oil.

The switch to heavy crude oil is a major contributor to GHGs and increased public health risk as discussed above. Some of the State's own low carbon fuel standards development experts have observed that: "these fuels are physically of lower quality, and exist naturally in less useful form than conventional oil, and thus are likely to have an excess of emissions even in the presence of technological progress."[18] Stopping this switch should be a major priority of the state to preclude this move toward building high carbon fuels from oil refineries into the state's infrastructure for many decades to come. Much more evaluation will be needed as this regulation develops. Pollution trading should not be allowed as a replacement for actual limits on carbon in the states' fuels.

It also appears that the LCFS may justify increased carbon intensity in oil refinery products (gasoline) by adding corn-based ethanol to gas and averaging the output. If this were to happen, such averaging would not include the full cradle-to-grave accounting of the carbon input caused by trucking heavy corn across the country and other energy use put into corn production. Biofuels plants in the Central Valley are a heavy industry, causing severe local impacts, and increasing smog and water pollution. Furthermore, the introduction of ethanol as an MTBE replacement in gasoline has been estimated to add 20 tons per day in VOC emissions to the South Coast due to permeation through vehicle seals, gaskets and lines, increasing fugitive emissions greatly. The South Coast cannot afford this major increase in smog precursors. Similar high impacts will occur throughout the state. Asthma is already an epidemic in the state, and any LCFS evaluation of introduction of corn ethanol must take into account the true carbon input and the health and environmental impacts. This source must also not

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[17] Email notice to listserve on Concept Outline for the California Low Carbon Fuel Standard Regulation, March 20, 2008, from , John Courtis - Manager, Alternative Fuels Section, ARB, http://www.arb.ca.gov/fuels/lcfs/lcfs.htm

[18] *Scraping the bottom of the barrel: Greenhouse gas emission consequences of a transition to low-quality and synthetic petroleum resources,* Climate Change (Journal), Brandt and Farrell, Energy and Resources Group, University of California, Berkeley, 2007, Abstract at http://www.springerlink.com/content/y283j2220jj365g4/ (Full article attached)

be used to justify heavier crude oil at refineries. The LCFS standard is still in development, and care must be taken not to allow these impacts.

## 3. Switch refinery electricity use to clean energy

Currently oil refineries use significant amounts of electric energy off the grid, from fossil-fueled power plants. Requiring that oil refineries contract with and switch to clean alternative energy sources while not directly reducing emissions at the oil refinery site, would reduce emissions that contribute significantly to Power Plant GHGs, smog precursors, and toxics. The following graph illustrates electrical energy purchases and generation by petroleum refineries from 1988-2001:

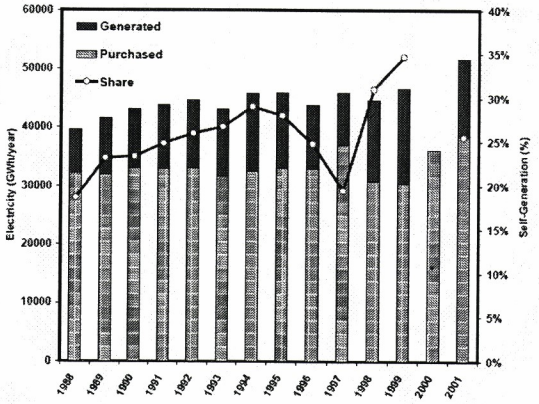



*Figure 16. Electricity purchases and generation by petroleum refineries from 1988 till 2001. On the right-hand axis the share of self-generation is expressed as function of total power consumption. Source: U.S. Census, Annual Survey of Manufacturers.*

*(page 26)*

Fossil-fueled grid electrical energy use at oil refineries results in many tons per day of local air pollution and very large GHG emissions which should be required to switch to clean alternative energy.

Oil refineries use substantial amounts of electricity which is generated at power plants by burning fossil fuels. These emissions occur near the power plants, but also cause regional smog and GHGs. Also, when reliability problems bring down the electrical grid, oil refineries shut down, causing upset conditions and huge air emissions near the oil refineries. Such events occurred in the fall of 2005, causing major flaring at several oil refineries in the South Coast region and in the Bay Area in 2002.

Alternative energy sources including wind and solar energy are now readily available and viable alternatives for replacing fossil-fuel electricity generation used at oil refineries. Such alternatives need to be evaluated and required statewide. Refineries frequently have open land where such alternatives can be put in place by the refineries. Refineries are already required to evaluate feasible alternatives

under CEQA (the California Environmental Quality Act), and although we have commented on the feasibility of clean alternative electricity to replace grid electricity for refinery projects (such as the ConocoPhillips Rodeo expansion) refineries have failed to do such clean electricity alternatives analysis in their Environmental Impact Reports. Requirements under CEQA that refineries evaluate and implement feasible clean alternative electricity sources should be enforced statewide, and evaluation and standards set by the state should also be done independently from CEQA.

If the oil refineries in the South Coast example in the table on page eight were to replace either the percentage of electricity not covered by cogeneration capacity (115 megawatts - MW), or to replace all the electrical demand (452 MW) by clean alternative energy regardless of cogeneration capacity at the refineries, electricity not generated through fossil fuels at these facilities would result in many tons per day of emissions reductions calculated below.

Information is available on emissions caused by power plants generated per megawatt hour. For example, PG&E published its 2002 Environmental Report online[19] which provides estimations of air emissions associated with generation of electrical energy. A table from the report is provided below, with air emissions in terms of pounds per megawatt-hour of energy. The two columns at the right are added to calculate daily emissions by power plants generating 115MW or 452MW.

***From PG&E 2002 Environmental Report***

| | Pounds per megawatt-hour of electricity produced | **Added Columns, calculating total tons/day using PG&E lbs/MW-hr:** **Emissions in 24 hours** for 115 and 452MW electrical energy needed from fossil-fueled power plant for the South Coast oil refineries | |
|---|---|---|---|
| ***Emissions Rates*** | **PG&E Corporation***1 | 115 MW or 2760 MW-hours per day | 452MW or 10,848 MW-hours per day |
| SO2 Fossil-Fuel Units Only | 3.2 | 4.4 tons/day | 17.4 tons/day |
| NOx Fossil-Fuel Units Only | 1.3 | 1.8 tons/day | 7.1 tons/day |
| **CO2 Fossil-Fuel Units Only** | **1,454** | **>730,000 US tons/year** | **>2.8 million US tons/year** |

1. Emissions rates for 2002 * Pounds per megawatt-hour of electricity produced

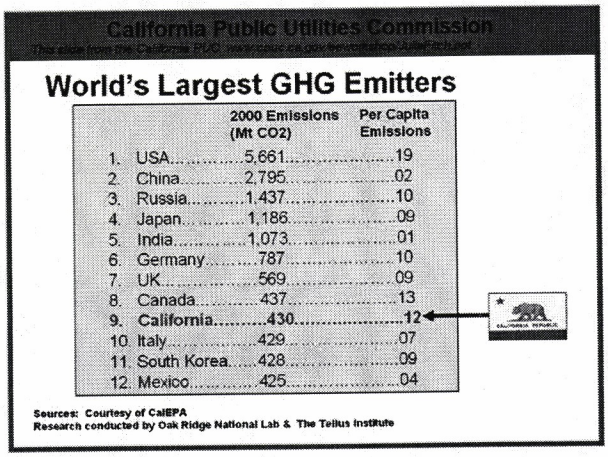
[19] *PG&E 2002 Environmental Report, 2002 Performance Results , Air Emissions: NOx, SO2, Mercury, and Greenhouse Gases,* available at http://www.pgecorp.com/corp_responsibility/environmental/report/2002/perf_results/02.html\

In a 24-hour period, refineries in the South Coast alone use 115 MW of electric energy continuously from fossil-fueled power plants, resulting in 4.4 tons per day of SOx emissions and 1.8 tons per day of NOx emissions, according to the data above. The total electrical energy use in the South Coast basin refineries of 452 MW continuously results in 17.4 tons/day of SOX emissions and 7.1 tons per day of NOx emissions. This calculation assumes that emission rates at the power plants in the state generating this electricity are similar to PG&E's, but national average pollution rates were even higher. Either way, the large air emissions caused by fossil fuel generation at Power Plants due to oil refinery electricity demand is worthy of phaseout requirements by the SCAQMD and other air quality management agencies throughout the state.

These calculations do not include VOC, CO, mercury emissions, methane, and SF6 (sulfur hexafluoride) emissions, also identified by PG&E's report. The emissions probably do not represent peak electricity use, which causes higher emissions. Clearly, refinery electrical energy use is a large source of GHG emissions.

## 4. Reducing demand over the medium term for California Oil Refinery Products is feasible and should be identified as a specific goal with a deadline under AB32

California emits as much GHG as many countries:




It is no longer possible to pretend that better technology alone at large industrial GHGs emitters like refineries can solve the problem of industrial GHG, smog precursor, and toxic emissions. Direct regulatory controls requiring BACT at refineries and specific plans for reducing the demand for oil refinery products are needed to make real progress. Stopping the disastrous trend to higher carbon inputs and refinery expansion is needed, with a specific plan to reduce oil refinery product demand with deadlines, percent reductions, and a map to get there. The following readily available methods are examples of ways to get big savings in the use of refinery products and to decrease energy use in

general. These methods preclude the need for refinery expansions and reduce demand at oil refineries as they are implemented. These can be included in the AB 32 process:

- **CAFE Standards:**
  - If the U.S. increased fuel economy to 45% higher miles per gallon using cost-efficient techniques, we'd save over 50 billion gallons of gasoline/year. (National Academy of Sciences[20])
  - This is equivalent to saving about 3 1/3 Californias worth of gas use each year (California used about 15 billion gallons per year in 2003).[21]
  - Increasing fuel efficiency of cars & trucks by only 3 miles per gallon can save > 1 million barrels of oil / day or five times the amount of Arctic Refuge might produce."[22]
- **PLUG IN HYBRIDS:**
  - For each mile driven on electricity instead of gasoline, CO2 emissions would be reduced 42% on average in the US (although this advantage could be hurt by coal-generated electric power plants) [23]
  - Plug-ins encourage development of renewable electricity because of they provide distributed battery storage.
  - Running a plug-in would reduce average fuel cost by about half, (based on a price of $2.77/gallon for gasoline (Sept 2005) and 8 cents per kWh for electricity, (Jan 2006)).
- **CLEAN ELECTRICITY:**
  - 80 GigaWatts of CSP could be economically deployed by 2030 (about 200 times today's US capacity) in the Southwest US.[24]
  - *"Analysis suggests that 10% of electric grid energy by 2030 could be supplied by PV without creating grid management issues."* (Equivalent to 275 GW in the US)[25]
  - Wind capacity in the US was found to be at least 245 GW, but higher amounts are possible if storage is available
- **SHIPPING EFFICIENCY IMPROVEMENTS:**
  - Shipping uses about 5% of global oil consumption
  - Reducing ship drag due to hull fouling has been found to result in at least 10% reduction in fuel use, which saves both money and reduces GHG and criteria

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[20] *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards*, National Academy of Sciences, 2002
[21] *Market Power in California's Gasoline Market,* University of California Energy Institute, Center for the Study of Energy Markets, 2004, page 4, http://repositories.cdlib.org/cgi/viewcontent.cgi?article=1035&context=ucei/csem
[22] According to the Arctic Refuge Defense Campaign, http://www.arcticrefuge.org/
[23] *Tackling Climate Change in the U.S.: Potential Carbon Emissions Reductions from Energy Efficiency and Renewable Energy by 2030*, American Solar Energy Society, Charles F. Kutscher, Editor, January 2007, http://www.ases.org/climatechange/toc/exec-summary.pdf
[24] Ibid.
[25] Ibid.

pollutant emissions.[26] Shipping in California may represent a larger portion of California's total consumption compared to the global average.

- Electrification of ports through alternative energy to replace the use of high carbon bunker fuel will reduce health risks for neighbors near ports and GHG emissions from the current use of bottom-of-the-barrel bunker fuel.

[26] *Fuel Conservation Through Managing Hull Resistance,* Motorship / BIMCO Propulsion Conference, Copenhagen April 26th, 2006, By: Torben Munk, M.Sc., Propulsion Dynamics Inc. (PDI), http://www.cleanhull.no/doc/PDF%20files/Fuel%20Conservation%20-%20CASPER.pdf

Back

## Best Available Control Technology (BACT ) Guideline 3.4.4
## Last Update: 4/5/2001

### Limited Use (< 877 hours per year) Gas Fired Turbine = or < 26 MW, without Heat Recovery

| Pollutant | Achieved in Practice or in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| CO | PUC quality natural gas. | 1. 90 % control efficiency (SCONOx, or equal). 2. 71% control efficiency (Oxidation catalyst, or equal) | |
| NOx | 42 ppmvd @ 15% O2 (Water injection system, or equal). | 1. 2.5 ppmv NOx @ 15% O2 (SCR, SCONOx, or equal). 2. 15 ppmv @ 15% O2 (Dry low NOx Combustors, or equal). 3. 25 ppmv @ 15% O2 (Dry low NOx Combustors, or equal). | |
| PM10 | Natural gas, air intake filter, and a maximum lube vent exhaust visible emissions of 0% opacity with either • a lube oil coalescer, • a lube vent high efficiency particulate filter , or • a lube vent routed to the turbine or exhaust for oxidation. | | |

| Pollutant | Achieved in Practice or in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| SOx | PUC quality natural gas. | | |
| VOC | PUC quality natural gas with fuel oil #2 as backup. | 1. 90 % control efficiency (SCONOx, or equal). 2. 71% control efficiency (Oxidation catalyst, or equal) | |

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

**This is a Summary Page for this Class of Source. For background information, see Permit Specific BACT Determinations on Details Page.**

Back

**Best Available Control Technology (BACT ) Guideline 1.4.8**
**Last Update: 9/1/2006**

**Refinery Flare**

| Pollutant | Achieved in Practice or in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| CO | Engineered flare, with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases. | | |
| NOx | Engineered flare, with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases. | Engineered flare or enclosed burner with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls, and having demonstrated emissions of NOx of less than 0.068 lb/MM Btu. Flare shall be equipped with a flare gas recovery system for non-emergency releases. | |

| Pollutant | Achieved in Practice or in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| PM10 | Engineered flare designed for and operated without visible emissions, except as allowed by 40CFR 60.18(c)(1) and District Rule 4101 and equipped with air or steam assisted combustion, staged combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG. | | |
| SOx | Flare shall be equipped with a flare gas recovery system for non-emergency releases. Pilot and purge gas shall be natural gas, treated refinery gas or LPG. | | |
| VOC | Engineered flare designed with a VOC destruction efficiency of = 98%. Flare design shall include air or steam assisted combustion, staged combustion, and/or equivalent District | Enclosed ground level flare or any other engineered flare designed with a VOC destruction efficiency of = 98.5%. Flare design shall include air or steam assisted combustion, staged | |

| Pollutant | Achieved in Practice or in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| | approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases, a continuous pilot or District approved alternative and a method for detecting flame. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG. | combustion, and/or equivalent District approved controls. Flare shall be equipped with a flare gas recovery system for non-emergency releases, a continuous pilot or District approved alternative and a method for detecting flame. Pilot and sweep fuel shall be natural gas, treated refinery gas or LPG. | |

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

**This is a Summary Page for this Class of Source. For background information, see Permit Specific BACT Determinations on Details Page.**

Back

## Best Available Control Technology (BACT) Guideline 1.8.2 D

| | | | |
|---|---|---|---|
| **Emissions Unit:** | Refinery Process Heater, Refinery Fuel Gas and/or Natural Gas | **Equipment Rating:** | 641 and 215 MM Btu/hr |
| **Facility:** | Big West of California LLC | **References:** | S-33-407-0 and '411-0 |
| **Location:** | Bakersfield | **Date of Determination:** | 9/1/2006 |

| Pollutant | BACT |
|---|---|
| CO | 10 ppmv @ 3% O2 (SCR and burner tuning) |
| NOx | 5 ppmv at 3% O2, (15 minute average) (Low NOx burners and SCR) |
| PM10 | Treated refinery gas and/or natural gas with no more than 100 ppmv total reduced sulfur (3-hour rolling average) |
| SOx | Treated refinery gas and/or natural gas with no more than 100 ppmv total reduced sulfur (3-hour rolling average) |
| VOC | Good combustion practices |

| BACT Status | Comment |
|---|---|
| Achieved in Practice | VOC, NOx, SOx and CO |
| Technologically Feasible BACT | PM10 |

## Best Available Control Technology (BACT) Guideline 1.8.2 C

| | | | |
|---|---|---|---|
| **Emissions Unit:** | Process Heater - Refinery | **Equipment Rating:** | All |
| **Facility:** | Equilon Enterprise | **References:** | ATC #: Withdrawn Project #: S-990010 |
| **Location:** | Bakersfield | **Date of Determination:** | 1/4/2001 |

| Pollutant | BACT |
|---|---|
| CO | BACT NOT TRIGGERED |

| Pollutant | BACT |
|---|---|
| NOx | BACT NOT TRIGGERED |
| PM10 | BACT NOT TRIGGERED |
| SOx | Natural gas or treated refinery gas @ 0.0621 grains H2S/dscf (100 ppmv H2S) |
| VOC | BACT NOT TRIGGERED |

| BACT Status | Comment |
|---|---|
| Achieved in Practice | |

**Best Available Control Technology (BACT) Guideline 1.8.2 B**

| | | | |
|---|---|---|---|
| **Emissions Unit:** | Process Heater - Refinery | **Equipment Rating:** | = or > 50.0 MMBtu/hr |
| **Facility:** | n/a | **References:** | District Proactive BACT Determination |
| **Location:** | n/a | **Date of Determination:** | 6/30/1999 |

| Pollutant | BACT |
|---|---|
| CO | BACT NOT TRIGGERED |
| NOx | 9.0 ppmvd @ 3% 02 (0.0108 lb/MMBtu) SCR |
| PM10 | BACT NOT TRIGGERED |
| SOx | BACT NOT TRIGGERED |
| VOC | BACT NOT TRIGGERED |

| BACT Status | Comment |
|---|---|
| Achieved in Practice | |

**Best Available Control Technology (BACT) Guideline 1.8.2 A**

| | | | |
|---|---|---|---|
| **Emissions Unit:** | Process Heater - Refinery | **Equipment Rating:** | 92 MMBtu/hr |
| **Facility:** | Equilon Enterprises LLC | **References:** | ATC #: S-33-17-7<br>Project #: S-981236 |

| **Location:** | Bakersfield | **Date of Determination:** | 6/11/1999 |
|---|---|---|---|

| **Pollutant** | **BACT** |
|---|---|
| CO | BACT NOT TRIGGERED |
| NOx | 30.0 ppmvd @ 3% 02 (0.036 lb/MMBtu) Ultra Low NOx burner with FGR. |
| PM10 | BACT NOT TRIGGERED |
| SOx | Treated Refinery gas with a sulfur content of 0.10 grains H2S/dscf (161 ppmv H2S) with natural gas as a supplemental fuel. |
| VOC | BACT NOT TRIGGERED |

| **BACT Status** | **Comment** |
|---|---|
| Achieved in Practice | |
| The following technologically feasible options were not cost effective | - Natural gas or treated refinery gas @ 100 ppmv H2S - Selective Catalytic Reduction |

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT

# FINAL STAFF REPORT

## Update to Rule 2201 Best Available Control Technology (BACT) Cost Effectiveness Thresholds

I thought it was interesting & may be useful to you

May 14, 2008

Prepared by: Ben Ellenberger, Air Quality Engineer
Leonard Scandura, Supervising Air Quality Engineer

Reviewed by: David Warner, Director of Permit Services
Carlos Garcia, Senior Air Quality Engineer

## I. Summary

The current Rule 2201 Best Available Control Technology (BACT) cost effectiveness thresholds were incorporated into the San Joaquin Valley Air Pollution Control District's (SJVAPCD) BACT policy upon formation of the SJVAPCD in 1991. The cost effectiveness thresholds used by the SJVAPCD have not been updated since that time.

In a November 2005 report on their 2003 program review of the SJVAPCD, the California Air Resources Board (CARB) indicated that the SJVAPCD's BACT cost effectiveness thresholds were substantially lower than other Districts with similar or better air quality status and suggested that the cost effectiveness thresholds be increased.

Although SJVAPCD staff has not seen differences in the results of BACT analyses when compared to other air Districts, in our 2006 response to the CARB program review we made a commitment to CARB to form a workgroup of SJVAPCD staff, industry representatives, environmental and community group representatives to investigate CARB's concerns and recommend SJVAPCD action, if appropriate, to the Air Pollution Control Officer.

Members of the workgroup included District staff, industry representatives Daryl Gunderson of Aera Energy, Chris Savage of E & J Gallo, and Roger Isom of California Cotton Ginners and Growers Association; and environmental and community group representatives Sarah Jackson of Earthjustice, Carolina Simunovic of Fresno Metro Ministry, and Caroline Farrell of Center on Race, Poverty and the Environment. CARB and EPA staff were invited to participate in this process; each provided verbal or written comments.

The proposed updates are the result of the workgroup's collaborative effort, careful discussion, and detailed analysis over several months in 2007. The investigations of this group confirmed overall impressions that there are no significant differences in the results of SJVAPCD's past BACT analyses when compared to other Districts. One conclusion was that the SJVAPCD's cost effectiveness thresholds are not directly comparable to those of other Districts because the method in which the calculated emission reduction is determined is inherently different.

By way of explanation, the SJVAPCD's comparatively low cost effectiveness thresholds are offset by the method in which the SJVAPCD calculates the emission reduction due to installation of technologically feasible control equipment. The SJVAPCD's current methodology calculates the emission reduction due to installing technologically feasible control equipment on equipment available on a nationwide basis. Equipment available on a nationwide basis typically has higher emissions than that allowed by SJVAPCD rules.

As a result, the calculated emission reduction due to installing technologically feasible control equipment is relatively large, making the cost effectiveness of such control equipment relatively low, using the standard cost effectiveness equation:

$$\text{cost effectiveness (\$/ton)} = \frac{\text{annualized cost of tech feasible control (\$/year)}}{\text{calculated emission reduction (ton/year)}}$$

The SJVAPCD's current relatively low cost effectiveness thresholds are appropriate given the typically large emission reductions determined using the SJVAPCD's current emission reduction calculation methodology.

Other Districts with higher cost effectiveness thresholds determine the calculated emission reduction due to installing technologically feasible control equipment on equipment that is in compliance with the District's rules. Such equipment typically has lower emissions than that available on a nationwide basis. In those cases, the calculated emission reduction is low, making the cost effectiveness high. In such cases, higher cost effectiveness thresholds are appropriate.

An examination of the BACT guidelines of the SJVAPCD and other Districts revealed that the SJVAPCD's BACT requirements are as stringent or more stringent that those of other California Districts. As such, the SJVAPCD's current thresholds and emission reduction calculation methodology do not result in less stringent BACT requirements.

To address CARB's concern and to eliminate the appearance of inconsistency when compared to other Districts, the workgroup has generally concluded that the cost effectiveness thresholds and emission reduction calculation methodology should be updated to make the SJVAPCD's cost effectiveness thresholds and emission reduction calculation methodology consistent with that of other Districts.

These two changes taken together should not have a significant effect on the outcome of the majority of cost effectiveness analyses performed by the SJVAPCD.

## II. Current Cost Effectiveness Thresholds And Emission Reduction Calculation Methodology

Rule 2201 section 3.9 defines BACT as the most stringent emission limitation or control technology that is:

- Achieved in practice for such category and class of source,
- Required by an EPA approved State Implementation Plan, i.e. required by a Rule that has been approved by EPA,
- Required by a Federal New Source Performance Standard (NSPS), or
- Is found to be both technologically feasible and cost effective for such class or category of sources or for a specific source.

The Rule 2201 definition of BACT is not proposed to be changed.

Please note that if an emission limit or control technology is achieved in practice for a category and class of source, required by an EPA approved SIP, or is required by a Federal NSPS such control is required regardless of cost. As such, the cost effectiveness analysis process only includes those technologically feasible control technologies that are not achieved in practice for a category and class of source, required by an SIP, or required by an NSPS requirement.

The cost effectiveness thresholds currently used by the SJVAPCD to determine if a technologically feasible control technology is cost effective are as follows:

| Pollutant | Cost effectiveness ($/ton) |
|---|---|
| $NO_x$ | 9,700 |
| CO | 300 |
| VOC | 5,000 |
| $SO_x$ | 3,900 |
| $PM_{10}$ | 5,700 |

In determining if a technologically feasible control technique is cost effective, the cost effectiveness of a particular control technology is compared to the cost effectiveness thresholds for a given pollutant.

For example, if the cost effectiveness for NOx control technique A is $6,000/ton, such a control technique is determined to be cost effective because its cost effectiveness ($6,000/ton) is less than the SJVAPCD's cost effectiveness threshold ($9,700/ton). As a result, NOx control technique A would be required.

Alternatively, if the cost effectiveness for NOx control technique B is $30,000/ton, such a control technique is determined not to be cost effective because its cost effectiveness ($30,000/ton) is greater than the SJVAPCD's cost effectiveness threshold ($9,700/ton). As a result, NOx control technique B would not be required.

Currently, to determine the cost effectiveness of a particular control technique, the annual costs of the control (annualized capital costs plus annual operating costs) are divided by the calculated emission reduction due to that particular control technique. The emissions reduction is calculated as the difference between emissions from equipment available on a nationwide basis and emissions from such equipment equipped with technologically feasible control.

Cost effectiveness ($/ton) =

$$\frac{\text{Annual cost (\$/year)}}{\text{Emissions (available nationwide)} - \text{Emissions (w/ tech feas BACT) (ton/year)}}$$

Emissions from equipment used nationwide can be higher than SJVAPCD prohibitory rules allow for existing equipment. As a result the calculated emission reduction can be overstated, i.e. the calculated emission reduction can be larger than the actual emissions reduced due to installing technologically feasible control on equipment that must otherwise meet SJVAPCD prohibitory rule requirements.

## III. Survey of other Districts, CARB, and EPA

The workgroup surveyed the South Coast Air Quality Management District (SCAQMD), Bay Area Air Quality Management District (BAAQMD), Sacramento Metropolitan Air Quality Management District (SMAQMD), Yolo-Solano Air Quality Management District (YSAQMD), San Diego County Air Pollution Control District (SDAPCD), California Air Resources Board (CARB), and the US Environmental Protection Agency (EPA) for the following:

- BACT cost effectiveness thresholds
- Methodology for calculating the "emission reduction" in cost effectiveness analyses

Survey of cost effectiveness thresholds:

| Summary of BACT Cost Effectiveness Thresholds ($/ton) | | | | | | | |
|---|---|---|---|---|---|---|---|
| | SCAQMD[1] | BAAQMD | SMAQMD | YSAQMD | SDAPCD[2] | CARB[2] | EPA[2] |
| $NO_x$ | 19,100 | 17,500 | 24,500 | 24,500 | 18,000 | N/A | N/A |
| CO | 400 | N/A | N/A | 300 | N/A | N/A | N/A |
| VOC | 20,200 | 17,500 | 17,500 | 17,500 | 10,200 | N/A | N/A |
| $SO_x$ | 10,100 | 18,300 | 18,300 | 3,900 | N/A | N/A | N/A |
| $PM_{10}$ | 4,500 | 5,300 | 11,400 | 5,700 | N/A | N/A | N/A |

Notes:

[1]The SCAQMD's method of amortizing control equipment costs is now inherently different from the methods used by the other Districts. The SCAQMD method tends to result in lower amortized control equipment costs (and therefore lower cost effectiveness thresholds). Because the SCAQMD amortization method is inherently different than that used by other Districts, it will not be considered further.

[2]SDPACD does not have thresholds for CO, SOx, and PM10. CARB and EPA do not have defined thresholds for any air contaminant.

The results of the survey indicate that all other Districts have cost effectiveness thresholds much greater than the SJVAPCD for each affected pollutant, except CO.

The average of other District's cost effectiveness thresholds (except SCAQMD) and the % difference from the SJVAPCD's existing levels are as follows:

| Average cost effectiveness thresholds ($/ton) | | | | |
|---|---|---|---|---|
| NOx | CO | VOC | SOx | PM10 |
| 21,100 | 300 | 15,700 | 13,500 | 7,500 |
| 117% | 0% | 214% | 246% | 32% |

The highest cost effectiveness thresholds of other surveyed Districts and the % difference from the SJVAPCD's existing levels are as follows:

| Highest cost effectiveness thresholds ($/ton) | | | | |
|---|---|---|---|---|
| NOx | CO | VOC | SOx | PM10 |
| 24,500 | 300 | 17,500 | 18,300 | 11,400 |
| 150% | 0% | 250% | 370% | 100% |

Survey of emission reduction calculation methodology:

| District | Emission reduction calculation methodology |
|---|---|
| SCAQMD | No defined method for determining "emissions without controls" emissions in BACT cost analyses. However, usually use the Prohibitory Rule limits to determine industry standard emissions. |
| BAAQMD | No defined method for determining "emissions without controls" in BACT cost effectiveness analyses. However, usually use the Prohibitory Rule limits to determine industry standard emissions. |
| SMAQMD | No defined method for determining "emissions without controls" in BACT cost effectiveness analyses. Case-by-case determination is used. |

| District | Emission reduction calculation methodology |
|---|---|
| YSAQMD | No defined method for determining "emissions without controls" in BACT cost effectiveness analyses. Case-by-case determination is used. |
| SDAPCD | No defined method for determining "emissions without controls" in BACT cost effectiveness analyses. However, for new and modified equipment that has never triggered BACT, usually use AP-42 to determine "emissions without controls" unless something else makes more sense. For modified equipment that has previously been subjected to BACT, they calculate the emission reductions from the currently permitted emission rate. |
| CARB | No guidance available |
| EPA | General guidance is the "emissions without controls" is the realistic upper boundary of uncontrolled emissions, i.e. the highest emitting operation that the facility would use (in the absence of a rule requirement). |

When performing a cost effectiveness analysis, most other Districts calculate the emission reduction based on the allowable emissions in District Rules, and not on emissions from equipment available on a nationwide basis.

## IV. Options For Revising The SJVAPCD BACT Policy:

Option #1: Do not change current cost thresholds and emission reduction calculation methodology

An examination of the results of SJVAPCD cost effectiveness analyses performed using the SJVAPCD's current thresholds and emission reduction calculation methodology and using other Districts' cost effectiveness thresholds and emission reduction calculation methodology revealed that results are typically similar, i.e. the current method usually results in BACT requirements no more or less stringent than other Districts' BACT requirements. However, continuing to use the current system can result in the impression by oversight agencies and others that the SJVAPCD's BACT requirements are less stringent than those of other Districts.

Additionally, using "nationwide emissions" in cost effectiveness calculations is problematic; the determination of such an emission level is somewhat subjective and such equipment can not typically be operated in the SJVAPCD.

Option #2: Increase the cost thresholds to the average of the other surveyed Districts and change the methodology used in calculating the emission reduction to that used by most other Districts, i.e. calculate the emission reductions as the difference between emissions required by SJVAPCD rules and emissions with technologically feasible controls.

Some of the Districts surveyed have a similar non-attainment status as the SJVAPCD (SCAQMD, SMAQMD, and YSAQMD) and others have a lesser non-attainment status (BAAQMD and SDAPCD). Districts with better air quality generally have lower cost effectiveness thresholds. As such their cost effectiveness thresholds tend to decrease the average cost effectiveness threshold.

Because of the SJVAPCD's extreme non-attainment status for ozone and non-attainment status for PM2.5, using the average of the other District's cost effectiveness thresholds in the SJVAPCD may not be adequately protective of the SJVAPCD's air quality.

Option #3: Increase the cost thresholds to the highest of the other surveyed Districts and change the methodology used in calculating the emission reduction to that used by most other Districts, i.e. calculate emission reductions as the difference between industry standard emissions (i.e. emissions required by SJVAPCD rules) and emissions with technologically feasible controls.

Option #3 is the recommended approach given the SJVAPCD's extreme non-attainment status. In addition, using SJVAPCD rule limits (or permitted emission limits) as the starting point for calculating emission reductions from installing technologically feasible controls is less subjective and is a better estimate of the actual emission reduction achievable due to installing technologically feasible controls.

## V. Proposed Cost Effectiveness Thresholds And Emission Reduction Calculation Methodology

The proposed cost effectiveness thresholds (option #3) to determine if a technologically feasible control technology is cost effective are as follows:

| Pollutant | Cost effectiveness ($/ton) |
|---|---|
| $NO_x$ | 24,500 |
| CO | 300 |
| VOC | 17,500 |
| $SO_x$ | 18,300 |
| $PM_{10}$ | 11,400 |

Proposed emission reduction calculation methodology:

Cost effectiveness ($/ton) =

$$\frac{\text{Annual cost (\$/year)}}{\text{District Standard Emissions} - \text{Emissions (w/ tech feas BACT) (ton/year)}}$$

Annual costs are equal to annualized cost of utilizing technologically feasible BACT controls on an emission unit that already meets District standard emissions. Annual costs do not include costs necessary to meet District standard emissions.

For new emission units, District standard emissions are equal to the emissions level allowed by applicable SJVAPCD rule requirements once the compliance date, i.e. the date at which the emission unit must meet a specific emission requirement, for the rule has passed. For rules with a phased compliance schedule, the earliest compliance date which applies to the equipment being analyzed shall be used. The emission limits in the applicable SJVUAPCD prohibitory rule shall be those that the particular emission unit is subject to. Please note that if the applicable rule has both a standard and enhanced compliance option, the emission level and earliest compliance date required by the standard compliance option shall be used.

For existing emission units, District standard emissions are equal to the emissions level allowed by the current PTO.

If there is no SJVAPCD prohibitory rule emission limit that applies to the particular new emission unit or if the existing emission unit does not have permitted emission limits, District standard emissions for the unit are equal to the emissions from similar equipment that is commonly available in the District. In no case shall the emissions used be higher than that allowed by State or Federal requirements. If insufficient information is available to make a determination regarding emissions from common available equipment in the District, District standard emissions will be estimated based on EPA's Compilation of Air Pollutant Emission Factors (AP-42), or other references as determined by the SJVAPCD to be appropriate.

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

APR 2 6 2016

Travis Goddard
All Phase Oilfield Service Inc.
17346 Kranenburg Ave.
Bakersfield, CA 93314

**Re: Notice of Preliminary Decision - Authority to Construct**
**Facility Number: S-8760**
**Project Number: S-1154230**

Dear Mr. Goddard:

Enclosed for your review and comment is the District's analysis of All Phase Oilfield Service Inc.'s application for an Authority to Construct for three flares to operate at various locations.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. After addressing all comments made during the 30-day public notice period, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. David Torii of Permit Services at (661) 392-5620.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:dbt

Enclosures

cc: Tung Le, CARB (w/ enclosure) via email

Seyed Sadredin
Executive Director/Air Pollution Control Officer

Northern Region
4800 Enterprise Way
Modesto, CA 95356-8718
Tel: (209) 557-6400 FAX: (209) 557-6475

Central Region (Main Office)
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244
Tel: (559) 230-6000 FAX: (559) 230-6061

Southern Region
34946 Flyover Court
Bakersfield, CA 93308-9725
Tel: 661-392-5500 FAX: 661-392-5585

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# San Joaquin Valley Air Pollution Control District

## Authority to Construct Application Review

### Well Test Flares

| | | | |
|---|---|---|---|
| Facility Name: | All Phase Oilfield Service Inc. | Date: | 3/23/16 |
| Mailing Address: | 17346 Kranenburg Ave.<br>Bakersfield, CA 93314 | Engineer: | David Torii |
| | | Lead Engineer: | Dan Klevann |
| Contact Person: | Travis E. Goddard | | |
| Telephone: | 661-618-1995 | | |
| Application #(s): | S-8730-2-0, '3-0 and '4-0 | | |
| Project #: | 1154230 | | |
| Deemed Complete: | 12/21/15 | | |

---

## I. Proposal

All Phase Oilfield Service Inc has requested Authority to Construct (ATC) permits for the installation of three flares for multiple uses including well testing. The flares will be authorized to operate at various unspecified locations.

## II. Applicable Rules

| | |
|---|---|
| Rule 2201 | New and Modified Stationary Source Review Rule (4/21/11) |
| Rule 2410 | Prevention of Significant Deterioration (6/16/11) |
| Rule 2520 | Federally Mandated Operating Permits (6/21/01) |
| Rule 4001 | New Source Performance Standards (4/14/99) |
| Rule 4002 | National Emissions Standards for Hazardous Air Pollutants (5/20/04) |
| Rule 4101 | Visible Emissions (2/17/05) |
| Rule 4102 | Nuisance (12/17/92) |
| Rule 4201 | Particulate Matter Concentration (12/17/92) |
| Rule 4301 | Fuel Burning Equipment (12/17/92) |
| Rule 4311 | Flares (06/18/09) |
| Rule 4801 | Sulfur Compounds (12/17/92) |
| CH&SC 41700 | Health Risk Assessment |
| CH&SC 42301.6 | School Notice |

Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

## III. Project Location

The flares will be operated at various unspecified locations in the SJVAPCD. The flares shall not operate within 1,000 feet of a K-12 school. Therefore, the noticing provisions of CH&SC 2301.6 do not apply.

## IV. Process Description

After drilling, and periodically during their productive lives, oil and gas wells are tested to establish their flow and pressure decline rates. The well test flares will incinerate the gases released from the well during testing.

## V. Equipment Listing

S-8730-2-0, '3-0 and '4-0:

3" DIA. X 20 FT. TALL WELL TEST FLARE WITH CONTINUOUS ELECTRIC IGNITION POWERED BY SOLAR/BATTERY, OPERATED AT VARIOUS UNSPECIFIED LOCATIONS, SJVUAPCD

## VI. Emission Control Technology Evaluation

A well test flare is an emission control and safety device used to incinerate combustible gases that would otherwise be released during testing of an oil or gas production well. The combustible gases include a significant fraction of VOC along with measurable concentrations of various sulfur compounds such as hydrogen sulfide ($H_2S$). By incinerating these gases, VOC emissions are reduced by at least 99%, while sulfur compounds are expected to be entirely converted to $SO_x$.

## VII. General Calculations

### A. Assumptions

Each Flare:

- Well test gas venting is limited to 1.0 MMscf/day and 288 MMscf/yr (applicant)
- Test gas higher heating value is 1,000 Btu/scf (applicant)
- Test gas sulfur content is 5 gr/100 scf (applicant)
- Pilot gas: propane (applicant)
- Pilot gas flow : 45 scf/hr (applicant)
- The pilot gas combustion emissions are assumed to be negligible
- VOC destruction efficiency is 99%
- No flares will operate together (at the same stationary source)

## B. Emission Factors

| Flare Emission Factors | | |
|---|---|---|
| | lb./MMBtu | Source |
| $NO_X$ | 0.068 | FYI 83 |
| *$SO_X$ | 0.0143 | Mass Balance Equation |
| $PM_{10}$ | 0.008** | FYI 83 |
| CO | 0.37 | FYI 83 |
| VOC | 0.063 | FYI 83 |

$$*\frac{5\,gr\cdot S}{100\,dscf}\left(\frac{dscf}{1{,}000\,Btu}\right)\frac{10^6\,Btu}{MMBtu}\left(\frac{1\,lb}{7{,}000\,gr}\right)\frac{64\,lb\cdot SO_2}{32\,lb\cdot S}=0.0143\frac{lb\cdot SO_2}{MMBtu}$$

**Note that the applicant has proposed the BACT-compliant PM10 emission factor pursuant to District FYI 83; therefore, visible emissions will be limited to less than Ringelmann ¼ and less than 5% opacity

## C. Calculations

### 1. Pre-Project Potential to Emit (PE1)

Since this is a new emissions unit, PE1 = 0 for all pollutants.

### 2. Post Project Potential to Emit (PE2)

| Pollutant | Daily PE2 (Each Flare) | | |
|---|---|---|---|
| | EF2 (lb./MMBtu) | Heat Input (MMBtu/day) | Daily Emissions (lb./day) |
| $NO_X$ | 0.068 | 1000 | 68.0 |
| $SO_X$ | 0.0143 | 1000 | 14.3 |
| $PM_{10}$ | 0.008 | 1000 | 8.0 |
| CO | 0.37 | 1000 | 370.0 |
| VOC | 0.063 | 1000 | 63.0 |

| Pollutant | Annual PE2 (Each Flare) | | |
|---|---|---|---|
| | EF2 (lb./MMBtu) | Heat Input (MMBtu/yr.) | Emissions (lb./yr.) |
| $NO_X$ | 0.068 | 288,000 | 19,584 |
| $SO_X$ | 0.0143 | 288,000 | 4,118 |
| $PM_{10}$ | 0.008 | 288,000 | 2,304 |
| CO | 0.37 | 288,000 | 106,560 |
| VOC | 0.063 | 288,000 | 18,144 |

### 3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the SSPE1 is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of Emission Reduction Credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions (AER) that have occurred at the source, and which have not been used on-site.

The District's longstanding permitting practice is that oilfield service activities are distinct from oil and gas production operations and are therefore not part of the oil and gas production stationary source they serve.

Furthermore, each well test flare is its own stationary source and no other permitted equipment, including other well test flares, are allowed to operate as part of a well test flare's stationary source. Therefore, these are new facility's (stationary sources); therefore, the SSPE1s are equal to zero.

## 4. Post Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site.

The District's longstanding permitting practice is that oilfield service activities are distinct from oil and gas production operations and are therefore not part of the oil and gas production stationary source they serve.

Furthermore, each well test flare is its own stationary source and no other permitted equipment, including other well test flares, are allowed to operate as part of a well test flare's stationary source.

| SSPE2 (lb/year) | | | | | |
|---|---|---|---|---|---|
| Permit Unit | $NO_X$ | $SO_X$ | $PM_{10}$ | CO | VOC |
| S-8730-2-0 | 19,584 | 4,118 | 2,304 | 106,560 | 18,144 |
| SSPE2 | 19,584 | 4,118 | 2,304 | 106,560 | 18,144 |

| SSPE2 (lb/year) | | | | | |
|---|---|---|---|---|---|
| Permit Unit | $NO_X$ | $SO_X$ | $PM_{10}$ | CO | VOC |
| S-8730-3-0 | 19,584 | 4,118 | 2,304 | 106,560 | 18,144 |
| SSPE2 | 19,584 | 4,118 | 2,304 | 106,560 | 18,144 |

| SSPE2 (lb/year) | | | | | |
|---|---|---|---|---|---|
| Permit Unit | $NO_X$ | $SO_X$ | $PM_{10}$ | CO | VOC |
| S-8730-4-0 | 19,584 | 4,118 | 2,304 | 106,560 | 18,144 |
| SSPE2 | 19,584 | 4,118 | 2,304 | 106,560 | 18,144 |

## 5. Major Source Determination

**Rule 2201 Major Source Determination:**

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

As shown in Section VII.C.5 above, the facility is not a Major Source for any pollutant.

Therefore BE=PE1.

**7. SB 288 Major Modification**

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is not a major source for any of the pollutants addressed in this project, this project does not constitute an SB 288 major modification.

**8. Federal Major Modification**

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification. Additionally, since the facility is not a major source for $PM_{10}$ (140,000 lb/year), it is not a major source for PM2.5 (200,000 lb/year).

## VIII. Compliance

### Rule 2201 New and Modified Stationary Source Review Rule

#### A. Best Available Control Technology (BACT)

**1. BACT Applicability**

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

- Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

| Rule 2201 Major Source Determination (lb/year) | | | | | | |
|---|---|---|---|---|---|---|
| Each Flare | $NO_X$ | $SO_X$ | $PM_{10}$ | $PM_{2.5}$ | CO | VOC |
| SSPE1 | 0 | 0 | 0 | 0 | 0 | 0 |
| SSPE2 | 19,584 | 4,118 | 2,304 | 2,304 | 106,560 | 18,144 |
| Major Source Threshold | 20,000 | 140,000 | 140,000 | 200,000 | 200,000 | 20,000 |
| Major Source? | No | No | No | No | No | No |

Note: PM2.5 assumed to be equal to PM10

As seen in the table above, the facility is not an existing Major Source and is not becoming a Major Source as a result of this project.

**Rule 2410 Major Source Determination:**

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

| PSD Major Source Determination (tons/year) | | | | | | |
|---|---|---|---|---|---|---|
| | NO2 | VOC | SO2 | CO | PM | PM10 |
| Estimated Facility PE before Project Increase | 0 | 0 | 0 | 0 | 0 | 0 |
| PSD Major Source Thresholds | 250 | 250 | 250 | 250 | 250 | 250 |
| PSD Major Source ? (Y/N) | n | n | n | n | n | n |

As shown above, the facility is not an existing PSD major source for any regulated NSR pollutant expected to be emitted at this facility.

## 6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the QNEC, and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

**a. New emissions units – PE > 2 lb/day**

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a well drilling and testing operation with PE greater than 2 lb. /day for $NO_X$, $SO_X$, CO, and VOC. As discussed in Section VI above, the flare is a VOC control device (not emissions units) and therefore BACT is triggered only for VOC only.

**b. Relocation of emissions units – PE > 2 lb/day**

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered.

**c. Modification of emissions units – AIPE > 2 lb/day**

As discussed in Section I above, there are no modified emissions units associated with this project. Therefore BACT is not triggered.

**d. SB 288/Federal Major Modification**

As discussed in Sections VII.C.7 and VII.C.8 above, this project does not constitute an SB 288 and/or Federal Major Modification. Therefore BACT is not triggered.

**2. BACT Guideline**

BACT Guideline 1.4.7 covers waste gas flares from oilfield well drilling and testing operations that incinerate less than 50 MMscf/day of waste gas.

**3. Top-Down BACT Analysis**

As shown by the Top-Down BACT Analysis in Appendix A, BACT is satisfied by the use of an elevated flare with a propane fueled pilot flame.

## B. Offsets

**1. Offset Applicability**

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.
The SSPE2 is compared to the offset thresholds in the following table.

| Offset Determination (lb/year) | | | | | |
|---|---|---|---|---|---|
| | $NO_X$ | $SO_X$ | $PM_{10}$ | CO | VOC |
| SSPE2 | 19,584 | 4,118 | 2,304 | 106,560 | 18,144 |
| Offset Thresholds | 20,000 | 54,750 | 29,200 | 200,000 | 20,000 |
| Offsets triggered? | No | No | No | No | No |

### 2. Quantity of Offsets Required

As seen above, the SSPE2 is not greater than the offset thresholds for all the pollutants; therefore offset calculations are not necessary and offsets will not be required for this project.

## C. Public Notification

### 1. Applicability

Public noticing is required for:
a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed, and/or
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.
e. Any project which results in a Title V significant permit modification

#### a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. As shown in Section VII.C.5 above, the SSPE2 is not greater than the Major Source threshold for any pollutant. Therefore, public noticing is not required for this project for new Major Source purposes.

As demonstrated in Sections VII.C.7 and VII.C.8, this project does not constitute an SB 288 or Federal Major Modification; therefore, public noticing for SB 288 or Federal Major Modification purposes is not required.

#### b. PE > 100 lb/day

The PE2 for this new unit is compared to the daily PE Public Notice thresholds in the following table:

| PE > 100 lb/day Public Notice Thresholds | | | |
|---|---|---|---|
| Pollutant | PE2 (lb/day) | Public Notice Threshold | Public Notice Triggered? |
| $NO_X$ | 68.0 | 100 lb/day | N |
| $SO_X$ | 14.3 | 100 lb/day | N |
| $PM_{10}$ | 8.0 | 100 lb/day | N |
| CO | 370.0 | 100 lb/day | Y |
| VOC | 63.0 | 100 lb/day | N |

Therefore, public noticing for PE > 100 lb/day purposes is required.

#### c. Offset Threshold

The SSPE1 and SSPE2 are compared to the offset thresholds in the following table.

| Offset Thresholds | | | | |
|---|---|---|---|---|
| Pollutant | SSPE1 (lb/year) | SSPE2 (lb/year) | Offset Threshold | Public Notice Required? |
| $NO_X$ | 0 | 19,584 | 20,000 lb/year | No |
| $SO_X$ | 0 | 4,118 | 54,750 lb/year | No |
| $PM_{10}$ | 0 | 2,304 | 29,200 lb/year | No |
| CO | 0 | 106,560 | 200,000 lb/year | No |
| VOC | 0 | 18,144 | 20,000 lb/year | No |

As detailed above, offset thresholds were not surpassed with this project; therefore public noticing is not required for offset purposes.

**d. SSIPE > 20,000 lb/year**

| SSIPE Public Notice Thresholds | | | | | |
|---|---|---|---|---|---|
| Pollutant | SSPE2 (lb/year) | SSPE1 (lb/year) | SSIPE (lb/year) | SSIPE Public Notice Threshold | Public Notice Required? |
| $NO_x$ | 19,584 | 0 | 19,584 | 20,000 lb/year | No |
| $SO_x$ | 4,118 | 0 | 4,118 | 20,000 lb/year | No |
| $PM_{10}$ | 2,304 | 0 | 2,304 | 20,000 lb/year | No |
| CO | 106,560 | 0 | 106,560 | 20,000 lb/year | Yes |
| VOC | 18,144 | 0 | 18,144 | 20,000 lb/year | No |

As demonstrated above, the SSIPEs for CO is greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

**e. Title V Significant Permit Modification**

Since this facility does not have a Title V operating permit, this change is not a Title V significant Modification, and therefore public noticing is not required.

**2. Public Notice Action**

As discussed above, public noticing is required for this project for CO emissions in excess of 100 lb/day and 20,000 lb/yr. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

## D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

***Proposed Rule 2201 (DEL) Conditions:***

Daily and annual amounts of gas flared shall not exceed 1.0 MMscf/day nor 288 MMscf/yr. [District Rules 2201 and 4102]

- Emission rates shall not exceed any of the following: 0.008 lb-PM10/MMBtu, 0.068 lb.-NOx/MMBtu(as NO2), 0.063 lb.-VOC/MMBtu, or 0.37 lb.-CO/MMBtu. [District Rule 2201]

- Sulfur compound concentration of gas flared shall not exceed 5 gr/100 scf. [District Rule 2201]

- Daily and annual amounts of gas flared shall not exceed 0.144 MMscf/day and 52.56 MMscf/yr. [District rule 2201

**E. Compliance Assurance**

**1. Source Testing**

Pursuant to District Policy APR 1705, source testing is not required to demonstrate compliance with Rule 2201.

**2. Monitoring**

No monitoring is required to demonstrate compliance with Rule 2201.

**3. Recordkeeping**

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. The following condition(s) are listed on the permit to operate:

- Permittee shall maintain accurate daily records indicating flare location, flared gas sulfur content at each location, and daily and annual rates of gas flared; and such records shall be made readily available for District inspection upon request for a minimum of 5 years. [District Rules 2201 and 4311] N

**4. Reporting**

No reporting is required to demonstrate compliance with Rule 2201.

**F. Ambient Air Quality Analysis (AAQA)**

An AAQA shall be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The District's Technical Services Division conducted the required analysis. Refer to **Appendix B** of this document for the AAQA summary sheet.

The proposed location is in an attainment area for $NO_X$, CO, and $SO_X$. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for $NO_X$, CO, or $SO_X$.

The proposed location is in a non-attainment area for the state's $PM_{10}$ as well as federal and state $PM_{2.5}$ thresholds. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for $PM_{10}$ and $PM_{2.5}$.

**Rule 2410 Prevention of Significant Deterioration**

As shown in Section VII. C. 9. above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

**Rule 2520 Federally Mandated Operating Permits**

Since this facility's potential emissions do not exceed any major source thresholds of Rule 2201, this facility is not a major source, and Rule 2520 does not apply.

**Rule 4001 New Source Performance Standards (NSPS)**

This rule incorporates by reference the NSPS established in Title 40, Code of Federal Regulations, Part 60 (40 CFR 60) and applies to any source subject to an applicable standard. However, no NSPS applies to these oil well test flares. No further discussion is required.

**Rule 4002 National Emissions Standards for Hazardous Air Pollutants (NESHAP)**

This rule incorporates by reference the NESHAP established in 40 CFR 61 and 63 and applies to any source subject to an applicable standard. However, no NESHAP applies to these oil well test flares. No further discussion is required.

**Rule 4101 Visible Emissions**

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity). The applicant has proposed the BACT-compliant PM10 emisson factor pursuant to District FYI 83; therefore, visible emissions will be limited to less than Ringelmann ¼ and less than 5% opacity. As long as the flaring system is operating correctly, compliance with this rule is expected.

**Rule 4102 Nuisance**

Rule 4102 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

**California Health & Safety Code 41700 (Health Risk Assessment)**

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source

or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (**Appendix B**), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project.

The cancer risk for this project is shown below:

| RMR Summary | | | |
|---|---|---|---|
| **Categories** | **Three Well Test Flares (Units 2-0, 3-0, 4-0)** | **Project Totals** | **Facility Totals** |
| **Prioritization Score** | 250.0[1] | 250.0[1] | >1.0 |
| **Acute Hazard Index** | 0.01[1] | 0.01[1] | 0.01[1] |
| **Chronic Hazard Index** | 0.00[1] | 0.00[1] | 0.00[1] |
| **Maximum Individual Cancer Risk** | 8.51E-07[1] | 8.51E-07[1] | 8.51E-07[1] |
| **T-BACT Required?** | No | | |
| **Special Permit Requirements?** | Yes | | |

### Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

### Rule 4201 Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot. For natural gas the EPA F-factor (adjusted to 60°F) is 8710 dscf/MMBtu (40 CFR 60 Appendix B).

$PM_{10}$ Emission Factor: 0.008 lb-$PM_{10}$/MMBtu
Percentage of PM as $PM_{10}$ in Exhaust: 100%
Exhaust Oxygen ($O_2$) Concentration: 3%

Excess Air Correction to F Factor = $\frac{20.9}{(20.9 - 3)} = 1.17$

$$GL = \left(\frac{0.008\ lb-PM}{MMBtu} \times \frac{7{,}000\ grain}{lb-PM}\right) / \left(\frac{8{,}710\ ft^3}{MMBtu} \times 1.17\right)$$

$$GL = 0.0055\ grain/dscf < 0.1\ grain/dscf$$

**Rule 4311 Flares**

This rule is intended to limit the emissions of $NO_x$, $SO_x$, and VOC from the operation of flares. However, pursuant to Section 4.3, except for the record keeping requirement of Section 6.1.4 the requirements of this rule do not apply to any flare located at a stationary source with potential emissions less than 10.0 tons per year of VOC and 10.0 tons per year of $NO_x$. Section 6.1.4 requires an operator claiming exemption under Section 4.3 to record annual throughput, material usage, or other information necessary to demonstrate compliance with the terms of the exemption. The following condition, previously stated in this evaluation, will ensure compliance with this recordkeeping requirement:

- *Permittee shall maintain accurate daily records of flare location and volume of well test gas flared. [District Rules 2201 and 4311]*

**Rule 4801 Sulfur Compounds**

Rule 4801 requires that a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: two-tenths (0.2) percent by volume calculated as sulfur dioxide (SO2), on a dry basis averaged over 15 consecutive minutes.

Emission calculations were calculated using a fuel with a 5 gr/100 dscf sulfur content. Therefore, the maximum $SO_x$ ppmv are calculated to be:

$SO_x$ = (5 gr/100 dscf fuel) x (1 lb./7000 gr S) x (1 mol/32 lb. S) x (379.5 dscf S/1 mol S) x (1 dscf fuel/1000 Btu) x (1 x $10^6$ Btu/8710 dscf) x (1 x $10^6$)
= **9.7 ppmv** < 2,000 ppmv

**California Health & Safety Code 42301.6 (School Notice)**

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

**California Environmental Quality Act (CEQA)**

CEQA requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The District adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities;
- Identify the ways that environmental damage can be avoided or significantly reduced;
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible; and
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

The District performed an Engineering Evaluation (this document) for the proposed project and determined that the activity consists of issuing a permit for a piece of transportable equipment to be used at various locations within the District. The District makes the following findings regarding this activity: 1) Issuance of the permit does not have a significant environmental impact. 2) Assessment of potential environmental effects resulting from the use of the transportable equipment on a development project is the responsibility of the Lead Agency approving the specific project, and will be determined on a project specific basis. The District has determined that no additional findings are required.

## IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATCs S-8730-2-0, '3-0 and '4-0 subject to the permit conditions on the attached draft ATCs in **Appendix C.**

## X. Billing Information

| Annual Permit Fees | | | |
|---|---|---|---|
| Permit Number | Fee Schedule | Fee Description | Annual Fee |
| S-8730-2-0 | 3020-02 H | 15.0 MMBtu/hr or greater | $1080 |
| S-8730-3-0 | 3020-02 H | 15.0 MMBtu/hr or greater | $1080 |
| S-8730-4-0 | 3020-02 H | 15.0 MMBtu/hr or greater | $1080 |

## Appendixes

A: BACT Guideline and BACT Analysis
B: HRA and AAQA Summary
C: Draft ATC BACT Analysis

# APPENDIX A
# BACT Guideline and BACT Analysis

**Best Available Control Technology (BACT ) Guideline 1.4.7**
**Last Update: 8/27/1999**

**Waste Gas Flare - Oilfield Well Drilling and Testing Operation, < 50 MMscf/day**

| Pollutant | Achieved in Practice or in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| VOC | Elevated Flare with propane fueled pilot light | | |

# BACT Analysis:

The well test flares are covered by BACT Guideline 1.4.7, which covers waste gas flares for oilfield well drilling and testing operations with a maximum flow rate less than 50 MMscf/day.

**Step 1 – Identify All Possible Control Technologies:**

1. Elevated flare with propane fueled pilot light – Achieved in Practice

**Step 2 – Eliminate Technologically Infeasible Options:**

All technologies listed in Step 1 are technologically feasible.

**Step 3 – Rank Remaining Control Technologies by Control Effectiveness**

1. Elevated flare with propane fueled pilot light

**Step 4 – Cost Effectiveness Analysis**

The applicant has proposed the highest-ranked control option remaining from Step 3. No cost effectiveness analysis is required.

**Step 5 – Select BACT**

BACT is satisfied by the applicant's proposal to use an elevated flare with a propane fueled pilot light. No further discussion is required.

# APPENDIX B
# HRA and AAQA Summary

# San Joaquin Valley Air Pollution Control District
# Risk Management Review

| | |
|---|---|
| To: | David Torii – Permit Services |
| From: | Cheryl Lawler – Technical Services |
| Date: | February 24, 2016 |
| Facility Name: | All Phase Oilfield Service Inc. |
| Location: | Various Unspecified Locations |
| Application #(s): | S-8730-2-0, 3-0, 4-0 |
| Project #: | S-1154230 |

## A. RMR SUMMARY

| RMR Summary | | | |
|---|---|---|---|
| **Categories** | **Three Well Test Flares (Units 2-0, 3-0, 4-0)** | **Project Totals** | **Facility Totals** |
| **Prioritization Score** | 250.0[1] | 250.0[1] | >1.0 |
| **Acute Hazard Index** | 0.01[1] | 0.01[1] | 0.01[1] |
| **Chronic Hazard Index** | 0.00[1] | 0.00[1] | 0.00[1] |
| **Maximum Individual Cancer Risk** | 8.51E-07[1] | 8.51E-07[1] | 8.51E-07[1] |
| **T-BACT Required?** | No | | |
| **Special Permit Requirements?** | Yes | | |

[1]Reported risks are for each individual flare. Each flare constitutes its own stationary source.

### Proposed Permit Requirements

To ensure that human health risks will not exceed District allowable levels; the following shall be included as requirements for:

Units 2-0, 3-0, 4-0

1. The flare shall vent vertically upward. The vertical exhaust flow shall not be impeded any obstruction.

## B. RMR REPORT

### I. Project Description

Technical Services received a request on February 17, 2016, to perform an Ambient Air Quality Analysis and a Risk Management Review for the installation of three flares for multiple uses including well testing. The flares will be authorized to operate at various unspecified locations. Each flare is also considered to be its own stationary source.

### II. Analysis

Toxic emissions for each flare were calculated using 2001 Ventura County Air Pollution Control District emission factors for Natural Gas fired external combustion and from a Refinery Gas composition analysis from the 2005 report, *FINAL REPORT Test of TDA's Direct Oxidation Process for Sulfur Recovery*. Emissions were then input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015), risks from the project were prioritized using the procedures in the 1990 CAPCOA Facility Prioritization Guidelines. The prioritization score for the project was greater than 1.0 (see RMR Summary Table). Therefore, a refined health risk assessment was required. The AERMOD model was used, with the parameters outlined below and meteorological data for 2010-2014 from Hanford to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the SHARP Program, which then used the Air Dispersion Modeling and Risk Tool (ADMRT) of the Hot Spots Analysis and Reporting Program Version 2 (HARP 2) to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

| **Analysis Parameters (each flare)[1] Units 2-0, 3-0, 4-0** | | | |
|---|---|---|---|
| **Source Type** | Flare | **Location Type** | Rural |
| **Effective Stack Height (m)** | 8.92 | **Closest Receptor (m)** | 25[2] |
| **Effective Diameter (m)** | 1.17 | **Type of Receptor** | Residential/ Business |
| **Effective Velocity (m/s)** | 54.99 | **Natural Gas/Waste Gas Process Rates (MMscf)** | 0.042 hr 288 yr |
| **Temperature (°K)** | 810.93 | | |

[1]All parameters are based on the District's Flare Modeling Parameter Estimator for open flares.
[2]The receptor distance of 25 meters represents the worst case distance that was modeled for this project.

Technical Services also performed modeling for criteria pollutants CO, $NO_x$, $SO_x$, and PM10 with the emission rates below:

| Unit # | $NO_x$ (Lbs.) | | $SO_x$ (Lbs.) | | CO (Lbs.) | | $PM_{10}$ (Lbs.) | |
|---|---|---|---|---|---|---|---|---|
| | Day | Yr. | Day | Yr. | Day | Yr. | Day | Yr. |
| **2-0** | 68 | 19,584 | 14.3 | 4,118 | 370 | 106,560 | 8 | 2,304 |
| **3-0** | 68 | 19,584 | 14.3 | 4,118 | 370 | 106,560 | 8 | 2,304 |
| **4-0** | 68 | 19,584 | 14.3 | 4,118 | 370 | 106,560 | 8 | 2,304 |

The results from the Criteria Pollutant Modeling are as follows:

**Criteria Pollutant Modeling Results***

| Three Flares | 1 Hour | 3 Hours | 8 Hours | 24 Hours | Annual |
|---|---|---|---|---|---|
| CO | Pass | X | Pass | X | X |
| $NO_x$ | Pass[1] | X | X | X | Pass |
| $SO_x$ | Pass | Pass | X | Pass | Pass |
| $PM_{10}$ | X | X | X | Pass[2] | Pass[2] |
| $PM_{2.5}$ | X | X | X | Pass[2] | Pass[2] |

*Results were taken from the attached PSD spreadsheet.
[1]The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures.
[2]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

## III. *Conclusion*

The acute and chronic indices are below 1.0, and the cancer risk factor associated with the project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit requirements listed on Page 1 of this report must be included for the proposed units.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

# APPENDIX C
# Draft ATC

San Joaquin Valley
Air Pollution Control District

# AUTHORITY TO CONSTRUCT

DRAFT

**PERMIT NO:** S-8730-2-0

**ISSUANCE DATE:** DRAFT

**LEGAL OWNER OR OPERATOR:** ALL PHASE OILFIELD SERVICES
**MAILING ADDRESS:** 17346 KRANENBURG AVENUE
BAKERSFIELD, CA 93314

**LOCATION:** VARIOUS LOCATIONS, SJVAPCD

**EQUIPMENT DESCRIPTION:**
3" DIA. X 20 FT. TALL WELL TEST FLARE WITH CONTINUOUS ELECTRIC IGNITION POWERED BY SOLAR/BATTERY, OPERATED AT VARIOUS UNSPECIFIED LOCATIONS, SJVUAPCD

## CONDITIONS

1. The equipment shall not be located within 1000 ft. of any K-12 school. [CH&SC 42301.6]
2. The flare shall vent vertically upward. The vertical exhaust flow shall not be impeded any obstruction. [District Rule 4102]
3. Flare shall only be used to combust gas released during well testing. [District Rule 2201]
4. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
5. Permittee shall notify the District Compliance Division of each location at which the operation is located in excess of 24 hours. Such notification shall be made no later than 48 hours after starting operation at the location. [District Rule 2201]
6. The flare shall not be operated at any location in conjunction with any other flare or permitted equipment operated by All Phase Oilfield Service Inc.. [District Rule 2201]
7. The unit must not be located and operated at an existing facility or operation such that it becomes part of an existing stationary source as defined by District Rule 2201. [District Rule 2201]
8. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1/4 or 5% opacity. [District Rules 2201 and 4101]
9. Gas line to flare shall be equipped with operational, volumetric flow rate indicator. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

**YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE.** Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DRAFT

Arnaud Marjollet, Director of Permit Services

S-8730-2-0 : Mar 29 2018 3:04PM -- TORID : Joint Inspection NOT Required

10. Amounts of gas flared shall not exceed 1.0 MMscf/day nor 288 MMscf/yr. [District Rules 2201 and 4102]
11. Sulfur compound concentration of gas flared shall not exceed 5 gr/100 scf. [District Rules 2201 and 4801]
12. Emission rates shall not exceed any of the following: 0.008 lb-PM10/MMBtu, 0.068 lb-NOx/MMBtu (as NO2), 0.063 lb-VOC/MMBtu, or 0.37 lb-CO/MMBtu. [District Rule 2201]
13. The flare shall be operated according to the manufacturer's specifications, a copy of which shall be maintained on site. [District Rule 2201]
14. Permittee shall inspect the flare in operation for visible emissions no less frequently than once every two weeks. If visible emissions are observed, corrective action shall be taken. If visible emissions persist, an EPA Method 9 test shall be performed within 72 hours. [District Rule 2201]
15. Permittee shall document compliance with well gas sulfur compound concentration limit by performing sulfur content analysis of well gas upon startup at each new location. [District Rule 2201]
16. The following test methods shall be used for well gas sulfur content: ASTM D3246 or double GC for H2S and mercaptan. [District Rule 1081]
17. Permittee shall maintain accurate daily records indicating flare location, flared gas sulfur content at each location, and daily and annual rates of gas flared; and such records shall be made readily available for District inspection upon request for a minimum of 5 years. [District Rules 2201 and 4311]

DRAFT

San Joaquin Valley
Air Pollution Control District

# AUTHORITY TO CONSTRUCT

DRAFT

**PERMIT NO:** S-8730-3-0

**ISSUANCE DATE:** DRAFT

**LEGAL OWNER OR OPERATOR:** ALL PHASE OILFIELD SERVICES
**MAILING ADDRESS:** 17346 KRANENBURG AVENUE
BAKERSFIELD, CA 93314

**LOCATION:** VARIOUS LOCATIONS, SJVAPCD

**EQUIPMENT DESCRIPTION:**
3" DIA. X 20 FT. TALL WELL TEST FLARE WITH CONTINUOUS ELECTRIC IGNITION POWERED BY SOLAR/BATTERY, OPERATED AT VARIOUS UNSPECIFIED LOCATIONS, SJVUAPCD

## CONDITIONS

1. The equipment shall not be located within 1000 ft. of any K-12 school. [CH&SC 42301.6]
2. The flare shall vent vertically upward. The vertical exhaust flow shall not be impeded any obstruction. [District Rule 4102]
3. Flare shall only be used to combust gas released during well testing. [District Rule 2201]
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7. The unit must not be located and operated at an existing facility or operation such that it becomes part of an existing stationary source as defined by District Rule 2201. [District Rule 2201]
8. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1/4 or 5% opacity. [District Rules 2201 and 4101]
9. Gas line to flare shall be equipped with operational, volumetric flow rate indicator. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

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Seyed Sadredin, Executive Director / APCO

DRAFT

Arnaud Marjollet, Director of Permit Services



Southern Regional Office • 34946 Flyover Court • Bakersfield, CA 93308 • (661) 392-5500 • Fax (661) 392-5585

10. Amounts of gas flared shall not exceed 1.0 MMscf/day nor 288 MMscf/yr. [District Rules 2201 and 4102]
11. Sulfur compound concentration of gas flared shall not exceed 5 gr/100 scf. [District Rules 2201 and 4801]
12. Emission rates shall not exceed any of the following: 0.008 lb-PM10/MMBtu, 0.068 lb-NOx/MMBtu (as NO2), 0.063 lb-VOC/MMBtu, or 0.37 lb-CO/MMBtu. [District Rule 2201]
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16. The following test methods shall be used for well gas sulfur content: ASTM D3246 or double GC for H2S and mercaptan. [District Rule 1081]
17. Permittee shall maintain accurate daily records indicating flare location, flared gas sulfur content at each location, and daily and annual rates of gas flared; and such records shall be made readily available for District inspection upon request for a minimum of 5 years. [District Rules 2201 and 4311]

DRAFT

San Joaquin Valley
Air Pollution Control District

# AUTHORITY TO CONSTRUCT

DRAFT

**PERMIT NO:** S-8730-4-0

**ISSUANCE DATE:** DRAFT

**LEGAL OWNER OR OPERATOR:** ALL PHASE OILFIELD SERVICES
**MAILING ADDRESS:** 17346 KRANENBURG AVENUE
BAKERSFIELD, CA 93314

**LOCATION:** VARIOUS LOCATIONS, SJVAPCD

**EQUIPMENT DESCRIPTION:**
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## CONDITIONS

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8. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1/4 or 5% opacity. [District Rules 2201 and 4101]
9. Gas line to flare shall be equipped with operational, volumetric flow rate indicator. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

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Seyed Sadredin, Executive Director / APCO

DRAFT

Arnaud Marjollet, Director of Permit Services



Southern Regional Office • 34946 Flyover Court • Bakersfield, CA 93308 • (661) 392-5500 • Fax (661) 392-5585

10. Amounts of gas flared shall not exceed 1.0 MMscf/day nor 288 MMscf/yr. [District Rules 2201 and 4102]
11. Sulfur compound concentration of gas flared shall not exceed 5 gr/100 scf. [District Rules 2201 and 4801]
12. Emission rates shall not exceed any of the following: 0.008 lb-PM10/MMBtu, 0.068 lb-NOx/MMBtu (as NO2), 0.063 lb-VOC/MMBtu, or 0.37 lb-CO/MMBtu. [District Rule 2201]
13. The flare shall be operated according to the manufacturer's specifications, a copy of which shall be maintained on site. [District Rule 2201]
14. Permittee shall inspect the flare in operation for visible emissions no less frequently than once every two weeks. If visible emissions are observed, corrective action shall be taken. If visible emissions persist, an EPA Method 9 test shall be performed within 72 hours. [District Rule 2201]
15. Permittee shall document compliance with well gas sulfur compound concentration limit by performing sulfur content analysis of well gas upon startup at each new location. [District Rule 2201]
16. The following test methods shall be used for well gas sulfur content: ASTM D3246 or double GC for H2S and mercaptan. [District Rule 1081]
17. Permittee shall maintain accurate daily records indicating flare location, flared gas sulfur content at each location, and daily and annual rates of gas flared; and such records shall be made readily available for District inspection upon request for a minimum of 5 years. [District Rules 2201 and 4311]

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San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

NOV 16 2016

Mr. Gregory Pritchett
Chevron USA Inc
PO Box 1392
Bakersfield, CA 93302

**Re: Proposed ATC / Certificate of Conformity (Significant Mod)**
**District Facility # S-1128**
**Project # 1162368**

Dear Mr. Pritchett:

Enclosed for your review is the District's analysis of an application for Authority to Construct for the facility identified above. You requested that a Certificate of Conformity with the procedural requirements of 40 CFR Part 70 be issued with this project. The project authorizes a new tank.

After addressing all comments made during the 30-day public notice and the 45-day EPA comment periods, the District intends to issue the Authority to Construct with a Certificate of Conformity. Please submit your comments within the 30-day public comment period, as specified in the enclosed public notice. Prior to operating with modifications authorized by the Authority to Construct, the facility must submit an application to modify the Title V permit as an administrative amendment, in accordance with District Rule 2520, Section 11.5.

If you have any questions, please contact Mr. Leonard Scandura, Permit Services Manager, at (661) 392-5500.

Thank you for your cooperation in this matter.

Sincerely,

Arnaud Marjollet
Director of Permit Services

Enclosures

cc: Tung Le, CARB (w/enclosure) via email
cc: Gerardo C. Rios, EPA (w/enclosure) via email

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Executive Director/Air Pollution Control Officer

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# Authority to Construct
# Application Review
## 2000 bbl Fixed-Roof Oil Field Production Gas- Blanketed Drain Tank

| | |
|---|---|
| Facility Name: | Chevron U.S.A. Inc. (CUSA) |
| Mailing Address: | PO Box 1392<br>Bakersfield, CA 93302 |
| Contact Person: | Gregory Pritchett and Kris Rickards |
| Telephone: | (661) 654-7150, (661) 654-7796 (KR) |
| Application #(s): | S-1128-1018-0 |
| Project #: | S-1162368 |
| Deemed Complete: | June 15, 2016 |

| | |
|---|---|
| Date: | November 8, 2016 |
| Engineer: | Richard Edgehill |
| Lead Engineer: | Dan Klevann |

## I. PROPOSAL

Chevron U.S.A. Inc. (CUSA) is requesting an Authority to Construct (ATC) for the installation of a new 2,000 barrel drain tank. The proposed tank will be used in conjunction with equipment located at the 2F Oil Cleaning Plant (OCP).

The increase in facility emissions will trigger BACT, offsets, and public notice.

CUSA Facility S-1128 is currently operating under a Title V Permit. This project is a Federal Major Modification and is classified as a Title V Significant Modification pursuant to Rule 2520, Section 3.20 and can be processed with a Certificate of Conformity (COC). The facility has specifically requested that this project be processed in that manner; therefore, the 45-day EPA comment period will be satisfied prior to the issuance of the Authority to Construct. CUSA must apply to administratively amend their Title V permit.

## II. APPLICABLE RULES

| | |
|---|---|
| Rule 2201 | New and Modified Stationary Source Review Rule (2/18/16) |
| Rule 2410 | Prevention of Significant Deterioration (6/16/11) |
| Rule 2520 | Federally Mandated Operating Permits (6/21/01) |
| Rule 4001 | New Source Performance Standards (4/14/99) |
| Rule 4002 | National Emissions Standards for Hazardous Air Pollutants (5/20/04) |
| Rule 4101 | Visible Emissions (2/17/05) |
| Rule 4102 | Nuisance (12/17/92) |
| Rule 4623 | Storage of Organic Liquids (5/19/05) |
| CH&SC 41700 | Health Risk Assessment |
| CH&SC 42301.6 | School Notice |

Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)

CCR, Title 14, Div 6, Chap 3, Sections 15000-15387: CEQA Guidelines

## III. PROJECT LOCATION

The project is located at the 2F (Oil Cleaning Plant (OCP), Midway Sunset Oilfield, CUSA's Western Kern County field heavy oil production stationary source. This location is not located within 1,000 feet of a K-12 school.

## IV. PROCESS DESCRIPTION

The proposal is for the installation of a 2,000 barrel drain tank at the 2F oil cleaning plant. The tank will be equipped with a pressure-vacuum (PV) relief vent valve set to within 10% of the maximum allowable working pressure of the tank. The PV-valve will reduce VOC wind induced emissions from the tank vent.

The tank will be equipped with a gas blanketing system which will maintain the tank's vapor space above the upper explosive limit (gas becomes too rich to burn) by the addition of PUC-quality natural gas. Applicant has stated that the PV vent will be set at a pressure higher than expected internal pressure spikes from daily spikes due to temperature changes. The tank is expected to be empty over 90% of the time.

The gas blanket gas exits to atmosphere through the relief valve once enough liquid enters the tank. Once the liquid level is reduced a regulator will allow pressure in the tank to build back up.

A diagram of the gas blanket system is included in **Attachment I.**

## V. EQUIPMENT LISTING

ATC Equipment Description:

S-1128-1018-0: 2000 BBL DRAIN TANK WITH NATURAL GAS BLANKETING (2F OCP)

## VI. EMISSION CONTROL TECHNOLOGY EVALUATION

The tank will be equipped with a pressure-vacuum (PV) relief vent valve set to within 10% of the maximum allowable working pressure of the tank. The PV-valve will reduce VOC wind induced emissions from the tank vent. The tank will be equipped with a gas blanketing system which will maintain the tank's vapor space above the upper explosive limit by the addition of PUC quality natural gas.

## VII. GENERAL CALCULATIONS

### A. Assumptions

- The tank operates as a spill prevention container. It will also be used periodically for routine removal of fluids (drains and maintenance).
- The tank is a potential source of volatile organic compound (VOC) emissions.
- Maximum throughput = 2,000 bbl/day and 70,000 bbl/yr
- The tank paint conditions are good, the color is gray and the shade is medium.
- TVP of oil = 0.5 psia (Applicant)
- Tank temperature, 200 °F
- Tank will be equipped with a pump which activates at 5 feet, pumping liquid from the tank to a pipeline. The pump shuts off when the liquid level reaches 4 feet. Therefore, an average height of 4 feet was used to calculate emissions from the tank.
- For Greenhouse Gas (GHG) Emissions tank emissions are assumed to be 100% methane.

- The VOC content of the gas blanket vapors does not exceed 10% by weight (9/9/16 applicant email, **Attachment II**). In accordance with District SSP 2015 policy "Quantifying Fugitive VOC Emissions at Petroleum and SOCMI Facilities", VOC emissions are not assessed to piping and components handling vapor streams with a VOC content of 10% and therefore fugitive emissions components do not emit VOCs.

- Fugitive emissions associated with the gas blanket system were neglected in the emissions used for the HRA.

### B. Emission Factors

Emissions from the uncontrolled tank with a PV valve were calculated using the District's spreadsheet for crude oil/organic liquids with API gravity < 26 degrees (**Attachment III**).

Greenhouse Gas (GHG) Emissions Calculations

GWP for CH4 = 21 lb-$CO_2e$ per lb-$CH_4$
GWP for N2O = 310 lb-$CO_2e$ per lb-$N_2O$

### C. Calculations

#### 1. Pre-Project Potential to Emit (PE1)

Since this is a new emissions units, PE1 = 0 for all criteria pollutants.

## 2. Post-Project Potential to Emit (PE2)

| Post-Project Potential to Emit (PE2) | | | |
|---|---|---|---|
| Permit Unit | Location | VOC – Daily PE2 (lb/day) | VOC – Annual PE2 (lb/yr) |
| S-1128-1018-0 | 2F | 103.00 | 4,588 |

GHG Emissions

4,588 lb/yr CH4 x 21 lb-$CO_2$e per lb-CH4 x short ton/2000 lb x 0.9072 metric tons/short ton = 43.7 mtons/yr < 230 mtons/yr

Emissions profiles are included in **Attachment IV**.

## 3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the Pre-Project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Facility emissions are already above the Offset and Major Source Thresholds for all pollutants. An estimate* of SSPE1 is provided below.

*SSPE Calculator (7-19-16, PTOs only)

| | lb/yr | Tons/yr |
|---|---|---|
| NOx | 748,121 | 374 |
| SOx | 2,121,476 | 1,061 |
| PM10 | 554,561 | 277 |
| CO | 1,379,562 | 690 |
| VOC | 1,601,897 | 801 |

## 4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

As shown above, facility emissions are already above the Offset and Major Source Thresholds for all criteria air contaminants.

## 5. Major Source Determination

**Rule 2201 Major Source Determination:**

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

| Rule 2201 Major Source Determination (lb/year) | | | | | | |
|---|---|---|---|---|---|---|
| | $NO_X$ | $SO_X$ | $PM_{10}$ | $PM_{2.5}$ | CO | VOC |
| SSPE1 | 748,121 | 2,121,476 | 554,561 | 554,561 | 1,379,562 | 1,601,897 |
| SSPE2 | 748,121 (374 tons) | 2,121,476 | 554,561 | 554,561 | 1,379,562 | 1,606,485 |
| Major Source Threshold | 20,000 | 140,000 | 140,000 | 140,000 | 200,000 | 20,000 |
| Major Source? | Yes | yes | yes | yes | yes | yes |

Note: PM2.5 assumed to be equal to PM10
Annual emissions do not include emissions increases from outstanding ATCs

As seen in the table above, the facility is an existing Major Source for NOx, SOx, PM10, CO, and VOCs.

**Rule 2410 Major Source Determination:**

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

| PSD Major Source Determination (tons/yr) | | | | | | |
|---|---|---|---|---|---|---|
| | $NO_2$ | VOC | $SO_2$ | CO | PM | $PM_{10}$ |
| Estimated Facility PE before Project Increase (tpy) | 374 | | | | | |
| PSD Major Source Thresholds (tpy) | 250 | 250 | 250 | 250 | 250 | 250 |
| PSD Major Source? (Y/N) | y | | | | | |

As shown above, the facility is an existing major source for PSD for at least one pollutant. Therefore, the facility is an existing major source for PSD.

**6. Baseline Emissions (BE)**

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project, to calculate the QNEC and if applicable, to determine the amount of offsets required.

Since this is a new emissions units, **$BE = PE_1 = 0$** for VOC.

**7. SB 288 Major Modification**

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "*any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.*"

As discussed in Section VII.C.6 above, the facility is an existing Major Source for all criteria air contaminants.

| Major Modification Thresholds (Existing Major Source) | | | |
|---|---|---|---|
| Pollutant | Project PE2 (lb/year) | Threshold (lb/year) | Major Modification |
| VOC | 4,588 | 50,000 | N |

The project's PE2 is less than the SB 2588 Major Modification Threshold for VOC.

## 8. Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

The determination of Federal Major Modification is based on a two-step test. For the first step, only the emission *increases* are counted. Emission decreases may not cancel out the increases for this determination.

For new emissions units, the increase in emissions is equal to the PE2 for each new unit included in this project.

The project's combined total emission increases are compared to the Federal Major Modification Thresholds in the following table.

| Federal Major Modification Thresholds for Emission Increases | | | |
|---|---|---|---|
| **Pollutant** | **Total Emissions Increases (lb/yr)** | **Thresholds (lb/yr)** | **Federal Major Modification?** |
| $NO_x$ | 0 | 0 | Yes |
| VOC | 4,588 | 0 | Yes |
| $PM_{10}$ | 0 | 30,000 | No |
| SOx | 0 | 80,000 | No |

Since there is an increase in VOC emissions, this project constitutes a Federal Major Modification and no further analysis is required.

**Federal Offset Quantities:**

The Federal offset quantity is calculated only for the pollutants for which the project is a Federal Major Modification. The Federal offset quantity is the sum of the annual emission changes for all new and modified emission units in a project calculated as the potential to emit after the modification (PE2) minus the actual emissions (AE) during the baseline period for each emission unit times the applicable federal offset ratio. There are no special calculations performed for units covered by an SLC.

Only pollutants for which the project is a Federal Major Modification have Federal offset quantities. The calculated Federal offset quantity, listed in the table below, is entered into the Major Modification tracking spreadsheet under the heading "Federal Offset Quantity"

NOx

| Permit No. | Actual Emissions (lb/year) | Potential Emissions (lb/year) | Federal Offset Ratio 1.5 Emissions Change (lb/yr) |
|---|---|---|---|
| S-1128-1018 | 0 | 4,588 | 4,588 |
| | | Net Emission Change (lb/year): | 4,588 |
| | | Federal Offset Quantity: (NEC * 1.5) | 6,882 |

### 9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10
- Sulfuric acid mist
- Hydrogen sulfide (H2S)
- Total reduced sulfur (including H2S)
- Reduced sulfur compounds

## I. Project Location Relative to Class 1 Area

As demonstrated in the "PSD Major Source Determination" Section above, the facility was determined to be a existing PSD Major Source. Because the project is not located within 10 km (6.2 miles) of a Class 1 area – modeling of the emission increase is not required to determine if the project is subject to the requirements of Rule 2410.

## II. Project Emission Increase – Significance Determination

### a. Evaluation of Calculated Post-project Potential to Emit for New or Modified Emissions Units vs PSD Significant Emission Increase Thresholds

As a screening tool, the post-project potential to emit from all new and modified units is compared to the PSD significant emission increase thresholds, and if the

total potentials to emit from all new and modified units are below the applicable thresholds, no futher PSD analysis is needed.

| PSD Significant Emission Increase Determination: Potential to Emit (tons/year) | | | | | |
|---|---|---|---|---|---|
| | NO2 | SO2 | CO | PM | PM10 |
| Total PE from New and Modified Units | 0 | 0 | 0 | 0 | 0 |
| PSD Significant Emission Increase Thresholds | 40 | 40 | 100 | 25 | 15 |
| PSD Significant Emission Increase? | N | N | N | N | N |

As demonstrated above, because the post-project total potentials to emit from all new and modified emission units are below the PSD significant emission increase thresholds, this project is not subject to the requirements of Rule 2410 and no further discussion is required.

**10. Quarterly Net Emissions Change (QNEC)**

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - BE, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post Project Potential to Emit for each emissions unit, lb/qtr.
BE = Baseline Emissions (per Rule 2201) for each emissions unit, lb/qtr.

Using the values in Sections VII.C.2 and VII.C.6 in the evaluation above, quarterly PE2 and quarterly BE is calculated in the following tables:

| QNEC | | | |
|---|---|---|---|
| **Pollutant** | **PE2** | **BE** | **QNEC** |
| $NO_X$ | 0 | 0 | 0 |
| $SO_X$ | 0 | 0 | 0 |
| $PM_{10}$ | 0 | 0 | 0 |
| CO | 0 | 0 | 0 |
| VOC | 4,588 | 0 | 1,147 |

## VIII. COMPLIANCE

### Rule 2201 New and Modified Stationary Source Review Rule

#### A. Best Available Control Technology (BACT)

##### 1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

**a. New emissions units – PE > 2 lb/day**

As seen above, the applicant is proposing to install a new tank with a PE greater than 2 lb/day for VOC. BACT is triggered for VOC since the PE is greater than 2 lb/day.

**b. Relocation of emissions units – PE > 2 lb/day**

As discussed in Section I above, there are no existing emissions units being relocated from one stationary source to another; therefore BACT is not triggered.

**c. Modification of emissions units – AIPE > 2 lb/day**

As discussed in Section I above, there are no modified emissions units associated with this project; therefore BACT is not triggered.

**d. SB 288/Federal Major Modification**

As discussed above, this project constitutes a Federal Major Modification for VOC; therefore BACT is triggered for VOC Federal Major Modification purposes.

### 2. BACT Guideline

BACT Guideline 7.3.1 applies to tanks/vessels issued (see **Attachment V**).

### 3. Top-Down BACT Analysis

Pursuant to the attached Top-Down BACT Analysis (see **Attachment VI**), BACT has been satisfied with the following:

VOC: PV-vent set to within 10% of maximum allowable pressure.

Proposed Rule 2201 BACT Condition:

*This tank shall be equipped with a pressure-vacuum (PV) relief valve set to within 10% of the maximum allowable working pressure of the tank, labeled with the operating pressure settings, properly maintained in good operating order in accordance with the manufacturer's instructions, and shall remain in gas-tight condition except when the operating pressure exceeds the valve's set pressure. [District Rule 2201]*

Note that the BACT Technologically Feasible requirement of vapor control was not found to be cost effective.

## B. Offsets

### 1. Offset Applicability

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals or exceeds the offset threshold levels in Table 4-1 or Rule 2201.

The applicant concedes they are over the offset threshold for VOCs. Therefore offsets are triggered for the emissions increases associated with this project approval.

### 2. Quantity of Offsets Required

As seen above, the SSPE2 is greater than the offset thresholds for VOCs; therefore offset calculations will be required for this project.

The quantity of offsets in pounds per year is calculated as follows for sources with an SSPE1 greater than the offset threshold levels before implementing the project being evaluated.

Offsets required (lb/year) = (Σ[PE2 – BE] + ICCE) x DOR, for all new or modified emissions units in the project,

Where,
PE2 = Post Project Potential to Emit, (lb/year)
BE = Baseline Emissions, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

BE = Pre-project Potential to Emit for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, Located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE)

BE = 0 for this new emissions unit.

The facility is proposing to install a new emissions unit; therefore Baseline Emissions are equal to zero. Also, there are no increases in cargo carrier emissions; therefore offsets can be determined as follows:

**Offsets Required** (lb/year) = PE2 x DOR

The project is a federal Major modification and therefore the Distance Offset Ration (DOR) is 1.5:1. The required offsets and proposed ERCs are summarized below:

The DOR is 1.5:1 as the project is a Federal Major Modification.

Offsets Required (lb/year) = 4,588 x 1.5
= 6,882 lb VOC/year

Calculating the appropriate quarterly emissions to be offset is as follows:

Quarterly offsets required (lb/qtr) = (6,882 lb VOC/year) ÷ (4 quarters/year)
= 1,720.5 lb/qtr

Calculating the appropriate quarterly emissions to be offset is as follows:

As shown in the calculation above, the quarterly amount of offsets required for this project, when evenly distributed to each quarter, results in fractional pounds of offsets being required each quarter. Since offsets are required to be withdrawn as whole pounds, the quarterly amounts of offsets need to be adjusted to ensure the quarterly values sum to the total annual amount of offsets required.

To adjust the quarterly amount of offsets required, the fractional amount of offsets required in each quarter will be summed and redistributed to each quarter based on the number of days in each quarter. The redistribution is based on the Quarter 1 having the fewest days and the Quarters 3 and 4 having the most days. The redistribution method is summarized in the following table:

| **Redistribution of Required Quarterly Offsets** (where X is the annual amount of offsets, and X ÷ 4 = Y.z) | | | | |
|---|---|---|---|---|
| **Value of z** | **Quarter 1** | **Quarter 2** | **Quarter 3** | **Quarter 4** |
| .0 | Y | Y | Y | Y |
| .25 | Y | Y | Y | Y+1 |
| .5 | Y | Y | Y+1 | Y+1 |
| .75 | Y | Y+1 | Y+1 | Y+1 |

Therefore the appropriate quarterly emissions to be offset are as follows:

| 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter | Total Annual |
|---|---|---|---|---|
| 1,720 | 1,720 | 1,721 | 1,721 | 6,882 |

The following ERCs will be used to offset the emissions increase for the project.

| Current Certificate | 1Q | 2Q | 3Q | 4Q | Total |
|---|---|---|---|---|---|
| S-410-1 | 5 | 7 | 11 | 15 | 38 |
| S-3404-1 | 171 | 202 | 232 | 232 | 837 |
| S-4004-1 | 460 | 466 | 471 | 470 | 1,867 |
| S-4110-1 | 90 | 93 | 83 | 66 | 332 |
| S-4549-1 | 0 | 182 (42 to Q1) | 257 (157 to Q1) | 114 | 553 |
| From S-4549-1 2Q | 42 | | | | |
| From S-4549-1 3Q | 157 | | | | |
| S-1878-1 | 230 | 136 | 143 | 82 | 591 |
| S-1912-1 | 225 | 238 | 250 | 250 | 963 |
| S-1983-1 | 340 | 438 | 431 | 492 | 1701 |
| Total | 1,720 | 1,762 (1720 +42) | 1,878 (1,721+157) | 1,721 | 6,882 |
| Total Offsets/Qtr | 1,720 | 1,720 | 1,721 | 1,721 | 6,882 |

As seen above, the facility has sufficient credits to fully offset the quarterly VOC emissions increases associated with this project.

***Proposed Rule 2201 (offset) Conditions:***

*Prior to operating equipment under this Authority to Construct, permittee shall surrender VOC emission reduction credits for the following quantity of emissions: 1st quarter – 1,720 lb, 2nd quarter – 1,720 lb, 3rd quarter – 1,721 lb, and fourth quarter - 1721 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 2/18/16) for the ERC specified below. [District Rule 2201] Y*

*ERC Certificate Numbers S-410-1, S-3404-1, S-4004-1, S-4110-1, S-4549-1, S-1878-1, S-1912-1, and S-1983-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201] Y*

## C. Public Notification

### 1. Applicability

Public noticing is required for:
a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed, and/or
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.
e. Any project which results in a Title V significant permit modification

#### a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. Since this is not a new facility, public noticing is not required for this project for New Major Source purposes.

As demonstrated in Sections VII.C.7 and VII.C.8, this project is a Federal Major Modification. Therefore, public noticing for SB 288 or Federal Major Modification purposes is required.

#### b. PE > 100 lb/day

Applications which include a new emissions unit with a PE greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. As seen in Section VII.C.2 above, this project does not include a new emissions unit which has daily emissions greater than 100 lb/day for any pollutant, therefore public noticing for PE > 100 lb/day purposes is not required.

#### c. Offset Threshold

The SSPE1 and SSPE2 are compared to the offset thresholds in the following table.

| Offset Thresholds | | | | |
|---|---|---|---|---|
| **Pollutant** | **SSPE1 (lb/year)** | **SSPE2 (lb/year)** | **Offset Threshold** | **Public Notice Required?** |
| $NO_X$ | >20,000 lb/year | >20,000 lb/year | 20,000 lb/year | No |
| $SO_X$ | >54,750 lb/year | >54,750 lb/year | 54,750 lb/year | No |
| $PM_{10}$ | >29,200 lb/year | >29,200 lb/year | 29,200 lb/year | No |
| CO | >200,000 lb/year | >200,000 lb/year | 200,000 lb/year | No |
| VOC | >20,000 lb/year | >20,000 lb/year | 20,000 lb/year | No |

As detailed above, there were no thresholds surpassed with this project; therefore public noticing is not required for offset purposes.

**d. SSIPE > 20,000 lb/year**

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

| SSIPE Public Notice Thresholds | | | | | |
|---|---|---|---|---|---|
| **Pollutant** | **SSPE2 (lb/year)** | **SSPE1 (lb/year)** | **SSIPE (lb/year)** | **SSIPE Public Notice Threshold** | **Public Notice Required?** |
| $NO_x$ | >20,000 lb/year | >20,000 lb/year | 0 | 20,000 lb/year | No |
| $SO_x$ | >54,750 lb/year | >54,750 lb/year | 0 | 20,000 lb/year | No |
| $PM_{10}$ | >29,200 lb/year | >29,200 lb/year | 0 | 20,000 lb/year | No |
| CO | >200,000 lb/year | >200,000 lb/year | 0 | 20,000 lb/year | No |
| VOC | >20,000 lb/year | >20,000 lb/year | 4,588 | 20,000 lb/year | No |

As demonstrated above, the SSIPEs for all pollutants were less than 20,000 lb/year; therefore public noticing for SSIPE purposes is not required.

**e. Title V Significant Permit Modification**

As shown in the Discussion of Rule 2520 below, this project constitutes a Title V significant modification. Therefore, public noticing for Title V significant modifications is required for this project.

### 2. Public Notice Action

As discussed above, public noticing is required for this project. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

## D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

The permit DELs will be included as follows.

- *This tank shall only store, place, or hold organic liquid with a true vapor pressure (TVP) of less than 0.5 psia under all storage conditions. [District Rule 4623]*
- *Tank liquid throughput shall not exceed 2,000 barrels per day or 70,000 barrels per year. [District Rule 2201]*
- *VOC emission rate from the tank shall not exceed 103 lb/day or 4,588 lb/year. [District Rule 2201]*

## E. Compliance Assurance

### 1. Source Testing

Pursuant to District Policy APR 1705, source testing is not required to demonstrate compliance with Rule 2201.

### 2. Monitoring

No monitoring is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201.

### 3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. A condition addressing this requirement is included on the S-1128 facility-wide permit.

### 4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

### F. Ambient Air Quality Analysis (AAQA)

An AAQA shall be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. There are no AAQA standards for VOCs and therefore an AAQA is not required.

### G. Compliance Certification

Section 4.15.2 of this Rule requires the owner of a new Major Source or a source undergoing a Title I Modification to demonstrate to the satisfaction of the District that all other Major Sources owned by such person and operating in California are in compliance or are on a schedule for compliance with all applicable emission limitations and standards. As discussed in Section VIII above, this facility is a new major source and this project does constitute a Title I modification; therefore this requirement is applicable. CUSA's compliance certification is included in **Attachment VII**.

### H. Alternate Siting Analysis

The current project occurs at an existing facility. The applicant proposes to authorize an organic liquid transfer operation.

Since the project will provide a tank to be used at the same location, the existing site will result in the least possible impact from the project. Alternative sites would involve the relocation and/or construction of various support structures on a much greater scale, and would therefore result in a much greater impact.

## Rule 2410 Prevention of Significant Deterioration

As shown in Section VII. C. 9. above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

## Rule 2520 Federally Mandated Operating Permits

This facility is subject to this Rule, and has received their Title V Operating Permit. Section 3.29 defines a significant permit modification as a "permit amendment that does not qualify as a minor permit modification or administrative amendment."

The project is Federal Major Modification and therefore is also a Title V Significant Modification. As discussed above, the facility has applied for a Certificate of Conformity (COC); therefore, the facility must apply to modify their Title V permit with an administrative amendment, prior to operating with the proposed modifications. Continued compliance with this rule is expected. The Title V Compliance Certification form is included in **Attachment VIII**.

**District Rule 4001 New Source Performance Standards**

This rule incorporates the New Source Performance Standards from 40 CFR Part 60. 40 CFR Part 60, Subparts K, Ka, Kb and OOOO could potentially apply to the tanks located at this facility. However, Subparts K, Ka and Kb do not apply to storage vessels less than 10,000 barrels used for petroleum or condensate that is stored, processed and/or treated at a drilling and production facility prior to transfer. Subpart OOOO has no standards for tanks with annual VOC emissions less than 6 tons per year.

Therefore, the requirements of these subparts are not applicable to this project.

**District Rule 4101 Visible Emissions**

District Rule 4101, Section 5.0, indicates that no air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour, which is dark or darker than Ringlemann 1 or equivalent to 20% opacity.

As long as the equipment is properly maintained and operated, compliance with visible emissions limits is expected under normal operating conditions.

**Rule 4102 Nuisance**

Rule 4102 prohibits discharge of air contaminants, which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations provided the equipment is well maintained. Therefore, compliance with this rule is expected.

**California Health & Safety Code 41700 (Health Risk Assessment)**

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (**Attachment IX**), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project.

The cancer risk for this project is shown below:

| HRA Summary | | |
|---|---|---|
| **Unit** | **Cancer Risk** | **T-BACT Required** |
| S-1128-1018-0 | 0.224 per million | No |

**Discussion of T-BACT**

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

**District Rule 4623 Storage of Organic Liquids**

This rule applies to any tank with a capacity of 1,100 gallons or greater in which any organic liquid is placed, held or stored.

Per Section 4.4, tanks exclusively receiving and/or storing organic liquids with a TVP less than 0.5 psia are exempt from this rule except for complying with Sections 6.2, 6.3.6, 6.4, and 7.2. This tank will be limited to receiving and/or storing organic liquids with a TVP less than 0.5 psia. The following condition shall be placed on the ATC:

- *{2480} This tank shall only store, place, or hold organic liquid with a true vapor pressure (TVP) of less than 0.5 psia under all storage conditions. [District Rule 4623]*

The tank will not be served by a vapor control system. The applicant has elected to participate in the voluntary tank preventative inspection, maintenance, and tank cleaning program. Tank cleaning will be conducted according to the requirements of Table 6. As the tank is not subject to the requirements of District Rule 4623, the rule reference will be changed to District Rule 2080.

As this tank will not be equipped with a vapor recovery system, TVP and API gravity testing is required. The following conditions will be included on the permit:

- *Permittee shall conduct true vapor pressure (TVP) testing of the organic liquid stored in this tank, or representative tank as provided in District Rule 4623, at least once every 24 months during summer (July-September), and/or whenever there is a change in the source or type of organic liquid stored in this tank in order to maintain exemption from this rule. [District Rule 4623]*

- *{2482} The API gravity of crude oil or petroleum distillate shall be determined by using ASTM Method D 287-92 "Standard Test Method for API Gravity of Crude Petroleum Products (Hydrometer Method)". Sampling for API gravity shall be performed in accordance with ASTM Method D-4057-95 "Standard Practices for Manual Sampling of Petroleum and Petroleum Products". [District Rule 4623]*

- *{2483} For crude oil with an API gravity of 26 degrees or less, the TVP shall be determined using the latest version of the Lawrence Berkeley National Laboratory "Test Method for Vapor Pressure of Reactive Organic Compounds in*

*Heavy Crude Oil using Gas Chromatograph", as approved by ARB and EPA. [District Rule 4623]*

- *Instead of testing each uncontrolled fixed roof tank, the permittee may conduct a TVP test of the organic liquid stored in a representative tank. [District Rule 4623]*

- *{2911} The TVP testing shall be conducted at actual storage temperature of the organic liquid in the tank. The permittee shall also conduct API gravity testing. [District Rule 4623]*

- *The permittee shall keep accurate records of API gravity, true vapor pressure, storage temperature and types of liquids stored. [District Rules 2201 and 4623]*

- *Permittee shall submit the records of TVP and API gravity testing to the APCO within 45 days after the date of testing. The records shall include the tank identification number, Permit to Operate number, type of stored organic liquid, TVP and API gravity of the organic liquid, test methods used, and a copy of the test results. [District Rule 4623]*

Heavy Oil Tank Inspection and Maintenance:

- *Operator shall visually inspect tank shell, hatches, seals, seams, cable seals, valves, flanges, connectors, and any other piping components directly affixed to the tank and within five feet of the tank at least once per year for liquid leaks, and with a portable hydrocarbon detection instrument conducted in accordance with EPA Method 21 for gas leaks. Operator shall also visually or ultrasonically inspect as appropriate, the external shells and roofs of uninsulated tanks for structural integrity annually. [District Rule 2080]*

- *Upon detection of a liquid leak, defined as a leak rate of greater than or equal to 30 drops per minute, operator shall repair the leak within 8 hours. For leaks with a liquid leak rate of between 3 and 30 drops per minute, the leaking component shall be repaired within 24 hours after detection. [District Rule 2080]*

- *Upon detection of a gas leak, defined as a VOC concentration greater than 10,000 ppmv measured in accordance with EPA Method 21, operator shall take one of the following actions: 1) eliminate the leak within 8 hours of detection; or 2) if the leak cannot be eliminated, then minimize the leak to the lowest possible level within 8 hours after detection by using best management practices, and eliminate the leak within 48 hours after minimization. In no event shall the total time to minimize and eliminate a leak exceed 56 hours after detection. [District Rule 2080]*

- *Components found to be leaking either liquids or gases shall be immediately affixed with a tag showing the component to be leaking. Operator shall maintain records of the liquid or gas leak detection readings, date/time the leak was*

*discovered, and date/time the component was repaired to be a leak-free condition. [District Rule 2080]*

- *Leaking components that have been discovered by the operator that have been tagged and repaired within the timeframes specified in District Rule 4623, Table 3 shall not constitute a violation of this rule. Leaking components as defined by District Rule 4623 discovered by the District staff that were not previously identified and/or tagged by the operator, and/or leaks that were not repaired within the timeframes specified in District Rule 4623, Table 3 shall constitute a violation of this rule. [District Rule 2080]*

- *If a component type for a given tank is found to leak during an annual inspection, operator shall conduct quarterly inspections of that component type on the tank or tank system for four consecutive quarters. If no components are found to leak after four consecutive quarters, the operator may revert to annual inspections. [District Rule 2080]*

- *Any component found to be leaking on two consecutive annual inspections is in violation of this rule, even if covered under the voluntary inspection and maintenance program. [District Rule 2080]*

*Heavy Oil Tank Cleaning:*

- *Permittee shall notify the APCO in writing at least three (3) days prior to performing tank degassing and interior tank cleaning activities. Written notification shall include the following: 1) the Permit to Operate number and physical location of the tank being degassed, 2) the date and time that tank degassing and cleaning activities will begin, 3) the degassing method, as allowed in the permit, to be used, 4) the method to be used to clean the tank, including any solvents to be used, and 5) the method to be used to dispose of any removed sludge, including methods that will be used to control emissions from the receiving vessel and emissions during transport. [District Rule 4623 or 2080]*

- *This tank shall not be required to de-gas before commencing cleaning activities. All other applicable requirements shall be complied with before, during, and after tank cleaning activities. [District Rule 4623 or 2080]*

- *While performing tank cleaning activities, operators may only use the following cleaning agents: diesel, solvents with an initial boiling point of greater than 302 degrees F, solvents with a vapor pressure of less than 0.5 psia, or solvents with 50 grams of VOC per liter or less. [District Rule 2080]*

- *Steam cleaning shall only be allowed at locations where wastewater treatment facilities are limited, or during the months of December through March. [District Rule 2080]*

Compliance with District Rule 4623 requirements is expected.

**California Health & Safety Code 42301.6 (School Notice)**

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

**California Environmental Quality Act (CEQA)**

CEQA requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The District adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities;
- Identify the ways that environmental damage can be avoided or significantly reduced;
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible; and
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

**Greenhouse Gas (GHG) Significance Determination**

District is a Responsible Agency

Oil and gas operations in Kern County must comply with the *Kern County Zoning Ordinance – 2015 (C) Focused on Oil and Gas Local Permitting.* In 2015, Kern County revised the Kern County Zoning Ordinance Focused on Oil and Gas Activities (Kern Oil and Gas Zoning Ordinance) in regards to future oil and gas exploration, and drilling and production of hydrocarbon resource projects occurring within Kern County.

Kern County served as lead agency for the revision to their ordinance under the California Environmental Quality Act (CEQA), and prepared an Environmental Impact Report (EIR) that was certified on November 9, 2015. The EIR evaluated and disclosed to the public the environmental impacts associated with the growth of oil and gas exploration in Kern County, and determined that such growth will result in significant GHG impacts in the San Joaquin Valley. As such, the EIR included mitigation measures for GHG.

The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). As a Responsible

Agency, the District is limited to mitigating or avoiding impacts for which it has statutory authority. The District does not have statutory authority for regulating GHGs. The District has determined that the applicant is responsible for implementing GHG mitigation measures imposed in the EIR by the Kern County for the Kern County Zoning Ordinance.

**District CEQA Findings**

The proposed project is located in Kern County and is thus subject to the *Kern County Zoning Ordinance – 2015 (C) Focused on Oil and Gas Local Permitting.* The *Kern County Zoning Ordinance* was developed by the Kern County Planning Agency as a comprehensive set of goals, objectives, policies, and standards to guide development, expansion, and operation of oil and gas exploration within Kern County.

In 2015, Kern County revised their *Kern County Zoning Ordinance* in regards to exploration, drilling and production of hydrocarbon resources projects. Kern County served as lead agency for the revision to their ordinance under the California Environmental Quality Act (CEQA), and prepared an Environmental Impact Report (EIR) that was certified on November 9, 2015. The revised Kern County Zoning Ordinance establishes a written process (Conformity Review permit process or Minor Activity permit) by which oil and gas exploration projects involving site-specific operations can be evaluated to determine whether the environmental effects of the operation were covered in the *Kern County Zoning Ordinance* EIR.

For stationary source emissions that are below the offset threshold, i.e. not required to surrender ERCs, and for non-stationary source emissions, Kern County entered into an Oil and Gas Emission Reduction Agreement (Oil and Gas ERA) with the District pursuant to the EIR. Per the Oil and Gas ERA, the applicant shall fully mitigate project emissions that are not required to be offset by District permit rules and regulations. Such mitigation can be achieved through any of the three options: (1) the applicants pay an air quality mitigation fee with each Oil and Gas Conformity Review permit issued by the Kern County, (2) the applicants may develop and propose to implement their own emission reduction projects instead of paying all or part of the mitigation fee, or (3) the applicants will be allowed to enter into an agreement directly with the District (if approved by Kern County) to develop an alternative fee schedule.

Kern County, as the lead agency, is the agency that will enforce the mitigation measures identified the EIR, including the mitigation requirements of the Oil and Gas ERA. As a responsible agency the District complies with CEQA by considering the EIR prepared by the Lead Agency, and by reaching its own conclusion on whether and how to approve the project involved (CCR §15096). The District has reviewed the EIR prepared by Kern County, the Lead Agency for the project, and finds it to be adequate. To reduce project related impacts on air quality, the District evaluates emission controls for the project such as Best

Available Control Technology (BACT) under District Rule 2201 (New and Modified Stationary Source Review). In addition, the District is requiring the applicant to surrender emission reduction credits (ERC) for stationary source emissions above the offset threshold.

Thus, the District concludes that through a combination of project design elements, permit conditions, and the Oil and Gas ERA, the project will be fully mitigated to result in no net increase in emissions. Pursuant to CCR §15096, prior to project approval and issuance of ATCs the District prepared findings.

**Indemnification Agreement/Letter of Credit Determination**

According to District Policy APR 2010 (CEQA Implementation Policy), when the District is the Lead or Responsible Agency for CEQA purposes, an indemnification agreement and/or a letter of credit may be required. The decision to require an indemnity agreement and/or a letter of credit is based on a case-by-case analysis of a particular project's potential for litigation risk, which in turn may be based on a project's potential to generate public concern, its potential for significant impacts, and the project proponent's ability to pay for the costs of litigation without a letter of credit, among other factors.

The revision to the *Kern County Zoning Ordinance* went through an extensive public process that included a Notice of Preparation, a preparation of an EIR, scoping meetings, and public hearings. The process led to the certification of the final EIR and approval of the revised *Kern County Zoning Ordinance* in November 2015 by the Kern County Board of Supervisors. As mentioned above, the proposed project will be fully mitigated and will result in no net increase in emissions. In addition, the proposed project is not located at a facility of concern; therefore, an Indemnification Agreement and/or a Letter of Credit will not be required for this project in the absence of expressed public concern.

## IX. Recommendation

Compliance with all applicable rules and regulations is expected. Make preliminary decision to issue the requested Authority to Construct subject to the proposed conditions presented in **Attachment X**.

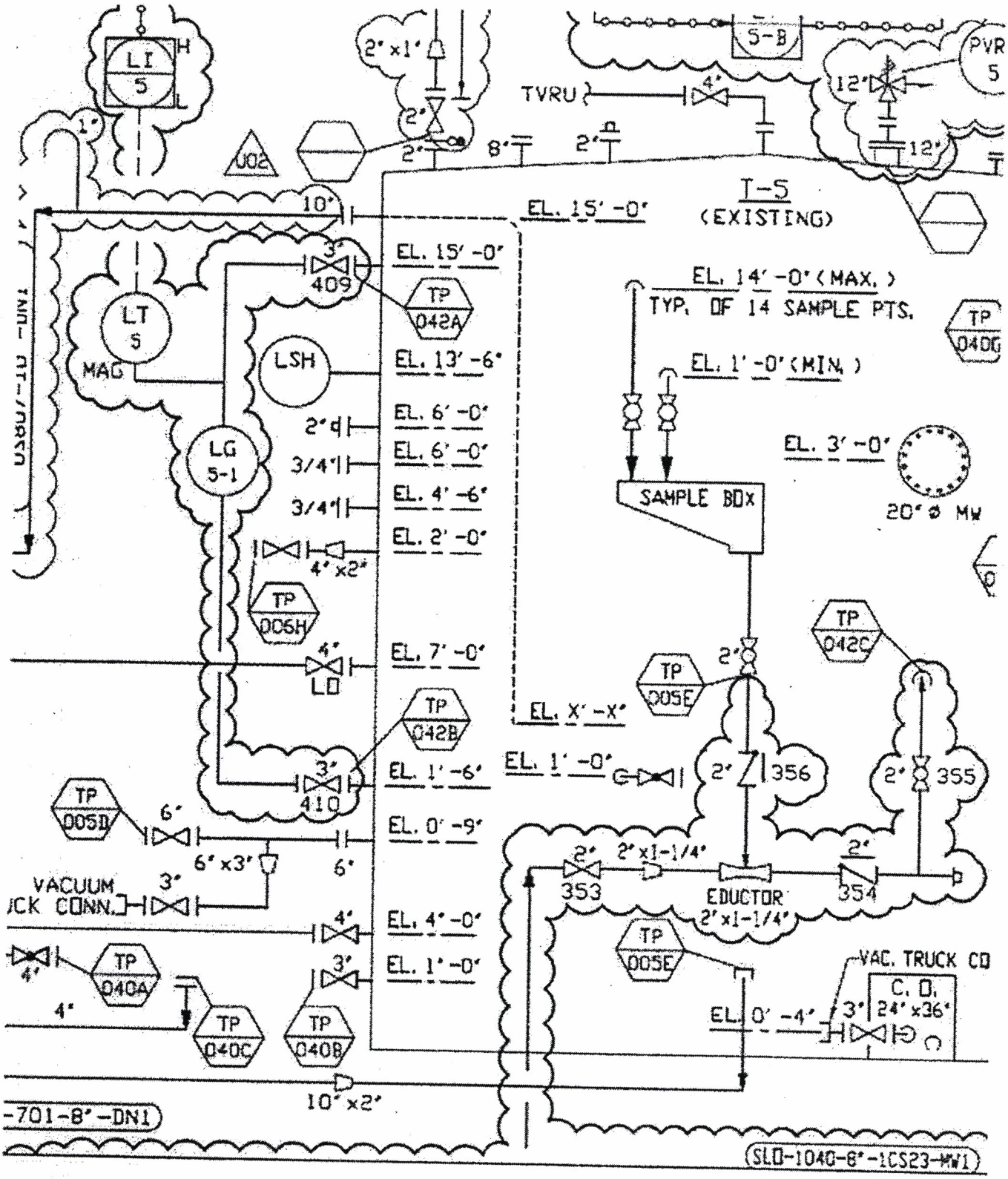
## X. Billing Information

| Annual Permit Fees | | | |
|---|---|---|---|
| Permit Number | Fee Schedule | Fee Description | Annual Fee |
| S-1128-1018-0 | 3020-05-D | 84,000 gallons | $203.00 |

**Attachments**

I: Process Diagram
II: Laboratory Analysis
III: Tank Emissions
IV: Emissions Profiles
V: BACT Guideline
VI: BACT Analysis
VII: Statewide Compliance Statement
VIII: Title V Compliance Certification Form
IX: HRA
X: Draft ATCs

# ATTACHMENT I
# Process Diagram




**Kris Rickards**
**Environmental Engineer/Specialist - Air**
San Joaquin Valley Business Unit

**Chevron North America Exploration & Production**

# ATTACHMENT II
## Laboratory Analysis

# GENERAL GAS ANALYSIS (C-6 +) [2,3,8]

CHG Compliant
Title 40 CFR Part 98

ELAP Cert.1396-A

Rev 10/08/14

Chevron SATURN Reporting Format

**Customer:** Chevron Corporation
**Address:** 26251 Highway 33
Fellows, CA 93224
**Attention:** Bo Bravo
**Sample Description:** Xerto Blend Fuel Gas TF 159, Temp 82°F Pressure 212 psia

**Log #:** 30598-4
**Date Received:** 5/2/15
**Date Completed:** 5/2/16
**Report Date:** 5/2/16

| Constituent | | Mole % | Wt % | Lv % |
|---|---|---|---|---|
| Oxygen/Argon | O2 / Ar | 0.097 | 0.174 | 0.050 |
| Nitrogen | N2 | 0.733 | 1.138 | 0.463 |
| Carbon Dioxide | CO2 | 3.938 | 9.607 | 3.854 |
| Carbon Monoxide | CO | 0.000 | 0.000 | 0.000 |
| Methane | C-1 | 89.862 | 79.912 | 87.374 |
| Ethene | C-2 | 5.135 | 8.559 | 7.876 |
| Propane | C-3 | 0.198 | 0.485 | 0.314 |
| Iso-Butane | C-4 | 0.015 | 0.047 | 0.027 |
| N-Butane | C-4 | 0.016 | 0.052 | 0.029 |
| Neo Pentane | C-5 | 0.000 | 0.000 | 0.000 |
| Iso-Pentane | C-5 | 0.003 | 0.014 | 0.007 |
| N-Pentane | C-5 | 0.001 | 0.005 | 0.003 |
| Hexanes Plus | C-6 (+) | 0.001 | 0.006 | 0.003 |
| Hydrogen | $H_2$ | 0.000 | 0.000 | 0.000 |
| Hydrogen Sulfide | H2S | 0.000 | 0.000 | 0.000 |
| | Total | 100.000 | 100.000 | 100.000 |

| | | ppmv | Grains H2S /100 cu.ft. | **** VOC's | [§] Water Content | § VOC/THC |
|---|---|---|---|---|---|---|
| [1,2] | Hydrogen Sulfide, H2S = | 0.00 | 0.000 | (% by Wt. C-3+) | (lbs/MM C.F.) | (% by Wt) |
| [1,2] | Total Sulfur, as H2S = | 0.00 | Grains 'S' /100 cu.ft. 0.000 | 0.609 | NR | 0.584 |

| | Physical Data | Gross BTU dry | Gross BTU wet | Net BTU dry | Net BTU wet | |
|---|---|---|---|---|---|---|
| [4,6,7,8] | *** BTU cu.ft. Ideal = | 1,004.72 | 987.24 | 906.09 | 890.32 | |
| | *** BTU cu.ft. real = | 1,007.05 | 989.53 | 908.18 | 892.38 | |
| | BTU/lb, ideal = | 21,135.57 | 20,767.82 | 19,059.38 | 18,727.75 | [6,8] |

| | | | |
|---|---|---|---|
| | (Density) Sp. Gr. Ideal = | 0.6228 | 0.6120 |
| | (Density) Sp. Gr. Real = | 0.6240 | 0.6132 |
| | Density lbm/[1000 ft³] = | 47.533 | 46.706 |

| | |
|---|---|
| ** GPM C-2+ = | 3.4964 |
| ** GPM C-3+ = | 0.0656 |
| ** GPM C-4+ = | 0.0121 |
| ** GPM C-5+ = | 0.0022 |
| z-factor = | 0.9977 |
| * F-factor (60°F) DSCF/MM Btu = | 8,548 |
| * F-factor (68°F) DSCF/MM Btu = | 8,678 |
| Sp.Vol. Cu.Ft./Lb = | 21.03 |
| Av. Mol. Wt. = | 18.04 |

| C-H-O-N-S | % by Wt. |
|---|---|
| % Carbon = | 69.787 |
| % Hydrogen = | 21.916 |
| % Oxygen = | 7.159 |
| % Nitrogen = | 1.138 |
| % Sulfur = | 0.000 |
| Total = | 100.000 |

| QC Ck's | Measured | Range |
|---|---|---|
| 1. Fidelity Ck. = | 100 | (0.97-1.11) |
| 2. Cont area Ck. = | 0.17E+05 | (8.3 – 9.2)E+8 |
| 3. Un-Norm Sum = | 97.0 | (95 - 105) |

Notes:

* F-factor = dcf/MMBTU (CARB)
** GPM = Gallons Per 1000 Ft³
*** Hexane (+) BTU Calc. using GPA 2261 Constant
**** VOC's Volatile Organic Constituents
N.R.= "Not Requested"
Density-Specific Gravity where Air = 1.0000
DSCF = Dry Standard Cubic Feet
§ VOC/THC = Wt. % [Volatile fraction / Total Hydrocarbon fraction] X 100
Btu/Lb Net Physical Constants not available in GPA 2145-09 [4,6,8]

References

1. ASTM D 5228-10
2. ASTM D 1945-03 (10)
3. ASTM D 1946-90 (11)
4. ASTM D 3588-98 (11)
5. ASTM D 1142-95 (12)
6. GPA 2172-09
7. GPA 2145-09
8. GPA 2261-00

QC_____Date_____

All Calculations Tabulated @ 60/60
dry, 14.696psia
(288.15°K, 101.325kPa)

_____ Date:_____
Kurt R. Buckle, BS Laboratory Director Midway Laboratory, Inc.

# ATTACHMENT III
# Tank Emissions

| Tank Input Data | |
|---|---|
| permit number (S-xxxx-xx-xx) | S-1128-XXXX |
| facility tank I.D. | TBD |
| nearest city {1: Bakersfield, 2: Fresno, 3: Stockton} | 1 |
| tank ROC vapor pressure (psia) | 0.5 |
| liquid bulk storage temperature, Tb (°F) | 152 |
| is this a constant-level tank? **{yes, no}** | no |
| will flashing losses occur in this tank (only if first-line tank)? **{yes, no}** | no |
| breather vent pressure setting range (psi) | 0.06 |
| diameter of tank (feet) | 30 |
| capacity of tank (bbl) | 2,000 |
| conical or dome roof? **{c, d}** | c |
| shell height of tank (feet) | 8 |
| average liquid height (feet) | 4 |
| are the roof and shell the same color? **{yes,no}** | yes |
| For roof: color {1:Spec Al, 2:Diff Al, 3:Light, 4:Med, 5:Red, 6:White} | 4 |
| condition {1: Good, 2: Poor} | 1 |
| -----This row only used if shell is different color from roof----- | 4 |
| -----This row only used if shell is different color from roof----- | 1 |

| Liquid Input Data | A | B |
|---|---|---|
| maximum daily fluid throughput (bbl) | | 2000 |
| maximum annual fluid throughput (bbl) | | 70,000 |
| -----This row only used if flashing losses occur in this tank----- | | 0 |
| -----This row only used if flashing losses occur in this tank----- | | - |
| molecular weight, Mw (lb/lb-mol) | | 100 |

| Calculated Values | A | B |
|---|---|---|
| daily maximum ambient temperature, Tax (°F) | | 77.65 |
| daily minimum ambient temperature, Tan (°F) | | 53.15 |
| daily total solar insulation factor, I (Btu/ft^2-day) | | 1648.9 |
| atmospheric pressure, Pa (psia) | | 14.47 |
| water vapor pressure at daily maximum liquid surface temperature (Tlx), Pvx (psia | 128.1 | 2.1269 |
| water vapor pressure at daily minimum liquid surface temperature (Tln), Pvn (psia | 117.4 | 1.5845 |
| water vapor pressure at average liquid surface temperature (Tla), Pva (psia) | 122.8 | 1.8408 |
| roof outage, Hro (feet) | | 0.3125 |
| vapor space volume, Vv (cubic feet) | | 3048.33 |
| paint factor, alpha | | 0.68 |
| vapor density, Wv (lb/cubic foot) | | 0.0080 |
| daily vapor temperature range, delta Tv (degrees Rankine) | | 49.04 |
| vapor space expansion factor, Ke | | 0.1223 |

| Results | lb/year | lb/day |
|---|---|---|
| Standing Storage Loss | 1,088 | 2.98 |
| Working Loss | 3,500 | 100.00 |
| Flashing Loss | N/A | N/A |
| **Total Uncontrolled Tank VOC Emissions** | **4,588** | **103.0** |

# ATTACHMENT IV
# Emissions Profiles

# Application Emissions



Permit #: S-1128-1018-0 **Last Updated**
Facility: CHEVRON USA INC 09/09/2016 EDGEHILR

Equipment Pre-Baselined: NO

| | NOX | SOX | PM10 | CO | VOC |
|---|---|---|---|---|---|
| Potential to Emit (lb/Yr): | 0.0 | 0.0 | 0.0 | 0.0 | 4588.0 |
| Daily Emis. Limit (lb/Day) | 0.0 | 0.0 | 0.0 | 0.0 | 103.0 |
| Quarterly Net Emissions Change (lb/Qtr) | | | | | |
| Q1: | 0.0 | 0.0 | 0.0 | 0.0 | 1147.0 |
| Q2: | 0.0 | 0.0 | 0.0 | 0.0 | 1147.0 |
| Q3: | 0.0 | 0.0 | 0.0 | 0.0 | 1147.0 |
| Q4: | 0.0 | 0.0 | 0.0 | 0.0 | 1147.0 |
| Check if offsets are triggered but exemption applies | N | N | N | N | N |
| Offset Ratio | | | | | 1.5 |
| Quarterly Offset Amounts (lb/Qtr) | | | | | |
| Q1: | | | | | 1720.0 |
| Q2: | | | | | 1720.0 |
| Q3: | | | | | 1721.0 |
| Q4: | | | | | 1721.0 |

# ATTACHMENT V
# BACT Guideline

San Joaquin Valley
Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 7.3.1*

Last Update 10/1/2002

## Petroleum and Petrochemical Production - Fixed Roof Organic Liquid Storage or Processing Tank, < 5,000 bbl Tank capacity **

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| VOC | PV-vent set to within 10% of maximum allowable pressure | 99% control ( Waste gas incinerated in steam generator, heater treater, or other fired equipment and inspection and maintenance program; transfer of noncondensable vapors to gas pipeline; reinjection to formation (if appropriate wells are available); or equal). | |

** Converted from Determinations 7.1.11 (10/01/02).

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

*This is a Summary Page for this Class of Source

# ATTACHMENT VI
# BACT Analysis

## Top Down BACT Analysis

### Step 1 - Identify All Possible Control Technologies

BACT Guideline 7.3.1 lists the controls that are considered potentially applicable to fixed-roof organic liquid storage or processing tank <5,000 bbl tank capacity. The VOC control measures are summarized below.

*Technologically Feasible*

99% control (waste gas incinerated in steam generator, heater treater, or other fired equipment and inspection and maintenance program; transfer of uncondensed vapors to gas pipeline or reinjection to formation, if appropriate wells are available).

*Achieved in Practice*

PV relief valve set to within 10% of maximum allowable pressure.

### Step 2 - Eliminate Technologically Infeasible Options

None of the above listed technologies are technologically infeasible.

### Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 99 % control (waste gas incinerated in steam generator, heater treater, or other fired equipment and inspection and maintenance program; transfer of uncondensed vapors to gas pipeline or reinjection to formation, if appropriate wells are available)
2. PV relief valve set to within 10% of maximum allowable pressure

### Step 4 - Cost Effectiveness Analysis

As provided in the attached quote, the capital cost for a vapor control system to address the technologically feasible option is $1,889,000.

The annualized capital cost is:

$AP = (P) \{[(i) (1 + i)^n]/[(1 + i)^n - 1]\}$, where
AP = Equivalent Annual Capital Cost of Control Equipment
P = Present value of the control equipment, including installation cost
= $2,300,000

i = interest rate (use 10% per policy)
n = equipment life (assume 10 years per policy)

AP = ($2,300,000) {[(0.1)(1+0.1)$^{10}$]/[(1+0.1)$^{10}$ – 1]} = $374,210/year

Excluding annual operation costs, total annual cost of vapor control = $374,210

For calculation of the amount of VOCs removed from the tank with the vapor control system, 100% control is assumed. The VOCs removed annually are 4,588 lb/yr (2.3 tons/yr)

Annualized cost = $374,210/yr / 2.3 tons/yr
= $162,700/ton

This value exceeds the cost effectiveness threshold for VOCs of $17,500/ton. Therefore, the vapor control system is not cost effective.

**Step 5 - Select BACT**

PV relief valve set to within 10% of maximum allowable pressure of the tank.

Client: CHEVRON N.A.
Project: TANK VAPOR RECOVERY SYSTEM
Location: TAFT, CA
Country: USA

FLUOR
Contract No. A6JG
06-Oct-16
Rev. No. 3

# ROM Class 1 Estimate for CHEVRON N.A. - TANK VAPOR RECOVERY SYSTEM

**(Based on one existing Tank being serviced)**

| | DESCRIPTION | CAPACITY BASIS | | TOTAL EQUIP. PRICE | | MULTIPLIER: EQUIP to DFC | | TOTAL ESTIM. DFC | | MULTIPLIER: DFC to TIC | TOTAL ESTIMATED TIC |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **MECHANICAL EQUIPMENT:** | | | | | | | | | | |
| | TANK VAPOR RECOVERY UNIT | | | | | | | | | | |
| K-2 | COMPRESSOR - JA-A65 Single Acting Two Cylinder | 25 HP Motor | | 62,400 | x | 4.0 | = | 329,600 | x | 1.90 | $626,000 |
| | INLET SEPARATOR - | 10"dia x 5'7" s/s | | 15,450 | x | 5.0 | = | 77,250 | x | 1.90 | $147,000 |
| E-K2 | GAS COOLER | Duty = 43 MMBTU/HR ??? | | 10,300 | x | 8.0 | = | 82,400 | x | 1.90 | $157,000 |
| | DEMOLITION (if required) | | | | | ALLOW | | 30,000 | x | 1.90 | $57,000 |
| | | Lineal Feet | Diam | $/LF | | DFC | | DFC Rounded | | | |
| | NEW PIPING (Bulks & Labor) | 70 | 4" | 375 | | $26,250 | | 26,000 | x | 1.60 | $42,000 |
| | etc. | 100 | 2" | 315 | | $31,500 | | 32,000 | x | 1.60 | $51,000 |
| | | 25 | 1.5" | 280 | | $7,250 | | 7,000 | x | 1.60 | $11,000 |
| | | 25 | 1" | 250 | | $6,250 | | 6,000 | x | 1.60 | $10,000 |
| | - Straight Run Pipe, including Pipe, minimal fittings, paint, supports, labor, etc. | 500 | 2" | 175 | | $87,500 | | 88,000 | x | 1.60 | $141,000 |
| | NEW ELECTRICAL (Bulks & Labor) | | | | | | | | | | |
| | - Electrical Equipment, labor, etc. (Allow) | 1 | Lot | 30,000 | | $30,000 | | 30,000 | x | 1.60 | $48,000 |
| | - Electrical Runs, including wire, cable, conduit, terminations, labor, etc. | 500 | LF | 50 | | $25,000 | | 25,000 | x | 1.60 | $40,000 |
| | OTHER MISCELLANEOUS BULKS & LABOR Incl. CIVIL, STRUCTURAL, CONTROLS SYSTEMS, Etc. (not covered in Equipment to DFC multipliers above) | ALLOW | | | | $100,000 | | 100,000 | x | 1.60 | $160,000 |
| | TIE-INS TO EXISTING FACILITIES / SYSTEMS | ALLOW | | | | $30,000 | | 30,000 | x | 1.60 | $48,000 |
| | SUBTOTAL ALL SCOPE (excluding Contingency) | | | $108,150 | | | | $663,250 | | 1.78 | $1,538,000 |
| | CONTINGENCY | 50.0% | | | | | | | | | $769,000 |
| | **TOTAL ALL SCOPE (including Contingency)** | | | | | | | | | | $2,307,000 |

| | |
|---|---|
| **TOTAL ALL SCOPE (Rounded)** | **$2,300,000** |

NOTES:

# ATTACHMENT VII
# Statewide Compliance Statement

Chevron

**Donald Puckett**
General Manager - Operations

**San Joaquin Valley SBU**
Chevron North America
Exploration and Production
P. O. Box 1392

January 13, 2015

Mr. Seyed Sadredin
San Joaquin Valley Air Pollution Control District
34946 Flyover Court
Bakersfield, CA 93308

**RE: Statewide Compliance Certification**

Dear Mr. Sadredin:

As required under District Rule 2201, Subsection 4.15.2 and Section 173(a)(3) of the Clean Air Act, 42 U.S.C. Section 7503, Chevron U.S.A. Inc. hereby submits this letter of certification regarding statewide compliance as of this date.

Based on reasonable inquiry and to the best of my knowledge and belief, the major stationary sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by Chevron U.S.A. Inc. in the State of California as listed below are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act:

- El Segundo Refinery
- El Segundo Marketing Terminal
- Richmond Refinery
- Banta Marketing Terminal
- Huntington Beach Marketing Terminal
- Montebello Marketing Terminal
- Sacramento Marketing Terminal
- Van Nuys Marketing Terminal
- Cross Valley Carneras Gas Compressor Facility (Kern County)
- Kettleman City Pump Station (Kings County)
- 27G Pump Station (Kern County)

- San Joaquin Valley Business Unit:
  - Fresno County Heavy Oil Source (Coalinga)
  - Fresno County Natural Gas Source (Coalinga)
  - Kern County Central Heavy Oil Source (Kern River)
  - Kern County Western Heavy Oil Source (Midway Sunset & Cymric)
  - Kern County Western Light Oil Source (Midway Sunset, Cymric & Lost Hills)
  - Kern County Western Gas Source (Cymric & Lost Hills)
  - San Ardo (Monterey County)

- San Luis Obispo (San Luis Obispo County)

- Global Power (Joint Venture Facilities):
  - Coalinga Cogeneration Company in Fresno County
  - Kern River Cogeneration Company in Kern County
  - Mid-Set Cogeneration Company in Kern County
  - Salinas River Cogeneration Company in Monterey County
  - Sargent Canyon Cogeneration Company in Monterey County
  - Sycamore Cogeneration Company in Kern County

Please telephone Ashley Dahlstrom at (661) 654-7293 or Dave Bone at (661) 654-7150 if there are questions.

Sincerely,

Donald Puckett
General Manager - Operations

# ATTACHMENT VIII
# Title V Compliance Certification Form

# San Joaquin Valley
# Unified Air Pollution Control District

## TITLE V MODIFICATION - COMPLIANCE CERTIFICATION FORM

### I. TYPE OF PERMIT ACTION (Check appropriate box)

[X] SIGNIFICANT PERMIT MODIFICATION
[ ] MINOR PERMIT MODIFICATION
[ ] ADMINISTRATIVE AMENDMENT

| COMPANY NAME: CHEVRON U.S.A. INC. | FACILITY ID: S-1128 |
|---|---|
| 1. Type of Organization:[X] Corporation [ ] Sole Ownership [ ] Government [ ] Partnership [ ] Utility | |
| 2. Owner's Name: CHEVRON U.S.A. INC. | |
| 3. Agent to the Owner: N/A | |

### II. COMPLIANCE CERTIFICATION (Read each statement carefully and initial all circles for confirmation):

(RA) Based on information and belief formed after reasonable inquiry, the equipment identified in this application will continue to comply with the applicable federal requirement(s).

(RA) Based on information and belief formed after reasonable inquiry, the equipment identified in this application will comply with applicable federal requirement(s) that will become effective during the permit term, on a timely basis.

(RA) Corrected information will be provided to the District when I become aware that incorrect or incomplete information has been submitted.

(RA) Based on information and belief formed after reasonable inquiry, information and statements in the submitted application package, including all accompanying reports, and required certifications are true accurate and complete.

I declare, under penalty of perjury under the laws of the state of California, that the forgoing is correct and true:

Signature of Responsible Official

6/2/16
Date

Robert Allen
Name of Responsible Official (please print)

Application for new 2,000 barrel drain tank

Name of Responsible Official (please print)

Operations Supervisor
Title of Responsible Official (please print)

# ATTACHMENT IX
# HRA

# San Joaquin Valley Air Pollution Control District
# Risk Management Review

| | |
|---|---|
| To: | Richard Edgehill, AQE – Permit Services |
| From: | Stephanie Pellegrini, AQS – Technical Services |
| Date: | October 17, 2016 |
| Facility Name: | Chevron USA, Inc |
| Location: | 2F OCP NW/4 Sec 2, T 11N, R 24W |
| Application #(s): | S-1128-1018-0 |
| Project #: | S-1162368 |

## A. RMR SUMMARY

| RMR Summary | | | |
|---|---|---|---|
| **Categories** | **Oil Tank (Unit 1018-0)** | **Project Totals** | **Facility Totals[1]** |
| **Prioritization Score** | 0.05 | 0.05 | >1.0 |
| **Acute Hazard Index** | 0.10 | 0.10 | 0.74 |
| **Chronic Hazard Index** | 0.00 | 0.00 | 0.02 |
| **Maximum Individual Cancer Risk** | 2.24E-07 | 2.24E-07 | 7.78E-06 |
| **T-BACT Required?** | **No** | | |
| **Special Permit Requirements?** | **No** | | |

[1] Facilities S-1128, 1129, 1141, 2592 and 1549 are all considered the same facility. The facility totals in this summary represent the combined score for the facilities.

## B. RMR REPORT

### I. Project Description

Technical Services received a request on October 5, 2016, to perform a Risk Management Review for a proposed installation of a 200 bbl crude oil storage tank. An Ambient Air Quality Analysis was not required because VOCs are the only emissions for this project.

### II. Analysis

Toxic emissions from Oilfield Fugitives were calculated using emission factors derived from 1991 source tests of central valley sites, and input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015), risks from the proposed unit's toxic emissions were prioritized using the procedure in the 1990 CAPCOA Facility Prioritization Guidelines. The prioritization score for the facility is greater than 1.0 (see RMR Summary Table). Therefore, a refined health risk assessment was required. The AERMOD model was used, with the parameters outlined below and

meteorological data for 2004-2008 from Fellows to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the SHARP Program, which then used the Air Dispersion Modeling and Risk Tool (ADMRT) of the Hot Spots Analysis and Reporting Program Version 2 (HARP 2) to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

| Analysis Parameters<br>Unit 1018-0 | | | |
|---|---|---|---|
| **Source Type** | Circular Area | **Location Type** | Rural |
| **Tank Height (m)** | 2.44 | **Closest Receptor (m)** | 550 |
| **Tank Diameter (m)** | 9.14 | **Type of Receptor** | Residential |
| **VOC Emissions (lb/hr)** | 4.29 | **VOC Emissions (lb/yr)** | 4,588 |

## III. Conclusion

The acute and chronic indices are below 1.0 and the cancer risk factor associated with the project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

## IV. Attachments

A. RMR request from the project engineer
B. Additional information from the applicant/project engineer
C. Prioritization score w/ toxic emissions summary
D. Facility Summary

# ATTACHMENT X
## Draft ATC

San Joaquin Valley
Air Pollution Control District

# AUTHORITY TO CONSTRUCT

DRAFT

**PERMIT NO:** S-1128-1018-0

**ISSUANCE DATE:** DRAFT

**LEGAL OWNER OR OPERATOR:** CHEVRON USA INC
**MAILING ADDRESS:** P O BOX 1392
BAKERSFIELD, CA 93302

**LOCATION:** HEAVY OIL WESTERN STATIONARY SOURCE
KERN COUNTY

**EQUIPMENT DESCRIPTION:**
2000 BBL DRAIN TANK WITH NATURAL GAS BLANKETING (2F OCP)

## CONDITIONS

1. This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201] Federally Enforceable Through Title V Permit
2. Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Federally Enforceable Through Title V Permit
3. Prior to operating equipment under this Authority to Construct, permittee shall surrender VOC emission reduction credits for the following quantity of emissions: 1st quarter - 1,720 lb, 2nd quarter - 1,720 lb, 3rd quarter - 1,721 lb, and fourth quarter - 1721 lb. These amounts include the applicable offset ratio specified in Rule 2201 Section 4.8 (as amended 2/18/16) for the ERC specified below. [District Rule 2201] Federally Enforceable Through Title V Permit
4. ERC Certificate Numbers S-410-1, S-3404-1, S-4004-1, S-4110-1, S-4549-1, S-1878-1, S-1912-1, and S-1983-1 (or a certificate split from these certificates) shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this Authority to Construct shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of this Authority to Construct. [District Rule 2201] Federally Enforceable Through Title V Permit
5. This tank shall only store, place, or hold organic liquid with a true vapor pressure (TVP) of less than 0.5 psia under all storage conditions. [District Rule 4623] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DRAFT

Arnaud Marjollet, Director of Permit Services

S-1128-1018-0 : Sep 9 2016 2:32PM -- EDGEHILR : Joint Inspection NOT Required

6. Tank liquid throughput shall not exceed 2,000 barrels per day or 70,000 barrels per year. [District Rule 2201] Federally Enforceable Through Title V Permit

7. VOC emission rate from the tank shall not exceed 103.0 lb/day or 4,588 lb/year. [District Rule 2201 and 40 CFR Part 60, Subpart OOOO] Federally Enforceable Through Title V Permit

8. Permittee shall conduct true vapor pressure (TVP) testing of the organic liquid stored in this tank, or representative tank as provided in District Rule 4623, at least once every 24 months during summer (July - September), and/or whenever there is a change in the source or type of organic liquid stored in this tank in order to maintain exemption from the rule. [District Rule 4623] Federally Enforceable Through Title V Permit

9. The API gravity of crude oil or petroleum distillate shall be determined by using ASTM Method D 287 e1 "Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method). Sampling for API gravity shall be performed in accordance with ASTM Method D 4057 "Standard Practices for Manual Sampling of Petroleum and Petroleum Products." [District Rule 4623] Federally Enforceable Through Title V Permit

10. For crude oil with an API gravity of 26 degrees or less, the TVP shall be determined using the latest version of the Lawrence Berkeley National Laboratory "test Method for Vapor pressure of Reactive Organic Compounds in Heavy Crude Oil Using Gas Chromatograph", as approved by ARB and EPA. [District Rule 4623] Federally Enforceable Through Title V Permit

11. Instead of testing each uncontrolled fixed roof tank, the permittee may conduct a TVP test of the organic liquid stored in a representative tank. [District Rule 4623] Federally Enforceable Through Title V Permit

12. The TVP testing shall be conducted at actual storage temperature of the organic liquid in the tank. The permittee shall also conduct an API gravity testing. [District Rule 4623] Federally Enforceable Through Title V Permit

13. This tank shall be equipped with a pressure-vacuum (PV) relief valve set to within 10% of the maximum allowable working pressure of the tank, labeled with the operating pressure settings, properly maintained in good operating order in accordance with the manufacturer's instructions, and shall remain in gas-tight condition except when the operating pressure exceeds the valve's set pressure. [District Rule 4623] Federally Enforceable Through Title V Permit

14. Permittee shall submit the records of TVP and API gravity testing to the APCO within 45 days after the date of testing. The records shall include the tank identification number, Permit to Operate number, type of stored organic liquid, TVP and API gravity of the organic liquid, test methods used, and a copy of the test results. [District Rule 4623] Federally Enforceable Through Title V Permit

15. Operator shall visually inspect tank shell, hatches, seals, seams, cable seals, valves, flanges, connectors, and any other piping components directly affixed to the tank and within five feet of the tank at least once per year for liquid leaks, and with a portable hydrocarbon detection instrument conducted in accordance with EPA Method 21 for gas leaks. Operator shall also visually or ultrasonically inspect as appropriate, the external shells and roofs of uninsulated tanks for structural integrity annually. [District Rule 2080] Federally Enforceable Through Title V Permit

16. Upon detection of a liquid leak, defined as a leak rate of greater than or equal to 30 drops per minute, operator shall repair the leak within 8 hours. For leaks with a liquid leak rate of between 3 and 30 drops per minute, the leaking component shall be repaired within 24 hours after detection. [District Rule 2080] Federally Enforceable Through Title V Permit

17. Upon detection of a gas leak, defined as a VOC concentration of greater than 10,000 ppmv measured in accordance with EPA Method 21, operator shall take on of the following actions: 1) eliminate the leak within 8 hours after detection; or 2) if the leak cannot be eliminated, then minimize the leak to the lowest possible level within 8 hours after detection by using best maintenance practices, and eliminate the leak within 48 hours after minimization. In no event shall the total time to minimize and eliminate a leak exceed 56 hours after detection. [District Rule 2080] Federally Enforceable Through Title V Permit

18. Components found to be leaking either liquids or gases shall be immediately affixed with a tag showing the component to be leaking. Operator shall maintain records of the liquid or gas leak detection readings, date/time the leak was discovered, and date/time the component was repaired to a leak-free condition. [District Rule 2080] Federally Enforceable Through Title V Permit

DRAFT

CONDITIONS CONTINUE ON NEXT PAGE

19. Leaking components that have been discovered by the operator that have been immediately tagged and repaired within the timeframes specified in District Rule 4623, Table 3 shall not constitute a violation of this rule. Leaking components as defined by District Rule 4623 discovered by District staff that were not previously identified and/or tagged by the operator, and/or any leaks that were not repaired within the timeframes specified in District Rule 4623, Table 3 shall constitute a violation of this rule. [District Rule 2080] Federally Enforceable Through Title V Permit

20. If a component type for a given tank is found to leak during an annual inspection, operator shall conduct quarterly inspections of that component type on the tank or tank system for four consecutive quarters. If no components are found to leak after four consecutive quarters, the operator may revert to annual inspections. [District Rule 2080] Federally Enforceable Through Title V Permit

21. Any component found to be leaking on two consecutive annual inspections is in violation of this rule, even if covered under the voluntary inspection and maintenance program. [District Rule 2080] Federally Enforceable Through Title V Permit

22. Permittee shall notify the APCO in writing at least three (3) days prior to performing tank degassing and interior tank cleaning activities. Written notification shall include the following: 1) the Permit to Operate number and physical location of the tank being degassed, 2) the date and time that tank degassing and cleaning activities will begin, 3) the degassing method, as allowed in this permit, to be used, 4) the method to be used to clean the tank, including any solvents to be used, and 5) the method to be used to dispose of any removed sludge, including methods that will be used to control emissions from the receiving vessel and emissions during transport. [District Rule 2080] Federally Enforceable Through Title V Permit

23. This tank shall not be required to de-gas before commencing cleaning activities. All other applicable requirements shall be complied with before, during, and after tank cleaning activities. [District Rule 2080] Federally Enforceable Through Title V Permit

24. While performing tank cleaning activities, operators may only use the following cleaning agents: diesel, solvents with an initial boiling point of greater than 302 degrees F, solvents with a vapor pressure of less than 0.5 psia, or solvents with 50 grams of VOC per liter or less. [District Rule 2080] Federally Enforceable Through Title V Permit

25. Steam cleaning shall only be allowed at locations where wastewater treatment facilities are limited, or during the months of December through March. [District Rule 2080] Federally Enforceable Through Title V Permit

26. The permittee shall keep accurate records of each organic liquid stored in the tank, including its storage temperature, TVP, and API gravity. [District Rule 4623] Federally Enforceable Through Title V Permit

DRAFT

www.baagmd.gov/rules-and-compliance/currentrules

# REGULATION 6
# PARTICULATE MATTER
# RULE 5
# PARTICULATE EMISSIONS FROM REFINERY FLUIDIZED CATALYTIC CRACKING UNITS

## INDEX


**6-5-100 GENERAL**

6-5-101 Description

**6-5-110 EXEMPTIONS**

6-5-111 Exemption, Emissions Abated by Wet Scrubber
6-5-112 Limited Exemption, Emissions during Startup or Shutdown Periods
6-5-113 Limited Exemption, Installation of Wet Scrubber
6-5-114 Limited Exemption, FCCU without Nitrogen-Based Additives
6-5-115 Limited Exemption, Ammonia Optimization

**6-5-200 DEFINITIONS**

6-5-201 Ammonia Slip
6-5-202 Catalyst Regeneration Unit (CRU)
6-5-203 Condensable Particulate Matter
6-5-204 Daily Average
6-5-205 FCCU Shutdown
6-5-206 FCCU Startup
6-5-207 Fluidized Catalytic Cracking Unit (FCCU)
6-5-208 Petroleum Refinery
6-5-209 Primary Particulate Matter
6-5-210 Secondary Particulate Matter
6-5-211 Wet Scrubber

**6-5-300 STANDARDS**

6-5-301 Fluidized Catalytic Cracking Unit (FCCU) Emission Limits

**6-5-400 ADMINISTRATIVE REQUIREMENTS**

6-5-401 Ammonia Control Plan and Permit Applications
6-5-402 Ammonia Monitoring Plan
6-5-403 Ammonia Optimization

**6-5-500 MONITORING AND RECORDS**

6-5-501 Ammonia Monitoring
6-5-502 Ammonia Records

**6-5-600 MANUAL OF PROCEDURES**

6-5-601 Compliance Determination
6-5-602 Determination of Ammonia and Oxygen

# REGULATION 6
# PARTICULATE MATTER
# RULE 5
# PARTICULATE EMISSIONS FROM REFINERY FLUIDIZED CATALYTIC CRACKING UNITS

(Adopted December 16, 2015)

## 6-5-100 GENERAL

**6-5-101** **Description:** This rule limits the emissions of condensable particulate matter emissions from petroleum refinery fluidized catalytic cracking units (FCCUs) as well as emissions of precursors of secondary particulate matter. Regulation 6, Rule 1 addresses filterable particulate emissions from FCCUs. For the purposes of this rule, commingled ammonia, condensable particulate and sulfur dioxide emissions from an FCCU and one or more other sources from a single exhaust point shall all be considered to be FCCU emissions.

## 6-5-110 EXEMPTIONS

**6-5-111** **Exemption, Emissions Abated by Wet Scrubber:** The emission limits in Section 6-5-301 shall not apply to emissions that are abated by a wet scrubber that is required to be operated by a District permit and that constitutes best available control technology (BACT) for any pollutant.

**6-5-112** **Limited Exemption, Emissions during Startup or Shutdown Periods:** The requirements of Section 6-5-301 shall not apply to emissions during an FCCU startup or shutdown period. FCCU startup and shutdown periods shall be as defined in this rule, unless a different period is specified in a District Permit to Operate for an FCCU, in which case the Permit to Operate shall take precedence. This exemption is also applicable to a non-FCCU source with startup or shutdown provisions specified in a Permit to Operate, if that source is subject to the requirements of Section 6-5-301 because the source emissions are commingled with those of an FCCU at a single exhaust point; the startup or shutdown provisions specified in the Permit to Operate shall be the basis for this exemption. Whenever this exemption applies to any source, it shall apply to all sources with commingled emissions.

**6-5-113** **Limited Exemption, Installation of Wet Scrubber:** The emission limit effective date for ammonia in Section 6-5-301 may be extended to a later date specified in a District Authority to Construct for an existing FCCU to be controlled with a new wet scrubber, but may not be extended by more than 36 months.

**6-5-114** **Limited Exemption, FCCU without Nitrogen-Based Additives:** The emission limit for ammonia in Section 6-5-301 shall not apply to an FCCU where ammonia, urea or any other nitrogen-based additive is not used in a way that contributes to ammonia or condensable particulate FCCU emissions.

**6-5-115** **Limited Exemption, Ammonia Optimization:** The ammonia emission limit in Section 6-5-301 shall not apply to the owner/operator of a refinery that implements an optimization of ammonia and/or urea injection in accordance with Section 6-5-403.

## 6-5-200 DEFINITIONS

**6-5-201** **Ammonia Slip:** Ammonia slip is the amount of unreacted ammonia emitted to the atmosphere from the FCCU, regardless of the source of the ammonia.

**6-5-202** **Catalyst Regeneration Unit (CRU):** A catalyst regeneration unit regenerates spent FCCU catalyst by burning off the coke that has deposited on the catalyst surface. The resulting CRU flue gas is the primary emission source addressed by this rule.

**6-5-203** **Condensable Particulate Matter:** Liquid droplets that coalesce, or gaseous emissions that condense to form liquid or solid particles. These liquid and/or solid particles are identified as condensable organic or condensable inorganic particulate matter using EPA Test Method 202.

**6-5-204** **Daily Average:** The arithmetic mean of the measured ammonia emissions subject to Section 6-5-301 on any calendar day that the FCCU operates.

**6-5-205** **FCCU Shutdown:** Unless otherwise specified in a District Permit to Operate, FCCU shutdown is a period which begins when fresh feed flow to the FCCU reactor stops and ends when the main blower for catalyst recirculation is shutdown.

**6-5-206** **FCCU Startup:** Unless otherwise specified in a District Permit to Operate, FCCU startup is a period not exceeding 120 hours which begins with the startup of the main blower for introduction of catalyst and ends after fresh feed is introduced to the FCCU reactor, when the process reaches steady state.

**6-5-207** **Fluidized Catalytic Cracking Unit (FCCU):** A fluidized catalytic cracking unit (FCCU) is a processing unit that converts heavy petroleum fractions, typically from crude oil distillation units, into lighter fuel intermediates by using a fine, powdered catalyst to promote a chemical reaction in which the heavy petroleum molecules are broken into smaller molecules. In addition to the cracking reactor, an FCCU includes a catalyst regeneration unit (CRU), ancillary equipment including blowers, and all equipment for controlling air pollutant emissions and recovering heat.

**6-5-208** **Petroleum Refinery:** An establishment that is located on one or more contiguous or adjacent properties that processes crude oil to produce more usable products such as gasoline, diesel fuel, aviation fuel, lubricating oils, asphalt or petrochemical feedstocks. Petroleum refinery processes include separation processes (e.g., atmospheric or vacuum distillation, and light ends recovery), petroleum conversion processes (e.g., cracking, reforming, alkylation, polymerization, isomerization, coking, and visbreaking) petroleum treating processes (e.g., hydrodesulfurization, hydrotreating, chemical sweetening, acid gas removal, and deasphalting), feedstock and product handling (e.g., storage, blending, loading, and unloading), auxiliary facilities (e.g., boilers, waste water treatment, hydrogen production, sulfur recovery plant, cooling towers, blowdown systems, compressor engines, and power plants).

**6-5-209** **Primary Particulate Matter:** Material emitted to the atmosphere as filterable or condensable particulate matter.

**6-5-210** **Secondary Particulate Matter:** Material emitted to the atmosphere in a gaseous form that will not coalesce or condense to a solid or liquid form at atmospheric temperature and pressure, but that may react in the atmosphere into a solid or liquid form. For the purposes of this rule, precursors of Secondary Particulate Matter shall include sulfur dioxide ($SO_2$) and ammonia.

**6-5-211** **Wet Scrubber:** A device that removes air pollutants from gas streams by contacting the gas stream with a scrubbing liquid.

**6-5-300** **STANDARDS**

**6-5-301** **Fluidized Catalytic Cracking Unit (FCCU) Emission Limits:** The owner/operator of a Petroleum Refinery that includes an FCCU shall not cause emissions to the atmosphere from the FCCU that exceed the limits in Table 1 on or after the indicated effectiveness date:

**Table 1 – FCCU Emission Limits**

| Pollutant | Emission Limit | Effective Date |
|---|---|---|
| Ammonia | 10 ppmvd at 3% $O_2$ as a daily average | January 1, 2018 |
| Condensable Particulate Matter | [future] | [future] |
| Sulfur Dioxide ($SO_2$) | [future] | [future] |

## 6-5-400 ADMINISTRATIVE REQUIREMENTS

**6-5-401** **Ammonia Control Plan and Permit Applications:** No later than January 1, 2017, the owner/operator of a Petroleum Refinery subject to the ammonia emission limit in Section 6-5-301 shall submit to the APCO a control plan detailing the measures, if any, to be taken in order to meet the requirements of Section 6-5-301, and also applications for all Authorities to Construct necessary for compliance with Section 6-5-301.

**6-5-402** **Ammonia Monitoring Plan:** No later than January 1, 2017, the owner/operator of a Petroleum Refinery that includes an FCCU subject to the ammonia emission limit in Section 6-5-301 shall submit to the APCO a plan for the installation of an ammonia monitoring system to perform monitoring as required by Section 6-5-501. This plan shall identify the proposed monitoring technique, monitoring equipment, installation details and installation schedule.

**6-5-403** **Ammonia Optimization:** As an alternative to compliance with the ammonia emission limit of Section 6-5-301, the owner/operator of a refinery may instead establish an enforceable ammonia emission limit for the FCCU that results in the minimization of total FCCU $PM_{2.5}$ emissions (including all condensable particulate matter), as follows:

403.1 No later than March 1, 2016, the refinery owner/operator shall submit to the APCO an Optimization and Demonstration Protocol for the purpose of establishing the minimum rate of ammonia and/or urea injection necessary to minimize total $PM_{2.5}$ FCCU emissions (including all condensable particulate matter) while complying with all existing permit requirements, excluding permit requirements that are not based on District BACT requirements, on District prohibitory rule limits or on federal consent decrees. The Optimization Protocol shall include the ammonia and/or urea injection rates to be evaluated and the criteria for selecting these rates, and also the criteria for determining the Optimized Ammonia Emissions Concentration that minimizes total FCCU $PM_{2.5}$ emissions.

403.2 Within 60 days, the APCO shall either approve or disapprove the Optimization and Demonstration Protocol.

403.3 The refinery owner/operator shall commence and complete the Optimization and Demonstration Protocol, approved by the APCO, no later than June 30, 2017.

403.4 The refinery owner/operator shall report to the APCO the results of the Optimization and Demonstration Protocol and the proposed Optimized Ammonia Emissions Concentration no later than August 31, 2017. No later than this same date, the refinery owner/operator shall submit a District permit application to 1) establish the Optimized Ammonia Emissions Concentration as an enforceable permit requirement, and to 2) relax any existing permit conditions that are not based on District BACT requirements, on District prohibitory rule limits or on federal consent decrees to the extent necessary to minimize total FCCU $PM_{2.5}$ emissions.

403.5 Disapproval of an Optimization and Demonstration Protocol, or a failure to meet any requirement or deadline in this section shall not constitute a violation of this rule, but shall preclude the applicability of the limited exemption in Section 6-5-115.

## 6-5-500 MONITORING AND RECORDS

**6-5-501** **Ammonia Monitoring:** The owner/operator of a Petroleum Refinery that includes an FCCU subject to the ammonia emission limit in Section 6-5-301 shall, no later than January 1, 2018, operate one of the following;

501.1 A mass-balance monitoring system that includes all of the following:

1.1 Parametric monitors that comply with District Regulation 1, Section 523 to continuously measure the injection or addition rate (pounds per hour) of ammonia, urea or any other nitrogen-based additive into the emission stream, and;

1.2 Continuous emission monitors that comply with District Regulation 1, Section 522 to continuously measure NOx and oxygen concentrations at appropriate locations to allow a calculation of the amount of ammonia and/or urea consumed in NOx-reduction reactions, and therefore the remaining, emitted amount of non-consumed ammonia.

501.2 Any other ammonia emission monitoring system approved in writing by the APCO.

**6-5-502** **Ammonia Records:** The owner/operator of a Petroleum Refinery subject to the ammonia emission limit in Section 6-5-301 shall maintain records of the data required to be measured in Section 6-5-501. These records shall be kept for a period of at least five years and shall be made available to the APCO on request.

**6-5-600** **MANUAL OF PROCEDURES**

**6-5-601** **Compliance Determination:** All compliance determinations shall be made in the as-found operating condition. No compliance determinations shall be made during periods subject to the exemption in Section 6-5-112.

**6-5-602** **Determination of Ammonia and Oxygen:** Determination of ammonia shall be by Regulation 1, Section 522 NOx monitors or other APCO approved ammonia monitoring system. Determination of oxygen shall be by Regulation 1, Section 522 oxygen monitor.

# REGULATION 8
# ORGANIC COMPOUNDS
# RULE 6
# ORGANIC LIQUID BULK TERMINALS AND BULK PLANTS

## INDEX


**8-6-100 GENERAL**

8-6-101 Description
8-6-110 Exemption, Low Vapor Pressure Organic Liquids
8-6-111 Exemption, Low Throughput
8-6-112 Deleted February 2, 1994
8-6-113 Deleted February 2, 1994
8-6-114 Exemption, Maintenance and Repair
8-6-115 Exemption, Bulk Gasoline Distribution Facilities
8-6-116 Exemption, Small Transportable Containers
8-6-117 Exemption, Liquefied Organic Gases

**8-6-200 DEFINITIONS**

8-6-201 Bulk Plant
8-6-202 Deleted February 2, 1994
8-6-203 Submerged Fill Pipe
8-6-204 Bulk Terminal
8-6-205 True Vapor Pressure
8-6-206 Vapor Tight
8-6-207 Organic Compound
8-6-208 Loading Equipment
8-6-209 Organic Liquid
8-6-210 Transportable Containers
8-6-211 Leak Free
8-6-212 Delivery Vehicle
8-6-213 Switch Loading
8-6-214 Vapor Loss Control System
8-6-215 Liquefied Petroleum Gas
8-6-216 Vapor Balance System
8-6-217 Throughput

**8-6-300 STANDARDS**

8-6-301 Bulk Terminal Limitations
8-6-302 Bulk Plant Limitations
8-6-303 Deleted February 2, 1994
8-6-304 Deliveries to Storage Tanks
8-6-305 Delivery Vehicle Requirements
8-6-306 Equipment Maintenance
8-6-307 Operating Practices

**8-6-400 ADMINISTRATIVE REQUIREMENTS**

8-6-401 Deleted February 2, 1994
8-6-402 Deleted February 2, 1994
8-6-403 Compliance Schedule

**8-6-500 MONITORING AND RECORDS**

8-6-501 Records
8-6-502 Portable Hydrocarbon Detector
8-6-503 Burden of Proof

**8-6-600 MANUAL OF PROCEDURES**

8-6-601 Efficiency and Rate Determination
8-6-602 Deleted February 2, 1994
8-6-603 Analysis of Samples, True Vapor Pressure
8-6-604 Determination of Applicability

# REGULATION 8
# ORGANIC COMPOUNDS
# RULE 6
# ORGANIC LIQUID BULK TERMINALS AND BULK PLANTS

## 8-6-100 GENERAL

**8-6-101** **Description:** The purpose of this rule is to limit emissions of organic compounds as defined in Section 8-6-207 from transfer operations at non-gasoline organic liquid bulk terminals and bulk plants. (Amended March 17, 1982; February 2, 1994)

**8-6-110** **Exemption, Low Vapor Pressure Organic Liquids:** Until December 1, 1994, the requirements in this Rule shall not apply to loading or delivery of any organic liquid having a true vapor pressure less than 77.5 mmHg (1.5 psia). After December 1, 1994, the requirements of this Rule shall not apply to loading and delivery of any organic liquid having a true vapor pressure less than 25.8 mmHg (0.5 psia), as determined by the methods specified in Sections 8-6-603 or 604. (Amended February 2, 1994)

**8-6-111** **Exemption, Low Throughput:** The vapor recovery requirements of subsection 8-6-302.1 do not apply when the total annual throughput of organic liquids with at least 77.5 mmHg (1.5 psia) true vapor pressure transferred into delivery vehicles only is less than 2,271 cubic meters (600,000 gallons) on a facility-wide basis. (Amended February 2, 1994)

**8-6-112** **Deleted February 2, 1994**

**8-6-113** **Deleted February 2, 1994**

**8-6-114** **Exemption, Maintenance and Repair:** The requirements of Section 8-6-306 shall not apply to spills resulting from maintenance or repair operations provided proper operating practices are employed to minimize evaporation of organic compounds into the atmosphere.

**8-6-115** **Exemption, Bulk Gasoline Distribution Facilities:** Gasoline bulk terminals and bulk plants are not subject to the requirements of this rule. Such facilities are subject to the provisions of Regulation 8, Rules 33 or 39. (Adopted November 30, 1983; Amended February 2, 1994)

**8-6-116** **Exemption, Small Transportable Containers:** The requirements of subsection 8-6-302.2 shall not apply to loading organic liquids into any transportable container with a capacity less than 0.114 cubic meters (30 gallons).(Amended February 2, 1994)

**8-6-117** **Exemption, Liquefied Organic Gases:** The requirements of this rule do not apply to transfer operations involving liquefied organic gases such as liquefied petroleum gas (LPG) and halogenated gases. (Amended February 2, 1994)

## 8-6-200 DEFINITIONS

**8-6-201** **Bulk Plant:** Until December 1, 1994, any storage and distribution facility that receives organic liquid by pipeline, railcar, and/or delivery vehicle; stores it in stationary tanks; and/or mixes it in blending tanks; and/or loads it into delivery vehicles or transportable containers, for delivery to distributors, marketers or any product end user; and which has an annual throughput of not more than 22,710 cubic meters (6,000,000 gallons). After December 1, 1994, the annual throughput shall include organic liquids of at least 25.8 mmHg (0.5 psia) true vapor pressure. (Amended July 2, 1980; February 2, 1994)

**8-6-202** **Deleted February 2, 1994**

**8-6-203** **Submerged Fill Pipes:** Any discharge pipe, lance, or nozzle which meets either of the following conditions:

203.1 Where the vessel is filled from the top, the end of the discharge pipe or nozzle must be submerged when the liquid level is 15 centimeters (6 inches) from the bottom of the vessel. When the vessel is filled from the top with a

retractable lance, the lance shall remain below the liquid surface during the transfer operation.

203.2 Where the vessel is filled from the side, the discharg pipe or nozzle must be totally submerged when the liquid level is 46 centimeters (18 inches) from the bottom of the vessel.

(Renumbered March 17, 1982; Amended February 2, 1994)

**8-6-204** **Bulk Terminal:** Until December 1, 1994, any storage and distribution facility that receives organic liquid; stores it in stationary tanks; and/or mixes it in blending tanks; and/or loads it into delivery vehicles and transportable containers, for delivery to distributors, marketers or any product end user; and which has an annual throughput of more than 22,710 cubic meters (6,000,000 gallons). After December 1, 1994, the annual throughput shall include organic liquids of at least 25.8 mmHg (0.5 psia) true vapor pressure. (Renumbered March 17, 1982; Amended February 2, 1994)

**8-6-205** **True Vapor Pressure:** The pressure exerted when an organic liquid is in equilibrium with its own vapor at 25°C (77°F). For liquid mixtures, true vapor pressure is the sum of the equilibrium partial pressures exerted by all organic compounds in the liquid and can be estimated using Raoult's Law as follows:

$$P^* = \sum_{i=1}^{n} \frac{(w_i)(VP_i) / MW_i}{\frac{W_w}{MW_w} + \sum_{i=1}^{n} \frac{W_i}{MW_i}}$$

Where:
$W_i$ = Weight of the "i"th organic compound, in grams
$W_W$ = Weight of water, in grams
$MW_i$ = Molecular weight of the "i"th organic compound, in grams/gram-mole
$MW_W$ = Molecular weight of water, in grams/gram-mole
$P^*$ = True vapor pressure of liquid mixture at 25°C, in mmHg
$VP_i$ = Vapor pressure of the "i"th organic compound at 25°C, in mmHg

For organic liquids and organic liquid mixtures to which heat is applied, the true vapor pressure shall be determined at 25°C (77°F) or the actual loading temperature, whichever is higher.

(Renumbered March 17, 1982; Amended February 2, 1994)

**8-6-206** **Vapor Tight:** A leak less than 100 percent of the Lower Explosive Limit on a portable hydrocarbon detector measured at a distance of 1 centimeter from the source.

(Renumbered March 17, 1982; Amended February 2, 1994)

**8-6-207** **Organic Compound:** Any compound of carbon, excluding methane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides of carbonates, and ammonium carbonate. (Adopted February 2, 1994)

**8-6-208** **Loading Equipment:** Any combination of loading arms, pumps, flexible hosing, dispensing nozzles, meters, and other piping and valves necessary to fill delivery vehicles or transportable containers with organic liquids. (Adopted February 2, 1994)

**8-6-209** **Organic Liquid:** Any organic compound or mixture of organic compounds that exists in the liquid phase at actual loading conditions. For the purposes of this rule, organic liquids shall not include coatings, adhesives and sealants.

(Adopted February 2, 1994)

**8-6-210** **Transportable Containers:** Any portable enclosed vessel such as a tote tank or cylindrical drum, which contains 550 gallons or less and is used to transport and distribute organic liquids. (Adopted February 2, 1994)

**8-6-211** **Leak Free:** An organic liquid leak not exceeding three drops per minute excluding losses which occur upon disconnecting transfer fittings. Such disconnect losses shall not exceed 10 milliliters (ml) during a bottom loading operation or no more than two milliliters (ml) during a top loading operation, averaged over three disconnects.

Adopted February 2, 1994)

**8-6-212** **Delivery Vehicle:** Any motor truck or truck trailer equipped with a stationary cargo tank having a capacity more than 550 gallons and designed and built for the transportation of organic liquids. (Adopted February 2, 1994)

**8-6-213** **Switch Loading:** For the purpose of this rule, switch loading refers to the transfer of organic liquids into a delivery vehicle cargo tank, which results in displacement of organic vapors remaining from a previous load. Adopted February 2, 1994)

**8-6-214** **Vapor Loss Control System:** A system for reducing emissions to the atmosphere, consisting of an abatement device and a collection system, which achieves the abatement efficiency or emission limit specified in the applicable standard(s) during the transfer operation and meets the requirements of Regulation 2, Rule 1.
Adopted February 2, 1994)

**8-6-215** **Liquefied Petroleum Gas:** A compressed gas composed of one or more of the following flammable hydrocarbons (propane, n-butane, isobutane, propylene, and butylenes), which is used especially as a fuel or as raw material for chemical synthesis. (Adopted February 2, 1994)

**8-6-216** **Vapor Balance System:** A piping system that is designed to collect organic vapors displaced from organic liquid transfer operations, and to route the collected vapors to the vessel from which the liquid being loaded originated. (Adopted February 2, 1994)

**8-6-217** **Throughput:** The total volume of organic liquid transferred into delivery vehicles and transportable containers. The volume of water in an organic liquid/water mixture shall not be considered part of the facility throughput. (Adopted February 2, 1994)

**8-6-300** **STANDARDS**

**8-6-301** **Bulk Terminal Limitations:** A person shall not transfer or allow the transfer of organic liquids from bulk terminal loading equipment unless a vapor loss control system is properly connected and used. Such transfer operations shall not emit into the atmosphere more than 21 grams of organic compounds per cubic meter (0.17 pounds per 1,000 gallons) of organic liquid loaded. Switch loading shall be subject to this standard. (Amended March 17, 1982; February 2, 1994)

**8-6-302** **Bulk Plant Limitations:** A person shall not load or allow the loading of any organic liquid from bulk plant loading equipment unless the following requirements are satisfied:

302.1 Vapor Recovery Requirement: Any emissions displaced while transferring an organic liquid with a true vapor pressure of at least 77.5 mmHg (1.5 psia) into a delivery vehicle shall be controlled by a vapor balance system or a vapor loss control system, which is properly connected and used during loading. Emissions to atmosphere shall not exceed 44 grams of organic compounds per cubic meter (0.35 pounds per 1,000 gallons) of organic liquid loaded.

302.2 Submerged Fill Requirement: Except as provided in Section 8-6-116, either a submerged fill pipe, bottom filling, or a vapor loss control system shall be used when transferring an organic liquid into a delivery vehicle or transportable container. When a vapor loss control system is used, emissions to atmosphere shall not exceed 44 grams of organic compound per cubic meter (0.35 pounds per 1000 gallons) of organic compound loaded.
(Amended July 2, 1980; February 2, 1984)

**8-6-303** **Deleted February 2, 1994**

**8-6-304** **Deliveries to storage Tanks:** A person shall not transfer or allow the transfer of any organic liquid with a true vapor.pressure of at least 77.5 mmHg (1.5 psia) into any bulk terminal or bulk plant storage tank having a capacity between 7.6 and 150 cubic meters, (2,008 and 39,630 gallons) inclusive, unless a vapor balance system or vapor loss control system, has been properly installed on the storage tank and is properly connected during delivery. Emissions to atmosphere shall not exceed 21 grams of organic compounds per cubic meter (0.17 pounds per 1,000 gallons) of organic compound loaded. (Amended February 2, 1994)

**8-6-305** **Delivery Vehicle Requirements:** Any delivery vehicle loaded at a terminal or bulk plant which is subject to the requirements of Sections 8-6-301 or 302.1 shall be equipped to allow proper connection to the vapor balance system or vapor loss

control system required by the section and shall be maintained to be vapor tight, leak free, and in good working order. (Amended February 2, 1994)

**8-6-306** **Equipment Maintenance:** All equipment associated with organic liquid delivery and loading operations shall be maintained to be vapor tight, leak free and in good working order. (Amended February 2, 1994)

**8-6-307** **Operating Practices:** Any organic liquid subject to this Rule shall not be spilled, discarded in sewers, stored in open containers, or handled in any other manner that would result in evaporation to the atmosphere. (Amended February 2, 1994)

## 8-6-400 ADMINISTRATIVE REQUIREMENTS

**8-6-401** **Deleted February 2, 1994**

**8-6-402** **Deleted February 2, 1994**

**8-6-403** **Compliance Schedule:** Any person who must install or modify equipment to comply with the requirements of Sections 301, 302 or 304 shall comply with the following increments of progress:

403.1 By June 1, 1994 submit a completed application to the APCO for an Authority to Construct.

403.2 After December 1, 1994 be in final compliance. (Adopted February 2, 1994)

## 8-6-500 MONITORING AND RECORDS

**8-6-501** **Records:** After December 1, 1994, a person whose loading equipment is subject to this rule shall comply with the following requirements:

501.1 A person shall maintain a current record of the true vapor pressure of each organic liquid and organic liquid mixture.

501.2 A person shall maintain monthly records that provide the throughput (gallons) of each organic liquid and organic liquid mixture transferred into delivery vehicles and transportable containers with at least 25.8 mmHg (0.5 psia) true vapor pressure.

501.3 Such records shall be retained for the previous 24-month period and be available to the APCO upon request. (Adopted February 2, 1994)

**8-6-502** **Portable Hydrocarbon Detector:** Any instrument used for the measurement of organic compounds shall meet the specifications and performance criteria, and shall be calibrated in accordance with EPA Reference Method 21 (40CFR60, Appendix A). (Adopted February 2, 1994)

**8-6-503** **Burden of Proof:** The burden of proof of eligibility for exemption from the requirements of this rule is on the applicant. Persons seeking such an exemption shall maintain adequate records and furnish them to the APCO upon request. (Adopted February 2, 1994)

## 8-6-600 MANUAL OF PROCEDURES

**8-6-601** **Efficiency and Rate Determination:** The means for determining compliance with Sections 8-6-301, 302, and 304 are set forth in the Manual of Procedures, Volume IV, ST-3 or ST-34. (Amended March 17, 1982; February 2, 1994)

**8-6-602** **Deleted February 2, 1994**

**8-6-603** **Analysis of Samples, True Vapor Pressure:** Samples of organic compounds as specified in Section 8-6-110 shall be analyzed for true vapor pressure at 25$^{o}$C (77$^{o}$F), as prescribed in the Manual of Procedures, Volume III, Method 28. For organic liquids and organic liquid mixtures to which heat is applied, the true vapor pressure shall be determined at 25$^{o}$C (77$^{o}$F) or the actual loading temperature, whichever is higher. (Adopted March 17, 1982; Amended February 2, 1994)

**8-6-604** **Determination of Applicability:** Any of the following methods may be used to determine if an organic liquid is subject to the requirements of this rule based on its true vapor pressure:

604.1 EPA-450/3-87-026 (Exhibit A-2 in Appendix A or Appendix D), or

604.2 Standard reference texts, or

604.3 For liquid mixtures, use Raoult's Law of Partial Pressures as defined in Section 8-6-205 or ASTM Method D 2879-83. (Adopted February 2, 1994)

# REGULATION 8
# ORGANIC COMPOUNDS
# RULE 5
# STORAGE OF ORGANIC LIQUIDS

## INDEX


**8-5-100 GENERAL**

8-5-101 Description
8-5-110 Exemptions
8-5-111 Limited Exemption, Tank Removal From and Return to Service
8-5-112 Limited Exemption, Preventative Maintenance and Inspection of Tanks in Operation
8-5-113 Deleted May 4, 1988
8-5-114 Deleted May 4, 1988
8-5-115 Deleted May 4, 1988
8-5-116 Exemption, Gasoline Storage Tanks at Gasoline Dispensing Facilities
8-5-117 Limited Exemption, Low Vapor Pressure
8-5-118 Limited Exemption, Gas Tight Requirement
8-5-119 Limited Exemption, Repair Period

**8-5-200 DEFINITIONS**

8-5-201 Deleted October 18, 2006
8-5-202 Storage Tank
8-5-203 Deleted November 27, 2002
8-5-204 Organic Liquid
8-5-205 Gasoline
8-5-206 Gas Tight
8-5-207 Approved Emission Control System
8-5-208 Degassing
8-5-209 External Floating Roof Tank
8-5-210 Internal Floating Roof Tank
8-5-211 True Vapor Pressure
8-5-212 Organic Compound
8-5-213 Viewport
8-5-214 Gauge Float
8-5-215 Guidepole
8-5-216 Zero Gap Pole Wiper Seal
8-5-217 Decommissioning
8-5-218 Stock Change
8-5-219 Tank Cleaning
8-5-220 Temporary Removal From Service
8-5-221 Liquid Balancing
8-5-222 Pressure Relief Device
8-5-223 Pressure Vacuum Valve
8-5-224 Connection
8-5-225 Good Operating Condition
8-5-226 Emission Minimization

**8-5-300 STANDARDS**

8-5-301 Storage Tank Control Requirements
8-5-302 Requirements for Submerged Fill Pipes
8-5-303 Requirements for Pressure Vacuum Valves
8-5-304 Requirements for External Floating Roof Tanks
8-5-305 Requirements for Internal Floating Roof Tanks

8-5-306 Requirements for Approved Emission Control Systems
8-5-307 Requirements for Fixed Roof Tanks, Pressure Tanks and Blanketed Tanks
8-5-310 Deleted May 4, 1988
8-5-311 Deleted November 27, 2002
8-5-312 Deleted January 20, 1993
8-5-313 Deleted January 20, 1993
8-5-314 Deleted January 20, 1993
8-5-320 Floating Roof Tank Fitting Requirements
8-5-321 Primary Seal Requirements
8-5-322 Secondary Seal Requirements
8-5-323 Deleted January 20, 1993
8-5-324 Deleted January 20, 1993
8-5-325 Deleted January 20, 1993
8-5-326 Deleted May 4, 1988
8-5-327 Deleted May 4, 1988
8-5-328 Tank Degassing Requirements
8-5-329 Deleted November 27, 2002
8-5-330 Deleted November 27, 2002
8-5-331 Tank Cleaning Requirements
8-5-332 Sludge Handling Requirements

**8-5-400 ADMINISTRATIVE REQUIREMENTS**

8-5-401 Inspection Requirements for External Floating Roof Tanks
8-5-402 Inspection Requirements for Internal Floating Roof Tanks
8-5-403 Inspection Requirements for Pressure Relief Devices
8-5-404 Inspection, Abatement Efficiency Determination and Source Test Reports
8-5-405 Deleted October 18, 2006
8-5-410 Deleted May 4, 1988
8-5-411 Enhanced Monitoring Program
8-5-412 Monitoring of Leaking Pontoons

**8-5-500 MONITORING AND RECORDS**

8-5-501 Records
8-5-502 Source Test Requirements
8-5-503 Deleted October 18, 2006

**8-5-600 MANUAL OF PROCEDURES**

8-5-601 Analysis of Samples, Reid Vapor Pressure
8-5-602 Analysis of Samples, True Vapor Pressure
8-5-603 Determination of Abatement Efficiency
8-5-604 Determination of Applicability Based on True Vapor Pressure
8-5-605 Measurement of Leak Concentrations and Residual Concentrations
8-5-606 Analysis of Samples, Tank Cleaning Agents

# REGULATION 8
# ORGANIC COMPOUNDS
# RULE 5
# STORAGE OF ORGANIC LIQUIDS

(Adopted January 1, 1978)

**8-5-100 GENERAL**

**8-5-101 Description:** The purpose of this rule is to limit emissions of organic compounds from storage tanks.

Note: New storage tanks may also be subject to Regulation 10 and storage tanks located at bulk plants may also be subject to the requirements of Regulation 8, Rule 6 or Rule 33.

*(Amended 9/4/85; 5/4/88; 1/20/93; 10/18/06)*

**8-5-110 Exemptions:** This rule does not apply to emissions from the following sources:

110.1 Storage tanks having a capacity of less than 1.0 $m^3$ (264 gal).

110.2 Any storage tank installed prior to January 4, 1967, which is not used for storage of gasoline to be dispensed to internal combustion engine fuel tanks, and is either of a capacity of less than 7.6 $m^3$ (2,008 gal), or an underground tank with an offset fill line.

110.3 Any above ground gasoline tank of 7.6 $m^3$ (2,008 gal) or less capacity installed and in service prior to January 9, 1976, and equipped with a submerged fill pipe.

*(Amended 5/4/88; 1/20/93; 11/27/02, 10/18/06)*

**8-5-111 Limited Exemption, Tank Removal From and Return to Service:** The requirements of Sections 8-5-304, 305, 306 and 307 shall not apply to storage tanks during or after tank decommissioning, and shall not apply during temporary removal from service provided that the operator complies with the following requirements:

111.1 The operator shall notify the APCO. This notification shall identify the specific requirement for which an exemption is necessary and explain how the planned or performed activities necessarily prevent compliance with those requirements. The notification requirement may be satisfied in one of the following ways:

1.1 Three days prior to such work being done, written notification is received by the APCO; or

1.2 Telephone notification is made to the APCO prior to such work being done, and written notice is received by the APCO within three days after such work has been done.

111.2 The tank is in compliance with all applicable requirements of this rule at the time the notification in Section 8-5-111.1 is made.

111.3 When the floating roof is resting on the leg supports, the process of filling, emptying, and refilling shall be continuous and shall be accomplished as rapidly as possible.

111.4 Vapor recovery shall be used on tanks so equipped during filling and emptying procedures.

111.5 Emissions shall be minimized during the period of exemption. If the tank interior is to be opened to the atmosphere through an access hatch or manway, as much product as possible shall be drained from the tank, and degassing equipment and an associated abatement device shall be connected and operated, as required by Section 8-5-328, as soon as possible.

111.6 Effective January 1, 2007, if the tank operator discovers that the tank is not in compliance with all applicable requirements of this rule during the exemption period, telephone notification shall be made to the APCO within 24 hours of discovery and a written report that describes the non-compliance and any corrective actions taken shall be submitted within 60 days of discovery. This telephone notification and report are not required for tanks that are subject to deviation reporting requirements in a Major Facility Permit

issued pursuant to Regulation 2, Rule 6. Notification and reporting are not otherwise required when returning a tank to service.

*(Amended 1/20/93; 12/15/99; 11/27/02; 10/18/06)*

**8-5-112 Limited Exemption, Preventative Maintenance and Inspection of Tanks in Operation:** The requirements of Sections 8-5-304, 305, 306, 307.2, 307.3 and 328 shall not apply to storage tanks during preventative maintenance of a vapor control device, tank roof, roof fitting or tank seal; during primary seal inspection; or during removal and installation of a secondary seal provided that the operator complies with the following requirements:

112.1 The operator shall notify the APCO. This notification shall identify the affected tank and the specific requirement for which an exemption is necessary, shall explain how the planned or performed activities necessarily prevent compliance with those requirements, and shall describe the measures to be taken to minimize emissions. For secondary seal installations, the type of installed seal shall be specified. The notification requirement may be satisfied in one of the following ways:

1.1 Three days prior to such work being done, written notification is received by the APCO; or

1.2 Except for secondary seal replacements, which are subject to Section 8-5-112.1.1, telephone notification is made to the APCO prior to such work being done, and written notice is received by the APCO within three days after such work has been done.

112.2 The tank is in compliance with all applicable requirements of this rule at the time the notification in Section 8-5-112.1 is made.

112.3 Product shall be moved neither in nor out of the storage tank and emissions shall be minimized.

112.4 The time of exemption allowed under this section does not exceed 7 consecutive days.

112.5 Effective January 1, 2007, if the tank operator discovers that the tank is not in compliance with all applicable requirements of this rule during the exemption period, telephone notification shall be made to the APCO within 24 hours of discovery and a written report that describes the non-compliance and any corrective actions taken shall be submitted within 60 days of discovery. This telephone notification and report are not required for tanks that are subject to deviation reporting requirements in a Major Facility Permit issued pursuant to Regulation 2, Rule 6.

112.6 Effective June 1, 2007, the tank operator shall keep the following records for at least 24 months after each use of this exemption:

6.1 The affected tank and the date and duration of the exemption;

6.2 The preventative maintenance, inspection or other activity that was performed;

6.3 The specific standards of this rule for which an exemption was necessary; and

6.4 Actions taken to minimize emissions during the exemption period.

*(Adopted 9/4/85; Amended 5/4/88; 1/20/93; 12/15/99; 11/27/02; 10/18/06)*

**8-5-113 Deleted May 4, 1988**

**8-5-114 Deleted May 4, 1988**

**8-5-115 Deleted May 4, 1988**

**8-5-116 Exemption, Gasoline Storage Tanks at Gasoline Dispensing Facilities:** The provisions of this rule shall not apply to any gasoline storage tank located at a gasoline dispensing facility subject to the requirements of Regulation 8, Rule 7.

*(Adopted 1/20/93; Amended 10/18/06)*

**8-5-117 Limited Exemption, Low Vapor Pressure:** The provisions of this rule, except for Section 8-5-307.3, shall not apply to tanks storing organic liquids with a true vapor pressure of less than or equal to 25.8 mm Hg (0.5 psia) as determined by Sections 8-5-602 or 604.

*(Adopted 1/20/93; Amended 11/27/02; 10/18/06)*

**8-5-118 Limited Exemption, Gas Tight Requirement:** The gas tight requirement of Section 8-5-306.2 shall not apply to tanks at facilities that are subject to the requirements of Regulation 8, Rule 18.

*(Adopted October 18, 2006)*

**8-5-119 Limited Exemption, Repair Period:** A tank operator who has implemented an Enhanced Monitoring Program pursuant to Section 8-5-411 and who discovers equipment that fails to meet a requirement listed in Section 8-5-119.1 shall not be deemed in violation of that requirement, provided the operator complies with all of the conditions listed in Sections 8-5-119.2 and 119.3. The period of such an exemption shall not exceed the amount of time necessary to meet the requirement in accordance with Section 8-5-119.2.3. An operator shall not be entitled to this exemption for any violation discovered by the APCO during an APCO-initiated inspection.

119.1 The exemption is available only for the following requirements:

- 1.1 Section 8-5-303.1 (good operating condition requirement only), 303.2 (gas tight requirement only);
- 1.2 Sections 8-5-304.4, 304.5, 304.6, 305.5 and 305.6;
- 1.3 Section 8-5-306.2;
- 1.4 Sections 8-5-307.1 and 307.3;
- 1.5 Sections 8-5-320.3, 320.4.2, 320.4.3, 320.5.2 (gaps only), 320.5.3 and 320.6;
- 1.6 Sections 8-5-321.1, 321.3.1, 321.3.2, 321.3.3, and 321.4;
- 1.7 Sections 8-5-322.1, 322.2, 322.3, 322.4, and 322.5.

119.2 The following conditions shall be met for the exemption to be available:

- 2.1 The tank operator shall have implemented an Enhanced Monitoring Program in accordance with Section 8-5-411;
- 2.2 The tank operator shall minimize excess emissions resulting from the failure to meet the requirement as soon as possible, but no later than 8 hours after discovery;
- 2.3 The tank operator shall bring the tank into compliance with the requirement as soon as possible, but no later than 48 hours after discovery;
- 2.4 The tank operator shall not move material into or out of the tank until the tank is in compliance with all applicable requirements, except to the extent necessary to make repairs.

119.3 The tank operator shall submit a report within 60 days of any use of this exemption. The report shall include the following:

- 3.1 the affected tank and the date and duration of the exemption;
- 3.2 the repair or other activity that was performed;
- 3.3 the specific requirements of this rule for which an exemption was necessary; and
- 3.4 actions taken to minimize emissions during the exemption period.

*(Adopted October 18, 2006)*

## 8-5-200 DEFINITIONS

**8-5-201 Deleted October 18, 2006**

**8-5-202 Storage Tank:** Any container, reservoir, or tank used for the storage of organic liquids, excluding tanks that are permanently affixed to mobile vehicles such as railroad tank cars, tanker trucks or ocean vessels.

*(Adopted 9/4/85; Amended 11/27/02; 10/18/06)*

**8-5-203 Deleted November 27, 2002**

**8-5-204 Organic Liquid:** Any organic compound that exists as a liquid at actual conditions of use or storage.

*(Adopted 9/4/85; Amended 1/20/93)*

**8-5-205 Gasoline:** Petroleum distillates used as motor fuel with a Reid vapor pressure greater than 4.0 psia.

*(Adopted 9/4/85; Amended 5/4/88)*

**8-5-206 Gas Tight:** A concentration of organic compounds of less than 100 ppm (expressed as methane) above background, for any point or item, except for pressure relief devices; and less than 500 ppm (expressed as methane) above background, for pressure relief devices only.

*(Adopted 5/4/88; Amended 1/20/93; 11/27/02; 10/18/06)*

**8-5-207** **Approved Emission Control System:** A system for reducing emissions to the atmosphere that consists of a collection system and an abatement device, which is approved in writing by the APCO and achieves the overall abatement efficiency specified in the applicable standards section.

*(Adopted 1/20/93; Amended 11/27/02)*

**8-5-208** **Degassing:** The process of removing organic gases from a tank.

*(Adopted January 20, 1993)*

**8-5-209** **External Floating Roof Tank:** An open top tank with a storage vessel cover consisting of a double deck or pontoon single deck that rests upon and is supported by the liquid being contained.

*(Adopted 1/20/93; Amended 10/18/06)*

**8-5-210** **Internal Floating Roof Tank:** A tank with a floating cover or roof that rests upon or is floated upon the liquid being contained, and that also has a fixed roof on top of the tank shell to shield the floating roof from wind, rain and other elements. An external floating roof tank that has been retrofitted with a geodesic dome or other fixed roof shall be considered to be an internal floating roof tank for the purposes of this rule.

*(Adopted 1/20/93; Amended 11/27/02; 10/18/06)*

**8-5-211** **True Vapor Pressure:** The vapor pressure of a liquid at storage temperature.

*(Adopted 1/20/93; Amended 11/27/02)*

**8-5-212** **Organic Compound:** Any compound of carbon, excluding methane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates and ammonium carbonate.

*(Adopted January 20, 1993)*

**8-5-213** **Viewport:** An accessible opening in the fixed roof of an internal floating roof tank that measures at least 0.75 meters (30 inches) on each side or at least 0.75 meters (30 inches) in diameter.

*(Adopted January 20, 1993)*

**8-5-214** **Gauge Float**: A device to indicate the level of liquid within a tank. The float rests on the liquid surface inside a well in the tank.

*(Adopted December 15, 1999)*

**8-5-215** **Guidepole:** An anti-rotation device that is fixed to the top and bottom of a tank, passing through a well in a floating roof. Guidepoles may be solid or be equipped with slots or holes for gauging purposes.

*(Adopted December 15, 1999)*

**8-5-216** **Zero Gap Pole Wiper Seal:** A seal with no gap exceeding 0.06 inches between the guidepole or gauge well and pole wiper seal.

*(Adopted December 15, 1999)*

**8-5-217** **Decommissioning:** The removal of all organic liquid and gases from a storage tank with the intent of no longer using the tank for storage of organic liquids or gases.

*(Adopted November 27, 2002)*

**8-5-218** **Stock Change:** The removal of organic liquids from a tank prior to refilling the tank with a different organic liquid.

*(Adopted November 27, 2002)*

**8-5-219** **Tank Cleaning:** The process of washing or rinsing the interior of a storage tank, or removing sludge, or rinsing liquid from a storage tank.

*(Adopted November 27, 2002)*

**8-5-220** **Temporary Removal From Service:** The removal of organic liquid from a storage tank for tank cleaning, stock change, tank repair, roof repair, or removal of contaminated stock, followed by return to service.

*(Adopted November 27, 2002)*

**8-5-221** **Liquid Balancing:** The process of reducing the vapor pressure of the contents of a tank by adding lower-vapor pressure liquid without breaking tank vacuum, and, for floating roof tanks, without landing the floating roof on its supports.

*(Adopted November 27, 2002)*

**8-5-222** **Pressure Relief Device:** Any device that is used to relieve either positive or negative pressure upstream of the device, or both.

*(Adopted October 18, 2006)*

**8-5-223** **Pressure Vacuum Valve:** A type of pressure relief device that is used to control breathing losses from a fixed-roof tank by allowing slight positive or negative pressure variations in a tank while preventing the movement of gas into or out of the tank.

*(Adopted October 18, 2006)*

**8-5-224** **Connection:** Flanged, screwed, or other joined fittings used to connect any piping or equipment.

*(Adopted October 18, 2006)*

**8-5-225** **Good Operating Condition:** A tank component or related equipment is in good operating condition when it operates as designed without visible breaks, cracks or other defects that result in organic emissions.

*(Adopted October 18, 2006)*

**8-5-226** **Emission Minimization:** Emission minimization required in Sections 8-5-119.2.2 means reducing excess emissions caused by violation of a rule standard to the lowest achievable level using best modern practices while maintaining the associated tank in service.

*(Adopted October 18, 2006)*

## 8-5-300 STANDARDS

**8-5-301** **Storage Tanks Control Requirements:** A person shall not store organic liquid in any storage tank unless such tank is equipped with a vapor loss control device that is specified by the table below for the tank capacity, or for a higher capacity, and for the true vapor pressure of the tank organic liquid contents, or for a higher true vapor pressure.

| Tank Capacity | True Vapor Pressure of Tank Organic Contents | | |
|---|---|---|---|
| | >0.5 to ≤1.5 psia | >1.5 to <11 psia | ≥ 11 psia |
| ≥1.0 $m^3$ to ≤37.5 $m^3$ (≥264 gallons to ≤9,906 gallons) | Submerged fill pipe | Submerged fill pipe (underground tank or aboveground non-gasoline tank), pressure vacuum valve, internal or external floating roof | Pressure tank or approved emission control system |
| >37.5 $m^3$ to <75 $m^3$ (>9,906 gallons to <19,803 gallons) | Submerged fill pipe | Submerged fill pipe (underground tank), pressure vacuum valve, internal or external floating roof | Pressure tank or approved emission control system |
| ≥75 $m^3$ to <150 $m^3$ (≥19,803 gallons to <39,626 gallons) | Submerged fill pipe | Internal or external floating roof | Pressure tank or approved emission control system |
| ≥150 $m^3$ (≥39,626 gallons) | Internal or external floating roof | Internal or external floating roof | Pressure tank or approved emission control system |

*(Amended, Renumbered 9/4/85; Amended 5/4/88; 1/20/93; 12/15/99; Amended, Renumbered 11/27/02; Amended 10/18/06)*

**8-5-302** **Requirements for Submerged Fill Pipes:** A submerged fill pipe required by Section 8-5-301 must meet either of the following requirements:

302.1 Where the tank is filled from the top, the end of the discharge pipe or nozzle must be totally submerged when the liquid level is 15 cm (6 in.) from the bottom of the tank.

302.2 Where the tank is filled from the side, the discharge pipe or nozzle must be totally submerged when the liquid level is 46 cm (18 in.) from the bottom of the tank.

*(Adopted 9/4/85; Amended, Renumbered 11/27/02; Amended 10/18/06)*

**8-5-303** **Requirements for Pressure Vacuum Valves:** A pressure vacuum valve required by Section 8-5-301 must meet the following requirements:

303.1 The pressure vacuum valve must be set to either at least 90% of the tank's maximum allowable working pressure, or at least 25.8 mm Hg (0.5 psig), and the valve must be in good operating condition.

303.2 The pressure vacuum valve sealing mechanism must remain in a gas tight condition except when operating pressure exceeds the valve set pressure, or except when the sealing mechanism is vented to a vapor recovery or disposal system that has an overall abatement efficiency of at least 95% by weight.

*(Amended 9/4/85; 5/4/88; 1/20/93; Amended, Renumbered, 11/27/02; Amended 10/18/06)*

**8-5-304 Requirements for External Floating Roof Tanks:** An external floating roof required by Section 8-5-301 must meet the following requirements:

304.1 The floating roof fittings must meet the requirements of Section 8-5-320.

304.2 The floating roof must be equipped with a primary seal that meets the requirements of Section 8-5-321.

304.3 The floating roof must be equipped with a secondary seal that meets the requirements of Section 8-5-322.

304.4 The floating roof must rest on the surface of the liquid tank contents and must be in good operating condition. There shall be no liquid tank contents on top of either the primary or secondary seal, or on top of the floating roof (this requirement does not apply to liquid that clings to the inside tank walls as the tank is drained, or to liquid that drips from the tank walls onto the seals).

304.5 The tank shell must be in good operating condition with no liquid leakage through the shell.

304.6 An external floating roof tank shall not be operated with organic liquid tank contents in any tank pontoon unless the following conditions are met:

6.1 Within 48 hours of discovery of organic liquid in a pontoon, all lids or other openings on the affected pontoon shall be sealed and maintained in a gas tight condition; and

6.2 The next time the tank is removed from service, repairs shall be made on all pontoon leaks on that tank.

*(Amended, Renumbered 9/4/85; Amended 5/4/88; 1/20/93; Amended, Renumbered 11/27/02; Amended 10/18/06)*

**8-5-305 Requirements for Internal Floating Roof Tanks:** An internal floating roof required by Section 8-5-301 must meet the following requirements:

305.1 For a tank with seals installed on or before February 1, 1993, the tank must be equipped with one of the following:

1.1 A liquid mounted primary seal, mounted in full contact with the liquid in the annular space between the tank shell and floating roof,

1.2 A metallic shoe primary seal, or

1.3 A vapor mounted primary and a secondary seal

If sections of seal with a total length equal to or greater than the diameter of the tank are replaced at one time, or if sections of seal with a total cumulative length equal to or greater than 50% of the total seal circumference are replaced over time, then the seal shall be considered to be newly installed and subject to Section 8-5-305.2.

305.2 For a tank with seals installed after February 1, 1993, the tank must be equipped with a liquid mounted or metallic shoe primary seal that meets the requirements of Section 8-5-321 and a secondary seal that meets the requirements of Section 8-5-322.

305.3 Internal floating roof tanks that are placed into service or de-gassed after February 1, 1993 shall be equipped with at least 3 viewports in the fixed roof of the tank. This requirement shall not apply to external floating roof tanks retrofitted with domes or other fixed roofs after February 1, 1993, as long as the dome consists of translucent panels through which sufficient light passes to allow inspection of the floating roof seal.

305.4 The floating roof fittings must meet the requirements of Section 8-5-320.

305.5 The floating roof must rest on the surface of the liquid tank contents and must be in good operating condition. There shall be no liquid tank contents on top of either the primary or secondary seal, or on top of the floating roof (this requirement does not apply to liquid that clings to the inside tank walls as the tank is drained, or to liquid that drips from the tank walls onto the seals).

305.6 The tank shell must be in good operating condition with no liquid leakage through the shell.

*(Amended, Renumbered 9/4/85; Amended 5/4/88; 1/20/93; Amended, Renumbered 11/27/02; Amended 10/18/06)*

**8-5-306 Requirements for Approved Emission Control Systems:** An Approved Emission Control System required by Section 8-5-301 must meet the following requirements:

306.1 It must provide an abatement efficiency of at least 95% by weight, based on a comparison of controlled emissions to those emissions which would occur from a fixed or cone roof tank in the same product service without an approved emission control system, expressed as a percentage. Baseline emissions shall be calculated using the criteria in API Bulletin 2518

306.2 It must be gas tight.

*(Amended 1/20/93; Amended, Renumbered 11/27/02; Amended 10/18/06)*

**8-5-307 Requirements for Fixed Roof Tanks, Pressure Tanks and Blanketed Tanks:**

307.1 Fixed roof tank shells and pressure tank shells must be in good operating condition with no liquid leakage through the shell.

307.2 A pressure tank must maintain working pressures sufficient at all times to prevent organic vapor or gas loss to the atmosphere.

307.3 The sealing mechanism on pressure relief devices located on pressure tanks and on tanks blanketed with organic gases other than natural gas shall be maintained in a gas tight condition except when operating pressure exceeds the valve set pressure, or except when the sealing mechanism is vented to a vapor recovery or disposal system that has an overall abatement efficiency of at least 95% by weight.

*(Adopted 9/4/85; Amended 5/4/88; 1/20/93; Amended, Renumbered 11/27/02; Amended 11/18/06)*

**8-5-310 Deleted May 4, 1988**

**8-5-311 Deleted November 27, 2002**

**8-5-312 Deleted January 20, 1993**

**8-5-313 Deleted January 20, 1993**

**8-5-314 Deleted January 20, 1993**

**8-5-320 Floating Roof Tank Fitting Requirements:** The fittings on any floating roof storage tank subject to Section 8-5-304 or 305 shall meet the following conditions:

320.1 Deleted November 27, 2002.

320.2 All openings through the floating roof, except pressure relief devices, shall provide a projection below the liquid surface to prevent belching of liquid and reduce escaping organic vapors.

320.3 All openings through the floating roof, except floating roof legs, shall be equipped with a gasketed cover, seal or lid, which shall meet either of the following requirements, as applicable, except as provided in Sections 8-5-320.4, 320.5 or 320.6.

3.1 The gasketed cover, seal or lid shall have no measurable gap exceeding 0.32 cm (1/8 in.), except when the opening is in use.

3.2 For inaccessible openings on internal floating roof tanks, there shall be no visible gaps as viewed from the fixed roof manway or viewports, except when the opening is in use.

320.4 Solid sampling or gauging wells, and similar fixed projections through a floating roof such as an anti-rotational pipe, shall meet the following conditions:

4.1 The well shall provide a projection below the liquid surface.

4.2 The well shall be equipped with a cover, seal or lid, which shall at all times be in a closed position with no gap exceeding 0.32 cm (1/8 in.), except when the well is in use.

4.3 The gap between the well and the roof shall be added to the gaps measured to determine compliance of the secondary seal and in no case shall exceed 1.3 cm (1/2 in.).

320.5 Slotted sampling or gauging wells, and similar fixed projections through a floating roof such as an anti-rotational pipe, shall meet the following conditions:

5.1 The well shall provide a projection below the liquid surface.

5.2 The well on an external floating roof shall be equipped with the following: a sliding cover, a cover gasket, a pole sleeve, pole wiper and an internal float and float wiper designed to minimize the gap between the float and the well, provided that the gap shall in no case exceed 1.3 cm (1/2 in.), or shall be equipped with a well gasket, a zero gap pole wiper seal and a pole sleeve that projects below the liquid surface.

5.3 The gap between the well and the roof shall be added to the gaps measured to determine compliance of the secondary seal and in no case shall exceed 1.3 cm (1/2 in.).

320.6 Any emergency roof drain shall be provided with a slotted membrane fabric cover, or equivalent, that covers at least 90% of the area of the opening.

*(Amended 9/4/85; 5/4/88; 1/20/93; 12/15/99; 11/27/02; 10/18/06)*

**8-5-321 Primary Seal Requirements:** A person shall not operate a storage tank equipped with a primary seal subject to the requirements of Section 8-5-304 or 305 unless such tank meets the following conditions:

321.1 There shall be no holes, tears, or other openings in the primary seal fabric that allow the emission of organic vapors.

321.2 The seal shall be either a metallic shoe or a liquid mounted type, except as provided in Section 8-5-305.1.3.

321.3 Metallic-shoe-type seals shall be installed so that one end of the shoe extends into the stored liquid and the other end extends a minimum vertical distance of 61 cm (24 in.) for external floating roofs and 18 inches for internal floating roofs above the stored liquid surface. Measurements of the gap between tank shell and seals shall be made around the full circumference of the tank, and measured gaps shall meet the following requirements:

3.1 The geometry of the shoe shall be such that the maximum gap between the shoe and the tank shell is no greater than double the gap allowed by the seal gap criteria for a length of at least 46 cm (18 in.) in the vertical plane above the liquid surface.

3.2 For welded tanks, no gap between the tank shell and the primary seal shall exceed 3.8 cm (1-1/2 in.). No continuous gap greater than 0.32 cm (1/8 in.) shall exceed 10% of the circumference of the tank. The cumulative length of all primary seal gaps exceeding 1.3 cm (1/2 in.) shall be not more than 10% of the circumference, and the cumulative length of all primary seal gaps exceeding 0.32 cm (1/8 in.) shall be not more than 40% of the circumference.

3.3 For riveted tanks, no gap between the tank shell and the primary seal shall exceed 6.4 cm (2-1/2 in.). The cumulative length of all primary seal gaps exceeding 3.8 cm (1-1/2 in.) shall be not more than 10% of the circumference.

321.4 For resilient-toroid-seal equipped tanks, no gap between the tank shell and the primary seal shall exceed 1.3 cm (1/2 in.). The cumulative length of all gaps exceeding 0.32 cm (1/8 in.) shall be not more than 5% of the circumference. Measurements of the gap shall be made around the full circumference of the tank.

*(Amended 1/20/93; 12/15/99; 11/27/02; 10/18/06)*

**8-5-322 Secondary Seal Requirements:** A person shall not operate a storage tank equipped with a secondary seal subject to the requirements of Sections 8-5-304 or 305, unless such tank meets the following requirements. In determining compliance with seal gap requirements, measurements of the gap between tank shell and seals shall be made around the full circumference of the tank.

322.1 There shall be no holes, tears, or other openings in the secondary seal fabric that allow the emission of organic vapors.

322.2 The secondary seal shall allow easy insertion of probes up to 3.8 cm (1-1/2 in.) in width in order to measure gaps in the primary seal.

322.3 No gap between the tank shell and the secondary seal shall exceed 1.3 cm (1/2 in.). The cumulative length of all secondary seal gaps exceeding 0.32 cm (1/8 in.) shall be not more than 5% of the circumference of the tank.

322.4 For riveted tanks, the secondary seal shall consist of at least two sealing surfaces, such that the sealing surfaces prevent the emission of organic compounds around the rivets. Serrated sealing surfaces are allowable if the length of serration does not exceed 15.2 cm (6 in.).

322.5 For welded external floating roof tanks with seals installed after September 4, 1985 or welded internal floating roof tanks with seals installed after February 1, 1993, no gap between the tank shell and the secondary seal shall exceed 1.5 mm (0.06 in.). The cumulative length of all secondary seal gaps exceeding 0.5 mm (0.02 in.) shall be not more than 5% of the circumference of the tank excluding gaps less than 5 cm (1.79 in.) from vertical weld seams. If sections of seal with a total length equal to or greater than the diameter of the tank are replaced at one time, or if sections of seal with a total cumulative length equal to or greater than 50% of the total seal circumference are replaced over time, then the seal shall be considered to be newly installed for the purpose of this section.

322.6 The secondary seal shall extend from the roof to the tank shell and shall not be attached to the primary seal.

*(Amended 1/20/93; 11/27/02; 10/18/06)*

**8-5-323 Deleted January 20, 1993**

**8-5-324 Deleted January 20, 1993**

**8-5-325 Deleted January 20, 1993**

**8-5-326 Deleted May 4, 1988**

**8-5-327 Deleted May 4, 1988**

**8-5-328 Tank Degassing Requirements:** A tank operator shall not open the interior vapor space of a tank subject to this rule to the atmosphere through a hatch or manway, except to connect or disconnect degassing equipment or to conduct tank contents or emissions sampling, unless such tank meets the following conditions:

328.1 For tanks larger than 75 $m^3$, the emissions of organic compounds resulting from degassing shall be controlled by an abatement device that collects and processes all organic vapors and gases and has an abatement efficiency of at least 90% by weight. The system shall be operated until the concentration of organic compounds in the tank is less than 10,000 ppm expressed as methane. In order to satisfy this requirement, effective June 1, 2007, the residual organic concentration must be measured to be less than 10,000 ppm as methane for at least four consecutive measurements performed at intervals no shorter than 15 minutes each.

328.2 For all tanks subject to this rule, tank degassing shall not commence after the District predicts an excess of the Federal or State Ambient Air Quality Standard for ozone for the following day, unless emissions resulting from degassing are controlled as required by Section 8-5-328.1.

328.3 Effective June 1, 2007, the tank operator shall provide written notification that is received by the APCO at least 3 days before the start of a degassing operation that is subject to this rule. However, where degassing must be performed on an emergency basis, telephone notification shall be made to the APCO within 8 hours of commencing degassing. This notification shall identify the tanks to be degassed, including their location and the liquid stored in the tanks, the nature of the emergency, and the time and date degassing will commence.

*(Adopted 1/20/93; Amended 11/27/02; 10/18/06)*

**8-5-329 Deleted November 27, 2002**

**8-5-330 Deleted November 27, 2002**

**8-5-331 Tank Cleaning Requirements:** Effective June 1, 2007, tank interior cleaning agents must meet the following requirements, unless all organic vapors and gases emitted during tank cleaning are collected and processed at an abatement device that has an abatement efficiency of at least 90% by weight.

331.1 Agents used to clean tank interiors shall have an initial boiling point greater than 302 degrees F, a true vapor pressure less than 0.5 psia, or a VOC content less than 50 grams per liter.

331.2 Except as allowed in Section 8-5-331.3, steam shall not be used to clean tank interiors at facilities that operate wastewater treatment facilities.

331.3 Steam may be used to remove scale or film from tank interior surfaces only after routine tank cleaning, including sludge removal, has been completed.

*(Adopted October 18, 2006)*

**8-5-332 Sludge Handling Requirements:** Effective June 1, 2007, the operator of a tank shall place sludge removed from that tank directly into a sludge container that meets the following requirements. This section applies to sludge removed from any tank that was subject to the requirements of this rule at any time since it was last put into service.

332.1 The sludge container shall allow no liquid leakage.

332.2 The sludge container shall have no measurable gap exceeding 1.3 cm (1/2 in.) except when the container is being loaded or unloaded, and except during sludge sampling or treatment.

*(Adopted October 18, 2006)*

## 8-5-400 ADMINISTRATIVE REQUIREMENTS

**8-5-401 Inspection Requirements for External Floating Roof Tanks:** Tanks subject to the requirements of Section 8-5-304 shall be inspected by the operator as follows:

401.1 The entire circumference of each primary and secondary seal shall be inspected for compliance with the requirements of Sections 8-5-321 and 8-5-322 twice per calendar year at 4 to 8 month intervals, and 4 times per calendar year at 2 to 4 month intervals for tanks subject to enhanced monitoring pursuant to Section 8-5-411. If a new primary or secondary seal is installed, or if a primary or secondary seal is repaired, both seals shall be inspected at the time of the seal installation or repair. Flexible wiper seals shall be inspected when the outer edge of the seal is curved upward.

401.2 Tank fittings shall be inspected for compliance with the requirements of Section 8-5-320 twice per calendar year at 4 to 8 month intervals, and 4 times per calendar year at 2 to 4 month intervals for tanks subject to enhanced monitoring pursuant to Section 8-5-411.

*(Amended 1/20/93; Amended, Renumbered 11/27/02; Amended 10/18/06)*

**8-5-402 Inspection Requirements for Internal Floating Roof Tanks:** Tanks subject to the requirements of Section 8-5-305 shall be inspected by the operator as follows:

402.1 The entire circumference of each primary and secondary seal shall be inspected for compliance with the requirements of Sections 8-5-321 and 8-5-322. The time between inspections shall not exceed 10 years. If a new primary or secondary seal is installed, or if a primary or secondary seal is repaired, both seals shall be inspected at the time of the seal installation or repair. Flexible wiper seals shall be inspected when the outer edge of the seal is curved upward.

402.2 The entire circumference of the outermost seal (secondary seal where so equipped, or primary seal where no secondary seal is required) shall be visually inspected for compliance with the requirements of Sections 8-5-305.1, 8-5-305.2, 8-5-305.3, 8-5-321.1 and 8-5-322.1 twice per calendar year at 4 to 8 month intervals, and 4 times per calendar year at 2 to 4 month intervals for tanks subject to enhanced monitoring pursuant to Section 8-5-411. Flexible wiper seals shall be inspected when the outer edge of the seal is curved upward.

402.3 Tank fittings shall be inspected for compliance with the requirements of Section 8-5-320 twice per calendar year at 4 to 8 month intervals, and 4 times per calendar year at 2 to 4 month intervals for tanks subject to enhanced monitoring pursuant to Section 8-5-411. Standards involving gap measurements shall be checked whenever the tank roof is accessible, but need not be checked more frequently than twice per calendar year, or 4 times per calendar year for tanks subject to enhanced monitoring pursuant to Section 8-5-411.

*(Amended 1/20/93; Amended, Renumbered 11/27/02; Amended 10/18/06)*

**8-5-403** **Inspection Requirements for Pressure Relief Devices:** Pressure relief devices, including pressure vacuum valves, shall be inspected by the tank operator for compliance with the following requirements twice per calendar year at 4 to 8 month intervals, and 4 times per calendar year at 2 to 4 month intervals for tanks subject to enhanced monitoring pursuant to Section 8-5-411:

403.1 Pressure vacuum valves: gas tight standards in Section 8-5-303.

403.2 Effective June 1, 2007, for all pressure relief devices except pressure vacuum valves: gas tight standard in Section 8-5-307.3.

*(Adopted 11/27/02; Amended 10/18/06)*

**8-5-404** **Inspection, Abatement Efficiency Determination and Source Test Reports:** Within 60 days of any inspection, abatement efficiency determination or source test required by this rule, a report shall be submitted to the APCO that certifies compliance with each individual requirement associated with the inspection, abatement efficiency determination or source test, and that includes data, supported by necessary calculations, to support this certification.

*(Amended, Renumbered 9/4/85; Amended 5/4/88; 1/20/93; 11/27/02; 10/18/06)*

**8-5-405** **Deleted October 18, 2006**

**8-5-410** **Deleted May 4, 1988**

**8-5-411** **Enhanced Monitoring Program**: The operator of a tank that is subject to this rule may implement an Enhanced Monitoring Program by complying with all of the following:

411.1 The tank operator shall submit to the APCO a list of all tanks at a facility that are subject to this rule, and the capacity of each tank. At least 25% of these tanks, but no less than 1 tank at each facility, shall be selected by the operator for enhanced monitoring. The selected tanks shall constitute at least 20% of the total tank capacity at the facility that is subject to this rule. Only external floating roof tanks may be selected for enhanced monitoring unless there are not enough to constitute 25% of the total number of tanks. In this case, other tank types may be selected as necessary to constitute the required number. All tanks selected for enhanced monitoring must be subject to Section 8-5-401, 402 or 403.

411.2 An Enhanced Monitoring Program shall go into effect at a facility after the APCO determines that the criteria in Section 411.1 are satisfied. The specific tanks selected by the operator for enhanced monitoring may be changed at any time by the operator upon written notification to the APCO provided that the criteria in Section 8-5-411.1 continue to be satisfied. An Enhanced Monitoring Program may be discontinued at any time by the operator upon written notification to the APCO.

411.3 The operator shall perform enhanced monitoring as specified in Sections 8-5-401, 402 and 403.

*(Adopted October 18, 2006)*

**8-5-412** **Monitoring of Leaking Pontoons**: The operator of a floating roof tank on which a leaking pontoon has been discovered shall inspect the lids and other openings on any leaking pontoon for compliance with the requirements of Section 8-5-304.6.1 once per calendar quarter beginning the quarter after the leaking pontoon is discovered until a repair of the leak is completed.

*(Adopted October 18, 2006)*

**8-5-500** **MONITORING AND RECORDS**

**8-5-501** **Records:**

501.1 A person who operates a tank subject to this rule shall keep an accurate record of the type and amount of liquids stored, type of blanket gases used, and the true vapor pressure ranges of such liquids and gases. These records shall be kept for at least 24 months.

501.2 For internal and external floating roof tanks, a tank operator who replaces all or part of a primary or secondary seal shall keep an accurate record of the length of seal replaced and the date(s) on which replacement occurred. These records shall be kept for at least 10 years.

501.3 Unless otherwise specified, the tank operator shall retain all records required by this rule, and shall retain copies of any report, notification or other submittal required by this rule for at least 24 months.

501.4 The tank operator shall keep engineering data sheets showing setpoints for pressure vacuum valves installed after June 1, 2007.

*(Amended 1/20/93; 11/27/02; 10/18/06)*

**8-5-502 Source Test Requirements:** Any tank operator who uses an Approved Emission Control System or other abatement device to comply with the requirements of this rule shall perform a source test as specified in this section. Source testing, including prior notification of the District, shall be performed in accordance with the Manual of Procedures, Volume IV. This section does not apply to any device that collects all emissions and vents them to a fuel gas collection system for combustion, or to any device that is subject to periodic source testing in accordance with a District permit to operate.

502.1 A tank operator using an Approved Emission Control System or other abatement device to comply with the requirements of Sections 8-5-303.2, 306.1 or 307.3 shall perform a source test on the system verifying operation at the required abatement efficiency at least once in any calendar year in which the system is used to comply with this rule.

502.2 A tank operator using an abatement device to comply with the requirements of Sections 8-5-328.1 or 331 shall:

2.1 Demonstrate that a source test on the system verifying operation at the required abatement efficiency was completed within the 12 months prior to the operator's commencement of use and shall maintain a complete copy of the source test report; or

2.2 Perform such a source test during the operation in question.

*(Adopted 1/20/93; Amended 11/27/02; 10/18/06)*

**8-5-503 Deleted October 18, 2006**

**8-5-600 MANUAL OF PROCEDURES**

**8-5-601 Analysis of Samples, Reid Vapor Pressure**: Samples of organic compounds as specified in this rule shall be analyzed for Reid vapor pressure as prescribed in the Manual of Procedures, Volume III, Lab Method 13.

*(Amended 9/4/85; 5/4/88; 10/18/06)*

**8-5-602 Analysis of Samples, True Vapor Pressure:** Samples of organic compounds not listed in Table I shall be analyzed for true vapor pressure at the tank storage temperature as prescribed in the Manual of Procedures, Volume III, Lab Method 28.

*(Adopted 9/4/85; Amended 5/4/88; 10/18/06)*

**8-5-603 Determination of Abatement Efficiency:** Abatement efficiency of an Approved Emission Control System or other abatement device as specified in Section 8-5-502 shall be determined as prescribed in the Manual of Procedures, Volume IV, ST-7. For Approved Emission Control Systems subject to Section 8-5-306.1 only, baseline emissions shall be determined as specified in Section 8-5-306.1.

*(Renumbered 9/4/85; Amended 1/20/93; 11/27/02; 10/18/06)*

**8-5-604 Determination of Applicability Based on True Vapor Pressure**: Table I shall be used to determine if a storage tank is subject to the requirements of this rule. For organic compounds not listed in Table I, refer to Sections 8-5-601 or 602.

*(Adopted 9/4/85; Amended 5/4/88; 1/20/93; 10/18/06)*

**8-5-605 Deleted October 18, 2006**

**8-5-605 Measurement of Leak Concentrations and Residual Concentrations:** Determination of organic compound concentrations shall be conducted as follows:

605.1 Any instrument used for the measurement of organic compound concentration shall be a combustible gas indicator that meets the specifications and performance criteria of and has been calibrated in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A).

605.2 Measurements of organic compound concentration, except as otherwise specified, shall be conducted in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A). Measurements of residual organic concentration required by Section 8-5-328.1 shall be measured with the instrument probe

inlet placed at least 12 inches above the bottom of the tank and above the surface of any sludge material on the bottom of the tank, and at least 12 inches inside the tank measured from the inner surface of the tank wall.

*(Adopted 1/20/93; Amended 11/27/02; 10/18/06)*

**8-5-606 Analysis of Samples, Tank Cleaning Agents**

606.1 Initial boiling point shall be determined in accordance with ASTM D-1078-93, or by an alternate method approved in writing by the APCO and U.S. EPA.

606.2 True vapor pressure shall be determined in accordance with the Manual of Procedures, Volume III, Method 28, or by an alternate method approved in writing by the APCO and U.S. EPA.

606.3 VOC content shall be determined in accordance with the Manual of Procedures, Volume III, Method 31, or by an alternate method approved in writing by the APCO and U.S. EPA.

*(Adopted October 18, 2006)*

## TABLE I*

## STORAGE TEMPERATURE VERSUS TRUE VAPOR PRESSURE (TVP)

| | Density (lb/gal) | Reference Gravity API | IBP °F | Max. Temp. °F Not to Exceed 0.5 Psia TVP | Max. Temp. °F Not to Exceed 1.5 Psia TVP |
|---|---|---|---|---|---|
| **Crude Oils:*** | - | - | - | - | - |
| San Joaquin Valley | - | - | 390 | 249 | - |
| **Middle Distillates:** | | | | | |
| Kerosene | - | 42.5 | 350 | 195 | 250 |
| Diesel | - | 36.4 | 372 | 230 | 290 |
| Gas Oil | - | 26.2 | 390 | 249 | 310 |
| Stove Oil | - | 23 | 421 | 275 | 340 |
| **Jet Fuels:** | | | | | |
| JP-1 | - | 43.1 | 330 | 165 | 230 |
| JP-3 | - | 54.7 | 110 | - | 25 |
| JP-4 | - | 51.5 | 150 | 20 | 68 |
| JP-5 | - | 39.6 | 355 | 205 | 260 |
| JP-7 | - | 44-50 | 360 | 205 | 260 |
| **Fuel Oil:** | | | | | |
| No. 1 | - | 42.5 | 350 | 195 | 250 |
| No. 2 | - | 36.4 | 372 | 230 | 290 |
| No. 3 | - | 26.2 | 390 | 249 | 310 |
| No. 4 | - | 23 | 421 | 275 | 340 |
| No. 5 | - | 19.9 | 560 | 380 | 465 |
| No. 6 | - | 16.2 | 625 | 450 | - |
| **Asphalts:** | | | | | |
| 60-100 pen. | - | - | - | 490 | 550 |
| 120-150 pen. | - | - | - | 450 | 500 |
| 200-300 pen. | - | - | - | 360 | 420 |
| **Organic Compounds:** | | | | | |
| Acetone | 6.6 | 47 | 133 | - | 35 |
| Acrylonitrile | 6.8 | 41.8 | 173 | 30 | 62 |
| Benzene | 7.4 | 27.7 | 176 | 34 | 70 |
| Carbon Disulfide | 10.6 | 22.1 | 116 | - | 10 |
| Carbon Tetrachloride | 13.4 | - | 170 | 20 | 63 |
| Chloroform | 12.5 | - | 142 | - | 40 |
| Cyclohexane | 6.5 | 49.7 | 177 | 30 | 65 |
| 1,2 Dichloroethane | 10.5 | - | 180 | 35 | 75 |
| Ethyl Acetate | 7.5 | 23.6 | 171 | 38 | 70 |
| Ethyl Alcohol | 6.6 | 47.0 | 173 | 55 | 85 |
| Isopropyl Alcohol | 6.6 | 47.0 | 181 | 62 | 95 |
| Methyl Alcohol | 6.6 | 47.0 | 148 | 30 | 62 |
| Methyl Ethyl Ketone | 6.7 | 44.3 | 175 | 30 | 70 |
| Toluene | 7.3 | 30 | 231 | 75 | 120 |
| Vinylacetate | 7.8 | 19.6 | 163 | 30 | 65 |

* True vapor pressure for crude oils should be determined from the specific crude slate.

# REGULATION 8
# ORGANIC COMPOUNDS
# RULE 8
# WASTEWATER COLLECTION AND SEPARATION SYSTEMS

## INDEX


**8-8-100 GENERAL**

8-8-101 Description
8-8-110 Exemption, Less Than 760 Liters
8-8-111 Deleted November 1, 1989
8-8-112 Exemption, Wastewater Critical Organic Compound Concentration Or Temperature
8-8-113 Exemption, Secondary Wastewater Treatment Processes and Stormwater Sewer Systems
8-8-114 Exemption, Bypassed Oil-Water Separator or Air Flotation Influent
8-8-115 Exemption, Municipal Wastewater Collection, Separation and Treatment Facilities
8-8-116 Limited Exemption, Oil-Water Separation Trenches

**8-8-200 DEFINITIONS**

8-8-201 Organic Compounds
8-8-202 Wastewater (Oil-Water) Separator
8-8-203 Wastewater Separator Forebay
8-8-204 Vapor-tight
8-8-205 Oil-Water Separator Slop Oil
8-8-206 Oil-Water Separator Effluent Channel/Pond
8-8-207 Full Contact Fixed Cover
8-8-208 Secondary Treatment Processes
8-8-209 Air Flotation Unit
8-8-210 Critical Organic Compound
8-8-211 Wastewater
8-8-212 Pre-Air Flotation Unit Flocculation Sump, Basin, Chamber, or Tank
8-8-213 Oil-Water Separator Slop Oil Vessel
8-8-214 Oil-Water Separator Effluent
8-8-215 Sludge-dewatering Unit
8-8-216 Stormwater Sewer System
8-8-217 Junction Box
8-8-218 Sewer Line
8-8-219 Leak Minimization
8-8-220 Leak Repair
8-8-221 Lift Stations
8-8-222 Manholes
8-8-223 Oil-Water Separation Trench
8-8-224 Petroleum Refinery
8-8-225 Process Drains
8-8-226 Reaches
8-8-227 Sumps
8-8-228 Trenches
8-8-229 Vent pipe
8-8-230 Wastewater Collection System Components
8-8-231 Wastewater Separation System
8-8-232 Water Seal or Equivalent Control

**8-8-300 STANDARDS**

8-8-301 Wastewater Separators Designed Rated Capacity Greater Than 760 Liters per Day and Smaller Than 18.9 Liters per Second
8-8-302 Wastewater Separators Rated Capacity Larger Than or Equal to 18.9 Liters per Seconds
8-8-303 Gauging and Sampling Devices
8-8-304 Sludge-dewatering Unit
8-8-305 Oil-Water Separator And/Or Air Flotation Unit Slop Oil Vessels
8-8-306 Oil-Water Separator Effluent Channel, Pond, Trench, or Basin
8-8-307 Air Flotation Unit
8-8-308 Junction Box
8-8-309 Deleted October 6, 1993
8-8-310 Deleted October 6, 1993
8-8-311 Deleted October 6, 1993
8-8-312 Controlled Wastewater Collection System Components at Petroleum Refineries
8-8-313 Uncontrolled Wastewater Collection System Components at Petroleum Refineries
8-8-314 New Wastewater Collection System Components at Petroleum Refineries

**8-8-400 ADMINISTRATIVE REQUIREMENTS**

8-8-401 Deleted (October 6, 1993)
8-8-402 Wastewater Inspection and Maintenance Plan at Petroleum Refineries
8-8-403 Petroleum Refinery Compliance Schedule
8-8-404 Uncontrolled Wastewater Collection System Components Election

**8-8-500 MONITORING AND RECORDS**

8-8-501 API Separator or Air Flotation Bypassed Wastewater Records
8-8-502 Wastewater Critical Organic Compound Concentration Or Temperature Records
8-8-503 Inspection and Repair Records
8-8-504 Portable Hydrocarbon Detector
8-8-505 Records for Wastewater Collection System Components at Petroleum Refineries

**8-8-600 MANUAL OF PROCEDURES**

8-8-601 Wastewater Analysis for Critical Organic Compounds
8-8-602 Determination of Emissions
8-8-603 Inspection Procedures

# REGULATION 8
# ORGANIC COMPOUNDS
# RULE 8
# WASTEWATER COLLECTION AND SEPARATION SYSTEMS

(Adopted January 17, 1979)

## 8-8-100 GENERAL

**8-8-101** **Description**: The purpose of this Rule is to limit the emissions of organic compounds from wastewater collection and separation systems that handle liquid organic compounds from industrial processes.

(Amended 11/1/89; 9/15/04)

**8-8-110** **Exemption, Less Than 760 Liters:** The requirements of Section 8-8-301 shall not apply to any wastewater separator which processes less than 760 liters (200 gals.) per day of wastewater containing organic liquids. This exemption shall not apply to wastewater separators at petroleum refinery complexes after March 1, 1980.

**8-8-111** **Deleted November 1, 1989**

**8-8-112** **Exemption, Wastewater Critical Organic Compound Concentration Or Temperature:** The requirements of Sections 8-8-301, 302, 306, 307, and 308 shall not apply to any wastewater separation system that processes influent wastewater with a temperature of less than 20 degrees C (68 °F) except at petroleum refineries. Wastewater having a concentration of less than 1.0 ppm (volume) critical organic compounds, as defined in Section 8-8-210, dissolved in the water samples, is exempt from the requirements of Sections 8-8-301, 302, 306, 307, 308, 312 and 313. The requirements of Section 8-8-502 must be met.

(Adopted 11/1/89; Amended 9/15/04)

**8-8-113** **Exemption, Secondary Wastewater Treatment Processes And Stormwater Sewer Systems:** The requirements of Sections 8-8-301, 302, 306, and 308 shall not apply to any secondary wastewater treatment processes or stormwater sewer systems, as defined in Sections 8-8-208 and 216, that are used as a wastewater polishing step or for collection of stormwater that is segregated from the process wastewater collection system.

(Adopted 11/1/89; Amended 9/15/04)

**8-8-114** **Exemption, Bypassed Oil-Water Separator or Air Flotation Influent:** The requirements of Sections 8-8-301, 302, and 307 shall not apply for wastewater which bypasses either the oil-water separator or air flotation unit provided that: (1) the requirements of Section 8-8-501 are met; and (2) on that day the District did not predict an excess of the Federal Ambient Air Quality Standard for ozone.

(Adopted November 1, 1989)

**8-8-115** **Exemption, Municipal Wastewater Collection, Separation and Treatment Facilities:** The requirements of Sections 8-8-301, 302, 303, 304, 305, 306, 307, 308, 312, 313 and 314 shall not apply to any publicly owned municipal wastewater treatment facility.

(Adopted 11/1/89; Amended 9/15/04)

**8-8-116** **Limited Exemption, Oil-Water Separation Trenches:** The requirements of Sections 8-8-312, 313 or 314 shall not apply to oil-water separation trenches used as part of maintenance or turnaround activities.

(Adopted September 15, 2004)

## 8-8-200 DEFINITIONS

**8-8-201** **Organic Compound:** Any compound of carbon, excluding methane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate.

(Amended 11/1/89; 9/15/04)

**8-8-202** **Wastewater (Oil-Water) Separator:** Any device used to separate liquid organic compounds from oil-water waste streams (excluding wastewater separator forebays, air flotation (AF) units, sludge-dewatering units, oil-water separator and /or AF Unit slop oil vessels, and junction boxes).

(Amended November 1, 1989)

**8-8-203** **Wastewater Separator Forebay:** That section of a gravity-type separator which (a) receives the untreated, contaminated wastewater from the preseparator flume, and (b) acts as a header which distributes the influent to the separator channels.

(Amended November 1, 1989)

**8-8-204** **Vapor-tight:** A leak of less than 500 ppm (expressed as methane) above background, measured at the interface of the component in accordance with Section 8-8-603.

(Amended 11/1/89; 9/15/04)

**8-8-205** **Oil-Water Separator Slop Oil:** Floating oil, flocculant sludge, and solids which accumulate in an oil-water separator or air flotation unit.

(Adopted November 1, 1989)

**8-8-206** **Oil-Water Separator Effluent Channel/Pond:** An open channel, trench, pond, or basin which handles wastewater downstream of an oil-water separator that has not been treated by an air flotation unit (usually located between the separator and the air flotation unit).

(Adopted November 1, 1989)

**8-8-207** **Full Contact Fixed Cover:** A stationary separator cover which is always in full contact with the liquid surface of the oil-water separator.

(Adopted November 1, 1989)

**8-8-208** **Secondary Treatment Processes:** Any wastewater treatment process which is downstream of the air flotation unit, any other biological treatment process at a refinery, or any treatment process which is regulated by the EPA National Categorical Pretreatment Standards. These treatment processes are considered to be wastewater polishing steps and include: activated sludge tanks/basins, trickling or sand filters, aerated lagoons, oxidation ponds, rotating biological contactors, and other biological wastewater treatment processes.

(Adopted November 1, 1989)

**8-8-209** **Air Flotation Unit:** Any device, equipment, or apparatus in which wastewater is saturated with air or gas under pressure and removes floating oil, floating emulsified oil, or other floating liquid precursor organic compounds by skimming. Also included in this definition are: induced air flotation units and pre-air flotation unit flocculant sumps, tanks, or basins.

(Adopted November 1, 1989)

**8-8-210** **Critical Organic Compound:** Any compound of carbon, excluding methane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates and ammonium carbonate emitted during separation, processing, transportation or storage of wastewater, and having a carbon number of C-14 or less (excluding phenolic compounds).

(Adopted 11/1/89; Amended 9/15/04)

**8-8-211** **Wastewater:** Any process water which contains oil, emulsified oil, or other organic compounds which is not recycled or otherwise used within a facility.

(Adopted November 1, 1989)

**8-8-212** **Pre-Air Flotation Unit Flocculation Sump, Basin, Chamber, or Tank:** Any facility which pretreats the air flotation unit's influent with chemical coagulants, and/or adjusts the influent's pH.

(Adopted November 1, 1989)

**8-8-213** **Oil-Water Separator Slop Oil Vessel:** Any vessel which, as its sole function, treats or dewaters oil-water separator slop oil.

(Adopted November 1, 1989)

**8-8-214** **Oil-Water Separator Effluent:** Any process wastewater downstream of the oil-water separator that has not been treated by an air flotation unit.

(Adopted November 1, 1989)

**8-8-215** **Sludge-dewatering Unit:** Any device which, as its sole function, is used to dewater oil-water separator and air flotation slop oil/sludge.

(Adopted November 1, 1989)

**8-8-216** **Stormwater Sewer System:** A drain and collection system that is designed and operated for the sole purpose of collecting stormwater and is segregated from the wastewater collection system.

(Adopted 11/1/89; Amended 9/15/04)

**8-8-217** **Junction Box:** Any structure where sewer lines meet and one or more wastewater streams are co-mingled.

(Amended September 15, 2004)

**8-8-218** **Sewer Line:** A lateral, trunk line, branch line, ditch, channel, or other conduit used to convey wastewater to downstream oil-water separators.
(Adopted November 1, 1989)

**8-8-219** **Leak Minimization:** Reducing the leak to the lowest achievable level using best modern practices and without shutting down the process the equipment serves.
(Adopted September 15, 2004)

**8-8-220** **Leak Repair:** The tightening, adjustment, or addition of material, or the replacement of the equipment, which reduces leakage to the atmosphere below 500 ppm.
(Adopted September 15, 2004)

**8-8-221** **Lift Stations:** Any structure whose function is to take water from a low point on a gradient and transport it to the treatment system via a pumping mechanism.
(Adopted September 15, 2004)

**8-8-222** **Manholes:** Any service entrance into sewer lines that allows access for inspection and cleaning.
(Adopted September 15, 2004)

**8-8-223** **Oil-Water Separation Trench:** Any grated open topped culvert used to separate debris from oil-water during equipment washing or steaming associated with maintenance or turnaround.
(Adopted September 15, 2004)

**8-8-224** **Petroleum Refinery:** A facility that processes petroleum, as defined in the North American Industrial Classification Standard No. 32411 (1997).
(Adopted September 15, 2004)

**8-8-225** **Process Drains:** Any point in the wastewater collection system where streams from a source or sources enter the collection system. A process drain may be connected to the main process sewer line or to trenches, sumps, or ditches.
(Adopted September 15, 2004)

**8-8-226** **Reaches:** Any segments of sewer pipe that convey wastewater between two manholes or other sewer components such as lift stations or junction boxes.
(Adopted September 15, 2004)

**8-8-227** **Sumps:** Any below-grade structure typically used as a collection point for wastewater from multiple sewer lines prior to pumping or overflow to wastewater treatment.
(Adopted September 15, 2004)

**8-8-228** **Trenches:** Any open-topped culvert used to transport wastewater from the point of process discharge to subsequent wastewater collection system components, such as junction boxes and lift stations.
(Adopted September 15, 2004)

**8-8-229** **Vent Pipes:** Any piping used to ventilate a wastewater collection system component or a wastewater separation system.
(Adopted September 15, 2004)

**8-8-230** **Wastewater Collection System Components:** Any structure or part of structures used to collect and transport wastewater prior to any treatment. These structures are usually located before oil/water separators and may include but are not limited to process drains, sewer lines, trenches, manholes, junction boxes, reaches, sumps and lift stations (including vent pipes).
(Adopted September 15, 2004)

**8-8-231** **Wastewater Separation System:** Any structure used to remove oil from water via a physical process including but not limited to oil-water separators, dissolved air flotation units or dissolved gas flotation units.
(Adopted September 15, 2004)

**8-8-232** **Water Seal or Equivalent Control:** Any seal pot, p-leg trap, or other type of trap filled with a liquid not containing organic compounds in order to create a barrier between the sewer and the atmosphere, or an equivalent physical seal, enclosed piping, pollution prevention measure or abatement device that meets the criteria of Regulation 2, Rule 1.
(Adopted September 15, 2004)

**8-8-300** **STANDARDS**

**8-8-301** **Wastewater Separators Greater than 760 Liters per Day and Smaller than 18.9 Liters per Second:** A person shall not operate any wastewater separator and/or forebay with a design rated or maximum allowable capacity greater than 760 liters

per day and smaller than 18.9 liters per second (oil-water separators and/or forebays between 200 gals per day to 300 gals per min.) unless such wastewater separator and/or forebay is operated within its design rated or maximum allowable capacity and is equipped with one of the following:

301.1 A solid, gasketed, fixed cover totally enclosing the separator tank, chamber, or basin (compartment) liquid contents, with all cover openings closed, except when the opening is being used for inspection, maintenance, or wastewater sampling. Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps greater than 0.32 cm (0.125 inch) occur in the roof or between the roof and wall; and that the access doors and other openings are closed and gasketed properly; or

301.2 A floating pontoon or double-deck vapor-tight type cover. All floating roofs must rest entirely on the liquid surface. The floating roof shall consist of two seals, one above the other, the one below shall be referred to as the primary seal, while the other seal shall be referred to as the secondary seal.

2.1 Oil-Water Separator Liquid-Mounted Primary Seal Gap Criteria: No gap between the separator wall and the liquid-mounted primary seal shall exceed 3.8 cm (1.5 inch). No continuous gap greater than 0.32 cm (0.125 inch) shall exceed 10 percent of the perimeter of the separator. The cumulative length of all primary seal gaps exceeding 1.3 cm (0.5 inch) shall be not more than 10 percent of the perimeter and the cumulative length of all primary seal gaps exceeding 0.32 cm (0.125 inch) shall be not more than 40 percent of the perimeter.

2.2 Oil-Water Separator Secondary And Wiper Seals Gap Criteria: No gap between the separator wall and the secondary and wiper seals shall exceed 1.5 mm (0.06 inch). The cumulative length of all secondary and wiper seals gaps exceeding 0.5 mm (0.02 inch) shall be not more than 5 percent of the perimeter of the separator. The secondary and wiper seals must exert a positive pressure against the separator such that the seal surface in contact with the separator wall does not pull away from the separator wall more than the gaps allowed.

2.3 Primary And Secondary Seal Gap Inspection: The primary seal shall be inspected within 60 calendar days after initial installation of the floating roof and once every 5 years thereafter in accordance with the requirements of Section 8-8-301.2.1. The secondary seal shall be inspected within 60 calendar days after initial installation of the floating roof and once every year thereafter in accordance with the requirements of Section 8-8-301.2.2. The owner or operator shall make necessary repairs within 30 calendar days of identification of seals not meeting the requirements listed in Sections 8-8-301.2.1 and 301.2.2; or

301.3 An organic compound vapor recovery system with a combined collection and destruction efficiency of at least 95 percent, by weight.

301.4 Deleted October 6, 1993

(Amended 11/1/89; 10/6/93; 9/15/04)

**8-8-302 Wastewater Separators Larger than or Equal to 18.9 Liters per Second:** A person shall not operate any wastewater separator and/or forebay with a rated or maximum allowable capacity larger than or equal to 18.9 liters per second (300 gals per min.) unless such wastewater separator and/or forebay is operated within its design rated or maximum allowable capacity and is equipped with one of the following:

302.1 A solid, vapor-tight, full contact fixed cover which totally encloses the separator tank, chamber, or basin (compartment) liquid contents, with all cover openings closed and sealed, except when the opening is being used for inspection, maintenance, or wastewater sampling; or

302.2 A floating pontoon or double-deck vapor-tight type cover. All floating roofs must rest on the liquid surface. The floating roof shall consist of two seals,

one above the other, the one below shall be referred to as the primary seal, while the other seal shall be referred to as the secondary seal.

2.1 Oil-Water Separator Liquid-Mounted Primary Seal Gap Criteria: No gap between the separator wall and the liquid-mounted primary seal shall exceed 3.8 cm (1.5 inch). No continuous gap greater than 0.32 cm (0.125 inch) shall exceed 10 percent of the perimeter of the separator. The cumulative length of all primary seal gaps exceeding 1.3 cm (0.5 inch) shall be not more than 10 percent of the perimeter and the cumulative length of all primary seal gaps exceeding 0.32 cm (0.125 inch) shall be not more than 40 percent of the perimeter.

2.2 Oil-Water Separator Secondary And Wiper Seals Gap Criteria: No gap between the separator wall and the secondary and wiper seals shall exceed 1.5 mm (0.06 inch). The cumulative length of all secondary and wiper seals gaps exceeding 0.5 mm (0.02 inch) shall be not more than 5 percent of the perimeter of the separator. The secondary and wiper seals must exert a positive pressure against the separator such that the seal surface in contact with the separator wall does not pull away from the separator wall more than the gaps allowed; or

2.3 Primary And Secondary Seal Gap Inspection: The primary seal shall be inspected within 60 calendar days after initial installation of the floating roof and once every 5 years thereafter in accordance with the requirements of Section 8-8-302.2.1. The secondary seal shall be inspected within 60 calendar days after initial installation of the floating roof and once every year thereafter in accordance with the requirements of Section 8-8-302.2.2. The owner or operator shall make necessary repairs within 30 calendar days of identification of seals not meeting the requirements listed in Sections 8-8-302.2.1 and 302.2.2.; or

302.3 A vapor-tight fixed cover with an organic compound vapor recovery system which has a combined collection and destruction efficiency of at least 95 percent, by weight, inspection and access hatches shall be closed except when the opening is being used for inspection, maintenance, or wastewater sampling, or

302.4 A solid, sealed, gasketed, fixed cover which totally encloses the separator tank, chamber, or basin (compartment) liquid contents, with all cover openings closed and sealed, except when the opening is being used for inspection, maintenance, or wastewater sampling. The cover may include a pressure/vacuum valve. The concentration of organic compounds, measured at the interface of the roof seals, fixed cover, access doors, pressure/vacuum valve, and other openings shall not exceed 1,000 ppm (expressed as methane) above background. Roof seals, fixed cover, access doors, and other openings shall be inspected initially and semiannually thereafter to ensure that there are no emission leaks greater than 1,000 ppm. Any emission leak greater than 1,000 ppm must be reported to the APCO and repaired within 15 days.

302.5 Deleted October 6, 1993

302.6 Roof seals, fixed covers, access doors, and other openings at petroleum refineries shall be inspected initially and semiannually thereafter to ensure that they are vapor tight. A leak in any component that is not vapor tight must be minimized within 24 hours and repaired within 7 days.

(Adopted 1/1/89; Amended 10/6/93; 9/15/04)

**8-8-303 Gauging and Sampling Devices:** Any compartment or access hatch shall have a vapor tight cover. Any gauging and sampling device in the compartment cover shall be equipped with a vapor tight cover, seal, or lid. The compartment cover and gauging or sampling device cover shall at all times be in a closed position, except when the device is in use for inspection, maintenance, or wastewater sampling.

(Amended, Renumbered November 1, 1989)

**8-8-304** **Sludge-dewatering Unit**: Any sludge-dewatering unit, equipment, machinery, apparatus, or device shall be totally enclosed and vented to a control device which has a minimum combined collection and destruction efficiency of 95 percent by weight; or shall have vapor-tight covers on the unit, conveyer belts, and storage bins or tanks except during inspection, maintenance or when the solids storage bin is in use. Sludge must be maintained in vapor tight containers during storage.

(Adopted 11/1/89; Amended 10/6/93; 9/15/04)

**8-8-305** **Oil-Water Separator And/Or Air Flotation Unit Slop Oil Vessels:** A person shall not store any oil-water separator and/or air flotation unit sludges in an oil-water separator slop oil vessel unless such oil-water separator slop oil vessel is equipped with one of the following:

305.1 A solid, gasketed, fixed cover totally enclosing the vessel liquid contents, with all cover openings closed, except when the opening is being used for inspection, maintenance, or wastewater sampling. The cover may include an atmospheric vent or a pressure/vacuum valve. Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps greater than 0.32 cm (0.125 inch) occur in the roof or between the roof and wall; and that the access doors and other openings are closed and gasketed properly; or

305.2 An organic compound vapor recovery system with a combined collection and destruction efficiency of at least 70 percent, by weight.

305.3 Deleted October 6, 1993

(Adopted 11/1/89; Amended 10/6/93; 9/15/04)

**8-8-306** **Oil-Water Separator Effluent Channel, Pond, Trench, or Basin:** A person shall not operate any oil-water separator effluent channel, pond, trench, or basin a design rated or maximum allowable capacity greater than 25.2 liters per second (any oil-water separator effluent channel, pond, trench, or basin greater than 400 gals per min) unless such oil-water separator effluent channel, pond, trench, or basin is operated within its design rated or maximum allowable capacity and is equipped with one of the following:

306.1 A solid, gasketed, fixed cover totally enclosing the oil-water separator effluent channel, pond, trench, or basin (compartment) liquid contents, with all cover openings closed, except when the opening is being used for inspection, maintenance, or wastewater sampling. Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps greater than 0.32 cm (0.125 inch) occur in the roof or between the roof and wall; and that the access doors and other openings are closed and gasketed properly; or

306.2 An organic compound vapor recovery system with a combined collection and destruction efficiency of at least 70 percent, by weight.

306.3 Deleted October 6, 1993

(Adopted 11/1/89; Amended 10/6/93; 9/15/04)

**8-8-307** **Air Flotation Unit:** A person shall not operate any air flotation unit and/or pre-air flotation unit flocculation sump, basin, chamber, or tank with a design rated or maximum allowable capacity greater than 25.2 liters per second (air flotation units and/or pre-air flotation unit flocculation sump, basin, chamber, or tank greater than 400 gals per min.) unless such air flotation unit and/or pre-air flotation unit flocculation sump, basin, chamber, or tank is operated within its design rated or maximum allowable capacity and is equipped with one of the following:

307.1 A solid, gasketed, fixed cover totally enclosing the air flotation and pre-air-flotation-unit flocculation tank, chamber, or basin (compartment) liquid contents, with all cover openings closed, except when the opening is being used for inspection, maintenance, or wastewater sampling. The cover may include an atmospheric vent or pressure/vacuum valve. Roof seals, access doors, and other openings shall be checked by visual inspection initially and semiannually thereafter to ensure that no cracks or gaps greater than 0.32 cm (0.125 inch) occur in the roof or between the roof and wall; and that the access doors and other openings are closed and gasketed properly; or

307.2 An organic compound vapor recovery system with a combined collection and destruction efficiency of at least 70 percent, by weight.

307.3 Deleted October 6, 1993

(Adopted 11/1/89; Amended 10/6/93; 9/15/04)

**8-8-308 Junction Box:** Any junction box shall be equipped with either a solid, gasketed, fixed cover totally enclosing the junction box or a solid manhole cover. Junction boxes may include openings in the covers and vent pipes if the total open area of the junction box does not exceed 81.3 $cm^2$ (12.6 $in^2$) and all vent pipes are at least 3 feet in length.

(Adopted 11/1/89; Amended10/6/93)

**8-8-309 Deleted October 6, 1993**

**8-8-310 Deleted October 6, 1993**

**8-8-311 Deleted October 6, 1993**

**8-8-312 Controlled Wastewater Collection System Components at Petroleum Refineries:** Effective January 1, 2006, all controlled wastewater collection system components at petroleum refineries shall be vapor tight except when in use for active inspection, maintenance, repair or sampling. A leak in any controlled wastewater collection system component that is not vapor tight must be minimized within 24 hours and repaired within 7 days.

(Adopted September 15, 2004)

**8-8-313 Uncontrolled Wastewater Collection System Components at Petroleum Refineries:** Petroleum refineries shall comply with either Section 8-8-313.1 or 313.2 below:

313.1 Each uncontrolled wastewater collection system component must be equipped with a water seal or equivalent control according to the schedule in Section 8-8-403. Any uncontrolled collection system component that is not vapor tight must be minimized. Upon installation of a water seal or equivalent control, the provisions of Section 8-8-312 will apply; **or**

313.2 Effective January 1, 2006 and until January 1, 2007, each uncontrolled wastewater collection system component must be inspected bi-monthly. Effective January 1, 2007, each uncontrolled wastewater system component must be inspected semi-annually. Any uncontrolled wastewater collection system component that is not vapor tight shall be identified, minimized within 24 hours and re-inspected every 30 days. The component may be returned to a semi-annual inspection schedule if it is vapor tight during three consecutive 30-day inspections. Any uncontrolled wastewater collection system component that is not vapor tight during any three inspections in a five-year period must be equipped with a water seal or equivalent control within 30 days after the third inspection. Upon installation of the water seal or equivalent control, the provisions of Section 8-8-312 shall apply. Unless previously identified by the refinery, any wastewater system component discovered by the APCO not to be vapor tight must be minimized within 24 hours and repaired within 7 days.

(Adopted September 15, 2004)

**8-8-314 New Wastewater Collection System Components at Petroleum Refineries:** Effective January 1, 2005, any new wastewater collection system component at a petroleum refinery shall be equipped with a water seal or equivalent control.

(Adopted September 15, 2004)

## 8-8-400 ADMINISTRATIVE REQUIREMENTS

**8-8-401 Deleted October 6, 1993**

**8-8-402 Wastewater Inspection and Maintenance Plan at Petroleum Refineries:** All petroleum refineries must implement an inspection and maintenance plan that meets all of the following requirements:

402.1 By October 1, 2005, all wastewater collection system components must be identified and the APCO must be provided with lists, diagrams or other information sufficient to locate all components. It shall not be violation of this requirement if the refinery discovers that a component has been omitted from the list, diagram, or other information and submits information to the APCO

regarding the component. Effective October 1, 2005, any wastewater collection system component found by the APCO that was not identified pursuant to the provisions of this section shall constitute a violation.

402.2 By October 1, 2005, an initial inspection of all wastewater collection system components must be completed by the refinery. The results of the initial inspection shall be made available to the APCO, but any wastewater collection system component that is not vapor tight shall not trigger the requirements of Section 8-8-313 before the effective date of that Section.

402.3 Effective January 1, 2006, for petroleum refineries that elect to comply with Section 8-8-313.2, the plan must provide for the identification and minimization of leaking components and a re-inspection within 30 days of discovery. The plan must also provide for re-inspections every thirty days until the affected component is either controlled or is returned to the inspection schedule in Section 8-8-313.2.

402.4 Effective January 1, 2006, each controlled component shall be inspected semi-annually.

402.5 Records must be maintained pursuant to Section 8-8-505.

(Adopted September 15, 2004)

**8-8-403 Petroleum Refinery Compliance Schedule:** Any petroleum refinery electing to comply with Section 8-8-313.1 shall install controls on uncontrolled wastewater collection system components according to the following schedule:

403.1 By October 31, 2005, install controls on 25% of wastewater collection system components that were uncontrolled as of January 1, 2005.

403.2 By April 30, 2006, install controls on 50% of wastewater collection system components that were uncontrolled as of January 1, 2005.

403.3 By October 31, 2006, install controls on 75% of wastewater collection system components that were uncontrolled as of January 1, 2005.

403.4 By April 30, 2007, install controls on 100% of wastewater collection system components that were uncontrolled as of January 1, 2005.

(Adopted September 15, 2004)

**8-8-404 Uncontrolled Wastewater Collection System Components Election:** By November 1, 2004, each petroleum refinery shall choose a compliance option from Section 8-8-313 and notify the APCO in writing indicating which option has been chosen.

(Adopted September 15, 2004)

## 8-8-500 MONITORING AND RECORDS

**8-8-501 API Separator or Air Flotation Bypassed Wastewater Records:** Any person who bypasses wastewater past their API Separator or Air Flotation unit shall maintain records on the amount of bypassed wastewater, duration, date, causes for bypasses, and dissolved critical organic compound concentration (volume). These records shall be retained and available for inspection by the APCO for at least 24 months.

(Adopted 11/1/89; Amended 9/15/04)

**8-8-502 Wastewater Critical Organic Compound Concentration Or Temperature Records:** Any person who exempts their wastewater separator because of either wastewater critical organic compound concentration or temperature shall sample and test the wastewater initially and semiannually thereafter and maintain records on the date, time of test, location, and wastewater temperature and/or critical organic compound concentration (volume). These records shall be retained and available for inspection by the APCO for at least 24 months.

(Adopted 11/1/89; Amended 9/15/04)

**8-8-503 Inspection and Repair Records:** Records of inspections and repairs as required by Sections 8-8-301, 302, 305, 306 or 307 shall be retained and made available for inspection by the APCO for at least 24 months.

(Adopted October 6, 1993)

**8-8-504 Portable Hydrocarbon Detector:** Any instrument used for the measurement of organic compounds shall be a gas detector that meets the specifications and performance criteria of and has been calibrated in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A).

(Adopted June 15, 1994)

**8-8-505** **Records for Wastewater Collection System Components at Petroleum Refineries:** Any person subject to the requirements of this rule shall:

505.1 Maintain records of the type and location of each wastewater collection system component.

505.2 Record the date of each wastewater collection system component inspection, and re-inspection and leak concentration measured for each inspection or re-inspection.

505.3 Record a description of the minimization or repair efforts on each leaking component that is not vapor tight.

505.4 Maintain required records for at least 5 years and make them available to the APCO for inspection at any time.

(Adopted September 15, 2004)

**8-8-600** **MANUAL OF PROCEDURES**

**8-8-601** **Wastewater Analysis for Critical Organic Compounds:** Samples of wastewater as specified in this rule shall be taken at the influent stream for each unit and analyzed for the concentration of dissolved critical organic compounds as prescribed in the Manual of Procedures, Volume III, Lab Method 33.

(Amended 11/1/89; 10/6/93; 9/15/04)

**8-8-602** **Determination of Emissions:** Emissions of organic compounds as specified in Sections 8-8-301.3, 8-8-302.3, 8-8-304, 8-8-305.2, 8-8-306.2, and 8-8-307.2 shall be measured as prescribed by any of the following methods: 1) BAAQMD Manual of Procedures, Volume IV, ST-7, 2) EPA Method 25, or 25A). A source shall be considered in violation if the organic compound emissions measured by any of the referenced test methods exceed the standards of this rule.

(Amended 11/1/89; 10/6/93; 6/15/94; 9/15/04)

**8-8-603** **Inspection Procedures:** For the purposes of Sections 8-8-301, 302, 303, 304 312, 313 and 402, leaks shall be measured using a portable gas detector as prescribed in EPA Reference Method 21 (40 CFR 60, Appendix A).

(Adopted 6/15/94; Amended 9/15/04)

# REGULATION 8
# ORGANIC COMPOUNDS
# RULE 18
# EQUIPMENT LEAKS

## INDEX


**8-18-100 GENERAL**

8-18-101 Description
8-18-110 Exemption, Controlled Seal Systems and Pressure Relief Devices
8-18-111 Exemption, Small Facilities
8-18-112 Limited Exemption, Bulk Plant and Terminal Loading Racks
8-18-113 Limited Exemption, Initial Boiling Point
8-18-114 Limited Exemption, Research and Development
8-18-115 Limited Exemption, Storage Tanks
8-18-116 Limited Exemption, Vacuum Service
8-18-117 Limited Exemption, Visual Inspections
8-18-118 Deleted January 7, 1998
8-18-119 Limited Exemption, Open-Ended Valve or Line
8-18-120 Limited Exemption, Non-repairable Equipment

**8-18-200 DEFINITIONS**

8-18-201 Background
8-18-202 Bulk Plants and Terminals
8-18-203 Chemical Plant
8-18-204 Connection
8-18-205 Equipment
8-18-206 Inaccessible Equipment
8-18-207 Inspection
8-18-208 Leak
8-18-209 Leak Minimization
8-18-210 Leak Repair
8-18-211 Liquid Leak
8-18-212 Organic Compound
8-18-213 Petroleum Refinery
8-18-214 Pressure Relief Device
8-18-215 Process Unit
8-18-216 Quarter
8-18-217 Reinspection
8-18-218 Rupture Disc
8-18-219 Total Organic Compounds
8-18-220 Turnaround
8-18-221 Valve
8-18-222 Weephole
8-18-223 Deleted January 7, 1998
8-18-224 Deleted January 7, 1998
8-18-225 Deleted December 16, 2015
8-18-226 Essential Equipment
8-18-227 Open-Ended Valve or Line
8-18-228 Double Block Bleed System

**8-18-300 STANDARDS**

8-18-301 General
8-18-302 Valves
8-18-303 Pumps and Compressors

8-18-304 Connections
8-18-305 Pressure Relief Devices
8-18-306 Non-repairable Equipment
8-18-307 Liquid Leak
8-18-308 Alternate Compliance
8-18-309 Open-Ended Line or Valve
8-18-310 Recurrent Leaks
8-18-311 Mass Emissions

**8-18-400 ADMINISTRATIVE REQUIREMENTS**

8-18-401 Inspection
8-18-402 Identification
8-18-403 Visual Inspection Schedule
8-18-404 Alternate Inspection Schedule
8-18-405 Alternate Emission Reduction Plan
8-18-406 Interim Compliance
8-18-407 Recurrent Leak Schedule

**8-18-500 MONITORING AND RECORDS**

8-18-501 Portable Hydrocarbon Detector
8-18-502 Records
8-18-503 Reports

**8-18-600 MANUAL OF PROCEDURES**

8-18-601 Analysis of Samples
8-18-602 Inspection Procedures
8-18-603 Determination of Control Efficiency
8-18-604 Determination of Mass Emissions

# REGULATION 8
# ORGANIC COMPOUNDS
# RULE 18
# EQUIPMENT LEAKS

(Adopted October 1, 1980)

**8-18-100 GENERAL**

**8-18-101 Description:** The purpose of this Rule is to limit emissions of total organic compounds from equipment leaks at petroleum refineries, chemical plants, bulk plants and bulk terminals including, but not limited to: valves, connectors, pumps, compressors, pressure relief devices, diaphragms, hatches, sight-glasses, fittings, sampling ports, meters, pipes, and vessels.

*(Amended 3/17/82; 3/4/92; 1/7/98; 1/21/04, 9/15/04, 12/16/15)*

**8-18-110 Exemption, Controlled Seal Systems and Pressure Relief Devices:** The provisions of this Rule shall not apply to seal systems and pressure relief devices vented to a vapor recovery or disposal system which reduces the emissions of organic compounds from the equipment by 95% or greater as determined according to Section 8-18-603.

*(Amended, Renumbered 1/7/98; Amended 1/21/04)*

**8-18-111 Exemption, Small Facilities:** The provisions of this rule shall not apply to facilities which have less than 100 valves or less than 10 pumps and compressors. Such facilities are subject to the requirements of Regulation 8, Rule 22.

*(Adopted 3/4/92; Amended, Renumbered 1/7/98)*

**8-18-112 Exemption, Bulk Plant and Terminal Loading Racks:** The provisions of this rule shall not apply to those connections at the interface between the loading rack and the vehicle being loaded.

*(Adopted 3/4/92; Amended, Renumbered 1/7/98)*

**8-18-113 Limited Exemption, Initial Boiling Point:** Until January 1, 2018, the provisions of Sections 8-18-400 shall not apply to equipment which handle organic liquids having an initial boiling point greater than 302°F.

*(Adopted 3/4/92; Amended, Renumbered 1/7/98, Amended 12/16/15)*

**8-18-114 Limited Exemption, Research and Development:** The provisions of Sections 8-18-401, 402 and 502 shall not apply to research and development plants which produce only non-commercial products solely for research and development purposes.

*(Adopted 3/4/92; Amended, Renumbered 1/7/98)*

**8-18-115 Limited Exemption, Storage Tanks:** The provisions of this rule shall not apply to appurtenances on storage tanks including pressure relief devices, which are subject to requirements contained in Regulation 8, Rule 5: Storage of Organic Liquids.

*(Adopted January 7, 1998)*

**8-18-116 Limited Exemption, Vacuum Service:** The provisions of Sections 8-18-400 and 502 shall not apply to equipment in vacuum service.

*(Amended January 7, 1998)*

**8-18-117 Limited Exemption, Visual Inspection:** The provisions of Section 8-18-403 shall not apply to days when a facility is not staffed.

*(Amended, Renumbered January 7, 1998)*

**8-18-118 Deleted January 7, 1998**

**8-18-119 Limited Exemption, Open-Ended Valve or Line:** The provisions of Section 8-18-309 shall not apply to the following:

119.1 Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset.

119.2 Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system.

*(Adopted December 16, 2015)*

**8-18-120 Limited Exemption, Non-repairable Equipment:** The provisions of Sections 8-18-306 and 311 shall not apply to equipment added to the non-repairable equipment list prior to December 16, 2015 except that:

120.1 The equipment must be counted toward the total number of pieces of equipment allowed by Section 8-18-306.2.

120.2 Any connection on the list must be counted as two valves toward the total number of non-repairable valves allowed by Section 8-18-306.2.

120.3 Any valve on the list with a leak that cannot be minimized below a concentration of 10,000 parts per million (ppm), expressed as methane, may not remain on the list for more than 45 days after leak discovery unless the mass emission rate has been measured in accordance with Section 8-18-604 and has been determined to be less than 15 pounds per day.

120.4 The equipment must be repaired or replaced within five years or at the next scheduled turnaround, whichever date comes first.

*(Adopted December 16, 2015)*

**8-18-200 DEFINITIONS**

**8-18-201 Background:** The ambient concentration of total organic compounds determined at least 3 meters (10 feet) upwind from the equipment to be inspected and not influenced by any specific emission point as indicated by a hydrocarbon analyzer specified by Section 8-18-501.

*(Amended March 4, 1992)*

**8-18-202 Bulk Plants and Terminals:** A distribution facility that is subject to Regulation 8, Rule 6, 33 or 39.

*(Amended, Renumbered 1/7/98, Amended 12/16/15)*

**8-18-203 Chemical Plant:** Any facility engaged in producing organic or inorganic chemicals and/or manufacturing products by chemical processes, including (1) any facility or operation that has 325 as the first three digits in the North American Industrial Classification Standard (NAICS) code, (2) any facility that manufactures industrial inorganic and organic chemicals; plastic and synthetic resins, synthetic rubber, synthetic and other manmade fibers; drugs; soap, detergents and cleaning preparations; perfumes, cosmetics, and other toilet preparations; paints, varnishes, lacquers, enamels, and allied products; agricultural chemicals; safflower and sunflower oil extracts; and (3) any facility engaged in re-refining.

*(Amended, Renumbered 1/7/98; Amended 1/21/04, 12/16/15)*

**8-18-204 Connection:** Flanged, screwed, or other joined fittings used to connect any piping or equipment, including any fitting connecting equipment to piping or other equipment, such as a valve bonnet flange or pump flange

*(Amended, Renumbered 1/7/98; Amended 1/21/04, 12/16/15)*

**8-18-205 Equipment:** All components including, but not limited to: valves, connections, pumps, compressors, pressure relief devices, diaphragms, hatches, fittings, sampling ports, pipes, plugs, gauges or sight-glasses.

*(Amended, Renumbered 1/7/89, Amended 12/16/15)*

**8-18-206 Inaccessible Equipment:** Any equipment located over 13 feet above the ground when access is required from the ground; or any equipment located over 6.5 feet away from a platform when access is required from a platform.

*(Amended, Renumbered January 7, 1998)*

**8-18-207 Inspection:** The determination of the concentration of total organic compounds leaking from equipment using EPA Reference Method 21 as required by Section 8-18-501.

*(Amended, Renumbered January 7, 1998)*

**8-18-208 Leak:** The concentration of total organic compounds above background, expressed as methane, as measured in accordance with Section 8-18-602.

*(Amended, Renumbered 1/7/98; 1/21/04, Amended 12/16/15)*

**8-18-209 Leak Minimization:** Reducing the leak to the lowest achievable level using best modern practices and without shutting down the process the equipment serves. Leak minimization is the most common method for repair. Leak minimization includes but is not limited to tightening of packing gland nuts, injecting lubricant into lubricated packing, tightening bonnet bolts, tightening flange bolts, or installing plugs or caps into open ended lines or valves. Cleaning, scrubbing, or washing equipment alone is not considered best modern practice.

*(Renumbered 3/17/82; Amended 3/4/92, 1/7/98, 12/16/15)*

**8-18-210** **Leak Repair:** The tightening, adjustment, addition of material, or the replacement of the equipment using best modern practices, which reduces the leakage to the atmosphere below the applicable standard in Section 8-18-300.

*(Renumbered 3/17/82; Amended 3/4/92; 1/7/98, 12/16/15)*

**8-18-211** **Liquid Leak:** Dripping of liquid at a rate of greater than 3 drops per minute and a concentration of total organic compounds greater than the applicable leak standard in Section 8-18-300.

*(Amended, Renumbered January 7, 1998)*

**8-18-212** **Organic Compound:** Any compound of carbon, excluding methane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates and ammonium carbonate.

*(Amended, Renumbered January 7, 1998)*

**8-18-213** **Petroleum Refinery:** Any facility that processes petroleum products as defined in North American Industrial Classification Standard Number 32411, Petroleum Refining.

*(Amended, Renumbered January 7, 1998)*

**8-18-214** **Pressure Relief Device:** The automatic pressure-relieving device actuated by the static pressure upstream of the device including, but not limited to, pressure relief valves and rupture disks.

*(Amended, Renumbered January 7, 1998)*

**8-18-215** **Process Unit:** A manufacturing process which is independent of other processes and is continuous when supplied with a constant feed or raw materials and has sufficient storage facilities for product.

*(Amended, Renumbered January 7, 1998)*

**8-18-216** **Quarter:** One of the four consecutive 3-month divisions of the calendar year beginning on January 1.

*(Amended, Renumbered January 7, 1998)*

**8-18-217** **Reinspection:** Any inspection following the minimization or repair of leaking equipment.

*(Amended, Renumbered January 7, 1998)*

**8-18-218** **Rupture Disc:** The thin metal diaphragm held between flanges.

*(Amended, Renumbered January 7, 1998)*

**8-18-219** **Total Organic Compounds:** The concentration of organic compounds and methane as indicated by a hydrocarbon analyzer as specified by Section 8-18-501.

*(Amended, Renumbered 1/7/98; Amended 1/21/04)*

**8-18-220** **Turnaround:** The scheduled shutdown of a process unit for maintenance and repair work.

*(Amended, Renumbered January 7, 1998)*

**8-18-221** **Valve:** Any device that regulates the flow of process material by means of an external actuator acting to permit or block passage of liquids or gases.

*(Amended, Renumbered January 7, 1998)*

**8-18-222** **Weephole:** A drain hole in the discharge horn of a pressure relief device.

*(Adopted January 7, 1998)*

**8-18-223** **Deleted January 7, 1998**

**8-18-224** **Deleted January 7, 1998**

**8-18-225** **Deleted December 16, 2015**

**8-18-226** **Essential Equipment:** Any valve, connection, pressure relief device, pump or compressor that cannot be taken out of service without shutting down the process unit that it serves.

*(Adopted December 16, 2015)*

**8-18-227** **Open-Ended Valve or Line:** Any valve, except a safety relief valve, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

*(Adopted December 16, 2015)*

**8-18-228** **Double Block Bleed System:** Two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

*(Adopted December 16, 2015)*

**8-18-300** **STANDARDS**

**8-18-301** **General:** Except for valves, pumps and compressors, connections and pressure relief devices subject to the requirements of Sections 8-18-302, 303, 304, 305 and

306, a person shall not use any equipment that leaks total organic compounds in excess of 100 ppm unless the leak has been discovered by the operator, minimized within 24 hours and repaired within 7 days.

*(Amended 7/15/81; 3/17/82; 9/6/89; 3/4/92; 1/7/98)*

**8-18-302 Valves:** Except as provided in Section 8-18-306, a person shall not use any valve that leaks total organic compounds in excess of 100 ppm unless one of the following conditions is met:

302.1 If the leak has been discovered by the operator, minimized within 24 hours and repaired within 7 days; or

302.2 If the leak has been discovered by the APCO, the leak must be repaired within 24 hours.

*(Adopted 3/4/92; Amended 1/7/98, 1/21/04, 12/16/15)*

**8-18-303 Pumps and Compressors:** Except as provided in Section 8-18-306, a person shall not use any pump or compressor that leaks total organic compounds in excess of 500 ppm unless one of the following conditions is met:

303.1 If the leak has been discovered by the operator, minimized within 24 hours and repaired within 7 days; or

303.2 If the leak has been discovered by the APCO, the leak must be repaired within 24 hours.

*(Adopted 3/4/92; Amended 1/7/98, 1/21/04, 12/16/15)*

**8-18-304 Connections:** Except as provided in Section 8-18-306, a person shall not use any connection that leaks total organic compounds in excess of 100 ppm unless one of the following conditions is met:

304.1 If the leak has been discovered by the operator, minimized within 24 hours and repaired within 7 days; or

304.2 If the leak has been discovered by the APCO, the leak must be repaired within 24 hours.

*(Adopted 3/4/92; Amended 1/7/98, 1/21/04, 12/16/15)*

**8-18-305 Pressure Relief Devices:** Except as provided in Section 8-18-306, a person shall not use any pressure relief device that leaks total organic compounds in excess of 500 ppm unless the leak has been discovered by the operator, minimized within 24 hours and repaired within 15 days; or if the leak has been discovered by the APCO, minimized within 24 hours and repaired within 7 days.

*(Amended 1/7/98, 12/16/15)*

**8-18-306 Non-repairable Equipment:** Any essential equipment leak that cannot be repaired as required by Section 8-18-302, 303, 304 or 305 may be placed on a non-repairable list provided the operator complies with the following conditions:

306.1 Any essential equipment leak must be less than 10,000 ppm and mass emissions must be determined within 30 days of placing on the non-repairable list. The APCO must be notified no less than 96 hours prior to conducting mass emissions measurements.

306.2 The number of individual pieces of equipment awaiting repair does not exceed that portion of the total population for each equipment type expressed in the table below, rounded to the next higher whole number.

| Equipment | Total Number of Non-repairable Equipment Allowed (%) |
|---|---|
| Valves and Connections as allowed by Section 8-18-306.3 | 0.15% of total number of valves |
| Pressure Relief Devices | 0.5% of total number of pressure relief devices |
| Pumps and Compressors | 0.5% of total number of pumps and compressors |

306.3 A connection can be considered non-repairable equipment pursuant to Section 8-18-306 provided each non-repairable connection is counted as two valves toward the total number of non-repairable valves allowed.

306.4 The essential equipment is repaired or replaced within five years or at the next scheduled turnaround, whichever date comes first.

*(Adopted 3/4/92; Amended 1/7/98, 1/21/04, 12/16/15)*

**8-18-307 Liquid Leak:** A person shall not use any equipment that leaks liquid as defined in Section 8-18-211, unless the leak has been discovered by the operator, minimized within 24 hours and repaired within 7 days.

*(Adopted 3/4/92; Amended 1/7/98)*

**8-18-308 Alternate Compliance:** The requirements of Sections 8-18-301, 302, 303, 304, 305, 306 and 307 shall not apply to any facility which complies with an alternative emission reduction plan that satisfies all the requirements in Sections 8-18-405 and 406.

*(Adopted January 7, 1998)*

**8-18-309 Open-Ended Valve or Line:** Open-ended valves or lines shall be equipped with a cap, blind flange, plug or second valve which shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

309.1 When a double block and bleed system is installed, the second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

309.2 When a double block and bleed system is in use, the bleed valve or line may remain open during operations that require venting the line between the block valves, but shall comply with Sections 8-18-309 and 309.1 at all times.

309.3 When a double block and bleed system is not in use, the open end of the second valve shall not leak greater than 100 ppm.

*(Adopted December 16, 2015)*

**8-18-310 Recurrent Leaks:** If a valve, pump, compressor or PRD is found leaking more than 3 consecutive quarters, the inspection frequency shall change from quarterly to monthly pursuant to Section 8-18-407.

*(Adopted December 16, 2015)*

**8-18-311 Mass Emissions:** A person shall not use any equipment that emits total organic compounds in excess of five pounds per day except during any repair periods allowed by Sections 8-18-301, 302, 303, 304, and 305.

*(Adopted December 16, 2015)*

## 8-18-400 ADMINISTRATIVE REQUIREMENTS

**8-18-401 Inspection:** Any person subject to this Rule shall comply with the following inspection requirements:

401.1 All equipment that has been opened during a turnaround shall be inspected for leaks within 90 days after start-up is completed following a turnaround.

401.2 Except as provided under Subsection 8-18-401.3, 404, 405, and 406 all valves, pressure relief devices, pumps or compressors subject to this Rule shall be inspected quarterly.

401.3 Inaccessible valves and pressure relief devices subject to this Rule shall be inspected at least once a year unless found leaking pursuant to Subsection 8-18-403.

401.4 Any equipment subject to this Rule may be inspected at any time by the APCO.

401.5 Any equipment found to have a leak in excess of the standard in Section 8-18-300 shall be reinspected within 24 hours after any leak repair or minimization.

401.6 Any connections subject to this rule shall be inspected annually or be part of an APCO and EPA approved connection inspection program.

401.7 Any pressure relief device equipped with a weephole shall be inspected quarterly at the outlet of the weephole if the horn outlet is inaccessible.

401.8 Any pressure relief device that releases to the atmosphere shall be inspected within 5 working days after the release event.

401.9 Any essential equipment placed on the non-repairable list shall be inspected at least once per quarter.

401.10 The mass emission rate of any essential equipment placed on the non-repairable list in accordance with Section 8-18-306 shall be determined at least once per calendar year. The APCO shall be notified no less than 96 hours prior to conducting the measurements required by this section.

401.11 The owner/operator shall identify the equipment and/or source of any background reading greater than 50 ppm.

*(Amended 12/16/15)*

**8-18-402 Identification:** Any person subject to this Rule shall comply with the following identification requirements:

402.1 All valves, pressure relief devices, pumps and compressors, and, effective January 1, 2017, connectors shall be identified with a unique permanent identification code approved by the APCO. This identification code shall be used to refer to the valve, connector, pressure relief device, pump or compressor location. Records for each valve, connector, pressure relief device, pump or compressor shall refer to this identification code.

402.2 All equipment with a leak in excess of the applicable leak limitation in Section 8-18-300 shall be tagged with a brightly colored weatherproof tag indicating the date the leak was detected.

*(Amended 3/4/92, 1/7/98, 12/16/15)*

**8-18-403 Visual Inspection Schedule:** All pumps and compressors shall be visually inspected daily for leaks. If a leak is observed, the concentration shall be determined within 24 hours of discovery pursuant to Section 8-18-602.

*(Renumbered 1/7/98; Amended 12/16/15)*

**8-18-404 Alternative Inspection Schedule:** The inspection frequency for valves or pumps may change from quarterly to annually provided all of the conditions in Subsection 404.1 and 404.2 are satisfied.

404.1 The valve or pump has been operated leak free for five consecutive quarters; and

404.2 Records are submitted to the District and approved by the APCO.

404.3 The valve or pump remains leak free pursuant to the Sections 8-18-302 and 303. If a leak is discovered, the inspection frequency will revert back to quarterly.

*(Adopted 1/7/98; Amended 12/16/15)*

**8-18-405 Alternate Emission Reduction Plan:** Any person may comply with Section 8-18-308 by developing and submitting an alternate emission reduction plan to the APCO that satisfies all of the following conditions:

405.1 The plan shall contain all information necessary to establish, document, measure progress and verify compliance with an emission reduction level set forth in this rule.

405.2 All emission reductions must be achieved solely from equipment and connections subject to this rule.

405.3 Public notice and a 60-day public comment period shall be provided.

405.4 Following the public comment period, the plan shall be submitted to and approved in writing by the EPA, Region IX prior to the APCO approval of the plan.

405.5 An alternate emission reduction plan must provide for emission reductions equal to or greater than required by the specific limits in this rule.

*(Adopted 1/7/98; Amended 11/27/02)*

**8-18-406 Interim Compliance:** A facility is subject to the limits contained in Sections 8-18-301, 302, 303, 304, 305, 306 and 307 until receipt of the written approvals of both the APCO and the EPA of an Alternate Emission Reduction Plan that complies with Section 8-18-405.

*(Adopted1/7/98; Amended 11/27/02)*

**8-18-407 Recurrent Leak Schedule:** For any valve, pump, compressor or pressure relief device found leaking in more than three consecutive quarters, a person subject to this Rule shall comply with the following requirements:

407.1 The inspection frequency shall be changed from quarterly to monthly; and

407.2 Records of each valve, pump, compressor and pressure relief device changed to monthly monitoring shall be submitted to the District each quarter pursuant to Section 8-18-503.1.

407.3 If the valve, pump, compressor or pressure relief device remains leak free for four consecutive months pursuant to Sections 8-18-302, 303 and 305 the inspection frequency will revert back to quarterly upon request and after APCO approval.

## 8-18-500 MONITORING AND RECORDS

**8-18-501 Portable Hydrocarbon Detector:** Any instrument used for the measurement of total organic compounds shall be a combustible gas indicator that has been approved by the APCO and meets the specifications and performance criteria of and has been calibrated in accordance with EPA Reference Method 21 (40 CFR 60, Appendix A).

*(Amended 3/17/82, 9/6/89, 3/4/92, 12/16/15)*

**8-18-502 Records:** Any person subject to the requirements of this rule shall maintain records that provided the following information:

502.1 For equipment subject to Section 8-18-402.1, the equipment identification code, equipment type and the location of the equipment.

502.2 The date, time, type of repairs and corresponding leak concentrations measured on all inspections and reinspections as specified by Section 8-18-401.

502.3 Records shall be maintained for at least 5 years and shall be made available to the APCO for inspection at any time.

502.4 Records of all non-repairable equipment subject to the provisions of Section 8-18-306 shall be maintained and contain the equipment identification code, equipment type, equipment location, initial leak concentration measurement and date, quarterly leak concentration measurements and dates, the duration the equipment has been on the non-repairable list, date of any repair attempts made to equipment, mass emission rate determinations, date the determination was made, last process unit turnaround date, total number of non-repairable equipment awaiting repair, and explanation why equipment was deemed essential equipment.

502.5 Records of all equipment and/or sources identified as a result of background readings greater than 50 ppm.

502.6 Effective January 1, 2018, Piping and Instrumentation Diagrams (P&IDs) with all components in heavy liquid service clearly identified.

*(Adopted 3/4/92; Amended 1/7/98, 12/16/15)*

**8-18-503 Reports:** Any person subject to the requirements of this rule shall submit the following information to the District:

503.1 Effective July 1, 2016, a report shall be submitted to the APCO quarterly that includes the following information:

3.1.1 The equipment identification code, equipment type, stream service, equipment location, leak concentration measurement and date, leak repair method and concentration measurements of any valves, pumps, compressors and PRDs found leaking in more than 3 consecutive quarters pursuant to Section 8-18-310.

3.1.2 Records of all non-repairable equipment subject to the provisions of Section 8-18-306 shall be submitted to the District quarterly and contain the equipment identification code, equipment type, equipment location, initial leak concentration measurement and date, the duration the equipment has been on the non-repairable list, any repair attempts made to equipment, mass emission rate determination, date the determination was made, last process unit turnaround date, total number of non-repairable equipment awaiting repair and explanation why equipment was deemed essential equipment.

503.2 Effective July 1, 2016, a person subject to this rule shall submit to the District an inventory identifying the total numbers of valves, pressure relief devices, pumps and compressors and connections to which this rule applies broken down per unit or other grouping if component is not associated with an individual unit. After review and approval of the initial inventory by the APCO, annual inventory updates shall be submitted to the District every January 1st.

503.4 Inspection records of all equipment opened during a turnaround shall be submitted to the District the first month following completion of the 90-day startup up leak inspections pursuant to Section 8-18-401.1.

503.5 By January 1, 2018, submit records required by Section 8-18-502.6 and annually thereafter for information that has changed since last submittal.

*(Adopted 1/21/04; Amended 12/16/15)*

**8-18-600 MANUAL OF PROCEDURES**

**8-18-601 Analysis of Samples:** Samples of organic compounds as defined in Section 8-18-113 shall be analyzed for Initial Boiling Point as prescribed in ASTM D-1078- 98 or ASTM D-86.

*(Adopted 3/17/82; Amended 3/4/92; 1/7/98)*

**8-18-602 Inspection Procedure:** Inspections of equipment shall be conducted as prescribed by EPA Reference Method 21 (40 CFR 60, Appendix A).

*(Adopted 9/6/89; Amended 3/4/92; 1/7/98)*

**8-18-603 Determination of Control Efficiency:** The control efficiency as specified by Section 8-18-110 shall be determined by any of the following methods: 1) BAAQMD Manual of Procedures, Volume IV, ST-7, 2) EPA Method 25 or 25A. A source shall be considered in violation if the emissions of organic compounds measured by any of the referenced test methods exceed the standards of this rule.

*(Amended, Renumbered 1/7/98; Amended 1/21/04)*

**8-18-604 Determination of Mass Emissions:** The mass emission determination as specified by Section 8-18-306 and Section 8-18-311 shall be made using any of the following methods: 1) EPA Protocol for Equipment Leak Emission Estimates, Chapter 4, Mass Emission Sampling, (EPA-453/R-95-017) November, 1995 or 2) or a mass emission monitoring method determined to be equivalent by the EPA and approved by the APCO.

*(Adopted 1/7/98; Amended 1/21/04, 12/16/15)*

**Utah Retirement Systems**

**SANDRA L DIXON W58125865**

# Beneficiaries

## Beneficiary Confirmation

**Retirement System**

**JORDAN DAVIS** 04/23/1975
Primary

Changes to your beneficiaries have been successfully submitted (see details below). A confirmation letter will be mailed to your current address.

**Retirement System**

**401(k)**

| Designation | Beneficiary Name | Birth Date |
|---|---|---|
| Primary | **JORDY DAVIS** 04/23/1975<br>Primary<br>JORDAN DAVIS | 04/23/1975 |

**401(k)**

| Designation | Beneficiary Name | Birth Date |
|---|---|---|
| Primary | JORDY DAVIS | 04/23/1975 |

**Before signing,** make sure all beneficiary information is correct. You may be asked to provide additional information and/or documentation.

Revoking any previous nominations of beneficiary(ies), I hereby designate the above individual(s) to receive all benefits payable upon my death.

I hereby, represent all information is true and correct. I understand and agree that any false information I provide on this form may, at URS' sole discretion, result in a limitation or termination of my benefits. By signing below I hereby agree to the terms and conditions of URS Board Resolutions and Federal Law.

By typing my name in the indicated fields, I agree to conduct business electronically with URS/PEHP in accordance with the federal Electronic Signatures in Global and National Commerce Act (E-Sign), 15 U.S.C.A. §§ 7001-7031 (Supp. 2001) and Utah's Uniform Electronic Transactions Act (UETA), Utah Code Ann. §§ 46 4-101 to -501 (2000). I understand transactions and/or signatures in records may not be denied legal effect solely because they are conducted, executed, or prepared in electronic form, and that if a law requires a record or signature to be in writing, an electronic record or signature satisfies that requirement.

**Signed by SANDRA L DIXON on June 6, 2017 11:56 AM**

# REGULATION 8
# ORGANIC COMPOUNDS
# RULE 53
# VACUUM TRUCK OPERATIONS

## INDEX


**8-53-100 GENERAL**

8-53-101 Description
8-53-102 Applicability
8-53-103 Exemption, Emergencies
8-53-104 Limited Exemption, Positive Displacement Pump or Gravity Feed Loading
8-53-105 Exemption, Secondary Treatment Process

**8-53-200 DEFINITIONS**

8-53-201 Air-Mover
8-53-202 Affected Facility
8-53-203 Aviation Gas
8-53-204 Background Concentration
8-53-205 Bulk Plant
8-53-206 Bulk Terminal
8-53-207 Control Equipment
8-53-208 Crude Oil
8-53-209 Gasoline
8-53-210 Gasoline Blending Stock
8-53-211 Loading Event
8-53-212 Marine Terminal
8-53-213 Naphtha
8-53-214 Organic Compound
8-53-215 Organic Liquid Pipeline Facility
8-53-216 Petroleum Refinery
8-53-217 Positive Displacement Pump
8-53-218 Regulated Material
8-53-219 Slop
8-53-220 Total Organic Compounds (TOC)
8-53-221 Transmix
8-53-222 Vacuum Truck
8-53-223 Vacuum Truck Operation

**8-53-300 STANDARDS**

8-53-301 Emission Limit
8-53-302 Liquid Leaks
8-53-303 Vapor Leaks
8-53-304 Unloading of Regulated Material

**8-53-400 ADMINISTRATIVE REQUIREMENTS**

8-53-401 Loading Event Schedule Reporting Requirements

**8-53-500 MONITORING AND RECORDS**

8-53-501 Emissions Monitoring Requirement
8-53-502 Recordkeeping Requirement

**8-53-600 MANUAL OF PROCEDURES**

8-53-601 Measurement of TOC Concentrations
8-53-602 Analysis of Materials, True Vapor Pressure
8-53-603 Analysis of Materials, Percent Water Volume
8-53-604 Determination of Abatement Efficiency

# REGULATION 8
# ORGANIC COMPOUNDS
# RULE 53
# VACUUM TRUCK OPERATIONS

(Adopted April 18, 2012)

## 8-53-100 GENERAL

**8-53-101** **Description:** The purpose of this rule is to limit the emissions of organic compounds from the use of vacuum trucks to move materials at petroleum refineries, bulk plants, bulk terminals, marine terminals, and organic liquid pipeline facilities.

**8-53-102** **Applicability:** This rule applies to the following facilities:

102.1 Petroleum refineries;
102.2. Bulk plants;
102.3 Bulk terminals;
102.4 Marine terminals;
102.5 Organic liquid pipeline facilities.

**8-53-103** **Exemption, Emergencies:** Vacuum trucks responding to spills, equipment failures, and other emergency situations shall be exempt from the requirements of this rule, provided that (1) use of equipment capable of complying with the rule would delay the response, and (2) the delay would pose a risk of significant harm to facility equipment, personnel, the public, or the environment.

**8-53-104** **Limited Exemption, Positive Displacement Pump or Gravity Feed Loading:** A loading event in which gravity or a positive displacement pump is used to move regulated materials into a vacuum truck shall be exempt from the requirements of Sections 8-53-301 and 8-53-501.

**8-53-105** **Exemption, Secondary Treatment Processes:** Vacuum truck activities at secondary treatment processes, as defined in Regulation 8, Rule 8, Section 208, shall be exempt from this rule.

## 8-53-200 DEFINITIONS

**8-53-201** **Air Mover:** A specialized type of vacuum truck that uses a combination of vacuum and air flow to load a variety of material types into the truck.

**8-53-202** **Affected Facility:** A facility to which this rule applies pursuant to Section 8-53-102.

**8-53-203** **Aviation Gas:** Gasoline suitable for use in piston-driven aircraft.

**8-53-204** **Background Concentration:** The ambient concentration of TOC determined at least 3 meters (10 feet) upwind from the vacuum truck blower exhaust, as determined by a hydrocarbon analyzer pursuant to Section 8-53-501.

**8-53-205** **Bulk Plant:** A distribution facility that is subject to Regulation 8, Rule 39 or to Section 302 of Regulation 8, Rule 6.

**8-53-206** **Bulk Terminal:** A distribution facility that is subject to Regulation 8, Rule 33 or to Section 301 of Regulation 8, Rule 6.

**8-53-207** **Control Equipment:** Equipment used to reduce TOC emissions from vacuum truck operations in order to comply with emission limits set forth in Section 8-53-301 of this rule, including, but not limited to, carbon adsorption systems, internal combustion engines, thermal oxidizers, refrigerated condenser systems, and liquid scrubbers.

**8-53-208** **Crude Oil:** A naturally occurring mixture consisting predominantly of hydrocarbons and/or sulfur, nitrogen and oxygen derivatives of hydrocarbons that is removed from the earth in a liquid state or is capable of being so removed.

**8-53-209** **Gasoline:** Any petroleum-derived, volatile mixture of hydrocarbons suitable for use as a fuel in a spark-ignited, internal combustion engine.

**8-53-210** **Gasoline Blending Stock:** Any organic liquid used as a component of gasoline, including, but not limited to aromatic or alcohol octane boosters and oxygenates, isomerate, reformate, alkylate, straight run gasoline, cat gasoline, pyrolysis gasoline, FCC gasoline and light hydrocrackate.

**8-53-211** **Loading Event:** The loading at a single location within an affected facility of regulated materials into a vacuum truck or other container through a vacuum truck operation. The resumption of loading at the same location after an interruption shall not be considered a separate loading event.

**8-53-212** **Marine Terminal**: Any facility or structure constructed to load or unload organic liquid bulk cargo into or off of marine tank vessels.

**8-53-213** **Naphtha**: A general term for a variety of crude oil fractions in the gasoline boiling range that are used as feeds and products including but not limited to straight run naphtha, coker naphtha, cat cracked naphtha, and hydrocracked naphtha.

**8-53-214** **Organic Compound:** Any compound of carbon, excluding methane, carbon monoxide, carbonic acid, metallic carbides or carbonates and ammonium carbonate.

**8-53-215** **Organic Liquid Pipeline Facility:** Any pipeline used to transport petroleum, petroleum products, or petroleum product blending stock, along with any associated breakout stations.

**8-53-216** **Petroleum Refinery:** Any facility that processes petroleum products as defined in North American Industry Classification System code number 32411, Petroleum Refineries.

**8-53-217** **Positive Displacement Pump:** Equipment that, for each cycle of operation, draws in fluid at a constant volume and then forces that exact volume of fluid into a discharge line. For the purposes of this rule, a diaphragm pump is considered to be a positive displacement pump.

**8-53-218** **Regulated Material:** A regulated material is any of the following:

218.1 Gasoline, aviation gasoline, gasoline blending stock, naphtha;

218.2 Transmix, slop, or any other hydrocarbon mixture that includes a material listed in Section 8-53-218.1 if

2.1 For a mixture without significant water content, the true vapor pressure of the mixture is greater than 25.8 mmHg (0.5 psia) as determined pursuant to Section 8-53-602, or

2.2 For a mixture with significant water content, the water content is less than 90% as determined pursuant to Section 8-53-603.

Crude oil is not a regulated material.

**8-53-219** **Slop:** Any mixture of petroleum materials that does not meet product specifications and may not be used or distributed without further processing.

**8-53-220** **Total Organic Compounds (TOC):** Organic compounds and methane.

**8-53-221** **Transmix:** A mixture of hydrocarbons resulting from (1) the sequential transmission of batches of materials through a pipeline and mixing at the interface between different materials, or (2) the collection for re-refining of material that is not loaded, typically because it does not meet a fuel specification or has become contaminated.

**8-53-222** **Vacuum Truck:** Portable equipment with an affixed barrel or tank that relies on the creation of a pressure differential, typically through use of a pump or blower, to pneumatically load materials into the barrel or tank of the equipment.

**8-53-223** **Vacuum Truck Operation:** The movement of regulated material into a vacuum truck or into any other container through use of a vacuum truck. For purposes of this rule, the use of other means, typically gravity feed or an auxiliary pump, to push or pull materials into a vacuum truck shall be considered a vacuum truck operation.

## 8-53-300 STANDARDS

**8-53-301** **Emission Limit:** Effective April 1, 2013, for any loading event, the owner or operator of a facility subject to this rule shall control emissions to meet the requirements of Section 8-53-301.1 or, as an alternative, the requirements of Section 8-53-301.2.

301.1 The TOC concentration does not exceed 500 ppmv, expressed as methane (C1), above background, as measured at the exhaust outlet of a vacuum truck operation or, if an auxiliary control device is used to control emissions from a vacuum truck operation, at the exhaust outlet of the control device unless:

1.1 A second concentration reading taken within 60 seconds fails to confirm the exceedance, or

1.2 A second concentration reading taken within 60 seconds confirms a TOC concentration in excess of 500 ppmv, but the loading event is shut down within 3 minutes after the second reading.

301.2 TOC emissions are controlled with an abatement device with an abatement efficiency of at least 95 percent.

**8-53-302** **Liquid Leaks:** Effective April 1, 2013, for any loading event, the owner or operator of a facility subject to this rule shall not use a vacuum truck or associated equipment that leaks liquid at a rate in excess of three drops per minute unless the leak is discovered by the operator and eliminated within 3 minutes of discovery or unless the loading event is shut down within 3 minutes of the discovery of the leak. This does not apply to disconnect leaks provided procedures for minimizing disconnect leaks are used.

**8-53-303** **Vapor Leaks:** Effective April 1, 2013, for any loading event, the owner or operator of a facility subject to this rule shall not use a vacuum truck or associated abatement device that leaks organic vapor in excess of 500 ppmv, expressed as methane ($C_1$), above background unless the leak is discovered by the operator and minimized to a concentration below 500 ppmv within 3 minutes after discovery or unless the loading event is shut down within 3 minutes after the discovery of the leak.

**8-53-304** **Unloading of Regulated Material:** Effective April 1, 2013, the owner or operator of a facility subject to this rule shall meet the following requirements for unloading of regulated material from a vacuum truck at the facility where the vacuum truck was loaded:

304.1 Regulated material shall be unloaded into a tank, vessel or sump that meets the control requirements in Regulation 8, Rule 5 or Regulation 8, Rule 8, or

304.2 If regulated material is unloaded into a tank, vessel or sump that does not meet the control requirements of Regulation 8, Rule 5 or Regulation 8, Rule 8, regulated material shall be unloaded using a submerged fill pipe that complies with the submerged fill pipe discharge requirements of Regulation 8, Rule 5, Section 302 and promptly pumped into storage.

## 8-53-400 ADMINISTRATIVE REQUIREMENTS

**8-53-401** **Loading Event Schedule Reporting Requirements:** Effective April 1, 2013, upon request by the APCO or the designee of the APCO, the owner or operator of an affected facility subject to this rule shall provide a list of scheduled loading events and the following information, if available at the time of request, for each event:

401.1 Loading event start date and time;

401.2 Facility name, plant number (if applicable), and source number (if applicable), tank, pipeline, or reservoir address, and equipment location;

401.3 Vacuum truck company name, owner/operator's name, and telephone number;

401.4 Control equipment company name, control equipment type, operator's name and telephone number if the control equipment is operated by someone other than the vacuum truck owner/operator; and,

401.5 Tank, pipeline, box, container, or reservoir capacity, estimated volume and type of material to be loaded.

The list shall include loading events that are scheduled within thirty (30) days. The list shall be provided to District staff within three (3) working days and may be provided via hard copy or electronically. Changes to loading event schedules shall be reported to District staff no less than 24 hours prior to loading events.

## 8-53-500 MONITORING AND RECORDS

**8-53-501** **Emissions Monitoring Requirement:** Effective April 1, 2013, the owner or operator of an affected facility using a vacuum truck operation shall monitor and record emissions as follows:

501.1 To demonstrate compliance with Section 8-53-301.1 when controlling TOC emissions from a vacuum truck operation with technology other than a carbon adsorption system, emission concentrations from the control device shall be measured using the method specified in Section 8-53-601 and recorded as follows:

1.1 Conduct one measurement for each loading event before the vacuum truck is approximately 20% full. Conduct an additional measurement before the vacuum truck is approximately 60% full. If a vacuum truck is already 20% full prior to a loading event, conduct an initial measurement as soon as possible after the start of the loading event and an additional measurement before the vacuum truck is approximately 60% full. If a vacuum truck is already 60% full prior to a loading event, conduct one measurement as soon as possible after the start of the loading event.

1.2 Record the information required by Section 8-53-502.

501.2 To demonstrate compliance with Section 8-53-301.1 when controlling TOC emissions from a vacuum truck operation with a carbon adsorption system, emission concentrations from the control device shall be measured using the method specified in Section 8-53-601 and recorded as follows:

2.1 Commence emission measurements within 2 minutes of startup for each loading event. Additional measurements shall be performed approximately every 10 minutes during loading thereafter;

2.2 When a TOC stream is switched to a back-up or replacement carbon vessel, a new TOC emission measurement must occur within 2 minutes of the carbon vessel replacement.

2.3 Record the information required by Section 8-53-502.

501.3 To demonstrate compliance with Section 8-53-301.2, the owner or operator of an affected facility shall perform a source test verifying the required abatement efficiency during the vacuum truck operation or, for abatement devices that combust emissions to achieve the required efficiency, the owner or operator may instead show that a source test on the abatement device verifying the required abatement efficiency was completed within the 12 months prior to the commencement of the vacuum truck operation.

501.4 An alternative monitoring plan may be submitted and approved by the APCO.

501.5 The owner or operator of an affected facility shall retain records and lists required by this Section for two years and shall make them available for inspection by the APCO upon request.

**8-53-502 Recordkeeping Requirement:** A person subject to this rule shall keep the following records:

502.1 Effective April 1, 2013, record the following information for each loading event:

1.1 The date, time of commencement, and duration of the loading event;

1.2 The type and volume of regulated materials loaded;

1.3 Whether loading was by vacuum, positive displacement pump, or gravity;

1.4 Where vacuum truck control equipment or external control equipment is used, record the make and model of the control equipment, the results of the emission measurements required by Section 8-53-501, and the make, model, and serial number of the device used to measure the TOC concentrations;

1.5 Where loading was by positive displacement pump, the make and model of the pump.

502.2 Effective April 1, 2013, record the daily volume of crude oil and oil recovered from centrifuging that is loaded into vacuum trucks.

502.3 Effective April 1, 2013, keep records if the owner or operator of an affected facility chooses to perform a true vapor pressure analysis or a percent volume analysis to determine whether material loaded is a regulated material pursuant to Section 8-53-218.

502.4 The owner or operator of an affected facility shall maintain complete copies of source test reports required by Section 8-53-501.3.

502.5 The owner or operator of an affected facility shall retain records required by this Section for two years and shall make them available for inspection by the APCO upon request.

**8-53-600 MANUAL OF PROCEDURES**

**8-53-601** **Measurement of TOC Concentrations:** Measurements of TOC concentration for determining compliance with the limit set forth in Section 301 of this rule shall be conducted in accordance with USEPA Reference Methods 21 or 25A; or BAAQMD Manual of Procedures, Volume IV, ST-7, Non-methane Organic Carbon Sampling. If USEPA Reference Method 21 is used to determine compliance, the portable analyzer shall use flame ionization detection and shall meet the specifications and performance criteria of, and shall be calibrated in accordance with, EPA Reference Method 21 (40 CFR 60, Appendix A). Noncompliance established by any one of the specified test methods shall constitute a violation of this rule.

**8-53-602** **Analysis of Materials, True Vapor Pressure:** Materials sampled pursuant to Section 8-53-218.2.1, shall be analyzed for true vapor pressure at loading temperature as prescribed in the Manual of Procedures, Volume III, Lab Method 28: Determination of Vapor Pressure of Organic Liquids from Storage Tanks.

**8-53-603** **Analysis of Materials, Percent Water Volume:** Materials sampled pursuant to Section 8-53-218.2.2 shall be analyzed as prescribed in ASTM D96: Test Methods for Water and Sediment in Crude Oil by Centrifuge Method (Field Procedure), ASTM D1796: Water and Sediment in Fuel Oils by the Centrifuge Method (Laboratory Procedure) or ASTM D6304: Karl Fisher Water in Petroleum Products. Alternatively, percent water volume may be observed and calculated from a mixed, representative sample collected as specified by ASTM D4057: Standard Practice for Manual Sampling of Petroleum and Petroleum Products and allowed to settle in a graduated cylinder.

**8-53-604** **Determination of Abatement Efficiency:** Abatement efficiency of an abatement device shall be determined as specified in the Manual of Procedures, Volume IV, ST-7 or by EPA Method 25 or 25A. Noncompliance established by any one of the specified test methods shall constitute a violation of the rule.

# REGULATION 9
# INORGANIC GASEOUS POLLUTANTS
# RULE 1
# SULFUR DIOXIDE

## INDEX


**9-1-100 GENERAL**

9-1-101 Description
9-1-110 Conditional Exemption, Area Monitoring

**9-1-200 DEFINITIONS**

9-1-201 Deleted May 20, 1992
9-1-202 Deleted May 20, 1992
9-1-203 Deleted May 20, 1992
9-1-204 Start-up
9-1-205 Fresh Fruit Sulfuring Operations
9-1-206 Sulfur Removal and Recovery System
9-1-207 Sour Water Stripper
9-1-208 Regenerative Gas Treatment System
9-1-209 Sulfur Recovery Plant
9-1-210 Sulfuric Acid Plant
9-1-211 Shutdown

**9-1-300 STANDARDS**

9-1-301 Limitations on Ground Level Concentrations
9-1-302 General Emission Limitation
9-1-303 Emissions from Ships
9-1-304 Fuel Burning (Liquid and Solid Fuels)
9-1-305 Deleted May 20, 1992
9-1-306 Deleted May 20, 1992
9-1-307 Emission Limitations for Sulfur Recovery Plants
9-1-308 Deleted May 20, 1992
9-1-309 Emission Limitations for Sulfuric Acid Plants
9-1-310 Emission Limitations for Fluid Catalytic Cracking Units, Fluid Cokers, and Coke Calcining Kilns
9-1-311 Emission Limitations for Catalyst Manufacturing Plants
9-1-312 Emission Limitations for Fresh Fruit Sulfuring Operations
9-1-313 Sulfur Removal Operations at Petroleum Refineries

**9-1-400 ADMINISTRATIVE REQUIREMENTS**

9-1-401 Deleted May 20, 1992
9-1-402 Deleted May 20, 1992
9-1-403 Deleted May 20, 1992
9-1-404 Deleted May 20, 1992

**9-1-500 MONITORING AND RECORDS**

9-1-501 Area Monitoring Requirements
9-1-502 Emission Monitoring Requirements
9-1-503 Fresh Fruit Sulfuring Recordkeeping Requirements

**9-1-600 MANUAL OF PROCEDURES**

9-1-601 Sampling and Analysis of Gas Streams
9-1-602 Sulfur Content of Fuels
9-1-603 Averaging Times
9-1-604 Ground Level Monitoring
9-1-605 Emission Monitoring
9-1-606 Analysis of Gas Streams for $H_2S$
9-1-607 Analysis of Water Streams for $H_2S$
9-1-608 Analysis of Water Streams for $NH_3$
9-1-609 Analysis of Sulfur Content of Crude Oil

# REGULATION 9
# INORGANIC GASEOUS POLLUTANTS
# RULE 1
# SULFUR DIOXIDE

**9-1-100 GENERAL**

**9-1-101 Description:** This Rule establishes emission limits for sulfur dioxide from all sources including ships, and limits ground level concentrations of sulfur dioxide.

**9-1-110 Conditional Exemption, Area Monitoring:** The 300 ppm limitation of Section 9-1-302 shall not apply to a person who meets the requirements of subsections 9-1-110.1 and 110.2, provided such person has complied with those requirements prior to January 1, 1980.

110.1 A person shall be subject to the monitoring, records and reporting requirements contained in Regulation 1, including Sections 1-510, 530, 540, 542, 543, and 544.

110.2 A person shall not emit sulfur dioxide in quantities which result in ground level concentrations of sulfur dioxide in excess of the limits specified in Section 9-1-301. This subsection shall not apply to ground level concentrations occurring on the property from which such emission occurs, provided such property, from the emission point to the point where the excess occurs, is physically secured against public access by the person responsible for the emission. (Amended May 20, 1992)

**9-1-200 DEFINITIONS**

**9-1-201 Deleted May 20, 1992**

**9-1-202 Deleted May 20, 1992**

**9-1-203 Deleted May 20, 1992**

**9-1-204 Start-up:** For the purposes of Section 9-1-605, start-up begins at the time the feed stock is introduced into the process and may proceed for a period not to exceed four consecutive hours. (Amended May 20, 1992)

**9-1-205 Fresh Fruit Sulfuring Operation:** Any operation where freshly cut fruit is placed in a sulfur house in order to come into contact with sulfur dioxide. (Adopted February 16, 1983)

**9-1-206 Sulfur Removal and Recovery System:** A set of process units which remove $H_2S$ from refinery gas streams and the reduced sulfur compounds and ammonia from process water streams. The reduced sulfurous compounds are recovered as sodium hydrosulfide (NaSH), elemental sulfur, sulfuric acid, or other sulfate compounds. The sulfurous compounds are recovered as elemental sulfur or as sulfuric acid. The process units consist of a sour water stripper, regenerative gas treatment system, and a sulfur recovery plant, a sulfuric acid plant, or other process units and facilities which achieve removal efficiencies as required by Section 9-1-313.2. (Adopted July 18, 1990; Amended March 15, 1995)

**9-1-207 Sour Water Stripper:** A process unit which removes reduced sulfur compounds from process water using a distillation (stripping) process. (Adopted July 18, 1990)

**9-1-208 Regenerative Gas Treatment System:** A regenerative process system that removes $H_2S$ from refinery gas streams and recovers the $H_2S$ as $H_2S$ or sulfur. (Adopted July 18, 1990)

**9-1-209 Sulfur Recovery Plant:** A process unit which processes sulfur and ammonia containing material and produces a final product of elemental sulfur. (Adopted July 18, 1990)

**9-1-210 Sulfuric Acid Plant:** A process unit which processes sulfur containing material and produces a final product of sulfuric acid or oleum. (Adopted July 18, 1990)

**9-1-211** **Shutdown:** For the purposes of Section 9-1-605, shutdown begins at the time the feed stock is discontinued. (Adopted May 20, 1992)

**9-1-300 STANDARDS**

**9-1-301** **Limitations on Ground Level Concentrations:** A person shall not emit from sources other than ships, sulfur dioxide in quantities which result in ground level concentrations in excess of 0.5 ppm continuously for 3 consecutive minutes or 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. This section shall not apply to ground level concentrations occurring on the property from which such emission occurs, provided such property, from the emission point to the point where the excess occurs, is physically secured against public access by the person responsible for the emission. (Amended May 20, 1992)

**9-1-302** **General Emission Limitation:** A person shall not emit from any source, other than a ship, a gas stream containing sulfur dioxide in excess of 300 ppm (dry). This section shall not apply to the following sources:

302.1 Any source which is subject to any of the limitations in Sections 9-1-304 through 9-1-312.

302.2 Any source which satisfies the conditions in Sections 9-1-110.

(Amended February 16, 1983)

**9-1-303** **Emissions from Ships:** A person shall not emit a gas stream containing sulfur dioxide in excess of 2000 ppm from any ship, except when the ship is entering the port from outside the District. Emissions resulting only from the combustion of liquid fuel with a sulfur content less than or equal to 3.34% by weight shall be considered in compliance with this Section.

**9-1-304** **Fuel Burning (Liquid and Solid Fuels):** A person shall not burn any liquid fuel having a sulfur content in excess of 0.5% by weight, or solid fuel of such sulfur content as would result in the emission of a gas stream containing more than 300 ppm (dry) of sulfur dioxide. This section shall not apply to:

304.1 The burning of sulfur, hydrogen sulfide, acid sludge or other compounds used in the manufacture of sulfur compounds;

304.2 The use of liquid or solid fuels to propel any motor vehicle, aircraft, missile, boat or ship;

304.3 The use of liquid or solid fuels which do not result in the emission of a gas stream containing more than 300 ppm (dry) of sulfur dioxide.

**9-1-305** **Deleted May 20, 1992**

**9-1-306** **Deleted May 20, 1992**

**9-1-307** **Emission Limitations for Sulfur Recovery Plants:** A person shall not emit, from any source in a sulfur recovery plant, effluent process gas containing sulfur dioxide in excess of 250 ppm by volume (dry) calculated at zero percent oxygen. Plants which emit less than 45 kg (100 lbs.) per day of sulfur dioxide shall not be subject to this limitation. (Amended February 16, 1983; May 20, 1992)

**9-1-308** **Deleted May 20, 1992**

**9-1-309** **Emission Limitations for Sulfuric Acid Plants:** A person shall not emit, from any source in a sulfuric acid plant, effluent process gas containing sulfur dioxide in excess of 300 ppm by volume calculated at 12% oxygen.

(Amended February 16, 1983; May 20, 1992)

**9-1-310** **Emission Limitations for Fluid Catalytic Cracking Units, Fluid Cokers, and Coke Calcining Kilns:**

310.1 A person shall not emit, from any source in a fluid catalytic cracking unit or fluid coker, effluent process gas containing sulfur dioxide in excess of 1,000 ppm by volume.

310.2 A person shall not emit, from any coke calcining kiln, effluent process gas containing sulfur dioxide in excess of 400 ppm by volume or in excess of 113 kg (250 pounds) per hour, whichever is more restrictive.

310.3 A person subject to subsections 9-1-310.1 or 310.2 shall comply with the requirements in subsections 9-1-110.1 and 110.2.

**9-1-311** **Emission Limitations for Catalyst Manufacturing Plants:**

311.1 Deleted May 20, 1992

311.2 A person shall not emit, from any source in a catalyst manufacturing plant, effluent process gas containing sulfur dioxide in excess of 22 kg (50 pounds) per hour. (Adopted May 21, 1980; Amended May 20, 1992)

**9-1-312 Emission Limitations for Fresh Fruit Sulfuring Operations:**

312.1 A person shall not operate any fresh apricot sulfuring operation which uses greater than 4.5 kg (10 pounds) of elemental sulfur or 9.0 kg (20 pounds) of gaseous $SO_2$ per 9.0 metric ton (1 short ton) of fresh apricots.

312.2 A person shall not operate any fresh peach sulfuring operation which uses greater than 5.5 kg (12 pounds) of elemental sulfur or 10.9 kg (24 pounds) of gaseous $SO_2$ per 9.0 metric ton (1 short ton) of fresh peaches.

312.3 A person shall not operate any fresh pear sulfuring operation which uses greater than 6.8 kg (15 pounds) of elemental sulfur or 13.6 kg (30 pounds) of gaseous $SO_2$ per 9.0 metric ton (1 short ton) of fresh pears.

(Adopted February 16, 1983; Amended May 20, 1992)

**9-1-313 Sulfur Removal Operations at Petroleum Refineries:** Effective September 1, 1990, a person shall not operate a petroleum refinery processing more than 20,000 barrels per stream day of crude oil unless one of the following is met:

313.1 The sulfur content of the crude oil does not exceed 0.10 percent by weight, or

313.2 There is a sulfur removal and recovery system that removes and recovers, on a refinery wide basis, 95% of the $H_2S$ from the refinery fuel gas, that removes and recovers, on a refinery wide basis, 95% of the $H_2S$ from the process water streams, and removes 95% of the ammonia from the process water streams, provided, however, any refinery which removes sulfurous compounds containing sulfur equivalent of 16.5 tons or more of elemental sulfur in any one day shall install a sulfur recovery plant or a sulfuric acid plant.

313.3 A binding, legally enforceable agreement or court order exists which mandates the construction of a sulfur removal and recovery system pursuant to a schedule set forth therein; provided, however, that the sulfur removal and recovery system must be constructed by October 1, 1993, unless, in the judgment of the Air Pollution Control Officer, failure to complete construction by that date results from circumstances beyond the reasonable control of the refinery operator in which case the Air Pollution Control Officer may grant a reasonable extension of the October 1, 1993 deadline. The Air Pollution Control Officer may grant such extension, however, only if the refinery operator has made substantial progress in completing construction of its sulfur removal and recovery system by October 1, 1993.

(Adopted July 18, 1990; Amended March 15, 1995)

## 9-1-400 ADMINISTRATIVE REQUIREMENTS

**9-1-401 Deleted May 20, 1992**
**9-1-402 Deleted May 20, 1992**
**9-1-403 Deleted May 20, 1992**
**9-1-404 Deleted May 20, 1992**

## 9-1-500 MONITORING AND RECORDS

**9-1-501 Area Monitoring Requirements:** Upon request of the APCO, a person subject to Section 9-1-301 shall comply with the monitoring, maintenance, records, and reporting requirements of Regulation 1, including Sections 1-510, 1-530, 1-540, 1-542, 1-543 and 1-544.

**9-1-502 Emission Monitoring Requirements:** A person subject to Section 9-1-304, 307, 309 or 310 (with the exception of coke calcining kilns), shall comply with the monitoring requirements of 1-520 and 522. (Amended March 17, 1982; May 20, 1992)

**9-1-503** **Fresh Fruit Sulfuring Recordkeeping Requirements:** Any persons subject to Section 9-1-312 of this Rule shall record the daily weight of elemental sulfur burned or gaseous $SO_2$ used per unit weight of fresh fruit for each sulfuring operation. Records of the weights used shall be kept for the length of the specific fruit season and shall be made available to the APCO upon request. (Adopted February 16, 1983)

**9-1-600** **MANUAL OF PROCEDURES**

**9-1-601** **Sampling and Analysis of Gas Streams:** The method of sampling and analysis of gas streams of sulfur dioxide concentrations is described in the Manual of Procedures, Volume IV, ST-19 A or B. (Amended March 17, 1982)

**9-1-602** **Sulfur Content of Fuels:** The sulfur content of solid and liquid fuels shall be determined as specified in the Manual of Procedures, Volume III, Method 10. (Amended March 17, 1982)

**9-1-603** **Averaging Times:** The averaging times for production determination and emission analysis are specified in the Manual of Procedures, Volume IV. (Amended March 17, 1982)

**9-1-604** **Ground Level Monitoring:** The monitoring requirements for ground level concentrations of sulfur dioxide, including siting procedures and instrument specifications, calibration and maintenance procedures, are described in the Manual of Procedures, Volume VI, Section 1. (Amended March 17, 1982)

**9-1-605** **Emission Monitoring:** The emission monitoring requirements, including instrument placement, specifications, calibration, and maintenance procedures are described in the Manual of Procedures, Volume V. (Amended March 17, 1982).

**9-1-606** **Analysis of Gas Streams for $H_2S$:** The method for analyzing refinery fuel gas streams for $H_2S$ before and after control shall be as prescribed in the Manual of Procedures, Volume III, LAB 32 or equivalent method approved by the APCO. Adopted July 18, 1990; Amended May 20, 1992)

**9-1-607** **Analysis of Water Streams for $H_2S$:** The method for analyzing refinery process water streams for $H_2S$ before and after control shall be as prescribed in the Manual of Procedures, Volume III, LAB 32 or equivalent method approved by the APCO. (Adopted July 18, 1990; Amended May 20, 1992)

**9-1-608** **Analysis of Water Streams for $NH_3$:** The method for analyzing refinery process water streams for $NH_3$ before and after control shall be as prescribed in the Manual of Procedures, Volume III, LAB 1 or equivalent method approved by the APCO. Adopted July 18, 1990; Amended May 20, 1992)

**9-1-609** **Analysis of Sulfur Content of Crude Oil:** The method for analyzing the sulfur content of the crude oil shall be as prescribed in the Manual of Procedures, Volume III, Method LAB 10 or equivalent method approved by the APCO. (Adopted July 18, 1990; Amended May 20, 1992)

# REGULATION 9
# INORGANIC GASEOUS POLLUTANTS
# RULE 8
# NITROGEN OXIDES AND CARBON MONOXIDE FROM STATIONARY INTERNAL COMBUSTION ENGINES

## INDEX


**9-8-100 GENERAL**

9-8-101 Description
9-8-110 Exemptions
9-8-111 Limited Exemption for Low Usage
9-8-112 Registered Portable Equipment

**9-8-200 DEFINITIONS**

9-8-201 Gaseous Fuels
9-8-202 Nitrogen Oxide Emissions
9-8-203 Rated Brake Horsepower
9-8-204 Stationary Internal Combustion Engine
9-8-205 Rich-Burn Engine
9-8-206 Lean-Burn Engine
9-8-230 Emergency Standby Engine
9-8-231 Emergency Use
9-8-232 Reliability-related Activities
9-8-233 Essential Public Service
9-8-234 Best Available Control Technology (BACT)
9-8-235 Dual-Fueled Pilot Compression-Ignited Engines
9-8-236 Portable
9-8-237 Unforeseeable

**9-8-300 STANDARDS**

9-8-301 Emission Limits – Spark-Ignited Engines Powered by Fossil Derived Fuels
9-8-302 Emission Limits – Spark-Ignited Engines Powered by Waste Derived Fuels
9-8-303 Emissions Limits – Delayed Compliance, Existing Spark-Ignited Engines, 51 to 250 bhp or Model Year 1996 or Later
9-8-304 Emission Limits – Compression-Ignited Engines
9-8-305 Emission Limits – Delayed Compliance, Existing Compression-Ignited Engines, Model Year 1996 or Later
9-8-306 Emission Limits for Dual-Fueled Compression-Ignited Engines
9-8-330 Emergency Standby Engines, Hours of Operation
9-8-331 Essential Public Service, Hours of Operation

**9-8-400 ADMINISTRATIVE REQUIREMENTS**

9-8-401 Compliance Schedule
9-8-402 Reporting Requirements for Delayed Compliance

**9-8-500 MONITORING AND RECORDS**

9-8-501 Initial Demonstration of Compliance
9-8-502 Recordkeeping
9-8-503 Quarterly Demonstration of Compliance

9-8-530 Emergency Standby and Low Usage Engines, Monitoring and Recordkeeping

**9-8-600 MANUAL OF PROCEDURES**

9-8-601 Determination of Nitrogen Oxides
9-8-602 Determination of Carbon Monoxide and Stack Gas Oxygen

# REGULATION 9
# INORGANIC GASEOUS POLLUTANTS
# RULE 8
# NITROGEN OXIDES AND CARBON MONOXIDE FROM STATIONARY INTERNAL COMBUSTION ENGINES

(Adopted January 20, 1993)

## 9-8-100 GENERAL

**9-8-101** **Description:** This rule limits the emissions of nitrogen oxides and carbon monoxide from stationary internal combustion engines with an output rated by the manufacturer at more than 50 brake horsepower

*(Amended 8/1/01; 7/25/07)*

**9-8-110** **Exemptions:** The requirements of Sections 9-8-301 through 305, 501 and 503 shall not apply to the following:

110.1 Until January 1, 2012, engines rated by the manufacturer at less than 250 brake horsepower output rating.

110.2 Engines rated by the manufacturer at 50 brake horsepower output rating or less. Effective January 1, 2012.

110.3 Until January 1, 2012, engines fired exclusively by liquid fuels including, but not limited to, diesel fuel, gasoline, and methanol.

110.4 Engines used directly and exclusively for the growing of crops or the raising of animals.

110.5 Emergency standby engines.

*(Amended 8/1/01; 7/25/07)*

**9-8-111** **Limited Exemption for Low Usage:** The requirements of Sections 9-8-301, 302, 303, 304, and 305 shall not apply to the following low use operations provided the requirements of Sections 9-8-502.1 and 9-8-530 are met:

111.1 Until January 1, 2012, engines rated at, or below, 1000 brake horsepower that operate less than 200 hours, exclusive of any emergency use, in any 12-consecutive-month period.

111.2 Until January 1, 2012, engines rated above 1000 brake horsepower that operate less than 100 hours, exclusive of any emergency use, in any 12-consecutive-month period.

111.3 Effective January 1, 2012, engines that operate less than 100 hours, exclusive of any emergency use, in any 12-consecutive-month period

*(Amended July 25, 2007)*

**9-8-112** **Registered Portable Equipment:** The requirements of this section shall not apply to an internal combustion engine registered as portable pursuant to the Statewide Portable Engine and Equipment Registration Program, Sections 2450-2465, Article 5, Title 13, California Code of Regulations.

*(Adopted July 25, 2007)*

## 9-8-200 DEFINITIONS

**9-8-201** **Gaseous Fuels:** For the purposes of this rule, gaseous fuels include, but are not limited to:

201.1 Fossil derived fuel gas such as natural gas, methane, ethane, propane, refinery fuel gas, and butane, including gases stored as liquids such as liquified petroleum gas (LPG).

201.2 Waste derived fuel gas such as sewage sludge digester gas or landfill gas.

**9-8-202** **Nitrogen Oxide ($NO_x$) Emissions:** The sum of nitric oxide (NO) and nitrogen dioxide ($NO_2$) in the engine exhaust, collectively expressed as nitrogen dioxide.

**9-8-203** **Rated Brake Horsepower:** The maximum brake horsepower rating at maximum revolutions per minute (RPM) specified for the engine by the manufacturer or indicated on the engine nameplate.

**9-8-204** **Stationary Internal Combustion Engine (Engine):** Any spark or compression ignited internal combustion engine that is operated, or intended to be operated, at a specific site for more than one year or is attached to a foundation at that site.

**9-8-205** **Rich-Burn Engine:** Any spark or compression ignited internal combustion engine that is designed to be operated with an exhaust stream oxygen concentration of less than 4 percent, by volume. The exhaust gas oxygen content shall be determined from the uncontrolled exhaust stream.

**9-8-206** **Lean-Burn Engine:** Any spark or compression ignited internal combustion engine that is designed to be operated with an exhaust stream oxygen concentration of 4 percent, by volume, or greater. The exhaust gas oxygen content shall be determined from the uncontrolled exhaust stream.

**9-8-230** **Emergency Standby Engine:** Any engine that is exclusively operated:

230.1 For emergency use; and

230.2 For reliability-related activities.

*(Adopted August 1, 2001)*

**9-8-231** **Emergency Use:** The use of an emergency standby or low usage engine during any of the following:

231.1 In the event of unforeseeable loss of regular natural gas supply;

231.2 In the event of unforeseeable failure of regular electric power supply;

231.3 Mitigation or prevention of an imminent flood;

231.4 Mitigation of or prevention of an imminent overflow of sewage or waste water;

231.5 Fire or prevention of an imminent fire;

231.6 Failure or imminent failure of a primary motor or source of power, but only for such time as needed to repair or replace the primary motor or source of power; or

231.7 Prevention of the imminent release of hazardous material.

*(Adopted 8/1/01; Amended 7/25/07)*

**9-8-232** **Reliability-related Activities:** Either:

232.1 Operation of an emergency standby engine to test its ability to perform for an emergency use; or

232.2 Operation of an emergency standby engine during maintenance of a primary motor.

*(Adopted August 1, 2001)*

**9-8-233** **Essential Public Service:**

233.1 A sewage treatment facility, and associated collection system, which is publicly owned and operated;

233.2 Water treatment and delivery operations;

233.3 Public transit;

233.4 Police or fire fighting facility;

233.5 Airport runway lights; or

233.6 Hospital or other medical emergency facility.

*(Adopted August 1, 2001)*

**9-8-234** **Best Available Control Technology (BACT)**: As defined in Regulation 2, Rule 2, Section 2-2-206

*(Adopted July 25, 2007)*

**9-8-235** **Dual Fuel Pilot Compression-Ignited Engine**: Any dual-fueled engine that uses diesel fuel as a pilot ignition source at an annual average ratio of less then 5 parts diesel fuel to 100 parts total fuel on an energy equivalent basis.

*(Adopted July 25, 2007)*

**9-8-236** **Portable:** Designed for and capable of being carried or moved from one location to another. Indications of portability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform.

*(Adopted July 25, 2007)*

**9-8-237** **Unforeseeable:** Not able to be reasonably anticipated and demonstrated by the owner or operator to the satisfaction of the APCO to have been beyond the reasonable control of the owner or operator. The enforcement of a contractual obligation the owner or operator has with a third party or any other party is foreseeable.

*(Adopted July 25, 2007)*

## 9-8-300 STANDARDS

**9-8-301 Emission Limits - Spark-Ignited Engines Powered by Fossil Derived Fuels:** Effective January 1, 1997, a person shall not operate a stationary internal combustion engine fired exclusively on fossil derived fuels, unless the following emission limits are met:

301.1 Rich-Burn Engines: Nitrogen oxide (NOx) emissions shall not exceed 56 ppmv as corrected to 15% oxygen, dry basis. Effective January 1, 2012, nitrogen oxide (NOx) emissions shall not exceed 25 ppmv as corrected to 15% oxygen, dry basis.

301.2 Lean-Burn Engines: Nitrogen oxide (NOx) emissions shall not exceed 140 ppmv as corrected to 15% oxygen, dry basis. Effective January 1, 2012, nitrogen oxide (NOx) emissions shall not exceed 65 ppmv as corrected to 15% oxygen, dry basis.

301.3 Carbon monoxide (CO) emissions shall not exceed 2000 ppmv as corrected to 15% oxygen, dry basis.

*(Amended July 25, 2007)*

**9-8-302 Emission Limits - Spark-Ignited Engines Powered by Waste Derived Fuels:** Effective January 1, 1997, a person shall not operate a spark-ignited stationary internal combustion engine fired on waste derived fuels or any combination of waste- and fossil-derived gaseous fuels and liquid fuels unless the following emission limits are met:

302.1 Lean-Burn Engines: Nitrogen oxide ($NO_x$) emissions shall not exceed 140 ppmv as corrected to 15% oxygen, dry basis. Effective January 1, 2012, nitrogen oxide (NOx) emissions shall not exceed 70 ppmv as corrected to 15% oxygen, dry basis.

302.2 Rich-Burn Engines: Nitrogen oxide ($NO_x$) emissions shall not exceed 210 ppmv as corrected to 15% oxygen, dry basis. Effective January 1, 2012, nitrogen oxide (NOx) emissions shall not exceed 70 ppmv as corrected to 15% oxygen, dry basis.

302.3 Carbon monoxide (CO) emissions shall not exceed 2000 ppmv as corrected to 15% oxygen, dry basis.

*(Amended July 25, 2007)*

**9-8-303 Emissions Limits – Delayed Compliance, Existing Spark-Ignited Engines, 51 to 250 bhp or Model Year 1996 or Later:** In lieu of compliance with Section 9-8-301 or 302, a person may operate a stationary internal combustion, spark-ignited engine until January 1, 2016 provided:

303.1 The brake horsepower rating of the engine is between 51 and 250 bhp or the model year of the engine is 1996 or later;

303.2 The requirements of Section 9-8-402 are met;

303.3 The engine complies with Best Available Control Technology requirements for a stationary internal combustion, spark-ignited engines no later than January 1, 2016.

*(Adopted July 25, 2007)*

**9-8-304 Emission Limits – Compression-Ignited Engines:** Effective January 1, 2012, a person shall not operate a stationary internal combustion compression-ignited engine unless one the applicable emission limit in ppmv corrected 15% oxygen, dry basis set forth below for NOx and CO is met:

| | **Existing Compression-Ignited Engine** (bhp) | **Emission Standards** (ppmvd) | |
|---|---|---|---|
| | | **NOx** | **CO** |
| 304.1 | 51 to 175 | 180 | 440 |
| 304.2 | Greater than 175 | 110 | 310 |

*(Adopted July 25, 2007)*

**9-8-305** **Emission Limits – Delayed Compliance, Existing Compression-Ignited Engines, Model Year 1996 or Later:** In lieu of compliance with Section 9-8-304, a person may operate a stationary internal combustion compression-ignited engine of model year 1996 or later provided the requirements of Section 9-8-402 are met and one of the following conditions is met no later than January 1, 2016:

305.1 The NOx and CO emissions shall not exceed Best Available Control Technology limits for a stationary internal combustion, compression-ignited engines, or

305.2 the NOx emissions shall not exceed 22 ppmv corrected 15% oxygen, dry basis and the CO emissions shall not exceed 310 ppmv corrected 15% oxygen, dry basis.

*(Adopted July 25, 2007)*

**9-8-306** **Requirements for Dual Fuel Pilot Compression-Ignited Engines:** Effective January 1, 2012, compression-ignited engines powered by diesel fuel and waste gas shall comply with spark-ignited waste-derived fuel emission limits in Section 9-8-302, provided the diesel fuel use does not exceed five percent on an energy basis of the total fuel consumption in any calendar year.

*(Adopted July 25, 2007)*

**9-8-330** **Emergency Standby Engines, Hours of Operation:** A person may only operate an emergency standby engine under the following circumstances:

330.1 For emergency use for an unlimited number of hours; and

330.2 Until January 1, 2012, for reliability-related activities so long as total hours of operation for this purpose do not exceed 100 hours in a calendar year, or limitations contained in a District permit, whichever is lower.

330.3 Effective January 1, 2012, for reliability-related activities so long as total hours of operation for this purpose do not exceed 50 hours in a calendar year, or limitations contained in a District permit, whichever is lower. Hours of operation for reliability-related activities may exceed these limits only as necessary to comply with testing requirements of National Fire Protection Association (NFPA) 25 – "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition.

*(Adopted 8/1/01; Amended 7/25/07)*

**9-8-331** **Essential Public Service, Hours of Operation:** An essential public service may only operate an emergency standby engine under the following circumstances:

331.1 For emergency use for an unlimited number of hours; and

331.2 Until January 1, 2012, for reliability-related activities so long as total hours of operation for this purpose do not exceed 200 hours per calendar year, or limitations contained in a District permit, whichever is lower.

331.3 Effective January 1, 2012, for reliability-related activities so long as total hours of operation for this purpose do not exceed 100 hours in a calendar year, or limitations contained in a District permit, whichever is lower.

*(Adopted 8/1/01; Amended 7/25/07)*

## 9-8-400 ADMINISTRATIVE REQUIREMENTS

**9-8-401** **Compliance Schedule:** A person subject to the requirements of Section 9-8-301, 302, 303, 304, 305 or 306 shall submit an application for any Authority to Construct, necessary to achieve compliance with such requirements no later than one year prior to the applicable compliance date listed in Section 9-8-301, 302, 303, 304, 305 or 306.

*(Amended July 25, 2007)*

**9-8-402** **Reporting Requirements for Delayed Compliance:** A person opting to comply with one of the delayed compliance options set forth in Section 9-8-303 or 305 shall notify the APCO in writing no later than January 1, 2012 that the owner or operator of a stationary engine has elected to comply with requirements of Section 9-8-303 in lieu of Section 9-8-301 or 302, or to comply with the requirements of Section 9-8-305 in lieu of Section 9-8-304. The report shall include the following information about the engine: source number; plant number, name, contact, phone number, address; and engine make, model, model year, and size.

*(Amended July 25, 2007)*

## 9-8-500 MONITORING AND RECORDS

**9-8-501** **Initial Demonstration of Compliance:** A person who must modify existing sources or install new control equipment shall conduct a District approved source test, pursuant to Sections 9-8-601 and 602 according to the schedule listed in the following table:

| Engines Operated to Comply with Section | Date that the Initial Source Test Must Be Completed | Date that the Initial Source Test Results Must Be Submitted to the District |
|---|---|---|
| 9-8-301, 302, 304 or 306 | March 31, 2012 | May 31, 2012 |
| 9-8-303 or 305 | March 31, 2016 | May 31, 2016 |

*(Amended July 25, 2007)*

**9-8-502** **Recordkeeping:** Any person who operates any engine subject to Section 9-8-300 shall comply with the following recordkeeping requirements:

502.1 Any person who operates any engine that is exempt from the requirements of Section 9-8-301, 302, 303, or 304 by Section 9-8-110 or 111 shall keep records of the number of hours the engine is fired on a monthly basis. Such records shall be retained for a minimum of 24 months from the date of entry and made available to District staff upon request.

502.2 Any person who operates a dual fuel pilot compression-ignited engines in accordance to Sections 9-8-306 shall keep records of fuel usage for each type of fuel used for a minimum of 24 months and make them available to the District staff upon request.

502.3 Any person who conducts either an initial demonstration of compliance according to Sections 9-8-501 and 9-8-601, 9-8-602, a quarterly demonstration of compliance according to Section 9-8-503, or an annual demonstration of compliance according to Sections 9-8-504 and 9-8-601 shall keep records of the compliance demonstration for a minimum of 24 months from the date of creation and made available to the District staff upon request.

502.4 Any person who operates an engine pursuant to Section 9-8-305 shall keep records verifying the certification of that engine for a minimum of 24 months.

*(Amended July 25, 2007)*

**9-8-503** **Quarterly Demonstration of Compliance:** Any person who must comply with Section 9-8-301, 302, 303, 304, 305, or 306 shall use a portable analyzer to take NOx and CO emission readings to verify compliance with the applicable emission limits in Sections 9-8-301 through 305 at least once during each calendar quarter in which a source test is not performed. All emission readings shall be taken with the engine operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations. NOx emission readings taken pursuant to this section shall be averaged over a consecutive 15-minute period.

*(Adopted July 25, 2007)*

**9-8-530** **Emergency Standby and Low Usage Engines, Monitoring and Recordkeeping:** Each emergency standby and low usage engine shall be equipped with a non-resettable totalizing meter that measures hours of operation or fuel usage. All records shall be kept for at least two years, and shall be available for inspection by District staff upon request. The operator shall keep a monthly log of usage that shall indicate the following:

530.1 Hours of operation (total)

530.2 Hours of operation (emergency)

530.3 For each emergency, the nature of the emergency condition.

For low usage engines, these provisions become effective on January 1, 2012.

*(Adopted 8/1/01; Amended 7/25/07)*

## 9-8-600 MANUAL OF PROCEDURES

**9-8-601** **Determination of Nitrogen Oxides:** The methods by which samples of exhaust gases are collected and analyzed to determine concentrations of nitrogen oxides are set forth in the District's Manual of Procedures, Volume IV, ST-13 A.

*(Amended July 25, 2007)*

**9-8-602** **Determination of Carbon Monoxide and Stack Gas Oxygen:** The methods by which samples of exhaust gases are collected and analyzed to determine concentrations of carbon monoxide and stack gas oxygen are set forth in the District's Manual of Procedures, Volume IV, ST-6 (carbon monoxide) and ST-14 (oxygen).

# REGULATION 9
# INORGANIC GASEOUS POLLUTANTS
# RULE 7
# NITROGEN OXIDES AND CARBON MONOXIDE FROM INDUSTRIAL, INSTITUTIONAL AND COMMERCIAL BOILERS, STEAM GENERATORS AND PROCESS HEATERS

## INDEX


**9-7-100 GENERAL**

9-7-101 Description
9-7-110 Exemptions
9-7-111 Limited Exemption, Low Fuel Usage – Section 9-7-301
9-7-112 Limited Exemption, Low Fuel Usage – Section 9-7-307
9-7-113 Limited Exemption, Natural Gas Curtailment and Testing
9-7-114 Limited Exemption, Tune-up
9-7-115 Limited Exemption, Startup and Shutdown
9-7-116 Limited Exemption, Compliance Extension for Facilities Subject to Regulation 9, Rule 9
9-7-117 Limited Exemption, Devices Rated 75 MM BTU/hr and Higher Limited to 9 PPMV NOx

**9-7-200 DEFINITIONS**

9-7-201 Annual Heat Input
9-7-202 Annual Maximum Heat Capacity
9-7-203 Boiler or Steam Generator
9-7-204 British Thermal Unit (BTU)
9-7-205 Digester Gas
9-7-206 Digester Gas-Fired Device
9-7-207 Gaseous Fuel
9-7-208 Heat Input
9-7-209 Heat-Input Weighted Average Limit
9-7-210 Higher Heating Value (HHV)
9-7-211 Landfill Gas
9-7-212 Landfill Gas-Fired Device
9-7-213 Load-Following Unit
9-7-214 Natural Gas
9-7-215 Natural Gas Curtailment
9-7-216 Nitrogen Oxide (NOx) Emissions
9-7-217 Process Heater
9-7-218 Rated Heat Input
9-7-219 Shutdown Period
9-7-220 Startup Period
9-7-221 Therm

**9-7-300 STANDARDS**

9-7-301 Interim Emission Limits
9-7-302 Deleted
9-7-303 Deleted
9-7-304 Low Fuel Usage Requirements – Section 9-7-301
9-7-305 Deleted
9-7-306 Deleted
9-7-307 Final Emission Limits
9-7-308 Compliance Schedule
9-7-309 Low Fuel Usage Requirements – Section 9-7-307

9-7-310 Prohibition of Commerce in Uncertified Devices
9-7-311 Insulation Requirements
9-7-312 Stack Gas Temperature Limits
9-7-313 Deleted

**9-7-400 ADMINISTRATIVE REQUIREMENTS**

9-7-401 Deleted
9-7-402 Deleted
9-7-403 Initial Demonstration of Compliance
9-7-404 Registration
9-7-405 Deleted
9-7-406 Application for Certification
9-7-407 Deleted
9-7-408 Designation of Load-Following Units

**9-7-500 MONITORING AND RECORDS**

9-7-501 Combinations of Different Fuels
9-7-502 Deleted
9-7-503 Records
9-7-504 Low Fuel Usage - Monitoring and Records
9-7-505 Original Manufacture Date
9-7-506 Periodic Testing

**9-7-600 MANUAL OF PROCEDURES**

9-7-601 Determination of Nitrogen Oxides
9-7-602 Determination of Carbon Monoxide and Stack-Gas Oxygen
9-7-603 Compliance Determination
9-7-604 Tune-Up Procedures
9-7-605 Determination of Higher Heating Value
9-7-606 Certification and Periodic Test Methods

**ATTACHMENT 1 – DELETED**

# REGULATION 9
# INORGANIC GASEOUS POLLUTANTS
# RULE 7
# NITROGEN OXIDES AND CARBON MONOXIDE FROM INDUSTRIAL, INSTITUTIONAL AND COMMERCIAL BOILERS, STEAM GENERATORS AND PROCESS HEATERS

(Adopted September 16, 1992)

**9-7-100 GENERAL**

**9-7-101 Description:** This rule limits the emissions of nitrogen oxides (NOx) and carbon monoxide (CO) from industrial, institutional and commercial boilers, steam generators and process heaters.

**9-7-110 Exemptions:** The requirements of this rule shall not apply to the following:

110.1 Boilers, steam generators and process heaters with a rated heat input of 2 million BTU/hour or less, if fired exclusively with natural gas, liquefied petroleum gas (LPG), or any combination thereof;

110.2 Boilers, steam generators and process heaters with a rated heat input less than 1 million BTU/hour fired with any fuel;

110.3 Boilers, steam generators and process heaters that are used in petroleum refineries;

110.4 Boilers used by public electric utilities or qualifying small power production facilities, as defined in Section 228.5 of the Public Utilities Code, to generate electricity;

110.5 Waste heat recovery boilers that are used to recover sensible heat from the exhaust of combustion turbines or reciprocating internal combustion engines;

110.6 Kilns, ovens, and furnaces used for drying, baking, heat treating, cooking, calcining or vitrifying; or

110.7 Process heaters used to heat thermal fluid for radiant comfort heating.

*(Amended 7/30/2008; 5/4/2011)*

**9-7-111 Limited Exemption, Low Fuel Usage - Section 9-7-301:** The requirements of Section 9-7-301 shall not apply to the use of any boiler, steam generator, or process heater with an annual heat input less than 90,000 therms during each consecutive 12-month period after July 1, 1993, or that accepts a limiting condition in their operating permit to limit the annual heat input to less than 90,000 therms, provided the requirements of Sections 9-7-304 and 504 are satisfied. This exemption is not valid for a boiler, steam generator, or process heater that is subject to the requirements of Section 9-7-307 after the effective date of the applicable standard in that section.

*(Amended 7/30/2008; 5/4/2011)*

**9-7-112 Limited Exemption, Low Fuel Usage - Section 9-7-307:** The requirements of Sections 9-7-301, 307, 311 and 312 shall not apply to the use of any boiler, steam generator or process heater that was first operated prior to January 1, 2012 provided that all of the following conditions are met:

112.1 For devices with a rated heat input less than 10 million BTU/hr, the device uses less than 10% of its annual maximum heat capacity in each consecutive 12-month period beginning January 1, 2012 and the requirements of Sections 9-7-309 and 504 are satisfied;

112.2 For devices with a rated heat input of 10 million BTU/hr or more, the device uses less than 10% of its annual maximum heat capacity in each consecutive 12-month period beginning January 1, 2012 and the requirements of Section 9-7-504 are satisfied and the device does not exceed a NOx exhaust concentration of 30 ppmv or a CO exhaust concentration of 400 ppmv, both dry at 3 percent oxygen.

A boiler, steam generator or process heater that uses 10% of more of its annual maximum heat capacity in any consecutive 12-month period after the effective date specified in Section 9-7-112.1 or 112.2, as applicable, shall not thereafter be eligible for this exemption. An operator of a boiler, steam generator or process heater that loses eligibility for this exemption by using more than the specified amount of fuel in

any consecutive 12-month period shall comply with the applicable standards of Section 9-7-307 within 24 months.

*(Adopted 7/30/2008; Amended 5/4/2011)*

**9-7-113** **Limited Exemption, Natural Gas Curtailment and Testing:** The requirements of Section 9-7-307 shall not apply to any boiler, steam generator or process heater while it burns non-gaseous fuel during a natural gas curtailment or during testing to verify readiness for such a curtailment, provided that all of the following conditions are met:

113.1 The device does not burn non-gaseous fuel for more than 168 total hours in each consecutive 12-month period, plus 48 hours in each consecutive 12-month period for oil-burn readiness testing or state, federal or local agency-required performance testing,

113.2 The device does not exceed a NOx exhaust concentration of 150 ppmv, dry at 3 percent oxygen, and

113.3 The records specified in Section 9-7-503.3 are maintained.

*(Adopted 7/30/2008; Amended 5/4/2011)*

**9-7-114** **Limited Exemption, Tune-Up:** The emission limits of Section 9-7-307 shall not apply during the tune-up of a boiler, steam generator or process heater required by Section 9-7-313.

*(Adopted 7/30/2008; Amended 5/4/2011)*

**9-7-115** **Limited Exemption, Startup and Shutdown:** The emission limits of Section 9-7-307 shall not apply during startup and shutdown periods provided that all of the following conditions are met:

115.1 Each startup and shutdown period shall not exceed two hours, unless otherwise allowed in a District Permit to Operate. In no case shall the startup period exceed 12 hours, or the shutdown period exceed 9 hours.

115.2 All emission control systems shall be in operation and emissions shall be minimized, to the extent possible, during startup and shutdown periods.

*(Adopted July 30, 2008)*

**9-7-116** **Limited Exemption, Compliance Extension for Facilities Subject to Regulation 9, Rule 9:** Boilers, steam generators or process heaters located at the same facility as a turbine that is subject to Regulation 9, Rule 9 and that is modified or replaced to comply with Section 9-9-301.2 of that regulation, shall comply with the requirements of Section 9-7-307 no later than 24 months after the date otherwise specified for compliance in Section 9-7-308.

*(Adopted July 30, 2008)*

**9-7-117** **Limited Exemption, Devices Rated 75 MM BTU/hr or Higher Limited to 9 PPMV NOx:** The emission limits of Section 9-7-307.6 shall not apply to any boiler, steam generator or process heater that is limited to 9 ppmv NOx or less by a District Permit to Operate in effect on or before July 30, 2008 as long as that permit limit remains in effect.

*(Adopted July 30, 2008)*

**9-7-200** **DEFINITIONS**

**9-7-201** **Annual Heat Input:** The total heat input of fuels burned by a combustion source during any consecutive 12-month period, as determined from the higher heating value and cumulative annual usage of each fuel.

**9-7-202** **Annual Maximum Heat Capacity:** The amount of heat input that a device would have if it operated at its rated heat input continuously for 365 consecutive days.

*(Adopted July 30, 2008)*

**9-7-203** **Boiler or Steam Generator:** Any combustion equipment used to produce steam.

*(Renumbered 7/30/2008; Amended 5/4/2011)*

**9-7-204** **British Thermal Unit (BTU):** The amount of heat required to raise the temperature of one pound of water from 59° to 60°F at one atmosphere.

*(Renumbered July 30, 2008)*

**9-7-205** **Digester Gas:** Gas derived from the decomposition of organic matter in a digester.

*(Adopted July 30, 2008)*

**9-7-206** **Digester Gas-Fired Device:** A boiler, steam generator or process heater that fires or co-fires digester gas at least 90% of its operating time, on a calendar year basis.

*(Adopted July 30, 2008)*

**9-7-207** **Gaseous Fuel:** Any fuel that is a gas at 68°F and one atmosphere.

*(Adopted July 30, 2008)*

**9-7-208** **Heat Input:** The heat of combustion released due to burning a fuel in a source, using the higher heating value of the fuel. This does not include the sensible heat of incoming combustion air.

*(Renumbered July 30, 2008)*

**9-7-209** **Heat-Input Weighted Average Limit:** For devices using fuels with different NOx limits, the applicable limit is the heat-input weighted average of the limits for each fuel used, which is:

Σ ((heat input for a fuel) x (NOx limit for that fuel)) for all fuels used, divided by: (total heat input for all fuels).

*(Amended, Renumbered 7/30/2008; Amended 5/4/2011)*

**9-7-210** **Higher Heating Value (HHV):** The total heat liberated per mass of fuel burned (BTU per pound), when fuel and dry air at standard conditions undergo complete combustion and all resultant products are brought to their standard states at standard conditions. The HHV is determined as specified in Section 9-7-605.

*(Renumbered July 30, 2008)*

**9-7-211** **Landfill Gas:** Gas derived from the decomposition of waste in a landfill.

*(Adopted July 30, 2008)*

**9-7-212** **Landfill Gas-Fired Device:** A boiler, steam generator or process heater that fires or co-fires landfill gas at least 90% of its operating time, on a calendar year basis.

*(Adopted July 30, 2008)*

**9-7-213** **Load-Following Unit:** A unit that cannot be operated in a base-loaded mode, and that has normal operational load fluctuations and requirements, imposed by fluctuations in the process(es) served by the unit, that exceed the operational response range of a Ultra-Low NOx burner system operating at 9 ppmv NOx, as determined by the District and indicated on the device's permit to operate.

*(Adopted July 30, 2008)*

**9-7-214** **Natural Gas:** Any mixture of gaseous hydrocarbons containing at least 80 percent methane by volume, as determined according to Standard Method ASTM D1945-64.

*(Renumbered July 30, 2008)*

**9-7-215** **Natural Gas Curtailment:** A shortage in the supply of pipeline natural gas, due solely to supply limitations or restrictions in distribution pipelines by the utility supplying the gas, and not due to the cost of natural gas.

*(Adopted July 30, 2008)*

**9-7-216** **Nitrogen Oxide (NOx) Emissions:** The sum of nitric oxide (NO) and nitrogen dioxide ($NO_2$) in the flue gas, collectively expressed as nitrogen dioxide.

*(Renumbered July 30, 2008)*

**9-7-217** **Process Heater:** Any combustion equipment that transfers heat from combustion gases to water or process streams.

*(Amended, Renumbered 7/30/2008; Amended 5/4/2011)*

**9-7-218** **Rated Heat Input:** The heat input capacity specified on the nameplate of the boiler, steam generator or process heater, or the sum of the capacities on the nameplates of the burners in the boiler, steam generator or process heater, whichever is greater.

*(Amended, Renumbered July 30, 2008)*

**9-7-219** **Shutdown Period:** The period of time during which a unit is taken from an operational to a non-operational status.

*(Adopted July 30, 2008)*

**9-7-220** **Startup Period:** The period of time during which a unit is brought from a non-operational status to operating temperature, including the time required for the unit's emission control system to reach full operation.

*(Adopted July 30, 2008)*

**9-7-221** **Therm:** One hundred thousand (100,000) BTU's.

*(Renumbered July 30, 2008)*

**9-7-300** **STANDARDS**

**9-7-301** **Interim Emission Limits:** No person shall operate a boiler, steam generator or process heater with a rated heat input greater than or equal to 10 million BTU per hour unless the following emission limits are met:

301.1 Nitrogen oxide (NOx) emissions shall not exceed 30 ppmv, dry at 3 percent oxygen when gaseous fuel is used;

301.2 Nitrogen oxide (NOx) emissions shall not exceed 40 ppmv, dry at 3 percent oxygen when non-gaseous fuel is used;

301.3 Nitrogen oxide (NOx) emissions shall not exceed the heat-input weighted average of the limits in Sections 9-7-301.1 and 301.2 when a combination of gaseous and non-gaseous fuel is used;

301.4 Carbon monoxide (CO) emissions shall not exceed 400 ppmv, dry at 3 percent oxygen.

This section shall not apply to any boiler, steam generator or process heater subject to a NOx or CO emission limit in Section 9-7-307.

*(Amended July 30, 2008)*

**9-7-302 Deleted July 30, 2008**

**9-7-303 Deleted July 30, 2008**

**9-7-304 Low Fuel Usage Requirements – Section 9-7-301:** No person shall operate any boiler, steam generator or process heater under the limited exemption in Section 9-7-111, or with rated heat input less than 10 million BTU per hour with the capability of firing any non-gaseous fuel, without doing at least one of the following:

304.1 Operate in a manner that maintains stack-gas oxygen concentrations at less than or equal to 3 percent by volume on a dry basis; or

304.2 Perform an inspection and tune-up at least once every 12 months by a technician in accordance with the procedure specified in Section 9-7-604; or

304.3 Meet the emission limits specified in Sections 9-7-301.

*(Amended 7/30/2008; 5/4/2011)*

**9-7-305 Deleted July 30, 2008**

**9-7-306 Deleted July 30, 2008**

**9-7-307 Final Emission Limits:** No person shall operate a boiler, steam generator or process heater with a rated heat input listed in the table below that exceeds the corresponding NOx and CO emission limits on or after the corresponding effective date specified in Section 9-7-308.

| Emission Limit | Rated Heat Input (million BTU/hr) | Fuel | NOx Limit (ppmv, dry at 3% oxygen) | CO Limit (ppmv, dry at 3% oxygen) |
|---|---|---|---|---|
| 307.1 | >2 to 5 | gaseous, except landfill or digester gas | 30 | 400 |
| 307.2 | >5 to <10 | | 15 | 400 |
| 307.3 | 10 to <20 | | 15 | 400 |
| 307.4 | 20 or more, load-following unit | | 15 | 400 |
| 307.5 | 20 to <75 | | 9 | 400 |
| 307.6 | 75 or more | | 5 | 400 |
| 307.7 | 1 or more | landfill or digester gas | 30 | 400 |
| 307.8 | 1 or more | non-gaseous | 40 | 400 |
| 307.9 | 1 or more | multiple fuels | heat-input weighted average limit | 400 |

*(Adopted 7/30/2008; Amended 5/4/2011)*

**9-7-308 Compliance Schedule:** Boilers, steam generators and process heaters subject to the requirements of Section 9-7-307 shall comply with those requirements in accordance with the schedule in the table below.

| Applicable NOx Limit | At least 33% of devices at a single facility | At least 66% of devices at a single facility | 100% of devices at a single facility |
|---|---|---|---|
| 9-7-307.1<br>9-7-307.2 | Effective Date: January 1, 2013 | One year after Effective Date | Two years after Effective Date |
| 9-7-307.3<br>9-7-307.4<br>9-7-307.5<br>9-7-307.6 | Effective Date: January 1, 2012 | One year after Effective Date | Two years after Effective Date |
| 9-7-307.7<br>9-7-307.8<br>9-7-307.9 | Effective Date: January 1, 2013 for devices with rated input <10 MM BTU/hr; July 30, 2008 for devices with rated input ≥10 MM BTU/hr | One year after Effective Date | Two years after Effective Date |

For the purpose of complying with the required minimum percentages shown in this table, all boilers, steam generators and process heaters at a single facility with rated heat inputs less than 10 MM BTU/hr, including those subject to Section 9-7-112, may be grouped. All other boilers, steam generators and process heaters at a single facility, including those subject to Section 9-7-112, may be grouped, except for those that are subject to Sections 307.7, 307.8 or 307.9 that also have an effective date of July 30, 2008.

308.1 Notwithstanding the indicated minimum percentages, boilers, steam generators and process heaters rated >2 to 5 MM BTU/hr shall have an effective date 10 years after original manufacture date if manufactured prior to January 1, 2011, IF this is later than the normal effective date.

308.2 Notwithstanding the indicated minimum percentages, boilers, steam generators and process heaters rated >5 to <20 MM BTU/hr shall have an effective date 10 years after original manufacture date if manufactured prior to January 1, 2012, IF this is later than the normal effective date.

308.3 Notwithstanding the indicated minimum percentages, boilers, steam generators and process heaters rated 20 MM BTU/hr or higher shall have an effective date 5 years after original manufacture date if manufactured prior to January 1, 2012, IF this is later than the normal effective date.

*(Adopted 7/30/2008; Amended 5/4/2011)*

**9-7-309 Low Fuel Usage Requirements – Section 9-7-307:** No person shall operate any boiler, steam generator or process heater under the limited exemption in Section 9-7-112.1 without doing at least one of the following:

309.1 Deleted May 4, 2011

309.2 Perform an inspection and tune-up at least once per calendar year by a technician in accordance with the procedure specified in Section 9-7-604; or

309.3 Meet the applicable emission limits in Section 9-7-307.

*(Adopted 7/30/2008; Amended 5/4/2011)*

**9-7-310 Prohibition of Commerce in Uncertified Devices:** Effective January 1, 2012, no person shall sell, offer for sale, or install any boiler, steam generator or process heater subject to Section 9-7-307.1 or 307.2 unless the device is certified to comply with the applicable standards of these sections by the APCO. This certification requirement shall not apply to burner assembly retrofit packages, or to devices installed in accordance with a District Permit to Operate.

*(Adopted 7/30/2008; Amended 5/4/2011)*

**9-7-311 Insulation Requirements:** No person shall operate a boiler or steam generator unless the exposed, external surface of the device, including all pipes and ducts heated by the device, does not exceed a temperature of 120°F. This requirement shall not apply to any of the following:

311.1 Any device that meets the definition of a high-temperature water boiler in California Code of Regulations, Title 8.

311.2 Any surface or appurtenance that must remain un-insulated for safety or operational reasons.

311.3 Any surface that has at least one inch of insulation.

311.4 Any surface heated by a source other than the boiler or steam generator, including sunlight.

311.5 Any exhaust stack surface.

*(Adopted 7/30/2008; Amended 5/4/2011)*

**9-7-312 Stack Gas Temperature Limits:** Effective January 1, 2013, no person shall operate a boiler or steam generator with a stack gas temperature (downstream of any economizer) that exceeds the indicated maximum temperature unless the device is certified by the Air-Conditioning, Heating and Refrigeration Institute (AHRI) as having a thermal efficiency of 80% or more:

| Heater Design | Maximum Temperature (°F) | |
|---|---|---|
| | Gaseous Fuel | Non-Gaseous Fuel |
| **firetube** | 100°F over saturated steam temperature for steam boiler, 100°F over hot water temperature for hot water boiler OR 250 °F greater than combustion air temperature, whichever is higher | 100°F over saturated steam temperature for steam boiler, 100°F over hot water temperature for hot water boiler OR 300 °F greater than combustion air temperature, whichever is higher |
| **watertube** | 150°F over saturated steam temperature for steam boiler, 150°F over hot water temperature for hot water boiler OR 250 °F greater than combustion air temperature, whichever is higher | 150°F over saturated steam temperature for steam boiler, 150°F over hot water temperature for hot water boiler OR 300 °F greater than combustion air temperature, whichever is higher |

*(Adopted 7/30/2008; Amended 5/4/2011)*

**9-7-313 Deleted May 4, 2011**

**9-7-400 ADMINISTRATIVE REQUIREMENTS**

**9-7-401 Deleted July 30, 2008**

**9-7-402 Deleted July 30, 2008**

**9-7-403 Initial Demonstration of Compliance:** No person shall operate a boiler, steam generator or process heater that is subject to the requirements of Sections 9-7-307.1 through 307.6, or a boiler, steam generator or process heater with a rated heat input less than 10 MM BTU/hr that is subject to the requirements of Sections 9-7-307.7 though 9-7-307.9 unless compliance with these requirements is verified in accordance with Sections 9-7-601 or 602 within 1 year of the date on which these requirements become effective. However, devices with a rated heat input <10 MM BTU/hr may be tested using a portable analyzer in accordance with Section 9-7-606. This section does not apply to any device required to perform verification testing to establish compliance with applicable requirements of Sections 9-7-307 in accordance with a District Authority to Construct issued on or after January 1, 2013, or to any device that has had a previous source test performed in accordance with Sections 9-7-601 and 602 that verifies compliance with the applicable requirements of Section 9-7-307, or to any device certified in accordance with Section 9-7-310. The requirements of this section may be satisfied by monitoring emissions with a continuous emission monitoring system (CEMS) that meets the requirements of Regulation 1-522.

*(Amended 7/30/2008; 5/4/2011)*

**9-7-404 Registration:** Effective January 1, 2011, no person shall operate any boiler, steam generator or process heater with a rated heat input greater than 2 and less than 10 million BTU/hr unless the device is registered with the District. Any person registering a device shall pay the fees specified in Regulation 3. This registration requirement shall not apply to any device for which the operator holds a District Permit to Operate.

*(Adopted 7/30/2008; Amended 5/4/2011)*

**9-7-405 Deleted May 4, 2011**

**9-7-406** **Application for Certification:** A manufacturer may submit an application to certify compliance with the requirements of Section 9-7-307.1 or 9.7-307.2 for a boiler, steam generator or process heater model that is subject to these requirements. The application shall be made on forms specified by the APCO. The certification application shall include a demonstration that the boiler, steam generator or process heater model was tested in accordance with Section 9-7-606 and found to comply with the requirements of Sections 9-7-307.1 or 9.7-307.2. A portable analyzer may not be used for this testing. After completing review of the application for certification and source test report, the APCO will approve the certification and include the subject model on the list of certified devices, or will deny the certification.

*(Adopted 7/30/08; Amended 5/4/2011)*

**9-7-407** **Deleted May 4, 2011**

**9-7-408** **Designation of Load-Following Units:** To be eligible for the load-following emission standard in section 9-7-307, a unit must be designated a load-following unit by the APCO on the unit Permit to Operate. In order to support this designation, the unit operator shall include the following information with an application for an Authority to Construct or an application for a modification to a Permit to Operate, as specified in Regulation 2:

408.1 A description of the processes the unit serves and the normal operational load fluctuations and load requirements imposed on the unit, verifying that the unit cannot be operated in a base-loaded mode.

408.2 A detailed report on the design and condition of the unit, burner(s), burner controls, and any other subsystem that may affect the ability of the unit to comply with a 9 ppmv NOx limit, including a verification that the unit is free of air leaks, and is operated within normal design parameters, and is otherwise free of significant design defects and physical defects and is operated within reasonable parameters. This report shall verify that the inability of the unit to comply with a 9 ppmv NOx limit is substantially caused by the system load fluctuations and the limitations of state-of-the-art, commercially-available, 9 ppmv burners and burner controls, rather than any other factor.

408.3 Technical data such as steam demand charts or other information to support the description and report described above.

*(Adopted July 30, 2008)*

**9-7-500** **MONITORING AND RECORDS**

**9-7-501** **Combinations of Different Fuels:** No person shall simultaneously fire combinations of different fuels in a device subject to the requirements of Sections 9-7-301.3 or 307.9 without first installing a non-resettable totalizing fuel meter in each fuel line for each source.

*(Amended July 30, 2008)*

**9-7-502** **Deleted July 30, 2008**

**9-7-503** **Records:** Any person subject to the requirements of this rule shall keep records of the following:

503.1 Documentation verifying tune-ups performed in accordance with Sections 9-7-304.2, or 309.2.

503.2 In the event that the limited exemption in Section 9-7-113 is invoked, documentation from the natural gas supplier verifying that natural gas was unavailable due to a natural gas curtailment.

503.3 Documentation verifying the hours of equipment testing using non-gaseous fuel, and of total operating hours using non-gaseous fuel during each calendar month.

503.4 The results of any testing required by Sections 9-7-403 or 506.

503.5 Digester gas-fired and landfill gas-fired devices operating under Section 9-7-307.7 shall maintain records of total operating hours and operating hours firing or co-firing digester or landfill gas.

Such records shall be retained for a minimum of 24 months from date of entry and be made available to District staff upon request.

*(Amended 7/30/2008; 5/4/2011)*

**9-7-504** **Low Fuel Usage - Monitoring and Records:** Any person who operates a boiler, steam generator or process heater under the limited exemption of Section 9-7-111 or 112 shall comply with the following requirements:

504.1 Operate a non-resettable totalizing meter for each fuel that demonstrates that the source operated at or below the applicable heat input level, or receive APCO approval for using utility service meters, purchase or tank fill records, or any other acceptable methods for measuring the cumulative annual usage of each fuel; and

504.2 Have available for inspection by the APCO annual fuel use data and the Higher Heating Value of each fuel used, for the prior consecutive 12-month period. Records shall be maintained and made accessible to the APCO for a period of 24 months from the date the record is made.

An operator of a boiler, steam generator or process heater who claims eligibility for the limited exemption in Section 9-7-111 or 112, but who fails to maintain records to allow verification of fuel usage shall have the burden of proof to establish eligibility for the limited exemption.

*(Amended July 30, 2008)*

**9-7-505** **Original Manufacture Date:** Any person who operates a boiler, steam generator or process heater that is subject to a standard in Sections 9-7-307.1 through 307.6 and that elects to use an effective date for this standard that is based on the original manufacture date of the device shall make available the original manufacture date of the device on the original manufacturer's identification or rating plate permanently fixed to the device, or else on a copy of the manufacturer's invoice.

*(Adopted July 30, 2008)*

**9-7-506** **Periodic Testing:** No person shall operate a boiler, steam generator or process heater subject to an emission limit specified in the table below unless they verify compliance with the limit at the specified intervals. Testing shall be performed in accordance with Sections 9-7-601 and 602. Alternatively, devices may be tested using a portable analyzer in accordance with Section 9-7-606. No person shall operate a device that uses non-gaseous fuel unless they perform testing using non-gaseous fuel to verify compliance with Section 9-7-307.8 or 307.9, in addition to testing to verify compliance with any other applicable standard in Section 9-7-307. This section does not apply to any device required to perform periodic testing in accordance with a District Permit to Operate or to any device that verifies compliance with an emission limit with a continuous emission monitor that meets the requirements of Regulation 1-522.

| Emission Limit | Testing Interval |
|---|---|
| 9-7-307.1<br>9-7-307.2<br>9-7-307.3 | Every calendar year, beginning with the first complete year after the effective date in Section 9-7-308. |
| 9-7-307.4<br>9-7-307.5<br>9-7-307.6 | Every calendar year, beginning with the first complete year after the effective date in Section 9-7-308. |
| 9-7-307.8<br>9-7-307.9 | Within 60 days of the first use of non-gaseous fuel in any calendar year in which non-gaseous fuel is used. Use of non-gaseous fuel under limited exemption in Section 9-7-113 shall not trigger this requirement. |

*(Adopted 7/30/2008; Amended 5/4/2011)*

**9-7-600** **MANUAL OF PROCEDURES**

**9-7-601** **Determination of Nitrogen Oxides:** The methods by which samples of exhaust gases are collected and analyzed to determine concentrations of nitrogen oxides are set forth in the District Manual of Procedures, Volume IV, ST-13A.

*(Amended May 4, 2011)*

**9-7-602** **Determination of Carbon Monoxide and Stack-Gas Oxygen:** Compliance with the carbon monoxide emission requirements of Sections 9-7-301 and 307 and the stack-

gas oxygen concentration requirement of Section 9-7-304.1 shall be determined as set forth in the District Manual of Procedures, Volume IV, ST-6 (carbon monoxide) and ST-14 (oxygen).

*(Amended July 30, 2008)*

**9-7-603** **Compliance Determination:** All emission determinations shall be made in the as-found operating condition, except that no compliance determination shall be established during startup or shutdown.

*(Amended July 30, 2008)*

**9-7-604** **Tune-Up Procedures:** The tune-up procedure required by Sections 9-7-304.2 and 309.2 shall be performed in accordance with the procedure set forth in the District Manual of Procedures, Volume I, Chapter 5.

*(Adopted 9/15/1993; Amended 7/30/2008; 5/4/2011)*

**9-7-605** **Determination of Higher Heating Value:** If certification of the Higher Heating Value is not provided by the third-party fuel supplier, it shall be determined by one of the following test methods: (1) ASTM D2015-85 for solid fuels; (2) ASTM D240-87 or ASTM D2382-88 for liquid hydrocarbon fuels; or (3) ASTM D1826-88, or ASTM D1945-81 in conjunction with ASTM D3588-89, for gaseous fuels.

**9-7-606** **Certification, Initial Demonstration of Compliance and Periodic Test Methods**: The test methods specified in the following table may be used to perform an initial demonstration of compliance in accordance with Section 9-7-403, establish equipment certification in accordance with Section 9-7-406, and also to perform periodic monitoring in accordance with Section 9-7-506. Portable analyzers may only be used where explicitly allowed in Sections 9-7-403 and 506. In addition, any other test method approved for this purpose by the Air Pollution Control Officer of the District and by the regional administrator of the United States Environmental Protection Agency may also be used.

| Emission Limit or Parameter | Test Method |
|---|---|
| **NOx (ppmv)** | 1. BAAQMD Manual of Procedures, Volume IV, ST-13 A<br>2. California Air Resources Board Method 100<br>3. U.S. EPA Method 7E<br>4. U.S. EPA Method CTM-030 (if portable analyzer use is allowed) |
| **CO (ppmv)** | 1. BAAQMD Manual of Procedures, Volume IV, ST-6<br>2. California Air Resources Board Method 100<br>3. U.S. EPA Method 10<br>4. U.S. EPA Method CTM-030 (if portable analyzer use is allowed) |
| **oxygen (%)** | 1. BAAQMD Manual of Procedures, Volume IV, ST-14<br>2. California Air Resources Board Method 100<br>3. U.S. EPA Method 3 or 3A<br>4. U.S. EPA Method CTM-030 (if portable analyzer use is allowed) |

*(Adopted May 4, 2011)*

**ATTACHMENT 1 DELETED MAY 4, 2011**

# REGULATION 9
# INORGANIC GASEOUS POLLUTANTS
# RULE 9
# NITROGEN OXIDES FROM STATIONARY GAS TURBINES

## INDEX


**9-9-100 GENERAL**

9-9-101 Description
9-9-110 Exemption, Small Gas Turbines
9-9-111 Exemption, General
9-9-112 Limited Exemption, Low Usage
9-9-113 Exemption, Inspection and Maintenance Periods
9-9-114 Exemption, Start-up and Shutdown Periods
9-9-115 Limited Exemption, Minor Inspection and Maintenance Operations
9-9-116 Limited Exemption, Very Limited Use Turbines
9-9-120 Interchangeable Emission Reduction Credits

**9-9-200 DEFINITIONS**

9-9-201 Commercially Available
9-9-202 Dry Low NOx Combustion Technology
9-9-203 EFF
9-9-204 Emergency Use
9-9-205 Essential Gas Turbine
9-9-206 Heat Input Rating
9-9-207 HHV
9-9-208 LHV
9-9-209 Inspection and Maintenance Period
9-9-210 Natural Gas
9-9-211 Nitrogen Oxide (NOx) Emissions
9-9-212 Non-Gaseous Fuel
9-9-213 Power Augmentation
9-9-214 Power Output Rating
9-9-215 Refinery Fuel Gas
9-9-216 Selective Catalytic Reduction (SCR)
9-9-217 Shutdown Period
9-9-218 Start-up Period
9-9-219 Stationary Gas Turbine
9-9-220 Waste Gas
9-9-221 Water Injection / Steam Injection Enhancement

**9-9-300 STANDARDS**

9-9-301 Emission Limits, General
9-9-302 Emission Limits, Low Usage
9-9-303 Deleted December 6, 2006
9-9-304 Deleted December 6, 2006
9-9-305 Deleted December 6, 2006

**9-9-400 ADMINISTRATIVE REQUIREMENTS**

9-9-401 Certification, Efficiency

9-9-402 Compliance Schedule
9-9-403 Deleted December 6, 2006
9-9-404 Compliance Schedule for Future Commercial Availability of Retrofit Technology
9-9-405 Notification and Compliance Schedule, Very Limited Use Turbines
9-9-406 Other Useful Heat Recovery

**9-9-500 MONITORING AND RECORDS**

9-9-501 Monitoring and Recordkeeping Requirements
9-9-502 Records, Low Usage
9-9-503 Initial Demonstration of Compliance
9-9-504 Annual Demonstration of Compliance

**9-9-600 MANUAL OF PROCEDURES**

9-9-601 Determination of Emissions
9-9-602 Determination of Stack Gas Oxygen
9-9-603 Continuous Emission Monitoring
9-9-604 Determination of HHV and LHV
9-9-605 Compliance With Output Based NOx Emissions Standards

# REGULATION 9
# INORGANIC GASEOUS POLLUTANTS
# RULE 9
# NITROGEN OXIDES FROM STATIONARY GAS TURBINES

(Adopted May 5, 1993)

**9-9-100 GENERAL**

**9-9-101 Description:** The purpose of this Rule is to limit emissions of nitrogen oxides ($NO_X$) from stationary gas turbines.

**9-9-110 Exemption, Small Gas Turbines:** This Rule shall not apply to stationary gas turbines with a heat input rating less than 5 MM Btu/hr.

*(Amended December 6, 2006)*

**9-9-111 Exemption, General:** The requirements of this Rule shall not apply to:

111.1 Testing of aircraft gas turbine engines for flight certification.

111.2 Gas turbines used solely for firefighting and/or flood control.

111.3 Deleted December 6, 2006

*(Amended December 6, 2006)*

**9-9-112 Limited Exemption, Low Usage:** The requirements of this Rule shall not apply to the operation of gas turbines rated less than 50 MM Btu/hr heat input that operate less than 877 hours in any 12-month period, provided the requirements of Section 9-9-502 are satisfied.

*(Amended December 6, 2006)*

**9-9-113 Exemption, Inspection and Maintenance Periods:** The emission limits of Section 9-9-301 shall not apply during inspection and maintenance periods, with the following limitations:

113.1 Inspection and maintenance periods shall be limited to a total of 48 hours between May 1 and October 31 in a calendar year.

113.2 For a calendar year in which a boiler inspection required by California Labor Code Section 7682 is not performed, inspection and maintenance periods shall be limited to a total of 144 hours.

113.3 For a calendar year in which a boiler inspection required by California Labor Code Section 7682 is performed, inspection and maintenance periods shall be limited to 144 hours plus additional time required for the boiler inspection, provided, however, that the additional time shall not cause the calendar-year total of all inspection and maintenance periods to exceed 312 hours.

*(Adopted 9/21/94; Amended 12/6/06)*

**9-9-114 Exemption, Start-up and Shutdown Periods:** The emission limits of Sections 9-9-301 and 302 shall not apply during start-up or shutdown periods.

*(Adopted 9/21/94; Amended 12/6/06)*

**9-9-115 Limited Exemption, Minor Inspection and Maintenance Work:** The requirements of Section 9-9-301 shall not apply during periods of inspection and maintenance work on a gas turbine or associated components, not to exceed 4 hours on any day and 48 hours in any 12-month period, that are planned and scheduled at least 24 hours in advance. The operator shall keep records of these planned inspection and maintenance events and make them available to the APCO on request. This exemption shall not apply to low-usage turbines subject to Section 9-9-302. Any annual emissions limit required by permit condition shall include emissions resulting from this minor inspection and maintenance work.

*(Adopted December 6, 2006)*

**9-9-116 Limited Exemption, Very Limited Use Turbines:** The emission limits in Section 9-9-302.2 shall not apply to turbines that operate less than 1200 hours between January 1, 2007 and January 1, 2010, and do not operate more than 400 hours during any 12-month period after January 1, 2010, provided the requirements in Section 9-9-502 are met. Turbines that initially qualify for this limited exemption based on the number of hours of operation between January 1, 2007 and January 1, 2010, but operate more than 400 hours per 12-month period after January 1, 2010,

shall continue to comply with the emission limits in 9-9-302.2 subject to the compliance schedule set forth in Section 9-9-405. This limited exemption does not apply to the emission limits in Section 9-9-302.1.

*(Adopted December 6, 2006)*

**9-9-120** **Interchangeable Emission Reduction Credits:** Until such time as the December 6, 2006 amendments to this rule are approved into the State Implementation Plan by the EPA, the emission limits of Sections 9-9-301.2 and 9-9-302.2 may be complied with by interchangeable emission reduction credits used pursuant to and as limited by the provisions of Regulation 2, Rule 9. An operator must still comply with the emission limits of Sections 9-9-301.1 and 9-9-302.1 without using interchangeable emission reduction credits.

*(Adopted December 6, 2006)*

**9-9-200 DEFINITIONS**

**9-9-201** **Commercially Available:** Any control technology or equipment that is offered for a specific make and model of gas turbine by at least one vendor, is guaranteed by the vendor to achieve the emission control performance required by this Rule, has been demonstrated in practice at 3 or more sites, achieves the required emission control performance utilizing similar fuel composition for a regular or full-scale operation within the United States, and demonstrates at least 90% availability.

*(Adopted December 6, 2006)*

**9-9-202** **Dry Low-NOx Combustion Technology (DLN):** A turbine combustor design that uses multiple staging, air/fuel premixing or other modifications to achieve lower levels of NOx emissions as compared to conventional combustors.

*(Adopted December 6, 2006)*

**9-9-203** **EFF:** Thermal efficiency.

*(Renumbered December 6, 2006)*

**9-9-204** **Emergency Use:** Operation during a natural or civil disaster or emergency situation, as requested or ordered by any federal, state or local agency to protect the public, life or property.

*(Adopted December 6, 2006)*

**9-9-205** **Essential Gas Turbine:** A gas turbine that cannot be taken out of service without shutting down the process unit which it serves.

*(Adopted 9/21/94; Amended, Renumbered 12/6/06)*

**9-9-206** **Heat Input Rating:** The heat input requirement (based on fuel HHV) of a gas turbine at its International Standards Organization (ISO) 3977 nameplate rated power output at standard conditions of 1 atmosphere, 15° Centigrade, and 60% atmospheric humidity.

*(Adopted December 6, 2006)*

**9-9-207** **HHV:** The higher heating value of fuel.

*(Renumbered 9/21/94; 12/6/06)*

**9-9-208** **LHV:** The lower heating value of fuel.

*(Renumbered 9/21/94; 12/6/06)*

**9-9-209** **Inspection and Maintenance Period:** A period of time during which the heat recovery steam generator associated with an essential gas turbine is taken out of service for inspection or maintenance, and during which gas turbine emissions are vented to a bypass stack rather than through the heat recovery steam generator.

*(Adopted 9/21/94; Amended, Renumbered 12/6/06)*

**9-9-210** **Natural Gas:** Any mixture of gaseous hydrocarbons containing at least 80 percent methane by volume, as determined according to Standard Method ASTM D1945.

*(Adopted 9/21/94; Amended, Renumbered 12/6/06)*

**9-9-211** **Nitrogen Oxide (NOx) Emissions:** The sum of nitric oxide and nitrogen dioxide ($NO_2$) in the flue gas, collectively expressed as nitrogen dioxide.

*(Adopted 9/21/94; Renumbered 12/6/06)*

**9-9-212** **Non-Gaseous Fuel:** Any fuel which is not a gas at 68° F and one atmosphere.

*(Adopted 9/21/94; Renumbered 12/6/06)*

**9-9-213** **Power Augmentation:** An increase in the gas turbine shaft output or the decrease in turbine fuel consumption by the addition of energy recovered from exhaust heat.

*(Renumbered 9/21/94; 12/6/06)*

**9-9-214** **Power Output Rating:** The continuous megawatt (MW) rating or mechanical equivalent by a manufacturer for gas turbine(s) without power augmentation.

*(Renumbered 9/21/94; Amended, Renumbered 12/6/06)*

**9-9-215** **Refinery Fuel Gas:** A mixture of hydrogen and gaseous hydrocarbons generated by petroleum refinery processes and used by the refinery for on-site combustion in boilers, process heaters, turbines, and other combustion equipment.

*(Adopted 9/21/94; Renumbered 12/6/06)*

**9-9-216** **Selective Catalytic Reduction (SCR):** A post-combustion NOx control technique in which a reducing agent (for example: ammonia) is used in a gas-phase reaction with oxides of nitrogen in the presence of a catalyst to convert the oxides of nitrogen into nitrogen and water.

*(Renumbered 9/21/94; Amended, Renumbered 12/6/06)*

**9-9-217** **Shutdown Period:** A period of time, not to exceed two hours, during which a gas turbine is brought from normal operating power output to inactive status.

*(Adopted 9/21/94; Amended, Renumbered 12/6/06)*

**9-9-218** **Start-up Period:** A period of time, not to exceed four hours (six hours for cold steam turbine starts at combined cycle facilities), during which a gas turbine is brought from inactive status to normal operating power output.

*(Amended 9/21/94; Amended, Renumbered 12/6/06)*

**9-9-219** **Stationary Gas Turbine:** Any gas turbine system that is attached to a foundation and is gas and/or liquid fueled with or without power augmentation. Two or more gas turbines powering one shaft shall be treated as one unit.

*(Renumbered 9/21/94; Amended, Renumbered 12/6/06)*

**9-9-220** **Waste Gas:** A mixture of hydrogen, gaseous hydrocarbons and other diluent gases generated by sewage treatment or landfill biomass and used by the facility for on-site combustion in gas turbines or other combustion equipment.

*(Adopted December 6, 2006)*

**9-9-221** **Water Injection / Steam Injection Enhancement:** A retrofit design improvement to water or steam injection location, orientation, or turbine combustor or other modifications to achieve lower levels of NOx emissions as compared to existing water or steam injection design.

*(Adopted December 6, 2006)*

**9-9-300 STANDARDS**

**9-9-301 Emission Limits, General:**

301.1 A person shall not operate a stationary gas turbine unless nitrogen oxides (NOx) emission concentrations, corrected to 15 percent $O_2$ (dry basis), do not exceed the compliance limits listed below:

301.1.1 Gas turbines rated at 0.3 MW to less than 10.0 MW shall not exceed 42 ppmv, except that, for refinery fuel gas firing, the limit shall be 55 ppmv, and for non-gaseous fuel firing during natural gas curtailment or short testing periods, the limit shall be 65 ppmv.

301.1.2 Gas turbines rated at 10.0 MW and over, without SCR, shall not exceed 15 ppmv, except that, for non-gaseous fuel firing during natural gas curtailment or short testing periods, the limit shall be 42 ppmv.

301.1.3 Gas Turbines rated at 10.0 MW and over, with SCR, shall not exceed 9 ppmv, except that, for non-gaseous fuel firing during natural gas curtailment or short testing periods, the limit shall be 25 ppmv.

301.2 Effective January 1, 2010, a person shall not operate a stationary gas turbine unless nitrogen oxides ($NO_X$) emissions, corrected to 15 percent $O_2$ (dry basis), are less than either of the alternative compliance limits listed below for the turbine heat input rating and type of fuel burned:

| Turbine Heat Input Rating | Natural Gas | Refinery Fuel Gas, Waste Gas or LPG | Non-gaseous Fuel |
|---|---|---|---|
| < 5 MM Btu/hr | Exempt | Exempt | Exempt |

| Turbine Heat Input Rating | Natural Gas | Refinery Fuel Gas, Waste Gas or LPG | Non-gaseous Fuel |
|---|---|---|---|
| 5 - 50 MM Btu/hr | 2.12 lbs/MWhr or 42 ppmv | 2.53 lbs/MWhr or 50 ppmv | 3.28 lbs/MWhr or 65 ppmv |
| > 50 – 150 MM Btu/hr - no retrofit available[(a)] | 1.97 lbs/MWhr or 42 ppmv | 2.34 lbs/MWhr or 50 ppmv | 3.04 lbs/MWhr or 65 ppmv |
| > 50 – 150 MM Btu/hr - WI/SI enhancement available [(b)] | 1.64 lbs/MWhr or 35 ppmv | 2.34 lbs/MWhr or 50 ppmv | 3.04 lbs/MWhr or 65 ppmv |
| > 50 – 150 MM Btu/hr - DLN technology available [(c)] | 1.17 lbs/MWhr or 25 ppmv | 2.34 lbs/MWhr or 50 ppmv | 3.04 lbs/MWhr or 65 ppmv |
| > 150 – 250 MM Btu/hr | 0.70 lbs/MWhr or 15 ppmv | 0.70 lbs/MWhr or 15 ppmv | 1.97 lbs/MWhr or 42 ppmv |
| > 250 – 500 MM Btu/hr | 0.43 lbs/MWhr or 9 ppmv | 0.43 lbs/MWhr or 9 ppmv | 1.17 lbs/MWhr or 25 ppmv |
| > 500 MM Btu/hr | 0.15 lbs/MWhr or 5 ppmv | 0.26 lbs/MWhr or 9 ppmv | 0.72 lbs/MWhr or 25 ppmv |

(a) The emission limits on this line apply to turbines for which no Water Injection or Steam Injection enhancement or DLN combustion technology is commercially available.

(b) The emission limits on this line apply to turbines for which Water Injection or Steam Injection enhancement is commercially available.

(c) The emission limits on this line apply to turbines for which DLN combustion technology is commercially available and which have not been required to install Water Injection or Steam Injection enhancements to comply with this Section 301.2.

301.3 If a turbine burns a mixture of fuels, the turbine's NOx emission limit shall be the highest of the limits applicable to any of the fuels in the mixture.

301.4 Violation of either of the alternative standards in Section 301.2 applicable to a particular turbine shall create a rebuttable presumption that the turbine is in violation of Section 301.2. The operator of the turbine may rebut the presumption of violation by demonstrating that the turbine is in compliance with the other alternative standard.

*(Amended 9/21/94; 12/6/06)*

**9-9-302 Emission Limits, Low Usage:**

302.1 Until January 1, 2010, or other date provided under a compliance schedule pursuant to Section 9-9-402.2, a person may operate a stationary gas turbine for up to 877 hours in any 12-month period (not counting hours of emergency use) without complying with the emission limits Section 9-9-301 as long as nitrogen oxides (NOx) emission concentrations, corrected to 15 percent $O_2$ (dry basis), do not exceed 42 ppmv when firing with natural gas and 65 ppmv when firing with non-gaseous fuel, and the requirements of Section 9-9-502 are satisfied.

302.2 Effective January 1, 2010, a person may operate a stationary gas turbine rated at 50 MMBtu/hr or greater for up to 877 hours in any 12-month period (not counting hours of emergency use) without complying with the emission limits set forth in Section 9-9-301 as long as nitrogen oxides (NOx) emissions, corrected to 15 percent $O_2$ (dry basis), are less than either of the of the alternative limits listed below for the turbine's heat input rating and the type of fuel burned, and the requirements of Section 9-9-502 are satisfied:

| Turbine Heat Input Rating | Natural Gas | Refinery Fuel Gas, Waste Gas or LPG | Non-gaseous Fuel |
|---|---|---|---|
| < 50 MMBtu/hr | Exempt | Exempt | Exempt |
| 50 – 150 MMBtu/hr (3 – 10 MW) | 1.97 lbs/MWhr or 42 ppmv | N/A | 3.04 lbs/MWhr or 65 ppmv |

| Turbine Heat Input Rating | Natural Gas | Refinery Fuel Gas, Waste Gas or LPG | Non-gaseous Fuel |
|---|---|---|---|
| > 150 – 250 MMBtu/hr (10 – 19 MW) | 1.97 lbs/MWhr or 42 ppmv | N/A | 3.04 lbs/MWhr or 65 ppmv |
| > 250 – 500 MMBtu/hr (19 – 40 MW) | 1.17 lbs/MWhr or 25 ppmv | N/A | 1.97 lbs/MWhr or 42 ppmv |
| > 500 MMBtu/hr (40+ MW) | 0.72 lbs/MWhr or 25 ppmv | N/A | 1.21 lbs/MWhr or 42 ppmv |

302.3 If a turbine burns a mixture of fuels, the turbine's NOx emission limit shall be the highest of the limits applicable to any of the fuels in the mixture.

302.4 Violation of either of the alternative standards in Section 302.2 applicable to a particular turbine shall create a rebuttable presumption that the turbine is in violation of Section 302.2. The operator of the turbine may rebut the presumption of violation by demonstrating that the turbine is in compliance with the other alternative standard.

*(Amended9/21/94; 12/6/06)*

**9-9-303 Deleted December 6, 2006**

**9-9-304 Deleted December 6, 2006**

**9-9-305 Deleted December 6, 2006**

**9-9-400 ADMINISTRATIVE REQUIREMENTS**

**9-9-401 Certification, Efficiency:** If a person who operates a gas turbine subject to the limits of subsections 9-9-301.1.2 or 301.1.3 can demonstrate a thermal efficiency (EFF) greater than 25 percent in accordance with subsections 401.2.1 or 401.2.2, the emissions limit may be adjusted in accordance with Section 9-9-401.1.

401.1 $$Adjusted\ Emission\ Limit = \frac{Emission\ Limit \times EFF}{25}$$

401.2 EFF (percent efficiency) is the higher of 2.1 or 2.2. An EFF that is less than 25% shall be assigned a value of 25%.

2.1 $$EFF = \frac{3412 \times 100\%}{Actual\ Heat\ Rate\ at\ HHV\ of\ Fuel \times \frac{BTU}{KW - HR}}$$

which is the demonstrated percent efficiency of the gas turbine only as calculated without consideration of any downstream energy recovery (not used for power augmentation) from the actual heat rate, (BTU/KW-HR) or 1.34 (BTU/HP-HR); corrected to the HHV (higher heating value) of the fuel and standard conditions, as measured at peak load for that facility.

or

2.2 $$EFF = Manufacturer's\ Rated\ Efficiency\ ^{*} \times \frac{LHV}{HHV}$$

*With Air Pollution Equipment at LHV

which is the manufacturer's continuous rated percent efficiency of the gas turbine with air pollution equipment after correction from LHV to HHV of the fuel.

*(Amended 9/21/94; 12/6/06)*

**9-9-402 Compliance Schedule:**

402.1 A person who must modify existing sources or install new control equipment to meet the requirements of Section 9-9-301.2 or 302.2 shall submit an application for any Authority to Construct for the modification or installation of new control equipment by July 1, 2008, or by the date required pursuant to Section 9-9-404.3.

402.2 Any turbine subject to Sections 9-9-301.2 or 9-9-302.2 shall comply with the applicable emission limits set forth in those sections by January 1, 2010, or by the date required pursuant to Section 9-9-404.3, unless the turbine has not had a scheduled major maintenance outage by January 1, 2010, in which case the turbine shall comply with the applicable emission limits 30 days after the end of the next scheduled major maintenance outage, but in no event later than January 1, 2012.

*(Amended December 6, 2006)*

**9-9-403 Deleted December 6, 2006**

**9-9-404 Compliance Schedule for Future Commercial Availability of Retrofit Technology:** If water injection or steam injection enhancement retrofits or Dry Low NOx combustion technology become commercially available for a specific make and model of turbine after December 31, 2006, subjecting operators of that make and model of turbine to lower NOx emissions limits pursuant to Section 9-9-301.2, affected operators shall comply with Section 9-9-301.2 according to the following schedule.

404.1 Upon determining that water injection or steam injection enhancement retrofits or Dry Low NOx combustion technology are commercially available for a specific make and model of turbine, the APCO shall notify all operators of that make and model, in writing, of the commercial availability of the technology.

404.2 If any affected operator disagrees that the technology is commercially available for its turbine, as that term is defined in Section 9-9-201, the operator may object to the APCO in writing within 90 days of such notification. Within 30 days after receiving an objection, the APCO may amend the determination of commercial availability for the turbine for which the objection is made. If no objection is made for a particular turbine, or an objection is made and the APCO does not change the determination of commercial availability, the technology shall be deemed commercially available for that turbine. The APCO shall conduct a cost-effectiveness analysis prior to making a final determination of commercial availability.

404.3 Any affected operator that must install new equipment or modify its operation in a manner that requires a permit amendment in order to comply with the applicable NOx emissions limit in Section 9-9-301.2 shall (i) submit an application for Authority to Construct to install the new equipment or modify its operation within 18 months of the date of the initial notification from the APCO of the commercial availability, and (ii) comply with the more stringent emission standards associated with the commercially available technology within 36 months of the date of the initial notification, or 30 days after the end of the next scheduled major maintenance outage if no such outage is scheduled within 36 months of the date of the initial notification, but in no event more than 60 months after the date of initial notification.

404.4 If an affected operator can comply the applicable NOx emissions limit in Section 9-9-301.2 without having to install new equipment or modify its operation in a manner that requires a permit amendment, the operator shall (i) so inform the APCO in writing within 90 days of the date of the initial notification from the APCO of the commercial availability, and (ii) comply with the more stringent emission standards associated with the commercially available technology within 30 days thereafter.

*(Adopted December 6, 2006)*

**9-9-405 Notification and Compliance Schedule, Very Limited Use Turbines:** If a gas turbine exceeds 400 hours of operation in any 12-month period and is not compliant with the emission limits in Section 9-9-302.2, the operator must notify the APCO of that fact and must provide its best estimates for future operation of the turbine. Based on a review of these estimates, if the APCO determines that the turbine will likely continue to be operated at a rate exceeding 400 hours per 12-month period in the future, the APCO will provide written notice of that determination to the operator. If the APCO determines that the turbine will be operated at a rate exceeding 400 hours in the future, the turbine shall comply with the emission limits in Section 9-9-

302.2. If the operator will have to modify existing sources or install new control equipment to meet the emission limits in Section 9-9-302.2, the operator shall submit an application for Authority to Construct the modification or installation of new control equipment within 18 months of such notification, and shall comply with the emission limits in Section 9-9-302.2 within 36 months of such notification, or 30 days after the end of the next scheduled major maintenance outage if no such outage is scheduled within 36 months of the date of the initial notification, but in no event more than 60 months after the date of initial notification. The limited exemption in Section 9-9-115 shall cease to apply if the turbine violates this compliance schedule.

*(Adopted December 6, 2006)*

**9-9-406** **Other Useful Heat Recovery:** Any operator who wishes to get credit for other useful heat recovery for their gas turbines shall propose a calculation method to determine Po, as used in Section 9-9-605. This calculation method shall be subject to approval by the APCO.

*(Adopted December 6, 2006)*

**9-9-500 MONITORING AND RECORDS**

**9-9-501** **Monitoring and Recordkeeping Requirements:** A person who operates any stationary gas turbine with a heat input rating equal to or greater than 150 MMBtu/hr for more than 4000 hours in any 36-month period shall install, operate and maintain in calibration a continuous emissions monitor (CEM), or alternative monitoring system, capable of determining exhaust gas $NO_X$ concentrations. A CEM must meet the requirements of the District Manual of Procedures, Volume V. Any operator choosing to demonstrate compliance with Section 9-9-301.2 or 9-9-302.2 using the output-based NOx limits expressed in lbs/MWhr must also monitor and record fuel consumption by the gas turbine and any supplemental duct burners, electrical and mechanical output from both combustion and steam turbines, any steam production flow rates and steam enthalpy. Any alternative monitoring system must be approved by the APCO. Such approval will only be granted upon a determination, pursuant to the criteria of 40 CFR Part 75, Subpart E, that the alternative monitoring system provides information with the same precision, reliability, accessibility, and timeliness as that provided by a CEM for the source.

*(Amended 9/21/94; 12/6/06)*

**9-9-502** **Records, Low Usage:** A person claiming to be exempt from Section 9-9-301 based on the number of hours of turbine operation, or seeking exemption per Sections 9-9-112 or 9-9-116 of this Rule, shall maintain a daily gas turbine operating record that includes the actual start-up and stop time, total hours of operation, and type (liquid or gas) and quantity of fuel used. This information shall be available to District staff upon request for at least two years from the date of entry.

*(Amended December 6, 2006)*

**9-9-503** **Initial Demonstration of Compliance:** A person who must modify existing sources or install new control equipment shall conduct a District approved source test to demonstrate compliance with 9-9-301.2 or 302.2, and submit the results to the District within two months of initial operation of the new or modified equipment.

*(Amended 9/21//94; 12/6/06)*

**9-9-504** **Annual Demonstration of Compliance:** The operator of any turbine subject to this Rule that operates more than 400 hours in any 12-month period and is not equipped with a Continuous Emissions Monitor shall conduct a District-approved source test of the turbine at least once per calendar year, and at intervals not to exceed 15 months between tests, and shall submit the test results to the District within two months of the test date. The operator of any turbine that operates 400 hours or less in any 12-month period shall conduct a District-approved source test of the turbine every two calendar years, at a rate not to exceed 25 months.

*(Adopted December 6, 2006)*

**9-9-600 MANUAL OF PROCEDURES**

**9-9-601** **Determination of Emissions:** Source tests for determining compliance with the NOx emissions standards of this rule as specified in Sections 9-9-301 and 302 shall be conducted as prescribed in the District Manual of Procedures, Volume IV, ST-13A.

*(Amended 9/21/94; 12/6/06)*

**9-9-602** **Determination of Stack Gas Oxygen:** Oxygen content of the exhaust gas shall be determined by using District Manual of Procedures, Volume IV, ST-14.

**9-9-603** **Continuous Emission Monitoring:** Continuous Emissions Monitoring (CEM) procedures shall be determined using District Manual of Procedures, Volume V. For purposes of determining compliance with the NOx emissions standards of this rule, NOx emissions shall be calculated as the three hour average NOx emissions corrected to 15 percent $O_2$ (dry basis). Results of source tests conducted as prescribed in the District Manual of Procedures shall be deemed to be representative of three-hour average NOx emissions.

*(Amended December 6, 2006)*

**9-9-604** **Determination of HHV and LHV:** The HHV and LHV shall be determined using 1) ASTM D240-87 or ASTM D2382-88 ASTM D4809 for liquid hydrocarbon fuel; or 2) ASTM 1826-88 or ASTM 1945-81 in conjunction with ASTM D3588-89 for gaseous fuels.

*(Amended December 6, 2006)*

**9-9-605** **Compliance With Output Based NOx Emissions Standards:** For purposes of complying with the emissions standards in Section 9-9-301.2 and 9-9-302.2, emission rates expressed in lbs/MWhr shall be calculated in accordance with the following equations:

$$E = \frac{1.194X10^{-7} * (NOx)_c * Q_{std}}{(Pe)_t + (Pe)_c + Ps + Po}$$

E = hourly NOx emission rate, in lb/MWh
$(NOx)_c$ = Average NOx concentration, in ppmv adjusted to 15% O2
$Q_{std}$ – stack gas volumetric flow rate, in dry scf/hr
$(Pe)_t$ = electrical or mechanical energy output of the combustion turbine in MW
$(Pe)_c$ = Electrical or mechanical energy output of the steam turbine (if any) in MW
Ps = useful thermal energy of steam production
Po = other useful heat recovery.

$$Ps = \frac{Q * H}{3.413X10^6\ Btu/MWh}$$

Q = measured steam flowrate in lb/hr.
H = enthalpy of the steam at measured temperature and pressure in Btu/lb.

*(Adopted December 6, 2006)*

# REGULATION 9
# INORGANIC GASEOUS POLLUTANTS
# RULE 10
# NITROGEN OXIDES AND CARBON MONOXIDE FROM BOILERS, STEAM GENERATORS AND PROCESS HEATERS IN PETROLEUM REFINERIES

## INDEX


**9-10-100 GENERAL**

9-10-101 Description
9-10-110 Exemptions
9-10-111 Limited Exemption, Small Units
9-10-112 Limited Exemption, Low Fuel Usage
9-10-113 Limited Exemption, Alternate NOx Compliance Plan

**9-10-200 DEFINITIONS**

9-10-201 Deleted December 15, 2010
9-10-202 Boiler or Steam Generator
9-10-203 British Thermal Unit (BTU)
9-10-204 CO Boiler
9-10-205 Deleted December 15, 2010
9-10-206 Heat Input
9-10-207 Higher Heating Value (HHV)
9-10-208 Natural Gas
9-10-209 Nitrogen Oxides (NOx)
9-10-210 Non-Gaseous Fuel
9-10-211 Operating Day
9-10-212 Out of Service
9-10-213 Petroleum Refinery
9-10-214 Process Heater
9-10-215 Rated Heat Input
9-10-216 Refinery-wide Emission Rate
9-10-217 Small Unit
9-10-218 Start-up or Shutdown
9-10-219 Therm
9-10-220 Deleted December 15, 2010
9-10-221 Best Available Control Technology (BACT)
9-10-222 Curtailed Operation

**9-10-300 STANDARDS**

9-10-301 Refinery-wide NOx Emission Limit
9-10-302 Deleted July 17, 2002
9-10-303 Federal Refinery-wide and CO Boiler NOx Emission Limits
9-10-304 Interim NOx Emission Limit For CO Boilers
9-10-305 CO Emission Limit
9-10-306 Small Unit Requirements
9-10-307 Final NOx Emission Limits For CO Boilers
9-10-308 Alternate NOx Compliance Plan

**9-10-400 ADMINISTRATIVE REQUIREMENTS**

9-10-401 Deleted December 15, 2010

9-10-402 Deleted December 15, 2010
9-10-403 Deleted December 15, 2010
9-10-404 Final Control and Monitoring Plan
9-10-405 Application for Alternate NOx Compliance Plan
9-10-406 Determination of Compliance
9-10-407 Boiler, Steam Generator and Process Heater Status Report

**9-10-500 MONITORING AND RECORDS**

9-10-501 Deleted December 15, 2010
9-10-502 Monitoring
9-10-503 Modified Maximum Heat Input
9-10-504 Records
9-10-505 Reporting Requirements

**9-10-600 MANUAL OF PROCEDURES**

9-10-601 Determination of Nitrogen Oxides
9-10-602 Determination of Carbon Monoxide and Stack-Gas Oxygen
9-10-603 Compliance Determination
9-10-604 Determination of Higher Heating Value
9-10-605 Tune-Up Procedures

# REGULATION 9
# INORGANIC GASEOUS POLLUTANTS
# RULE 10
# NITROGEN OXIDES AND CARBON MONOXIDE FROM BOILERS, STEAM GENERATORS AND PROCESS HEATERS IN PETROLEUM REFINERIES

(Adopted January 5, 1994)

## 9-10-100 GENERAL

**9-10-101** Description: This rule limits the emissions of nitrogen oxides and carbon monoxide from boilers, steam generators, and process heaters, including CO boilers, in petroleum refineries.

*(Amended December 15, 2010)*

**9-10-110** **Exemptions:** The requirements of this rule shall not apply to the following:

110.1 Boilers, steam generators and process heaters with a rated heat input less than 2 million BTU/hour, if fired exclusively with natural gas, liquefied petroleum gas, or any combination thereof.

110.2 Boilers, steam generators and process heaters with a rated heat input less than 1 million BTU/hour fired with any fuel.

110.3 Waste heat recovery boilers that are used to recover sensible heat from the exhaust of combustion turbines or reciprocating internal combustion engines.

110.4 Boilers, steam generators and process heaters processing hydrogen sulfide process flue gas in sulfur recovery plants and their tail-gas treating units, or sulfuric acid manufacturing plants.

110.5 Boilers, steam generators and process heaters fired on non-gaseous fuel when natural gas is unavailable for use.

110.6 Boilers, steam generators and process heaters, including CO boilers, that receive an Authority to Construct subject to BACT requirements for NOx on or after January 5, 1994.

*(Amended December 15, 2010)*

**9-10-111** **Limited Exemption, Small Units:** The requirements of Sections 9-10-301, 303, 305 and 308 shall not apply to the use of any small units, provided the requirements of Section 9-10-306 are satisfied.

*(Amended 7/17/02; 12/15/10; 10/16/13)*

**9-10-112** **Limited Exemption, Low Fuel Usage:** The requirements of Sections 9-10-301, 303, 305 and 308 shall not apply to the use of any boiler, steam generator or process heater that has an annual heat input less than 90,000 therms during each consecutive 12-month period or that accepts a condition in its Permit to Operate limiting the annual heat input to less than 90,000 therms, provided the requirements for small units in Section 9-10-306 are satisfied and a fuel-flow meter as described in Section 9-10-502.2 is maintained and operated.

*(Amended 7/17/02; 12/15/10; 10/16/13)*

**9-10-113** **Limited Exemption, Alternate NOx Compliance Plan:** The requirements of Section 9-10-301 shall not apply to the use of any boiler, steam generator or process heater at a refinery subject to Section 9-10-308.

*(Adopted October 16, 2013)*

## 9-10-200 DEFINITIONS

**9-10-201** **Deleted December 15, 2010**

**9-10-202** **Boiler or Steam Generator:** Any combustion equipment used to produce steam or heat water.

**9-10-203** **British Thermal Unit (BTU):** The amount of heat required to raise the temperature of one pound of water from 59° F to 60° F at one atmosphere.

**9-10-204** **CO Boiler:** A CO boiler is any boiler or furnace that processes the off-gases from a catalytic cracking unit (CCU) regenerator or a coker burner. A partial-burn CO boiler

normally processes off-gases from a CCU regenerator that is operated in a partial-burn mode such that the off-gases normally have a CO concentration exceeding 2% by volume.

*(Amended December 15, 2010)*

**9-10-205** **Deleted December 15, 2010**

**9-10-206** **Heat-Input**: The heat of combustion released due to burning a fuel in a source, using higher heating value of the fuel. This does not include the sensible heat of incoming combustion air. In the case of carbon monoxide boilers, the heat input includes the sensible heat of regenerator off-gases and the heat of combustion of the incoming carbon monoxide and of the auxiliary fuel.

**9-10-207** **Higher Heating Value (HHV):** The total heat liberated per mass of fuel burned (BTU per pound) when fuel and dry air at standard conditions undergo complete combustion and all resultant products are brought to their standard states at standard conditions per Section 9-10-604.

**9-10-208** **Natural Gas:** Any mixture of gaseous hydrocarbons containing at least 80 percent methane by volume, as determined according to Standard Method ASTM D1945-64.

**9-10-209** **Nitrogen Oxides (NOx):** The sum of nitric oxide (NO) and nitrogen dioxide ($NO_2$) in the flue gas, collectively expressed as nitrogen dioxide.

**9-10-210** **Non-Gaseous Fuel:** Any fuel that is not a gas at 68° F and one atmosphere.

*(Amended December 15, 2010)*

**9-10-211** **Operating Day:** 24 hours from midnight to midnight.

**9-10-212** **Out of Service:** The period of time during which a unit is in an inactive state following shutdown.

**9-10-213** **Petroleum Refinery:** Any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives.

**9-10-214** **Process Heater:** Any combustion equipment that transfers heat from combustion gases to water or process streams.

**9-10-215** **Rated Heat Input:** The heat input capacity specified on the nameplate of the combustion source. If the combustion source has been physically modified and/or operated in such a manner that its maximum heat input is different from the heat input capacity specified on the nameplate, then the modified maximum heat input per Section 9-10-503 shall be considered as the rated heat input.

**9-10-216** **Refinery-wide Emission Rate:** The ratio of the total mass of discharge into the atmosphere of nitrogen oxides, in pounds, to the sum of the actual heat input, in million BTU, calculated over a twenty-four (24) hour operating day.

*(Amended December 15, 2010)*

**9-10-217** **Small Unit:** Any refinery boiler, steam generator or process heater with a rated heat input less than 10 million BTU/hour.

*(Amended December 15, 2010)*

**9-10-218** **Startup or Shutdown:** Startup is that period of time, not to exceed twelve (12) hours unless specifically extended by a Permit to Operate, during which a unit is brought up to its normal operating temperature from a cold start, initially at zero fuel flow, by following a prescribed series of separate steps or operations. Shutdown is that period of time, not to exceed nine (9) hours unless specifically extended by a Permit to Operate, during which a unit is taken out of service from a normal operating mode to an inactive status following a prescribed series of separate steps or operations.

*(Amended 12/15/10; 10/16/13)*

**9-10-219** **Therm:** One hundred thousand (100,000) BTUs.

**9-10-220** **Deleted December 15, 2010**

**9-10-221** **Best Available Control Technology (BACT):** As defined in Regulation 2, Rule 2.

*(Adopted December 15, 2010)*

**9-10-222** **Curtailed Operation:** Operation of a boiler, steam generator or process heater at no more than 30% of its rated heat input.

*(Adopted December 15, 2010)*

**9-10-300 STANDARDS**

**9-10-301 Refinery-wide NOx Emission Limit:** A person shall not exceed a refinery-wide emission rate from boilers, steam generators and process heaters, excluding CO boilers, of 0.033 pounds NOx per million BTU of heat input, based on an operating day average. Boilers, steam generators and process heaters that are test-fired on non-gaseous fuel, that are undergoing startup or shutdown, that are temporarily out of service, or that are in curtailed operation shall be included in the refinery-wide emission rate as follows:

301.1 Deleted December 15, 2010

301.2 Deleted December 15, 2010

301.3 Units Test-Fired On Non-Gaseous Fuel: For the purposes of determining compliance with the emission limit of Section 9-10-301, the emission contribution of each boiler, steam generator or process heater that is fired on non-gaseous fuel for equipment testing shall be taken as the operating day average of NOx emissions at the average heat input over the previous thirty (30) day period. Equipment testing shall not exceed a total of forty-eight (48) hours during any calendar year for any one unit.

301.4 Units in Start-up or Shutdown or in Curtailed Operation: For the purposes of determining compliance with the emission limit of Section 9-10-301, the emission contribution of each boiler, steam generator or process heater that is undergoing startup or shutdown, or that is in Curtailed Operation shall be one of the following:

4.1 The operating day average NOx emissions (either from a continuous emission monitoring system (CEMS) or from an equivalent parametric monitoring system developed in accordance with a Permit to Operate and Section 9-10-502.1), and the operating day heat input.

4.2 The operating day average NOx emissions (either from a CEMS or from an equivalent parametric monitoring system developed in accordance with a Permit to Operate and Section 9-10-502.1), and the operating day heat input averaged over the previous thirty (30) day period or, subject to the approval of the APCO, an alternate 30-day period representative of normal operation.

301.5 Units Temporarily Out of Service: For the purposes of determining compliance with the emission limit of Section 9-10-301, the emission contribution of each boiler, steam generator or process heater that is temporarily out of service shall be the operating day average NOx emissions (either from a continuous emission monitoring system (CEMS) or from an equivalent parametric monitoring system developed in accordance with a Permit to Operate and Section 9-10-502.1), and the operating day heat input, averaged over the previous thirty (30) day period or, subject to the approval of the APCO, an alternate 30-day period representative of normal operation.

*(Amended 12/15/10; 10/16/13)*

**9-10-302 Deleted July 17, 2002**

**9-10-303 Federal Refinery-wide and CO Boiler NOx Emission Limits:** A person shall not exceed a refinery-wide emission rate from boilers, steam generators or process heaters, excluding CO boilers, of 0.20 pounds NOx per million BTU of heat input, based on an operating day average.

303.1 Except during startup and shutdown, a person shall not operate a CO boiler unless the emissions of nitrogen oxides (NOx) do not exceed 300 ppmv, dry at 3% oxygen, based on an operating day average.

*(Amended 7/17/02; 12/15/10)*

**9-10-304 Interim NOx Emission Limit For CO Boilers:** Until Section 9-10-307 is effective, and except during startup and shutdown, a person shall not operate a CO boiler unless at least one of the following is met:

304.1 Emissions of nitrogen oxides (NOx) do not exceed 150 ppmv, dry at 3% oxygen, based on an operating day average; or

304.2 Emissions of nitrogen oxides (NOx) are controlled by an emission control system with a NOx control efficiency of at least 50 percent by weight.

*(Amended December 15, 2010)*

**9-10-305 CO Emission Limit:** Except during start-up, shutdown or curtailed operation, a person shall not operate a boiler, steam generator or process heater, including CO boilers, unless carbon monoxide emissions of 400 ppmv, dry at 3% oxygen, based on an operating day average, are not exceeded.

*(Amended December 15, 2010)*

**9-10-306 Small Unit Requirements:** A person shall not operate a small unit unless at least one of the following is met:

306.1 Operate in a manner that maintains stack-gas oxygen concentrations at less than or equal to 3 percent by volume on a dry basis; or

306.2 Tune at least once every twelve (12) months, or within two weeks of unit startup if not operated in the last twelve (12) months, by a technician in accordance with the procedure specified in Section 9-10-605; or

306.3 Meet the applicable emission limits in Sections 9-10-301, 303 and 305.

*(Amended December 15, 2010)*

**9-10-307 Final NOx Emission Limits For CO Boilers:** Effective January 1, 2015, and except during start-up or shutdown, a person shall not operate a CO boiler unless it meets the applicable NOx emission limits in Sections 9-10-307.1 and 307.2.

307.1 A person shall not operate a non-partial-burn CO boiler, unless the following NOx limits are not exceeded:

| Averaging Period | NOx (ppmv, dry at 3% $O_2$) |
|---|---|
| 1.1 Operating day | 150 |
| 1.2 Calendar year (excluding periods when the CO boiler does not process CCU regenerator offgas) | 45 |

307.2 A person shall not operate a partial-burn CO boiler, unless the following NOx limits are not exceeded:

| Averaging Period | NOx (ppmv, dry at 3% $O_2$) |
|---|---|
| 2.1 Operating day | 125 |
| 2.2 Calendar year | 85 |

*(Adopted 12/15/10; Amended 10/16/13)*

**9-10-308 Alternate NOx Compliance Plan:** A person at a refinery with an Alternate NOx Compliance Plan that has been approved in accordance with Section 9-10-405, shall not exceed the refinery-wide daily NOx limit from boilers, steam generators and process heaters, excluding CO boilers, as specified in the Plan. The boilers, steam generators and process heaters that are covered by the Alternate NOx Compliance Plan shall be referred to as devices in this Section.

308.1 A daily NOx limit shall apply to all devices at a refinery with an approved Alternate NOx Compliance Plan. The limit shall be the sum of the baseline NOx daily emissions for each device, expressed in pounds of NOx. The baseline NOx daily emissions for each device shall be the average of the daily emissions on any ten (10) different days during the 3-year period immediately preceding the date of the application for an Alternate Compliance Plan, on which the refinery operator was in compliance with Section 9-10-301. The same 10 days shall be used for all devices at a refinery. The APCO may consider allowing 10 days within a different time period, if the APCO finds that a different period allows the selection of operating days that better represent maximum daily emission levels for these devices.

1.1 At any refinery that used Interchangeable Emission Reduction Credits (IERC) to comply with Section 9-10-301 on any of the 10 baseline days, the average difference between actual operating

emissions, in pounds NOx/day, and the emissions that would meet the 0.033 pounds NOx/million BTU NOx limit in Section 9-10-301 shall be calculated for the 10 days used to develop the daily NOx limit, and the daily NOx limit shall be reduced by this difference. NOx Emission Reduction Credits (ERC) generated in accordance with Regulation 2, Rule 2 may be surrendered on a one-time basis at a 1.15 to 1 ratio to make up all or part of the difference, and the daily NOx emissions limit will be adjusted accordingly.

1.2 At any refinery with an Authority to Construct application submitted before the date of approval of an Alternate Compliance Plan described in Section 9-10-405, if the actions permitted in the Authority to Construct would reduce the number of devices subject to Section 9-10-301 and require additional NOx emissions reductions to comply with Section 9-10-301, the daily NOx emissions limit shall be reduced by the amount of reductions required. NOx ERC generated in accordance with Regulation 2, Rule 2 may be surrendered on a one-time basis at a 1.15 to 1 ratio to offset all or part of the NOx emissions reductions required, and the daily NOx emissions limit will be adjusted accordingly.

308.2 A person operating under a daily NOx limit shall determine compliance with that limit on a daily basis.

308.3 For any device for which baseline NOx emissions have been permanently reduced, a permit application may be submitted to modify the baseline daily NOx emissions for that device.

308.4 The daily NOx limit shall be reduced when a device is no longer subject to this rule. The amount of reduction shall be equal to the baseline NOx daily emissions for that device.

*(Adopted October 16, 2013)*

**9-10-400 ADMINISTRATIVE REQUIREMENTS**

**9-10-401 Deleted December 15, 2010**

**9-10-402 Deleted December 15, 2010**

**9-10-403 Deleted December 15, 2010**

**9-10-404 Final Control and Monitoring Plan:** A person subject to Section 9-10-307 shall comply with the following increments of progress:

404.1 No later than twenty-four (24) months prior to the effective date of Section 9-10-307, submit to the APCO a control plan detailing the proposed measures, if any, to be taken in order to meet the requirements of Section 9-10-307, as well as proposed measures, if any, to be taken to continue to meet the requirements of Section 9-10-301.

404.2 No later than eighteen (18) months prior to the effective date of Section 9-10-307, submit applications for all Authorities to Construct required for compliance with Section 9-10-307.

404.3 No later than 30 days after the effective date of Section 9-10-307, perform testing for nitrogen oxide and carbon monoxide emissions at each CO boiler subject to Section 9-10-307 at the rated heat input or as near thereto as practicable. This requirement may be satisfied by monitoring nitrogen oxide and carbon monoxide emissions with a continuous emission monitoring system (CEMS).

*(Adopted December 15, 2010)*

**9-10-405 Application for an Alternate NOx Compliance Plan:** An application for an Alternate NOx Compliance Plan may be submitted by a person who operates a refinery where a boiler, steam generator or process heater is subject to Section 9-10-301. The Alternate NOx Compliance Plan shall apply to all boilers, steam generators and process heaters that are subject to the NOx limit in Section 9-10-301 at the time the Alternate NOx Compliance Plan is approved, and only to these boilers, steam generators and process heaters. The application shall be submitted and processed

in accordance with Regulation 2, Rule 1. The fees for the application shall be as specified in Regulation 3 for an alternate compliance plan. The application shall include the following information, which shall be included in the Permit to Operate for the boiler, steam generator or process heater:

405.1 The proposed effective date of the Alternate NOx Compliance Plan.

405.2 A list of the boilers, steam generators and process heaters that will be subject to a daily NOx limit, as specified in Section 9-10-308, and for each:

2.1 The baseline NOx daily emissions determined in accordance with Section 9-10-308.1, including the data used to establish the baseline NOx daily emissions and the source(s) of the data. To the extent possible, the baseline NOx daily emissions shall be based on CEMS data.

2.2 One or two substitute emission factors to be used in the absence of CEMS data and determined from representative source test data measured in accordance with District Manual of Procedures, Volume IV, ST-13A (nitrogen oxides) and ST-14 (oxygen), including the source test report.

2.3 The amount of the required reductions to the daily NOx limit described in Sections 9-10-308.1.1 and 308.1.2 and any proposed mitigation to these reductions.

405.3 The amount of any ERC use allowed by Sections 9-10-308.1.1 and 308.1.2 shall be calculated as follows: (average difference between actual operating emissions, in pounds NOx/day, and the pounds NOx emissions/day that would meet the 0.033 pounds NOx/million BTU NOx limit in Section 9-10-301 for the 10 days used to develop the baseline NOx emissions)(365 days/year)(1.15) = NOx ERC surrendered. Any ERC use shall be surrendered before the application for the Alternate NOx Compliance Plan is considered complete. If an Authority to Construct that meets the conditions described in Section 9-10-308.1.2 is cancelled, any ERC surrendered shall be returned to the applicant.

*(Adopted October 16, 2013)*

**9-10-406 Determination of Compliance**: Compliance with the daily limit in Section 9-10-301 or 308 shall be determined by CEMS data and, for those boilers, steam generators and process heaters subject to parametric monitoring, the emission factor established according to Section 9-10-502.1.2 and the heat input rate as measured for each boiler, steam generator and process heater.

*(Adopted October 16, 2013)*

**9-10-407 Boiler, Steam Generator and Process Heater Status Report**: Any person who operates a boiler, steam generator or process heater that is subject to Section 9-10-301 or 308 shall, no later than April 16, 2014, submit information on the make, model and emission rates for all burners in each boiler, steam generator or process heater. Information shall be submitted in a format as specified by the APCO. The information shall be updated no later than 30 days after any non-identical burner change or replacement.

*(Adopted October 16, 2013)*

## 9-10-500 MONITORING AND RECORDS

**9-10-501 Deleted December 15, 2010**

**9-10-502 Monitoring:** A person subject to Sections 9-10-301, 303, 304, 305, 307 or 308 shall maintain in good working order, and operate the following equipment:

502.1 An in-stack nitrogen oxide (NOx), carbon monoxide (CO), and oxygen ($O_2$) continuous emission monitoring system (CEMS), or equivalent parametric monitoring system as specified in a Permit to Operate. The CEMS shall meet the requirements of the District Manual of Procedures, Volume V, Continuous Emission Monitoring, Policy and Procedures.

1.1 No later than April 16, 2014, a person who operates boilers, steam generators or process heaters that are subject to Section 9-10-301 or 308 shall submit a monitoring plan to the APCO for the installation

of NOx CEMS on these boilers, steam generators or process heaters such that no less than 95% of the NOx emissions, by weight, subject to either 9-10-301 or 308 is monitored with a NOx CEMS. The monitoring plan shall consider the actual NOx emission contribution from each boiler, steam generator or process heater subject to Section 9-10-301 or 308 during the most recent calendar year for which complete data are available at the time of the submittal of the monitoring plan. No later than October 16, 2014, the APCO shall approve each submitted monitoring plan, or else shall specify additional NOx CEMS that must be installed, and notify the affected refinery. The date of plan approval or notification shall serve as the "date of notification" specified in the District Manual of Procedures (MOP), Volume V, Continuous Emission Monitoring, Policy and Procedures. The installation of CEMS shall then be in accordance with the schedule and other provisions of MOP, Volume V, except that the completion of installation in Section 4.3 of Volume V shall be within 12 months of submittal of the Intent to Purchase.

1.2 Any person who operates a boiler, steam generator or process heater that uses a parametric monitoring system to monitor compliance with Section 9-10-301 or 308 shall estimate the NOx emission contribution of the boiler, steam generator or process heater based on one or two NOx emission factors (expressed as lb NOx / MM BTU) and on actual fuel input for all operating conditions, except as allowed by Section 9-10-301.3, 301.4 or 301.5. The emission factor shall be based on one or more District-approved source tests and included in a Permit to Operate. The operator shall conduct periodic monitoring of boilers, steam generators and process heaters that use a parametric monitoring system as follows:

2.1 Boilers, steam generators and process heaters rated less than 25 MM BTU/hr shall have one source test per consecutive 12 month period. The time interval between source tests shall not exceed 16 months. A boiler, steam generator or process heater that is out of service need not be placed into service for the purposes of conducting a source test. Notwithstanding the time limits specified above, a source test for a boiler, steam generator or process heater that is out of service may be delayed until it returns to service.

2.2 Boilers, steam generators and process heaters rated 25 MM BTU/hr or more shall have two source tests per consecutive 12 month period. The time interval between source tests shall be no less than 5 months and no more than 8 months. Notwithstanding the time limits specified above, a source test for a boiler, steam generator or process heater that is out of service may be delayed until it returns to service.

If a source test measures an emission factor higher than the emission factor in the Permit to Operate, then the higher emission factor shall become the new emission factor for determining compliance with Section 9-10-301 and 308. An operator may re-test at operating conditions substantially similar to those during the original test and appeal the change in emission factor to the APCO within 60 days. An operator may submit source test data with a permit application to establish a lower emission factor for a device that has been altered in a way that reduces the emission rate. The APCO may require that a source test be performed at a specific operating condition if the APCO determines that such a condition is a representative operating condition that has not been previously tested. Source test results shall be submitted to the APCO within 60 days of any test.

502.2 A fuel-flow meter in each fuel line for each boiler, steam generator and process heater, including each CO boiler.

*(Amended 7/17/02; 12/15/10; 10/16/13)*

**9-10-503 Modified Maximum Heat Input:** Any unit that has been physically modified such that its maximum heat input is different than the heat input specified on the nameplate shall demonstrate to the APCO the maximum heat input while operating the source at maximum capacity.

**9-10-504 Records:** The owner/operator of a source subject to this rule shall keep the following records, in a form suitable for inspection for a period of at least five (5) years. Such records shall be retained for a minimum of sixty (60) months from date of entry and made available to the APCO upon request. These records shall include, but are not limited to the following:

504.1 For all sources subject to the requirements of Sections 9-10-301, 303, 304, 305, 307, 308 or 404.3:

1.1 The continuous emission monitoring system (CEMS) measurements for NOx and CO (ppmv corrected to 3% oxygen) and $O_2$ (percent by volume on a dry basis) or equivalent parametric monitoring system parameters; and hourly (lb/hour) and daily (lb/day) NOx emissions for each source. Measurements shall be submitted in a digital format that can be readily imported into standard database tools as specified by the APCO. The APCO shall provide a reasonable amount of time to implement any required changes in data format.

1.2 The type, heat input (BTU/hr and BTU/day), and higher heating value of each fuel burned, and the injection rate for any reactant chemicals used by the emission control system(s) on a daily basis.

1.3 The date, time, and duration of any startup, shutdown or malfunction in the operation of any unit, emission control equipment or emission monitoring equipment.

1.4 The results of performance testing, evaluations, calibrations, checks, adjustments, and maintenance of any CEMS required by this rule.

1.5 A list of all sources subject to the NOx refinery-wide emission rate limits in Sections 9-10-301 and 303.

1.6 Total NOx emissions and total heat input for all sources listed in Section 9-10-504.1.5, on a daily basis.

1.7 The date, time and duration of all start-up and shutdown periods.

1.8 The results of source tests required by Section 9-10-404.3.

504.2 For all sources subject to Section 9-10-306.2, records of annual tune-ups.

*(Amended 7/17/02; 12/15/10; 10/16/13)*

**9-10-505 Reporting Requirements:** A person subject to the requirements of Sections 9-10-301, 303, 304, 305, 306, 307 or 308 shall meet the following reporting requirements:

505.1 Report to the APCO any violation of Section 9-10-301, 303, 304, 305, 306, 307 or 308 in accordance with the requirements of Regulation 1-522 for continuous emission monitoring systems (CEMS) and Regulation 1-523 for parametric monitoring systems.

505.2 Submit a written report for each calendar quarter to the APCO. The report shall be due on the 30th day following the end of the calendar quarter and shall include:

2.1 A summary of the data obtained from the CEMS or equivalent parametric monitoring system and the fuel meters installed pursuant to Section 9-10-502; and

2.2 The date, time, duration, and magnitude of emissions in excess of the appropriate standards; the nature and cause of the excess (if known); the corrective actions taken; and the preventive measure adopted.

505.3 A person subject to the requirements of Section 9-10-308 shall submit to the APCO a permit application to amend the Alternate NOx Compliance Plan whenever Section 9-10-308.4 is triggered. The application shall be submitted within 30 days of the event that triggers Section 9-10-308.4.

*(Amended 7/17/02; 12/15/10; 10/16/13)*

## 9-10-600 MANUAL OF PROCEDURES

**9-10-601 Determination of Nitrogen Oxides:** Compliance with the nitrogen oxide emission requirements of Sections 9-10-301, 303, 304, 307 and 308 shall be determined by a continuous emission monitoring system (CEMS) that meets the requirements of Regulation 1-522, or by an equivalent parametric monitoring system that is authorized in a Permit to Operate and that meets the requirements of Regulation 1-523. CEMS operation and compliance with Section 9-10-404.3 shall be verified by source test as set forth in the District Manual of Procedures, Volume IV, ST-13A (nitrogen oxides) and ST-14 (oxygen).

*(Amended 7/17/02; 12/15/10; 1016/13)*

**9-10-602 Determination of Carbon Monoxide and Stack-Gas Oxygen:** Compliance with the carbon monoxide emission requirements of Section 9-10-305 shall be determined by a continuous emission monitoring system (CEMS) that meets the requirements of Regulation 1-522, or by an equivalent parametric monitoring system that is authorized in a Permit to Operate and that meets the requirements of Regulation 1-523. CEMS operation and compliance with Section 9-10-404.3 shall be verified by source test as set forth in the District Manual of Procedures, Volume IV, ST-6 (carbon monoxide) and ST-14 (oxygen).

*(Amended 12/15/10; 10/16/13)*

**9-10-603 Compliance Determination:** All emission determinations shall be made in the as-found operating condition, except during periods of start-up or shutdown.

*(Amended December 15, 2010)*

**9-10-604 Determination of Higher Heating Value:** If certification of the higher heating value is not provided by the third-party fuel supplier, it shall be determined by one of the following test methods: (1) ASTM D2015-85 for solid fuels; (2) ASTM D240-87 or ASTM D2382-88 for liquid hydrocarbon fuels; or (3) ASTM D1826-88 or ASTM D1945-81 in conjunction with ASTM D3588-89 for gaseous fuels.

**9-10-605 Tune-Up Procedures:** The tuning procedure required by Section 9-10-306.2 shall be performed in accordance with the procedure set forth in the District Manual of Procedures, Volume I, Chapter 5.

# REGULATION 12
# MISCELLANEOUS STANDARDS OF PERFORMANCE
# RULE 11
# FLARE MONITORING AT PETROLEUM REFINERIES

## INDEX


**12-11-100 GENERAL**

12-11-101 Description
12-11-110 Exemption, Organic Liquid Storage and Distribution
12-11-111 Exemption, Marine Vessel Loading Terminals
12-11-112 Exemption, Wastewater Treatment Plants
12-11-113 Exemption, Pumps
12-11-114 Limited Exemption, Total Hydrocarbon and Methane Composition Monitoring and Reporting

**12-11-200 DEFINITIONS**

12-11-201 Flare
12-11-202 Flare Monitoring System
12-11-203 Flaring
12-11-204 Gas
12-11-205 Petroleum Refinery
12-11-206 Pilot Gas
12-11-207 Purge Gas
12-11-208 Sulfur Recovery Plant
12-11-209 Thermal Oxidizer
12-11-210 Vent Gas

**12-11-400 ADMINISTRATIVE REQUIREMENTS**

12-11-401 Flare Data Reporting Requirements
12-11-402 Semi-Annual Flow Verification Report

**12-11-500 MONITORING AND RECORDS**

12-11-501 Vent Gas Flow Monitoring
12-11-502 Vent Gas Composition Monitoring
12-11-503 Ignition Monitoring
12-11-504 Pilot and Purge Gas Monitoring
12-11-505 Recordkeeping Requirements
12-11-506 General Monitoring Requirements
12-11-507 Video Monitoring

**12-11-600 MANUAL OF PROCEDURES**

12-11-601 Testing, Sampling, and Analytical Methods
12-11-602 Flow Verification Test Methods

# REGULATION 12
# MISCELLANEOUS STANDARDS OF PERFORMANCE
# RULE 11
# FLARE MONITORING AT PETROLEUM REFINERIES

(Adopted June 4, 2003)

## 12-11-100 GENERAL

**12-11-101 Description:** The purpose of this rule is to require monitoring and recording of emission data for flares at petroleum refineries.

**12-11-110 Exemption, Organic Liquid Storage and Distribution:** The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from organic liquid storage vessels subject to Regulation 8, Rule 5 or exclusively from loading racks subject to Regulation 8 Rules 6, 33, or 39.

**12-11-111 Exemption, Marine Vessel Loading Terminals:** The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from marine vessel loading terminals subject to Regulation 8, Rule 44.

**12-11-112 Exemption, Wastewater Treatment Systems:** The provisions of this rule shall not apply to thermal oxidizers used to control emissions exclusively from wastewater treatment systems subject to Regulation 8, Rule 8.

**12-11-113 Exemption, Pumps:** The provisions of this rule shall not apply to thermal oxidizers used to control emissions exclusively from pump seals subject to Regulation 8, Rule 18. This exemption does not apply when emissions from a pump are routed to a flare header.

**12-11-114 Limited Exemption, Total Hydrocarbon and Methane Composition Monitoring and Reporting:** The provisions of Sections 12-11-401.2, 401.3, 401.5, 502.2 and 502.3 that require monitoring and reporting of total hydrocarbon and methane composition shall not apply to a flare that exclusively burns flexicoker gas with or without supplemental natural gas, provided that the owner or operator demonstrates by weekly sampling and analysis, verified by the APCO, that the methane content and the non-methane content of the vent gas flared are less than 2 percent and 1 percent by volume, respectively.

## 12-11-200 DEFINITIONS

**12-11-201 Flare:** A combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. Flares may be either continuous or intermittent and are not equipped with devices for fuel-air mix control or for temperature control. This term includes both ground and elevated flares.

**12-11-202 Flare Monitoring System:** All sample systems, transducers, transmitters, data acquisition equipment, data recording equipment, video monitoring equipment, and video recording equipment involved in flare monitoring.

**12-11-203 Flaring:** A high-temperature combustion process used to burn vent gases.

**12-11-204 Gas:** The state of matter that has neither independent shape nor volume, but tends to expand indefinitely. For the purposes of this rule, "gas" includes aerosols and the terms "gas" and "gases" are interchangeable.

**12-11-205 Petroleum Refinery:** A facility that processes petroleum, as defined in the North American Industrial Classification Standard No. 32411, and including any associated sulfur recovery plant.

**12-11-206 Pilot Gas:** The gas used to maintain the presence of a flame for ignition of vent gases.

**12-11-207 Purge Gas:** The gas used to prevent air backflow in the flare system when there is no vent gas.

**12-11-208 Sulfur Recovery Plant:** A process unit that processes sulfur and ammonia containing material and produces a final product of elemental sulfur.

**12-11-209 Thermal Oxidizer:** An enclosed or partially enclosed combustion device that is used to oxidize combustible gases, that generally comes equipped with controls for combustion chamber temperature and often with controls for air/fuel mixture, and that exhausts all combustion products through a vent, duct, or stack so that emissions can be measured directly.

**12-11-210 Vent Gas:** Any gas directed to a flare excluding assisting air or steam, flare pilot gas, and any continuous purge gases.

## 12-11-400 ADMINISTRATIVE REQUIREMENTS

**12-11-401 Flare Data Reporting Requirements:** The owner or operator of a flare shall submit a monthly report to the APCO on or before 30 days after the end of each month for each flare subject to this rule. Only one report is required for a staged or cascading flare system if all flares in the system serve the same header or headers. The report shall be in an electronic format approved by the APCO. Each monthly report shall include all of the following:

401.1 The total volumetric flow of vent gas in standard cubic feet for each day and for the month, and, effective for the first full month after the commencement of the monitoring required by Section 12-11-501, for each hour of the month.

401.2 If vent gas composition is monitored using sampling or integrated sampling, total hydrocarbon content as propane by volume, methane content by volume, and, hydrogen sulfide content by volume, for each sample or integrated sample required by Section 12-11-502. If the content of any additional compound or compounds is determined by the analysis of a sample or integrated sample, the content by volume of each additional compound.

401.3 If vent gas composition is monitored by a continuous analyzer or analyzers pursuant to Section 12-11-502, average total hydrocarbon content as propane by volume, average methane content by volume, and, depending upon the analytical method used pursuant to Section 12-11-601, total reduced sulfur content by volume or hydrogen sulfide content by volume of vent gas flared for each hour of the month. If the content of any additional compound or compounds is determined by the continuous analyzer or analyzers, the average content by volume for each additional compound for each hour of the month.

401.4 If the flow monitor installed pursuant to Section 12-11-501 measures molecular weight, the average molecular weight for each hour of the month.

401.5 For any pilot and purge gas used, the type of gas used, the volumetric flow for each day and for the month, and the means used to determine flow.

401.6 For any 24-hour period during which more than 1 million standard cubic feet of vent gas was flared, a description of the flaring including the cause, time of occurrence and duration, the source or equipment from which the vent gas originated, and any measures taken to reduce or eliminate flaring.

401.7 Flare monitoring system downtime periods, including dates and times.

401.8 The archive of images recorded for the month pursuant to Section 12-11-507.

401.9 For each day and for the month provide calculated methane, non-methane and sulfur dioxide emissions. For the purposes of emission calculations only, a flare control efficiency of 98 percent shall be used for hydrocarbon flares, and a flare control efficiency of 93 percent shall be used for flexi-gas flares or if, based on the composition analysis specified in Section 12-11-502, the calculated lower heating value of the vent gas is less than 300 British Thermal Units/Standard Cubic Foot (BTU/SCF).

**12-11-402 Flow Verification Report:** Effective twelve months after adoption of this rule and every six months thereafter, the owner or operator of a flare shall submit a flow verification report to the APCO for each flare subject to the rule. The flow verification report shall be included in the corresponding monthly report required by Section 12-11-401. Only one report is required for a staged or cascading flare system if all flares in the system serve the same header or headers. The report shall compare flow as measured by the flow monitoring equipment required by Section 12-11-501 and a flow verification pursuant to Section 12-11-602 for the same period or periods of time. The owner or operator shall demonstrate that the flow verification was performed using good engineering practices. If there are no flaring events as described in Section 12-11-401.6 during the preceding six-month period, a flow verification report is not required for that period.

## 12-11-500 MONITORING AND RECORDS

**12-11-501 Vent Gas Flow Monitoring:** Effective 180 days after adoption of this rule, the owner or operator of a petroleum refinery shall not operate a flare unless vent gas to the flare is continuously monitored for volumetric flow by a device that meets the following requirements:

501.1 The minimum detectible velocity shall be 0.1 foot per second.

501.2 The device shall continuously measure the range of flow rates corresponding to velocities from 0.5 to 275 feet per second in the header in which the device is installed.

501.3 The device shall have a manufacturer's specified accuracy of $\pm 5\%$ over the range of 1 to 275 feet per second.

501.4 The device shall be installed at a location where measured volumetric flow is representative of flow to the flare or to the flare system in the case of a staged or cascading flare system consisting of more than one flare.

501.5 Effective 180 days after adoption of this rule, the owner or operator shall provide access for the APCO to verify proper installation and operation of the flare monitoring system.

501.6 Effective 18 months after adoption of this rule, the flow monitoring system shall be maintained to be accurate to within $\pm 20\%$ as demonstrated by the flow verification report specified in Section 12-11-402.

**12-11-502 Vent Gas Composition Monitoring:** The owner or operator of a petroleum refinery shall not operate a flare unless the following requirements are met:

502.1 Requirements applicable to all vent gas composition monitoring:

1.1 Vent gas monitored for composition, whether by sampling, integrated sampling or continuous monitoring, shall be taken from a location at which samples are representative of vent gas composition. If flares share a common header, a sample from the header will be deemed representative of vent gas composition for all flares served by the header.

1.2 Effective 90 days after the adoption of this rule, the monitoring system shall provide access for the APCO to collect vent gas samples to verify the analyses required by Section 12-11-502.

502.2 Effective 90 days after adoption of this rule and until the requirements of Section 12-11-502.3 are met, the owner or operator shall monitor vent gas composition through sampling that meets the following requirements:

2.1 For each day on which flaring occurs, one sample shall be taken within 30 minutes of the commencement of flaring.

2.2 Samples may be taken from the flare header or from an alternate location at which samples are representative of vent gas composition.

2.3 Samples shall be analyzed pursuant to Section 12-11-601.

502.3 Effective 270 days after adoption of this rule, the owner or operator shall monitor vent gas composition using one of the following four methods:

3.1 Sampling that meets the following requirements:

a. If the flow rate of vent gas flared in any consecutive 15-minute period continuously exceeds 330 standard cubic feet per minute (SCFM), a sample shall be taken within 15 minutes, except that, for flares exclusively serving sulfur or ammonia plants, a sample shall be taken within 1 hour or composition data representing worst-case conditions shall be provided by the owner or operator and verified by the APCO. The sampling frequency thereafter shall be one sample every three hours and shall continue until the flow rate of vent gas flared in any consecutive 15-minute period is continuously 330 SCFM or less. In no case shall a sample be required more frequently than once every 3 hours.

b. Samples shall be analyzed pursuant to Section 12-11-601.

3.2 Integrated sampling that meets the following requirements:

a. If the flow rate of vent gas flared in any consecutive 15 minute period continuously exceeds 330 standard cubic feet per minute (SCFM), integrated sampling shall begin within 15 minutes and shall continue until the flow rate of vent gas flared in any consecutive 15 minute period is continuously 330 SCFM or less.

b. Integrated sampling shall consist of a minimum of one aliquot for each 15-minute period until the sample container is full. If sampling is still required pursuant to Section 12-11-502.3.2a, a new sample container shall be placed in service within one hour after the previous container was filled. A sample container shall not be used for a sampling period that exceeds 24 hours.

c. Samples shall be analyzed pursuant to Section 12-11-601.

3.3 Continuous analyzers that meet the following requirements:

a. The analyzers shall continuously monitor for total hydrocarbon, methane, and, depending upon the analytical method used pursuant to Section 12-11-601, hydrogen sulfide or total reduced sulfur.

b. The hydrocarbon analyzer shall have a full-scale range of 100% total hydrocarbon.

c. Each analyzer shall be maintained to be accurate to within 20% when compared to any field accuracy tests or to within 5% of full scale.

3.4 A continuous analyzer employing gas chromatography that meets the following requirements:

a. The gas chromatography system shall monitor for total hydrocarbon, methane, and hydrogen sulfide.

b. The gas chromatography system shall be maintained to be accurate to within 5% of full scale.

**12-11-503 Pilot Monitoring:** Any flare subject to this rule must be equipped and operated with an automatic igniter or a continuous burning pilot, which must be maintained in good working order. If a pilot flame is employed, the flame shall be monitored with a device to detect the presence of the pilot flame. If an electric arc ignition system is employed, the system shall pulse on detection of loss of pilot flame and until the pilot flame is reestablished.

**12-11-504 Pilot and Purge Gas Monitoring:** The owner or operator of a petroleum refinery shall not operate a flare unless (1) volumetric flows of purge and pilot gases are monitored by flow measuring devices, or (2) other parameters are monitored so that volumetric flows of pilot and purge gas may be calculated based on pilot design and the parameters monitored.

**12-11-505 Recordkeeping Requirements:** Except as provided in Section 12-11-507, the owner or operator of a flare shall maintain records for all the information required to

be monitored for a period of five years and make such records available to the APCO upon request.

**12-11-506 General Monitoring Requirements:** Persons responsible for monitoring subject to this rule shall comply with the following:

506.1 Periods of flare monitoring system inoperation greater than 24 continuous hours shall be reported by the following working day, followed by notification of resumption of monitoring. Adequate proof of expeditious repair shall be furnished to the APCO for downtime in excess of fifteen consecutive days. Periods of inoperation of the vent gas flow monitoring required by Section 12-11-501 shall not exceed 30 days per calendar year. Periods of inoperation of vent gas composition monitoring specified in Sections 12-11-502.3.2 (integrated sampling) and 12-11-502.3.4 (gas chromatography) shall not exceed 30 days per calendar year. Effective 450 days after the adoption of this rule, periods of inoperation of the vent gas composition monitoring specified in Section 12-11-502.3.3 (continuous analyzers) shall not exceed 30 days per calendar year per analyzer. Periods of inoperation of video monitoring specified in Section 12-11-507 shall not exceed 30 days per calendar year.

506.2 During periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 12-11-502, persons responsible for monitoring shall take samples as required by Section 12-11-502.2.1. During periods of inoperation of flow monitors required by Section 12-11-501, flow shall be calculated using good engineering practices.

506.3 The person(s) responsible for monitors subject to this rule shall maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications. In order to claim that a manufacturer's specification is not applicable, the person responsible for emissions must have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer's procedure.

506.4 Data Recording System: All in-line continuous analyzer and flow monitoring data must be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages.

**12-11-507 Video Monitoring:** For each flare equipped with video monitoring capability as of January 1, 2003, the owner or operator of a flare subject to this rule shall, effective 180 days after adoption of this rule, install and maintain equipment that records a real-time digital image of the flare and flame at a frame rate of no less than 1 frame per minute. The recorded image of the flare shall be of sufficient size, contrast, and resolution to be readily apparent in the overall image or frame. The image shall include an embedded date and time stamp. The equipment shall archive the images for each 24-hour period. Effective 180 days after adoption of this rule, for any flare for which the report required by Section 12-11-401 shows that more than 1 million standard cubic feet of vent gas was flared in any 24-hour period, the owner or operator of the flare shall, within 90 days after the end of the month covered by the report, meet the same requirements as those imposed by this Section for flares with existing video monitoring capability.

## 12-11-600 MANUAL OF PROCEDURES

**12-11-601 Testing, Sampling, and Analytical Methods:**

601.1 Samples and integrated samples shall be analyzed using the following test methods, or latest revision, where applicable:

1.1 Total hydrocarbon content and methane content of vent gas shall be determined using ASTM Method D1945-96, ASTM Method UOP 539-97, or EPA Method 18.

1.2 Hydrogen sulfide content of vent gas shall be determined using ASTM Method D1945-96 or ASTM Method UOP 539-97.

1.3 Any alternative method to the above methods if approved by the APCO and EPA.

601.2 Except as provided in Section 12-11-601.3, if vent gas composition is monitored using continuous analyzers, the analyzers shall employ the following methods, or latest revision, where applicable:

2.1 Total hydrocarbon content and methane content of vent gas shall be determined using EPA Method 25A or 25B.

2.2 Total reduced sulfur content of vent gas shall be determined using ASTM Method D4468-85.

2.3 Hydrogen sulfide content shall be determined using ASTM Method D4084-94.

2.4 Any alternative method to the above methods if approved by the APCO and EPA.

601.3 If vent gas composition is monitored with a continuous analyzer employing gas chromatography, the following requirements shall be met:

3.1 ASTM Method D1945-96 or latest revision, or ASTM Method UOP 539-97 or latest revision shall be used.

3.2 The system shall analyze samples for total hydrocarbon content, methane content, and hydrogen sulfide content.

3.3 The minimum sampling frequency shall be one sample every 30 minutes.

3.4 Any alternative method to the above methods if approved by the APCO and EPA.

**12-11-602 Flow Verification Test Methods:** For purposes of the semi-annual verification required by Section 12-11-402, vent gas flow shall be determined using one or more of the following methods:

602.1 District Manual of Procedures, Volume IV, ST-17 and ST-18;

602.2 EPA Methods 1 and 2;

602.3 Other flow monitoring devices or process monitors.

602.4 Any verification method recommended by the manufacturer of the flow monitoring equipment installed pursuant to Section 12-11-501.

602.5 Tracer gas dilution or velocity.

602.6 Any alternative method approved by the APCO and EPA.

# REGULATION 12
# MISCELLANEOUS STANDARDS OF PERFORMANCE
# RULE 12
# FLARES AT PETROLEUM REFINERIES

## INDEX


**12-12-100 GENERAL**

12-12-101 Description
12-12-110 Exemption, Organic Liquid Storage and Distribution
12-12-111 Exemption, Marine Vessel Loading Terminals
12-12-112 Exemption, Wastewater Treatment Plants
12-12-113 Exemption, Pumps

**12-12-200 DEFINITIONS**

12-12-201 Emergency
12-12-202 Feasible
12-12-203 Flare
12-12-204 Flare Minimization Plan (FMP)
12-12-205 Gas
12-12-206 Petroleum Refinery
12-12-207 Prevention Measure
12-12-208 Reportable Flaring Event
12-12-219 Responsible Manager
12-12-210 Shutdown
12-12-211 Startup
12-12-212 Thermal Oxidizer
12-12-213 Vent Gas

**12-12-300 STANDARDS**

12-12-301 Flare Minimization

**12-12-400 ADMINISTRATIVE REQUIREMENTS**

12-12-401 Flare Minimization Plan Requirements
12-12-402 Submission of Flare Minimization Plans
12-12-403 Review and Approval of Flare Minimization Plans
12-12-404 Update of Flare Minimization Plans
12-12-405 Notification of Flaring
12-12-406 Determination and Reporting of Cause
12-12-407 Deleted April 5, 2006
12-12-408 Designation of Confidential Information

**12-12-500 MONITORING AND RECORDS**

12-12-501 Water Seal Integrity Monitoring

# REGULATION 12
# MISCELLANEOUS STANDARDS OF PERFORMANCE
# RULE 12
# FLARES AT PETROLEUM REFINERIES

(Adopted July 20, 2005)

**12-12-100 GENERAL**

**12-12-101 Description:** The purpose of this rule is to reduce emissions from flares at petroleum refineries by minimizing the frequency and magnitude of flaring. Nothing in this rule should be construed to compromise refinery operations and practices with regard to safety.

**12-12-110 Exemption, Organic Liquid Storage and Distribution:** The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from organic liquid storage vessels subject to Regulation 8, Rule 5 or exclusively from loading racks subject to Regulation 8 Rules 6, 33, or 39.

**12-12-111 Exemption, Marine Vessel Loading Terminals:** The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from marine vessel loading terminals subject to Regulation 8, Rule 44.

**12-12-112 Exemption, Wastewater Treatment Systems:** The provisions of this rule shall not apply to thermal oxidizers used to control emissions exclusively from wastewater treatment systems subject to Regulation 8, Rule 8.

**12-12-113 Exemption, Pumps:** The provisions of this rule shall not apply to thermal oxidizers used to control emissions exclusively from pump seals subject to Regulation 8, Rule 18. This exemption does not apply when emissions from a pump are routed to a flare header.

**12-12-200 DEFINITIONS:** For the purposes of this rule, the following definitions apply:

**12-12-201 Emergency:** A condition at a petroleum refinery beyond the reasonable control of the owner or operator requiring immediate corrective action to restore normal and safe operation that is caused by a sudden, infrequent and not reasonably preventable equipment failure, natural disaster, act of war or terrorism or external power curtailment, excluding power curtailment due to an interruptible power service agreement from a utility.

**12-12-202 Feasible:** Capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social and technological factors.

**12-12-203 Flare:** A combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. This term includes both ground-level and elevated flares. When used as a verb, the term "flare" means the combustion of vent gas in a flare.

**12-12-204 Flare Minimization Plan (FMP):** A document intended to meet the requirements of Section 12-12-401.

**12-12-205 Gas:** The state of matter that has neither independent shape nor volume, but tends to expand indefinitely. Gas includes aerosols and the terms "gas" and "gases" are interchangeable.

**12-12-206 Petroleum Refinery:** A facility that processes petroleum, as defined in the North American Industrial Classification Standard No. 32411 and including any associated sulfur recovery plant.

**12-12-207 Prevention Measure:** A component, system, procedure or program that will minimize or eliminate flaring.

**12-12-208 Reportable Flaring Event:** Any flaring where more than 500,000 standard cubic feet per calendar day of vent gas is flared or where sulfur dioxide ($SO_2$) emissions are greater than 500 pounds per day. For flares that are operated as a backup,

staged or cascade system, the volume is determined on a cumulative basis; the total volume equals the total of vent gas flared at each flare in the system. For flaring lasting more than one calendar day, each day of flaring constitutes a separate flaring event unless the owner or operator demonstrates to the satisfaction of the APCO that the cause of flaring is the same for two or more consecutive days. A reportable flaring event ends when it can be demonstrated by monitoring required in Section 12-12-501 that the integrity of the water seal has been maintained sufficiently to prevent vent gas to the flare tip. For flares without water seals or water seal monitors as required by Section 12-12-501, a reportable flaring event ends when the rate of flow of vent gas falls below 0.5 feet per second.

*(Amended April 5, 2006)*

**12-12-209 Responsible Manager:** An employee of the facility or corporation who possesses sufficient authority to take the actions required for compliance with this rule.

**12-12-210 Shutdown:** The intentional cessation of a petroleum refining process unit or a unit operation within a petroleum refining process unit due to lack of feedstock or the need to conduct periodic maintenance, replacement of equipment, repair or other operational requirements. A process unit includes subsets and components of the unit operation. Subsets and components includes but are not limited to reactors, heaters, vessels, columns, towers, pumps, compressors, exchangers, accumulators, valves, flanges, sample stations, pipelines or sections of pipelines.

**12-12-211 Startup:** The setting into operation of a petroleum refining process unit for purposes of production. A process unit includes subsets and components of the unit operation. Subsets and components includes but are not limited to reactors, heaters, vessels, columns, towers, pumps, compressors, exchangers, accumulators, valves, flanges, sample stations, pipelines or sections of pipelines.

**12-12-212 Thermal Oxidizer:** An enclosed or partially enclosed combustion device, other than a flare, that is used to oxidize combustible gases.

**12-12-213 Vent Gas:** Any gas directed to a flare excluding assisting air or steam, flare pilot gas, and any continuous purge gases.

## 12-12-300 STANDARDS

**12-12-301 Flare Minimization:** Effective November 1, 2006, flaring is prohibited unless it is consistent with an approved FMP and all commitments due under that plan have been met. This standard shall not apply if the APCO determines, based on an analysis conducted in accordance with Section 12-12-406, that the flaring is caused by an emergency and is necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere.

## 12-12-400 ADMINISTRATIVE REQUIREMENTS

**12-12-401 Flare Minimization Plan Requirements:** The owner or operator of a petroleum refinery with one or more flares subject to this rule shall submit to the APCO a FMP in accordance with the schedule in Section 12-12-402. The FMP shall be certified and signed by a Responsible Manager and shall include, but not be limited to:

**401.1 Technical Data:** A description and technical information for each flare that is capable of receiving gases and the upstream equipment and processes that send gas to the flare including:

1.1 A detailed process flow diagram accurately depicting all pipelines, process units, flare gas recovery systems, water seals, surge drums and knock-out pots, compressors and other equipment that vent to each flare. At a minimum, this shall include full and accurate as-built dimensions and design capacities of the flare gas recovery systems, compressors, water seals, surge drums and knockout pots.

1.2 Full and accurate descriptions including locations of all associated monitoring and control equipment.

**401.2 Reductions Previously Realized:** A description of the equipment, processes and procedures installed or implemented within the last five years to reduce flaring. The description shall specify the year of installation.

**401.3 Planned Reductions:** A description of any equipment, processes or procedures the owner or operator plans to install or implement to eliminate or reduce flaring. The description shall specify the scheduled year of installation or implementation.

**401.4 Prevention Measures:** A description and evaluation of prevention measures, including a schedule for the expeditious implementation of all feasible prevention measures, to address the following:

4.1 Flaring that has occurred or may reasonably be expected to occur during planned major maintenance activities, including startup and shutdown. The evaluation shall include a review of flaring that has occurred during these activities in the past five years, and shall consider the feasibility of performing these activities without flaring.

4.2 Flaring that may reasonably be expected to occur due to issues of gas quantity and quality. The evaluation shall include an audit of the vent gas recovery capacity of each flare system, the storage capacity available for excess vent gases, and the scrubbing capacity available for vent gases including any limitations associated with scrubbing vent gases for use as a fuel; and shall consider the feasibility of reducing flaring through the recovery, treatment and use of the gas or other means.

4.3 Flaring caused by the recurrent failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. The evaluation shall consider the adequacy of existing maintenance schedules and protocols for such equipment. For purposes of this Section, a failure is recurrent if it occurs more than twice during any five year period as a result of the same cause as identified in accordance with Section 12-12-406.

**401.5** Any other information requested by the APCO as necessary to enable determination of compliance with applicable provisions of this rule.

Failure to implement and maintain any equipment, processes, procedures or prevention measures in the FMP is a violation of this section.

**12-12-402 Submission of Flare Minimization Plans**: On or before August 1, 2006, the owner or operator of a petroleum refinery with one or more flares subject to this rule shall submit a FMP as required by Section 12-12-401. On or before November 1, 2005 and every three months thereafter until a complete FMP is submitted, the owner or operator shall provide a status report detailing progress towards fulfilling the requirements of Section 12-12-401. Upon the submission of each status report, the APCO may require a consultation regarding the development of the plan to ensure that the plan meets the requirements of Section 12-12-401.

**12-12-403 Review and Approval of Flare Minimization Plans:** The procedure for determining whether the FMP meets the applicable requirements of this regulation is as follows:

**403.1 Completeness Determination:** Within 45 days of receipt of the FMP, the APCO will deem the plan complete if he determines that it includes the information required by Section 12-12-401. If the APCO determines that the proposed FMP is not complete, the APCO will notify the owner or operator in writing. The notification will specify the basis for this determination and the required corrective action.

**403.2 Corrective Action:** Upon receipt of such notification, the owner or operator shall correct the identified deficiencies and resubmit the proposed FMP within 45 days. If the APCO determines that the owner or operator failed to correct any deficiency identified in the notification, the APCO will disapprove the FMP.

**403.3 Public Comment:** The complete FMP (with exception of confidential information) will be made available to the public for 60 days. The APCO will

consider any written comments received during this period prior to approving or disapproving the FMP.

**403.4** **Final Action:** Within 45 days of the close of the public comment period, the APCO will approve the FMP if he determines that the plan meets the requirements of Section 12-12-401, and shall provide written notification to the owner or operator. This period may be extended if necessary to comply with state law. If the APCO determines that the FMP does not meet the requirements of Section 12-12-401, the APCO will notify the owner or operator in writing. The notification will specify the basis for this determination. Upon receipt of such notification, the owner or operator shall correct the identified deficiencies and resubmit the FMP within 45 days. If the APCO determines that the owner or operator failed to correct any deficiency identified in the notification, the APCO will disapprove the FMP.

If the owner or operator submitted a complete FMP in accordance with Section 12-12-402, and the APCO has not disapproved the FMP under this section, the FMP shall be considered an approved FMP for the purposes of Section 12-12-301 until the APCO takes final action under Section 12-12-403.4.

**12-12-404** **Update of Flare Minimization Plans:** The FMP shall be updated as follows:

**404.1** No more than 12 months following approval of the original FMP and annually thereafter, the owner or operator of a flare subject to this rule shall review the FMP and revise the plan to incorporate any new prevention measures identified as a result of the analyses prescribed in Sections 12-12-401.4 and 12-12-406. The updates must be approved and signed by a Responsible Manager.

**404.2** Prior to installing or modifying any equipment described in Section 12-12-401.1.1 that requires a District permit to operate, the owner or operator shall obtain an approved updated FMP addressing the new or modified equipment.

**404.3** Annual FMP updates (with exception of confidential information) shall be made available to the public for 30 days. The APCO shall consider any written comments received during this period prior to approving or disapproving the update.

**404.4** Within 45 days of the close of the public comment period, the APCO shall approve the FMP update if he determines that the update meets the requirements of Section 12-12-401, and shall provide written notification to the owner or operator. The previously approved FMP together with the approved update constitutes the approved plan for purposes of Section 12-12-301. This period may be extended if necessary to comply with state law. If the APCO determines that the FMP update does not meet the requirements of Section 12-12-401, the APCO will notify the owner or operator in writing. The notification will specify the basis for this determination and the required corrective action. Upon receipt of such notification, the owner or operator shall correct the identified deficiencies and resubmit the FMP update within 30 days. If the APCO determines that the owner or operator failed to correct the deficiencies identified in the notification, the APCO will disapprove the FMP update. For purposes of Section 12-12-301, disapproval of the update constitutes disapproval of the existing FMP, unless otherwise specified by the APCO.

**404.5** If the owner or operator fails to submit a plan update as required by this Section, the APCO shall provide written notification of the lapse. If the owner or operator fails to submit an update within 30 days of receipt of the notification, the existing FMP shall no longer be considered an approved plan for purposes of Section 12-12-301.

*(Amended April 5, 2006)*

**12-12-405** **Notification of Flaring:** Effective August 20, 2005, the owner or operator of a flare subject to this rule shall notify the APCO as soon as possible, consistent with safe operation of the refinery, if the volume of vent gas flared exceeds 500,000 standard

cubic feet per calendar day. The notification, either by phone, fax or electronically, shall be in a format specified by the APCO and include the flare source name and number, the start date and time, and the end date and time.

**12-12-406 Determination and Reporting of Cause:** The owner or operator of a flare subject to this rule shall submit a report to the APCO within 60 days following the end of the month in which a reportable flaring event occurs. The report shall include, but is not limited to, the following:

**406.1** The results of an investigation to determine the primary cause and contributing factors for the flaring event.

**406.2** Any prevention measures that were considered or implemented to prevent recurrence together with a justification for rejecting any measures that were considered but not implemented.

**406.3** If appropriate, an explanation of why the flaring is consistent with an approved FMP.

**406.4** Where applicable, an explanation of why the flaring was an emergency and necessary to prevent an accident, hazard or release of vent gas to the atmosphere or where, due to a regulatory mandate to vent to a flare, it cannot be recovered, treated and used as fuel gas at the refinery.

**406.5** The volume of vent gas flared, the calculated methane, non-methane hydrocarbon and sulfur dioxide emissions associated with the reportable flaring event.

*(Amended April 5, 2006)*

**12-12-407 Deleted April 5, 2006**

**12-12-408 Designation of Confidential Information:** When submitting the initial FMP, any updated FMP or any other report required by this Rule, the owner or operator shall designate as confidential any information claimed to be exempt from public disclosure under the California Public Records Act, Government Code section 6250 et seq. If a document is submitted that contains information designated confidential in accordance with this Section, the owner or operator shall provide a justification for this designation and shall submit a separate copy of the document with the information designated confidential redacted.

## 12-12-500 MONITORING AND RECORDS

**12-12-501 Water Seal Integrity Monitoring:** Effective August 1, 2006, the owner or operator of a flare subject to this rule with a water seal shall continuously monitor and record the water level and pressure of the water seal that services each flare. Any new installation of a water seal shall be subject to this requirement immediately. Records of these measurements shall be retained for one year. Monitoring devices required pursuant to this section shall be subject to the reporting and record keeping requirements of Regulation 1, Section 523: Parametric Monitors.