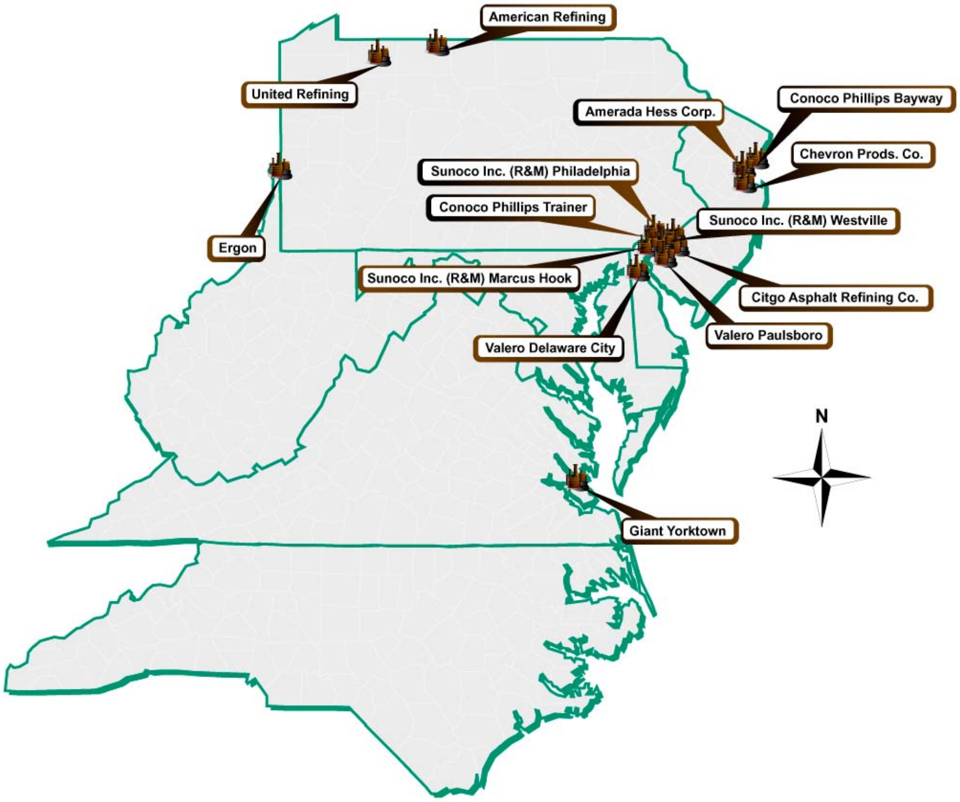
Mid-Atlantic Regional Air
Management Association

Assessment of Control Technology Options For Petroleum Refineries in the Mid-Atlantic Region

Final Report

January, 2007



About MARAMA

The Mid-Atlantic Regional Air Management Association is an association of ten state and local air pollution control agencies. MARAMA's mission is to strengthen the skills and capabilities of member agencies and to help them work together to prevent and reduce air pollution impacts in the Mid-Atlantic Region.

MARAMA provides cost-effective approaches to regional collaboration by pooling resources to develop and analyze data, share ideas, and train staff to implement common requirements.

The following State and Local governments are MARAMA members: Delaware, the District of Columbia, Maryland, New Jersey, North Carolina, Pennsylvania, Virginia, West Virginia, Philadelphia, and Allegheny County, Pennsylvania.

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Assessment of Control Technology Options
For Petroleum Refineries
In the Mid-Atlantic Region

Final Technical Support Document

Prepared for:

Mid-Atlantic Regional Air Management Association (MARAMA)

Prepared by:

MACTEC Federal Programs, Inc.

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Acronyms and Abbreviations

Acronym	**Description**
ACT	Alternative Control Technique
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
CO	Carbon Monoxide
CTG	Control Technique Guideline
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitator
FCCU	Fluid Catalytic Cracking Unit
FCU	Fluid Coking Unit
FGD	Flue Gas Desulfurization
HAP	Hazardous Air Pollutant
LAER	Lowest Achievable Emission Rate
LDAR	Leak Detection and Repair
MACT	Maximum Achievable Control Technology
MANE-VU	Mid-Atlantic/Northeast Visibility Union
MARAMA	Mid-Atlantic Regional Air Management Association
NESHAP	National Emission Standard for Hazardous Air Pollutants
NH3	Ammonia
NOx	Oxides of nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
PM10-PRI	Particulate matter less than or equal to 10 microns in diameter that includes both the filterable and condensable components of particulate matter
PM25-PRI	Particulate matter less than or equal to 2.5 microns in diameter that includes both the filterable and condensable components of particulate matter
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective non-Catalytic Reduction
SO2	Sulfur dioxide
SRU	Sulfur Recovery Unit
VOC	Volatile organic compounds
WGS	Wet Gas Scrubber
WWTP	Wastewater Treatment Plant

EXECUTIVE SUMMARY

This report was prepared for the Mid-Atlantic Regional Air Management Association (MARAMA) as part of an effort to assist states in developing State Implementation Plans (SIPs) for ozone, fine particles, and regional haze. MARAMA's members requested assistance in assessing control measure options for petroleum refinery emissions and in developing model rule provisions. The project was completed in three phases:

- Phase I analyzed emissions from all refinery processes, identified existing pollution control requirements, and assessed refinery processes in order of significance of emissions and the potential for additional emission reductions. Section 1 of this report presents the results of Phase I.
- Phase II identified potential control measures for seven refinery processes and evaluated the cost and technical feasibility of controls. Sections 2-8 contain the analyses of control measure options for the seven refinery processes selected for evaluation.
- Phase III involved the drafting of model rules for states to consider as they develop their SIPs. At the direction of the MARAMA board, model rules were developed for three processes: catalytic cracking units, equipment leaks, and flares.

This Executive Summary presents the key findings of the assessments.

This Technical Support Document (TSD) is intended to assist States in developing rules or other implementation mechanisms, as necessary and appropriate, as part of their control strategy analysis process for attaining the 8-hour ozone and fine particulate National Ambient Air Quality Standards (NAAQS) and regional haze goals. The TSD does not attempt to define Reasonably Available Control Technology (RACT) or any other particular control level for the refinery processes it examines. With many jurisdictions in the Mid-Atlantic Region facing the need to achieve additional emission reductions, MARAMA was asked by member States to analyze all refinery processes and determine where additional emission reductions were achievable. The TSD does not attempt to define RACT, best available control technology (BACT), lowest achievable emission rate (LAER), or best available retrofit technology (BART). MARAMA member States recognize that the determination of these control levels requires the consideration of site-specific factors. These considerations will be address in individual State and local rulemaking and permitting processes.

Evaluation of Available Control Options

MACTEC, in consultation with the MARAMA Refinery Technical Oversight Committee (TOC), reviewed the emission inventory and the existing requirements for each of the sources found at petroleum refineries. Based on that review, the TOC selected the following refinery processes for further evaluation of candidate control measures: 1) catalytic and thermal cracking units, 2) boilers and process heaters, 3) flares, 4) equipment leaks, 5) wastewater treatment, 6) storage tanks, and 7) sulfur recovery plants. These categories were chosen because they account for a large portion of the emission inventory and there is a potential for obtaining additional emission reductions. This study evaluated emissions, existing requirements, and available control technology options and typical costs. Table ES-1 presents the key findings regarding the emission inventory, existing requirements, and available control options.

Development of Model Rules

After reviewing the draft TSD, MARAMA's TOC instructed MACTEC to prepare three draft model rules for fluid catalytic cracking units, enhanced equipment leak detection and repair, and flares. While the recent consent decrees provide important air quality benefits, the MARAMA TOC decided to develop model rules to (a) to codify and perpetuate the requirements of the consent decrees, and (b) provide more stringent requirements where technologically feasible and cost-effective options have been identified. The model rule for the fluid catalytic cracking units is generally based on the requirements of the recent consent decrees, with a more stringent limit for carbon monoxide emissions. The model rule for enhanced LDAR is generally based on the requirements of the recent consent decrees, but with a lower leak definition for valves. The model rule for flares is primarily based on the requirements of the South Coast Air Quality Management District's recently amended flare rule, which includes more stringent requirements for flare gas recovery systems, flare minimization procedures, and flare monitoring.

Potential Impact of Model Rules

The assessment found that significant emission reductions will be achieved as a result of requirements already in place in recent Consent Decrees for 10 of the 14 petroleum refineries in the MARAMA region. Adoption of the model rules would achieve additional emission reductions at refineries where consent decrees have not been negotiated. These reductions would be modest, however, since the refineries in question are relatively small capacity facilities. Two refineries without Consent Decrees are in northwest Pennsylvania, and because of their location, modest reductions from these facilities may have little impact on the nonattainment areas.

Significant reductions in emissions from fluidized catalytic cracking units (FCCUs) will result from the implementation of the Consent Decrees. Some additional reductions in emissions from FCCUs may be possible, as a few refineries currently are only required to meet the NSPS limit of 1 lb/1000 lbs coke. The model rule limit of 0.5 lbs/ 1000 lbs coke would reduce PM emissions for these refineries by 50 percent. The model rule also reduces the CO limit for the FCCUs. Figures ES-1 to ES-4 show the anticipated emission reductions from FCCUs at refineries in the MARAMA region. Appendix A documents how the emission reductions were calculated.

Implementation of the Consent Decrees enhanced leak detection will reduce VOC emissions significantly. Implementation of the model rule will reduce emissions modestly beyond the levels established by the recently negotiated consent decrees. Figure ES-5 shows the anticipated emission reductions from equipment leaks at refineries in the MARAMA region.

Implementation of the model rules for flares would reduce refinery emissions beyond the levels established by the recently negotiated consent decrees to some extent. Figures ES-6, ES-7, and ES-8 show the anticipated emission reductions from flares at refineries in the MARAMA region. The flare rule will require better monitoring of flaring emissions, the development and implementation of flare monitoring and control of flare emissions. Recent studies at west coast refineries and in Texas have shown that flare emissions are larger than originally thought and likely larger than estimates contained in the current State emission inventories. As a result of the possible underestimation of emissions in the inventories, controlling flares may achieve more sizable emission reductions in the "real world" than are currently estimated based on the emission inventory.

Table ES-1 Key Findings

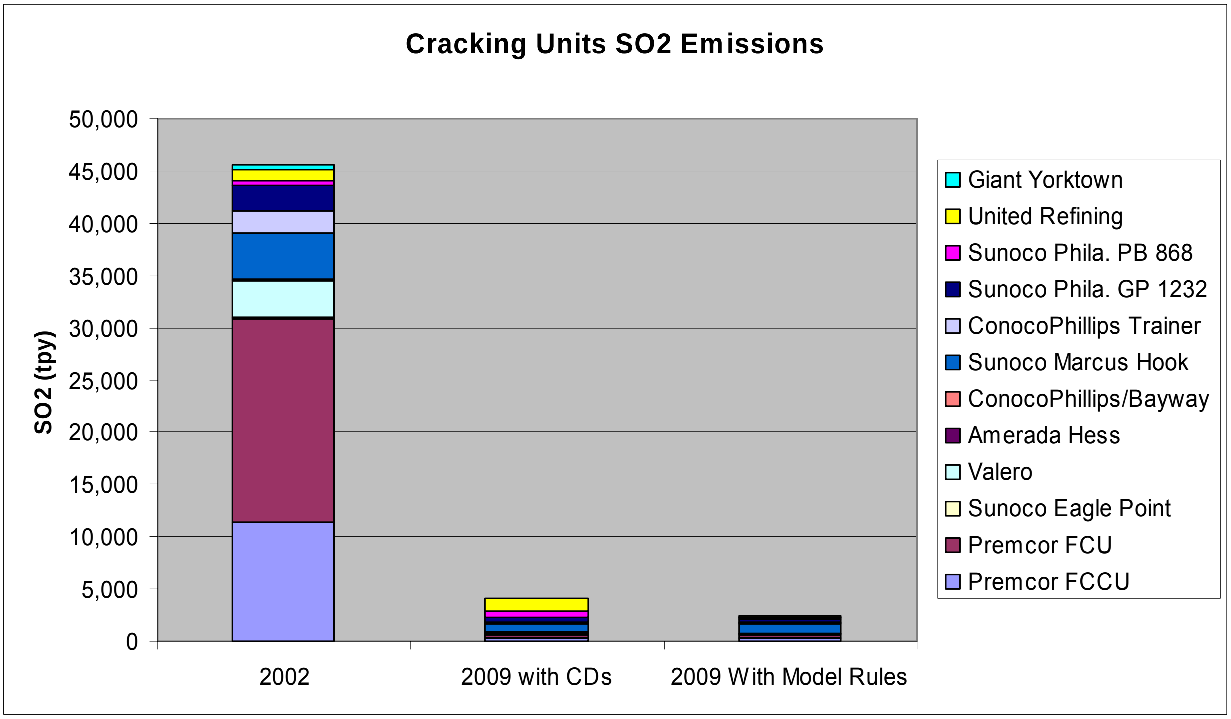
Refinery Process	Emission Inventory	Existing Requirements	Available Control Options
Fluid Catalytic Cracking Units (FCCUs) and Fluid Coking Units (FCUs)	There are 12 FCCUs and one FCU in the MARAMA region. These 13 emission units accounted for about 78% of the SO2 and 29% of the NOx emitted from all refinery processes in 2002. As a result of the existing requirements in Consent Decrees, SO2 emissions are expected to be reduced by 90% and NOx emissions by 38% by 2009.	Eight these FCCUs and the single FCU are required to control SO2 and NOx emissions as a result of Consent Decrees which contain more stringent requirements that existing federal rules, State/local rules, or permit requirements. Four other FCCUs are not affected by the Consent Decrees.	<u>SO2:</u> 1) Wet gas scrubber (or other technology) capable of meeting 25 ppmvd @ 0% O_2 based on 365-day rolling average or 50 ppmvd @ 0% O_2 based on 7-day rolling average. Cost Effectiveness: $500-3,000/ton 2) DeSOx additives capable of meeting 300 ppmvd. Cost Effectiveness*: $500-880/ton <u>NOx:</u> SCR or SNCR system (or other technology) capable of meeting 20 ppmvd, measured as a 365-day rolling average, and 40 ppmvd, measured as a 7-day rolling average, @ 0% O_2. NOx Cost Effectiveness*: $1520-2458/ton
Boilers and Process Heaters	Emissions from these units represent the largest category of NOx emission sources at refineries and the second largest source of SO2 emissions. Boilers and process heaters accounted for 63% of the NOx and 15% of the SO2 emitted from all refinery processes in 2002. As a result of the existing requirements in Consent Decrees, SO2 emissions are expected to be reduced by 32% and NOx emissions by 36% by 2009.	10 of the 14 refineries are required to control SO2 and NOx emissions as a result of Consent Decrees that contain more stringent requirements that existing federal rules, State/local rules, or permit requirements. The Consent Decrees will generally require the elimination of fuel oil burning in boilers/heaters, compliance with NSPS Subpart J refinery gas H2S limits, and installation of qualifying controls to reduce NOx emissions.	<u>SO2:</u> 1) Eliminate or limit liquid fuel firing 2) Limit sulfur content of liquid fuels; 3) Limit hydrogen sulfide content of refinery fuels to NSPS limit of 0.10 gr/dscf (162 ppm) SO2 Cost Effectiveness*: not quantified <u>NOx:</u> 1) San Joaquin Rule 4306 limits of 0.0062 to 0.036 lb/MMBtu for gaseous fuels and 0.052 lb/MMBtu for liquid fuels; Cost Effectiveness: to be determined. 2) SNCR, SCR, Ultra-low NOx burners (or other technology) capable of meeting 0.04 lb/MMBtu; Cost Effectiveness*: $750-7402 per ton, depending on size of unit and fuel type

Refinery Process	**Emission Inventory**	**Existing Requirements**	**Available Control Options**
Flares	Flares account for about 7% of the NOx, 4% of the SO2, and 10% of the VOC emitted at the 14 refineries in 2002. Actual emissions are uncertain due to inadequate monitoring of flare gas flow rates and composition. Evidence from California and Texas suggests that emissions from flaring activities (and other nonroutine releases) may be significantly underreported in current emission inventories.	Requirements contained in the Consent Decrees are generally more stringent than existing state/local rules and permit requirements. The Consent Decrees require compliance with NSPS emission limits and actions to prevent upsets that result in flaring.	SO2, VOC, NOx, PM: Establish and follow flare minimization plan; Install analyzers to measure vent gas flow, higher heating value, and VOC/sulfur concentration; Conduct emissions reviews and root cause analyses, and take corrective actions after significant flaring events; Install flare gas recovery and treatment systems. Cost Effectiveness*: $4527-7063 per ton (total SO2, NOx, VOC, and PM reduced).
Equipment Leaks (Fugitive Emissions)	Leaking equipment components account for 15% of the VOC emitted at the 14 refineries in 2002. Actual emissions are uncertain due to difficulty in accurately monitoring thousands of individual components.	The Consent Decrees contain requirements for "enhanced" leak detection and repair programs to reduce fugitive emissions; otherwise subject to NSPS or NESHAP requirements	VOC: "Enhanced" leak detection and repair program requirements based on program elements contained in the Consent Decrees. Elements include: written LDAR procedures; training of assigned personnel; internal and third party audits; more stringent leak definitions; increased monitoring frequency; corrective action for "chronic leakers"; electronic storing and reporting of data; additional QA/QC requirements. Cost Effectiveness*: $1300/ton
Wastewater Treatment	Wastewater treatment accounts for 21% of the VOC emitted at the 14 refineries in 2002	Many systems already subject to NSPS Subpart QQQ, NESHAP Subpart CC, or NESHAP Subpart FF requirements; Consent Decrees require review and verification of compliance status and corrective actions to correct noncompliance.	VOC: For wastewater collection systems, installing covers and seals on the collection components to reduce fugitive VOC emissions, For wastewater treatment system, maintaining or installing a control device such as carbon canisters to destroy VOCs released during treatment VOC Cost Effectiveness*: $1900-4200/ton

Refinery Process	**Emission Inventory**	**Existing Requirements**	**Available Control Options**
Storage Tanks	Storage tanks account for 26% of the VOC emitted at the 14 refineries in 2002	Most tanks already subject to either NSPS, NESHAP, or state requirements	VOC: Install floating roofs in fixed roof tanks; install domed fixed roof on external floating roof tank; replace vapor-mounted primary seal with a liquid-mounted primary seal; install secondary seals; use vapor recovery systems or incineration. VOC Cost Effectiveness*: not quantified
Sulfur Recovery Units	Sulfur recovery plants accounted for 2% of the SO2 emitted at the 14 refineries in 2002; over half of all SO2 emissions from sulfur recovery unit come from the Giant Yorktown, VA, SRU.	The Consent Decrees generally require compliance with NSPS Subpart J and the elimination, control, and monitoring of sulfur pit emissions. The Giant Yorktown refinery is required to install a tail gas unit or equivalent control technology. The ConocoPhillips Bayway refinery is to conduct an optimization study and implement recommendations.	SO2: A variety of control technologies are available which can meet the NSPS emission limit of 250 ppmv, dry basis, corrected to zero percent oxygen SO2 Cost Effectiveness*: $167-449/ton

* See Sections 2-8 for a discussion of the references used to determine the cost-effectiveness for each source category. The cost data provided in this table were obtained from the published literature as referenced. In general, the percent reductions and cost data represent data for typical sources that are uncontrolled. Site-specific factors can affect the actual cost effectiveness. Incremental costs for sources that already have some level of control will likely be higher.

Figure ES-1 Emission Reductions from Consent Decrees and Model Rules
SO2 Emissions from Fluidized Catalytic Cracking Units



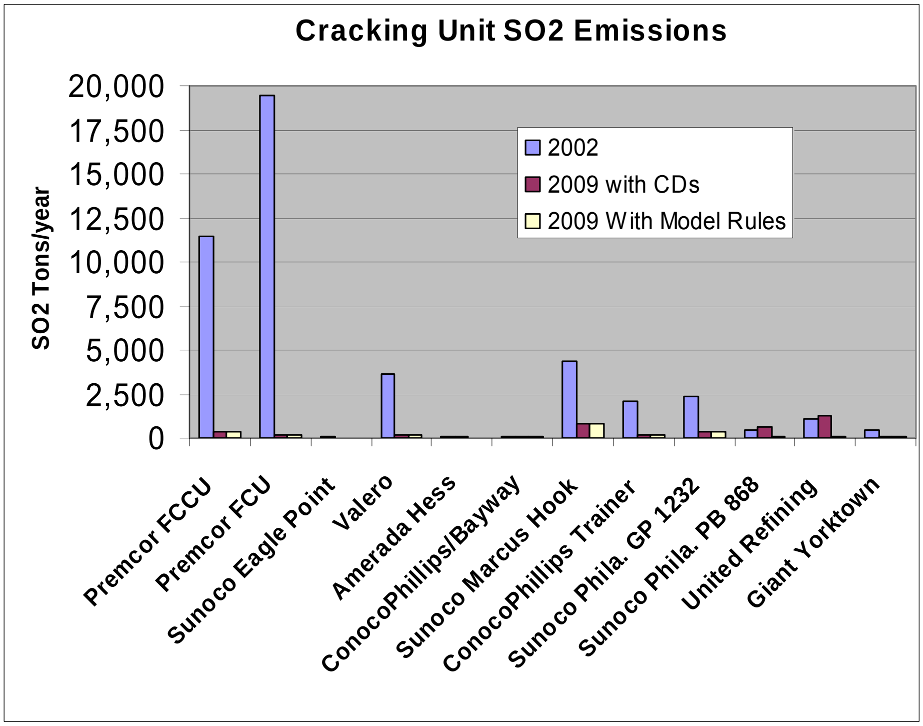
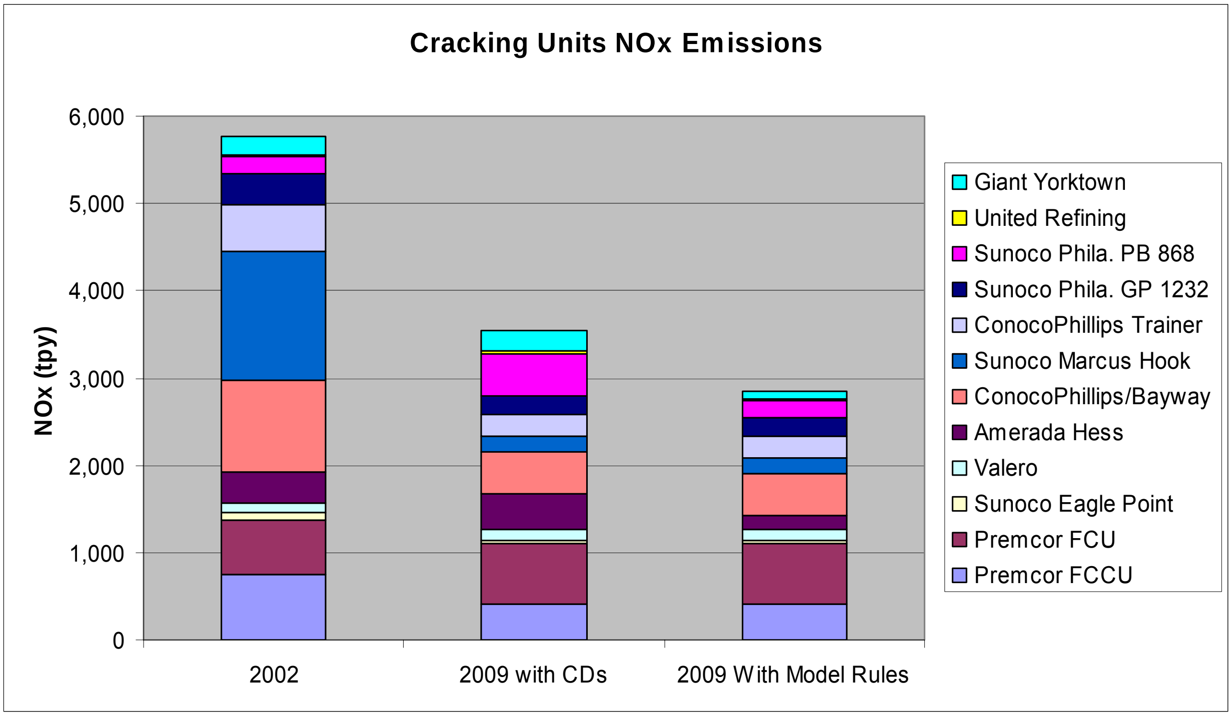


Figure ES-2 Emission Reductions from Consent Decrees and Model Rules NOx Emissions from Fluidized Catalytic Cracking Units



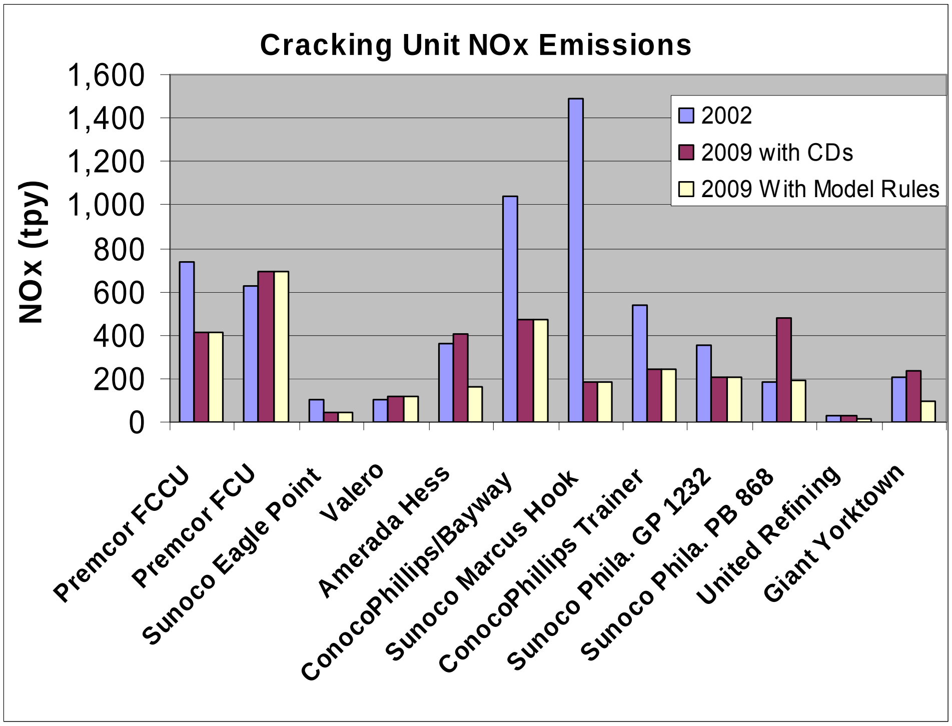
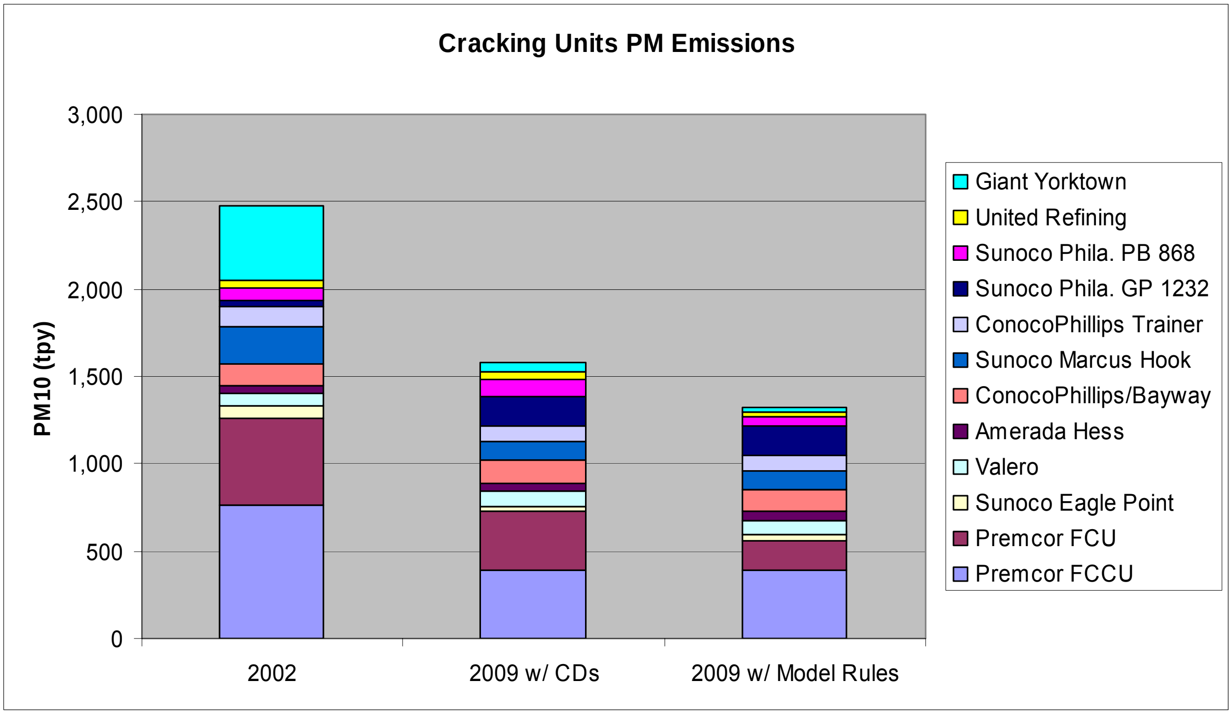


Figure ES-3 Emission Reductions from Consent Decrees and Model Rules PM Emissions from Fluidized Catalytic Cracking Units



This table shows reductions of total suspended particulate emissions; reductions in PM2.5 are not available.

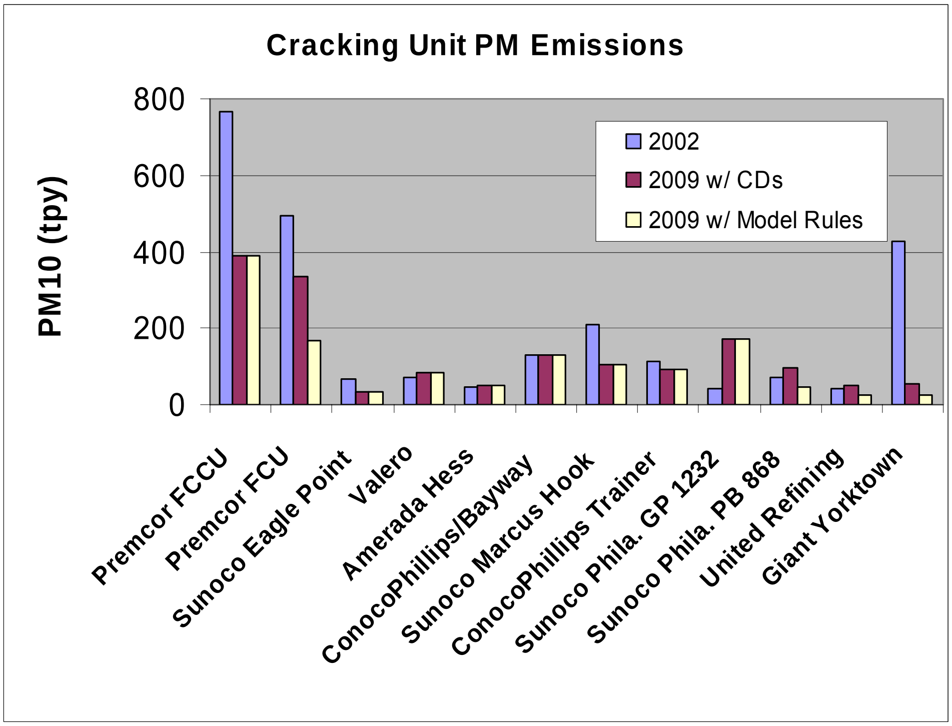
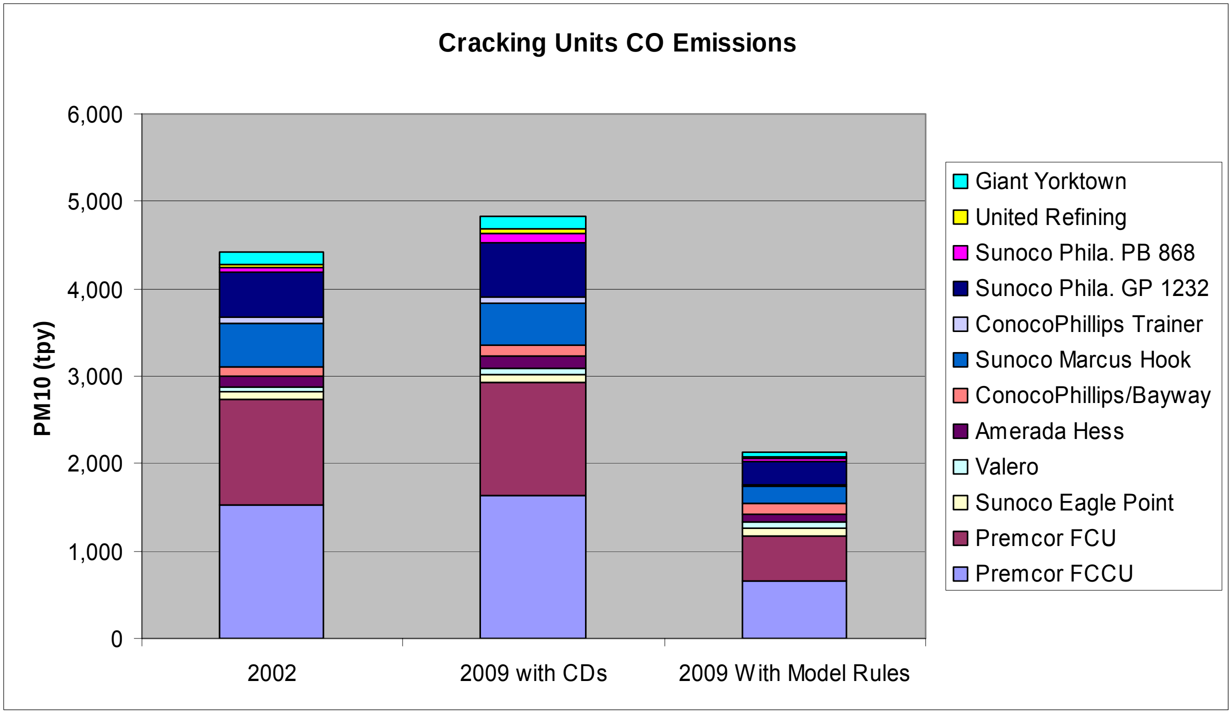


Figure ES-4 Emission Reductions from Consent Decrees and Model Rules CO Emissions from Fluidized Catalytic Cracking Units



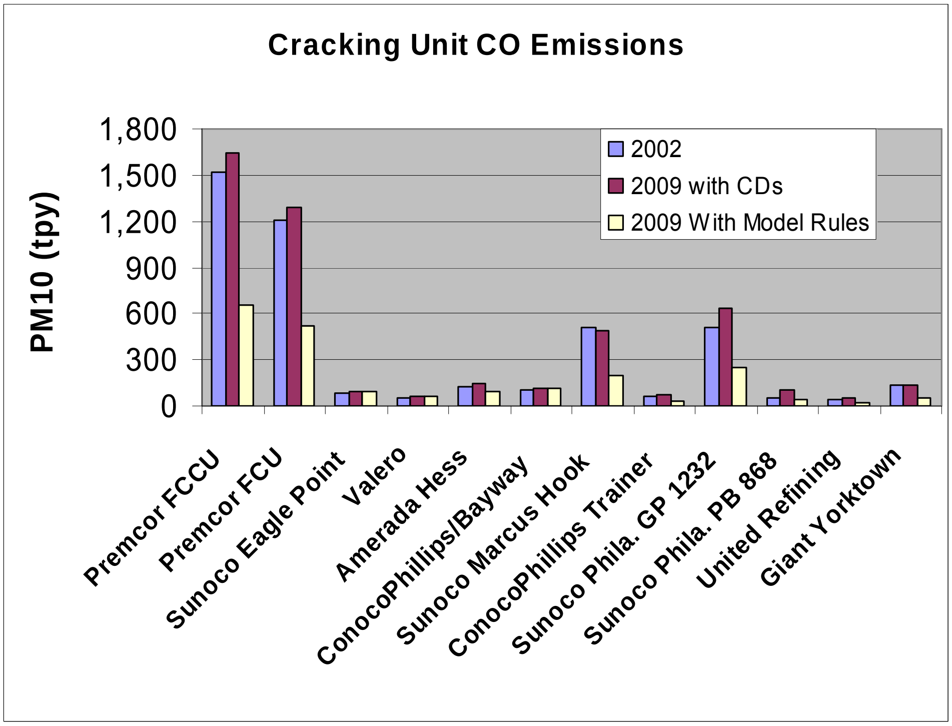
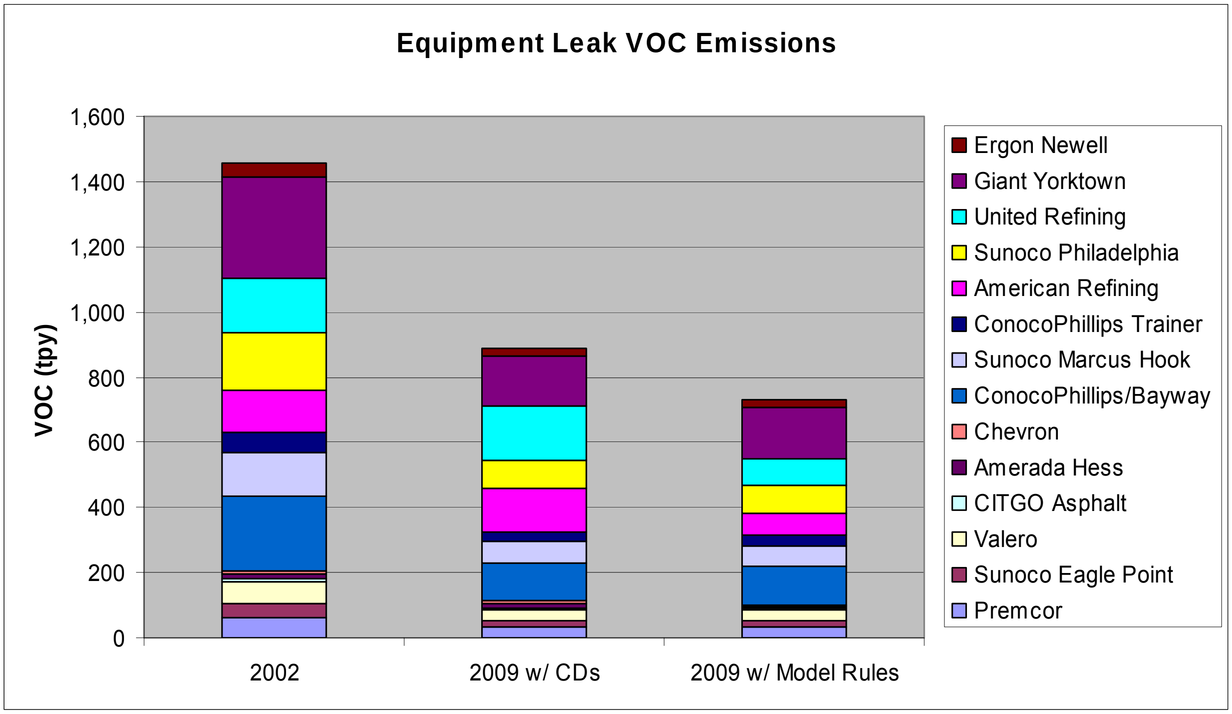


Figure ES-5 Emission Reductions from Consent Decrees and Model Rules VOC Emissions from Equipment Leaks



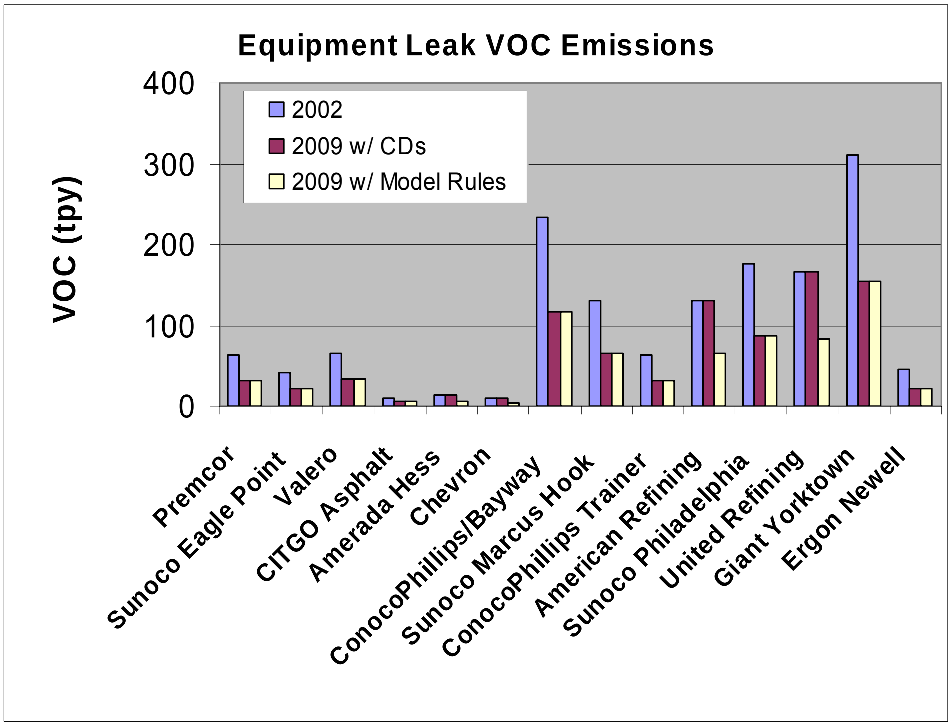
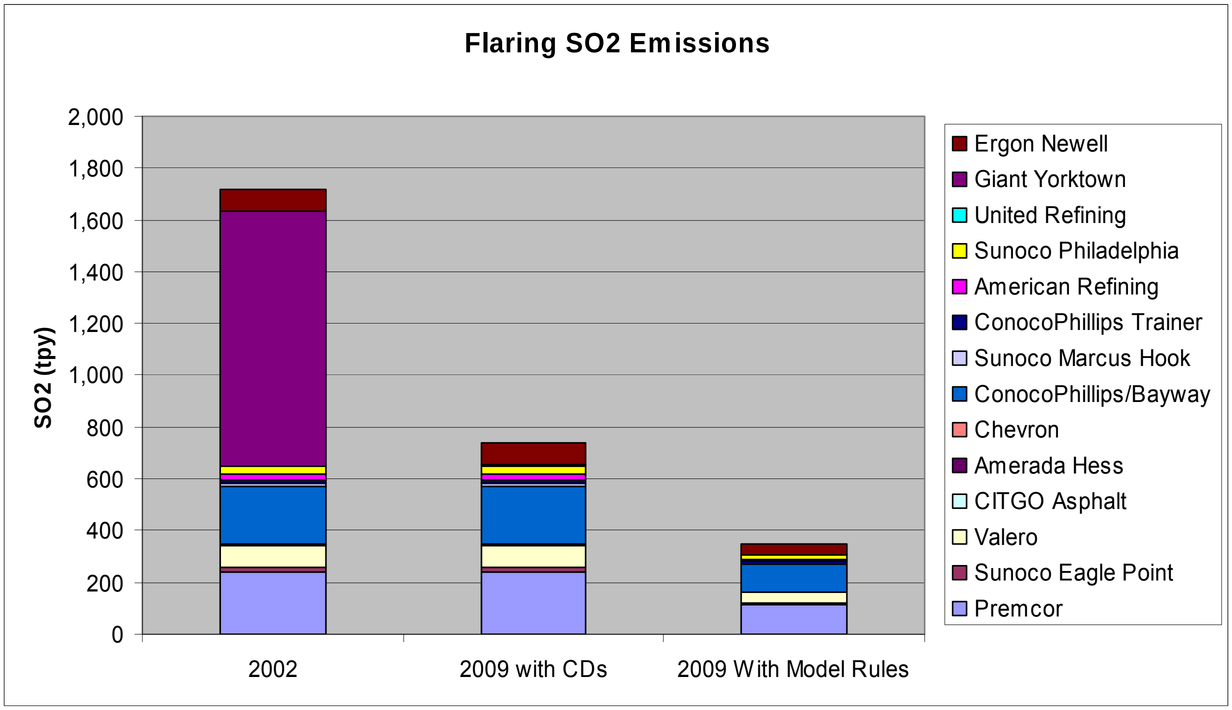


Figure ES-6 Emission Reductions from Consent Decrees and Model Rules

SO2 Emissions from Flaring



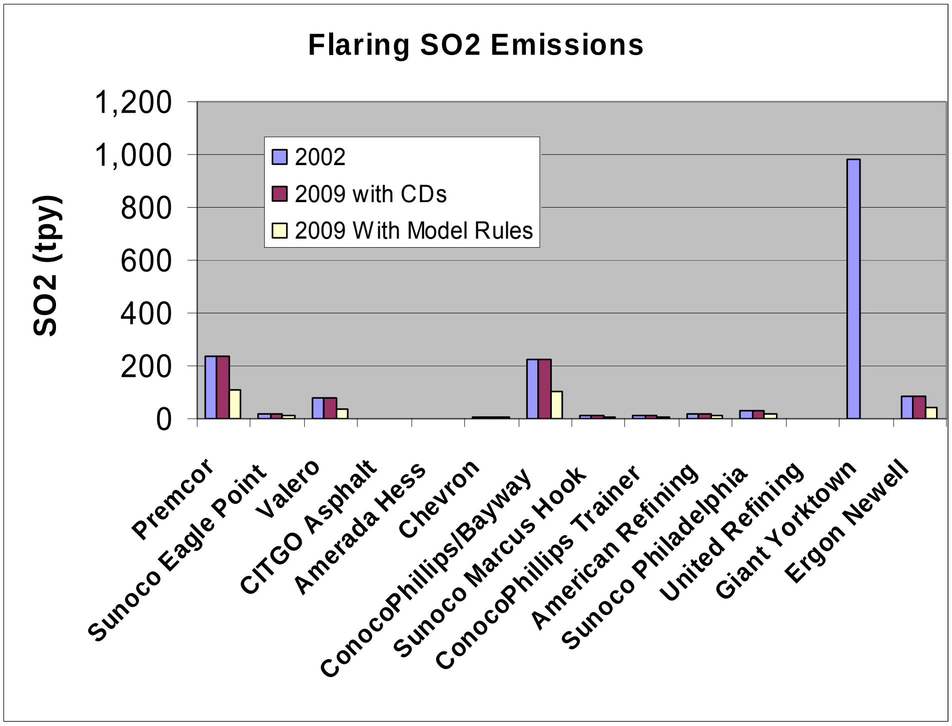
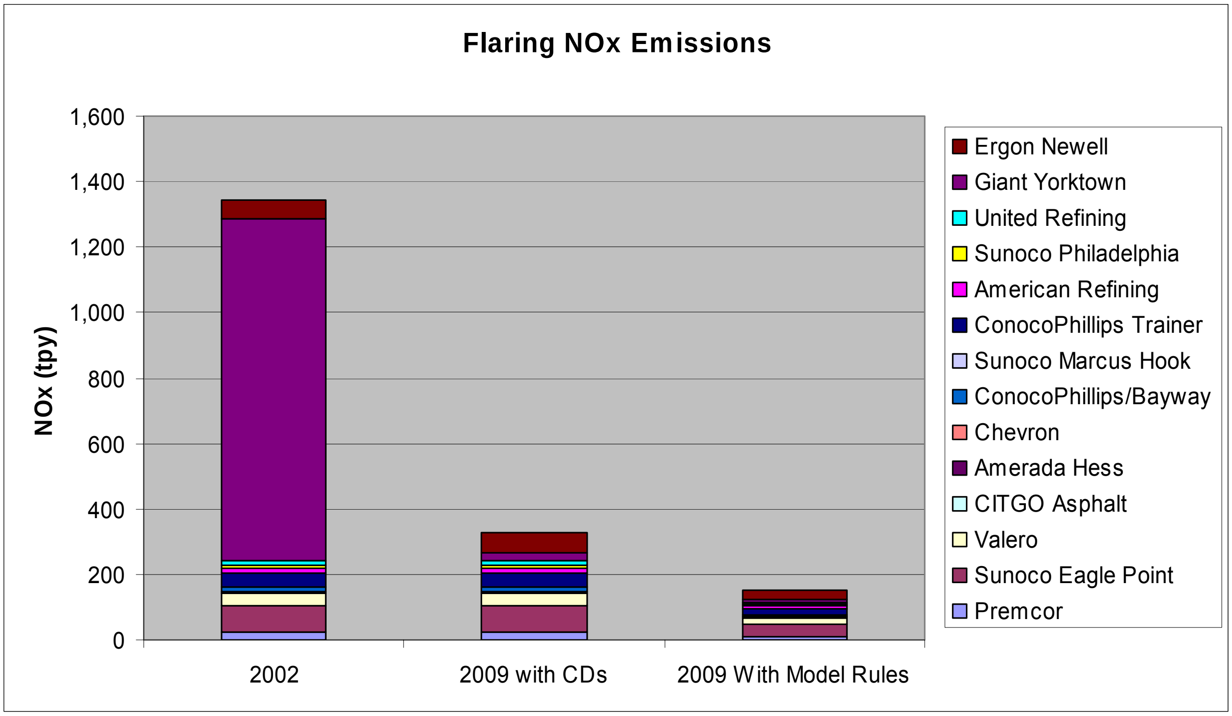


Figure ES-7 Emission Reductions from Consent Decrees and Model Rules NOx Emissions from Flaring



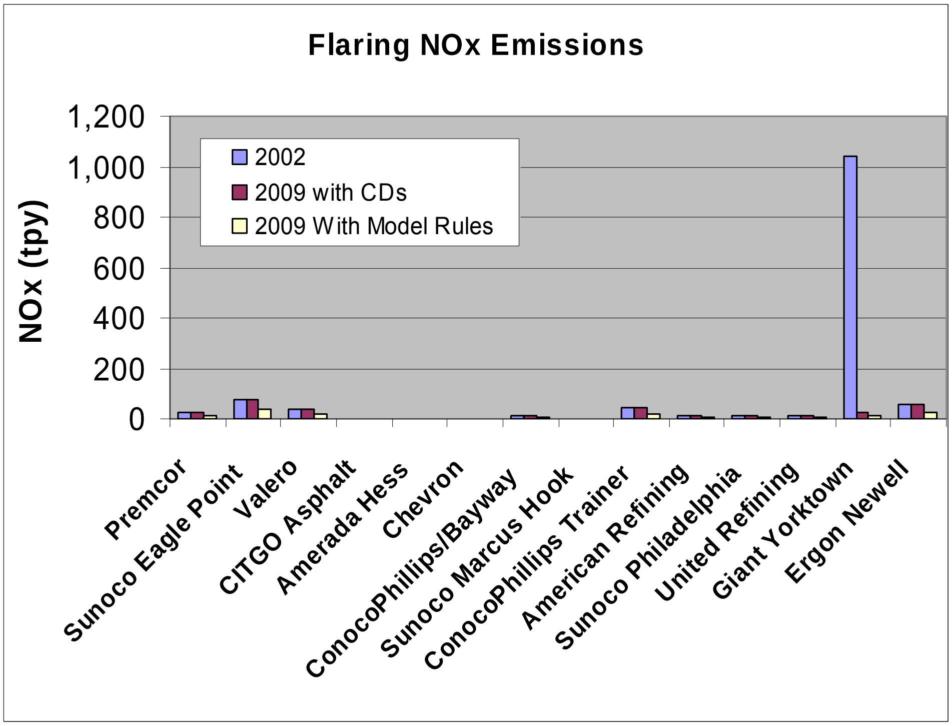
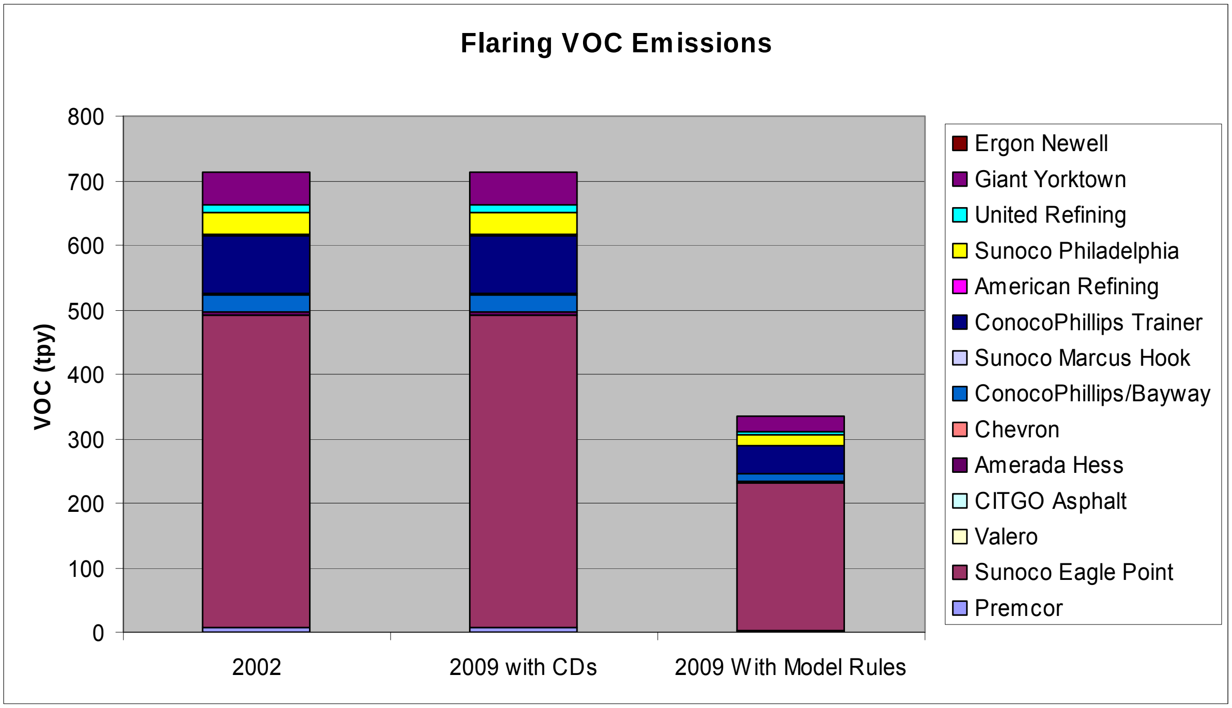
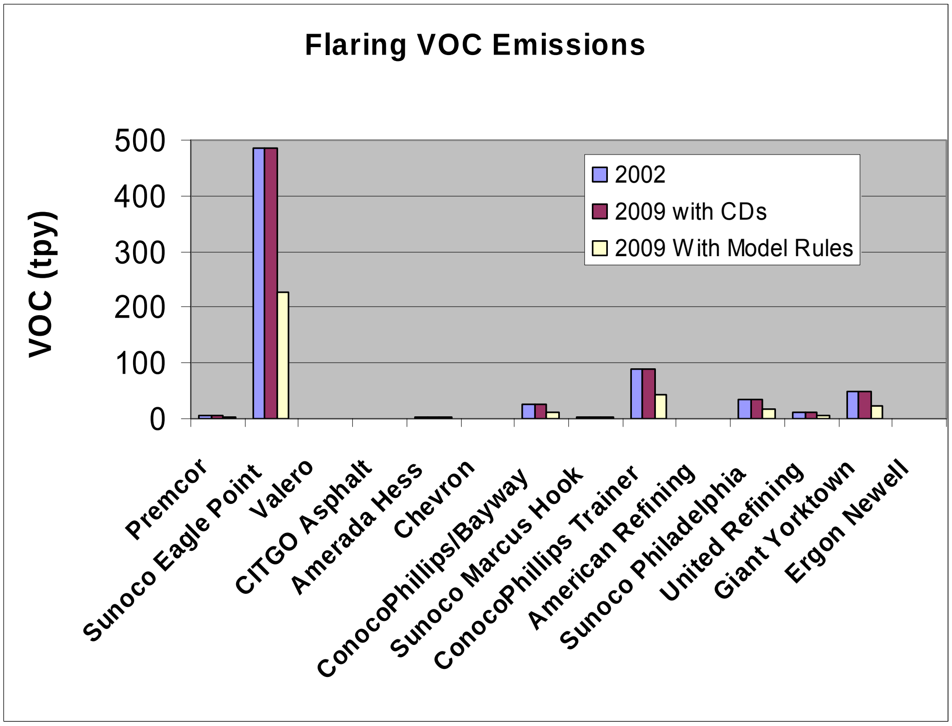


Figure ES-8 Emission Reductions from Consent Decrees and Model Rules
VOC Emissions from Flaring





1.0 EMISSION INVENTORY AND EXISTING REQUIREMENTS

This section presents the results of the Phase I analysis of petroleum refinery emissions and existing pollution control requirements. We used this information to rank refinery processes in order of significance of emissions, assess the potential for additional emission reductions, and select refinery processes for detailed control measure analysis.

1.1 EMISSION INVENTORY

Figure 1-1 shows the location of the 14 petroleum refineries in the Mid-Atlantic States. This section summarizes the emission inventories for these sources.

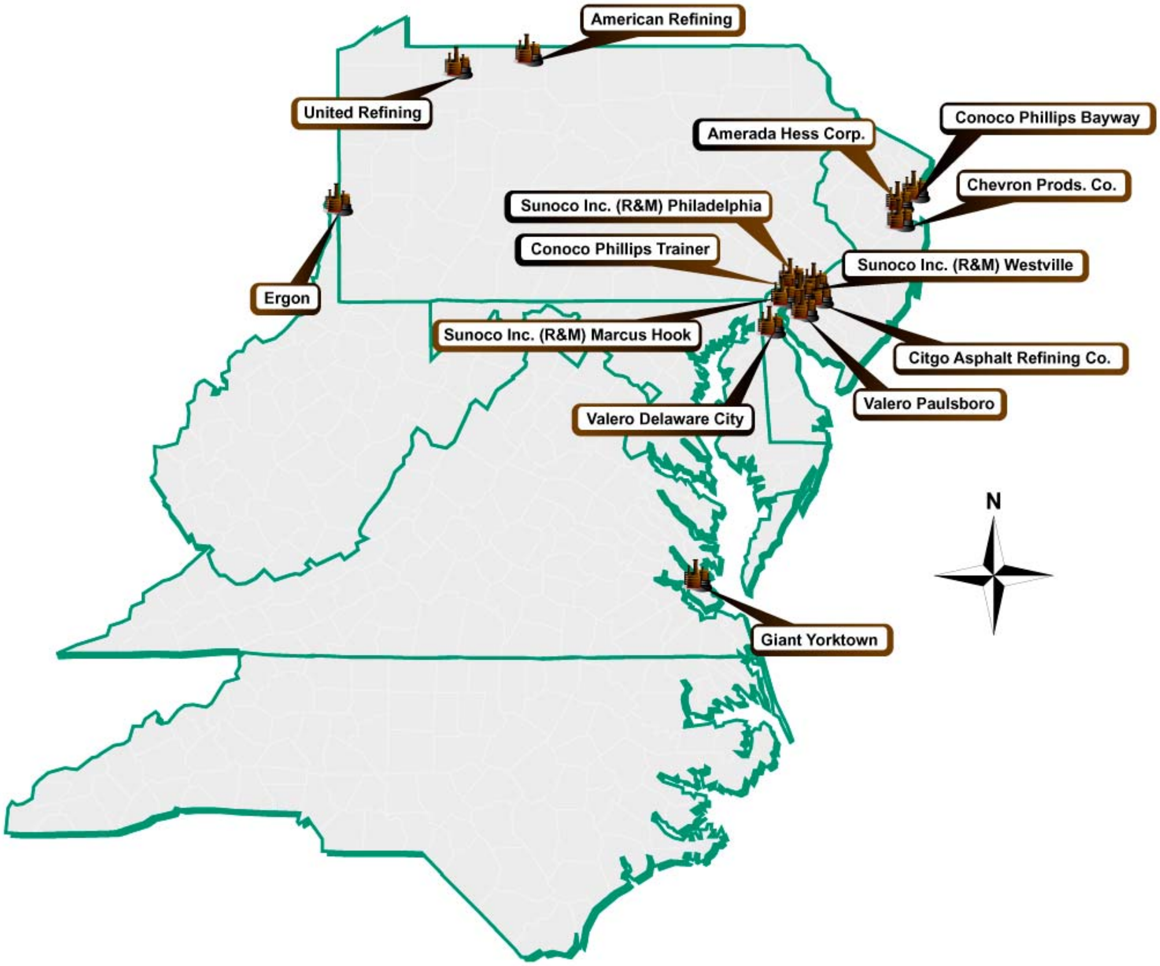


Figure 1-1. Location of Petroleum Refineries in the Mid-Atlantic States

1.1.1 Emissions by Refinery

Table 1-1 summarizes the 2002 emission inventory for each of the 14 refineries (note that the Sunoco Marcus Hook refinery is split into two facilities in the inventory: one facility for the equipment located in Pennsylvania and another facility for the equipment located in Delaware). The tables shows the emissions most important to forming ozone and fine particles: carbon monoxide (CO), ammonia (NH3), oxides of nitrogen (NOx), particulate matter less than 2.5 microns (PM2.5), sulfur dioxide (SO2), and volatile organic compounds (VOC). The 2002 annual emissions serve as the baseline for future SIP development. The 2002 emissions were obtained from the 2002 inventories developed by MANEVU and VISTAS.

Table 1-2 summarizes the projected emission inventory for 2009. The 2009 emissions were obtained from the MANEVU and VISTAS projection inventories that were developed to support modeling for SIP development. The 2009 inventories include the effects of anticipated growth as well as any planned controls that will result in emission reductions between 2002 and 2009 due to new regulations or enforcement settlements. The growth factors used for projecting emissions from 2002 to 2009 came from the U.S. Environmental Protection Agency's Economic Growth Analysis System (EGAS 5.0) and the U.S. Department of Energy's Annual Energy Outlook (2005) projections. The controls factors for 2009 were derived either from data supplied that the State/local agencies or from MACTEC's analysis of the requirements contained in the global enforcement settlements.

Tables 1-1 and 1-2 show how emissions are projected to change between 2002 and 2009:

- For SO2, refinery emissions are projected to decrease by 69 percent across the region between 2002 and 2009 due to requirements currently on-the-books. A primary reason for the decrease will be the installation of pollution controls on the catalytic cracking unit and fluid coking unit at the Delaware City refinery. Other causes for the decrease in SO2 emissions include the elimination of fuel oil combustion in boilers/heaters and installation of pollution controls at the catalytic cracking units at other refineries.
- For NOx, refinery emissions are projected to decrease by 12 percent due to requirements currently on-the-books. Reductions in NOx emissions are projected to result from additional control of emissions from the boilers/heaters and catalytic cracking units at some refineries.
- For VOC and PM2.5, refinery emissions are not projected to change very much between 2002 and 2009.
- For CO, an increase in emissions is projected due to forecasts of increased production at the refineries.

Table 1-1 Capacity and Emissions by Refinery for 2002

State	Refinery/City	Capacity (barrels/day)		2002 Annual Emissions (tons per year)					
		Crude Distillation	Catalytic Cracking	CO	NH3	NOx	PM2.5	SO2	VOC
DE	Valero Delaware City, DE	180,000	82,000[a]	3,858	43	3,535	1,308	34,096	829
DE	SUNCO R M Claymont, DE	0	0	183	8	610	31	881	49
NJ	Sunoco Inc. (R&M) Westville, NJ	145,000	55,000	280	0	1,478	167	155	1,042
NJ	Valero Refining Co. Paulsboro, NJ	160,000	55,000	260	0	1,267	161	4,450	711
NJ	Citgo Asphalt Paulsboro, NJ	51,000	0	51	0	147	6	19	28
NJ	Amerada Hess Corp. Port Reading, NJ	0	62,500	159	0	406	33	75	344
NJ	Chevron Prods. Co. Perth Amboy, NJ	80,000	0	9	0	139	12	18	317
NJ	Conoco Phillips Linden (Bayway) NJ	230,000	145,000	332	0	2,213	143	958	430
PA	Sunoco Inc. (R&M) Marcus Hook, PA	175,000	105,000	959	5	2,291	302	4,403	489
PA	Conoco Phillips Trainer, PA	185,000	53,000	972	7	2,488	97	2,530	299
PA	American Refining Bradford, PA	10,000	0	96	0	258	6	1,336	148
PA	Sunoco Inc. (R&M) Philadelphia, PA	335,000	123,500	1,806	0	3,112	398	3,982	671
PA	United Refining Co. Warren, PA	65,000	26,000	311	24	412	90	2,911	411
VA	Giant Yorktown, VA	58,600	28,200	329	0	1,629	658	2,150	1,327
WV	Ergon Newell, Congo, WV	19,400	0	140	5	239	11	116	248
	MARAMA Total	**1,694,000**	**653,200**	**9,745**	**92**	**20,224**	**3,423**	**58,080**	**7,343**

a) The Delaware City also has a fluid coking capacity of 46,500 barrels/day.

Table 1-2 Capacity and Emissions by Refinery for 2009 (Accounting for Growth and Effects of On-the-Books and On-the-Way Requirements)

		Capacity (barrels/day)		2009 Annual Emissions (tons per year)					
State	**Refinery/City**	**Crude Distillation**	**Catalytic Cracking**	**CO**	**NH3**	**NOx**	**PM2.5**	**SO2**	**VOC**
DE	Valero Delaware City, DE	180,000	82,000[a]	4,358	38	2,078	806	1,331	742
DE	SUNCO R M Claymont, DE	0	0	54	2	158	12	818	37
NJ	Sunoco Inc. (R&M) Westville, NJ	145,000	55,000	298	0	684	182	49	761
NJ	Valero Refining Co. Paulsboro, NJ	160,000	55,000	344	0	1,076	200	1,339	915
NJ	Citgo Asphalt Paulsboro, NJ	51,000	0	55	0	156	7	20	33
NJ	Amerada Hess Corp. Port Reading, NJ	0	62,500	190	0	475	38	86	330
NJ	Chevron Prods. Co. Perth Amboy, NJ	80,000	0	11	0	180	16	24	145
NJ	Conoco Phillips Linden (Bayway) NJ	230,000	145,000	390	0	1,129	160	929	566
PA	Sunoco Inc. (R&M) Marcus Hook, PA	175,000	105,000	1,079	6	716	273	236	548
PA	Conoco Phillips Trainer, PA	185,000	53,000	1,120	9	1,391	108	542	280
PA	American Refining Bradford, PA	10,000	0	106	0	293	4	1,386	148
PA	Sunoco Inc. (R&M) Philadelphia, PA	335,000	146,000	1,841	19	2,738	354	1,484	383
PA	United Refining Co. Warren, PA	65,000	26,000	382	28	501	97	3,450	202
VA	Giant Yorktown, VA	58,600	28,200	336	0	653	247	145	1,466
WV	Ergon Newell, Congo, WV	19,400	0	152	6	159	11	117	201
	MARAMA Total	**1,694,000**	**675,700**	**10,716**	**108**	**12,387**	**2,515**	**11,956**	**6,757**

a) The Delaware City refinery City also has a fluid coking capacity of 46,500 barrels/day.

ConocoPhillips Bayway initially estimated a VOC emissions of 1,629 tons/year from equipment leaks using the "leak/no leak" method and AP-42 emission factors consistent with the federal leak definition of 10,000 ppm. Emissions were recalculated using actual leak data and EPA correlation equations LeakDas software, resulting in a downward revision to 233 tons/year.

1.1.2 Emissions by Refinery Process

Figures 1-2a through 1-2d show NOx, PM2.5, SO2, and VOC emissions by refinery process. Actual emissions for 2002 are shown along side of the projected emissions for 2009.

The largest category of NOx emissions is the boiler and process heater group. About two-thirds of the refinery NOx emissions are from boilers and heaters. Other important NOx sources are the cracking/coking units and flares. NOx emissions from boilers and heaters are not expected to change much between 2002 and 2009 - anticipated reductions due to enforcement settlements and other planned controls appear to be offset by projected growth in fuel combustion. NOx emissions from cracking/coking units are projected to decrease by about 50 percent region wide due to planned installation of controls on these units.

The largest category of PM2.5 emissions is the cracking/coking group. About 58 percent of the fine particulate is emitted from this group. Boilers/heaters and flares are the other significant sources of PM2.5. PM2.5 emissions are projected to remain relatively constant between 2002 and 2009.

The four primary sources of SO2 emissions are the cracking/coking units, boilers/heaters, flares, and sulfur recovery plants. SO2 emissions from the cracking/coking units are anticipated to decline dramatically between 2002 and 2009, primarily because of the installation of pollution controls at the Delaware City refinery as well as other refineries in the region. SO2 emissions from boilers and heaters are not expected to change much between 2002 and 2009 - anticipated reductions due to elimination of the use of fuel oil appears to be offset by projected growth in fuel combustion. Little change in SO2 emissions from flares and the sulfur recovery plants are projected.

There are several significant sources of VOC emissions. Storage tanks containing crude oil, intermediate process feeds, and refined products represent the largest source of VOCs. Wastewater collection and treatment system units (process drains and collectors, oil-water separators, air flotation systems, and surface impound basins and ponds) generate VOC emissions. VOC emissions occur from process equipment whenever components in the liquid or gas stream leak. Components such as pumps, valves, pressure relief valves, and flanges are potential sources that can leak due to seal failure. A fourth source of VOC emissions is the loading of finished products into marine vessels, tank railcars, and tank trucks. Flaring activities also emit VOC. Other activities (cracking/coking units, boilers/heaters, cooling towers, process units) also emit VOC to a lesser degree.

A more detailed breakdown of emissions by specific process at each refinery is contained in the control measure assessments in Sections 2-8 of this report.

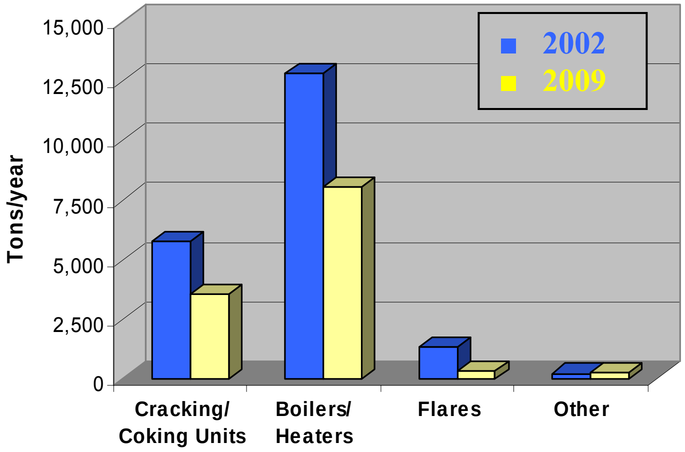


Figure 1-2a NOx Emissions by Process

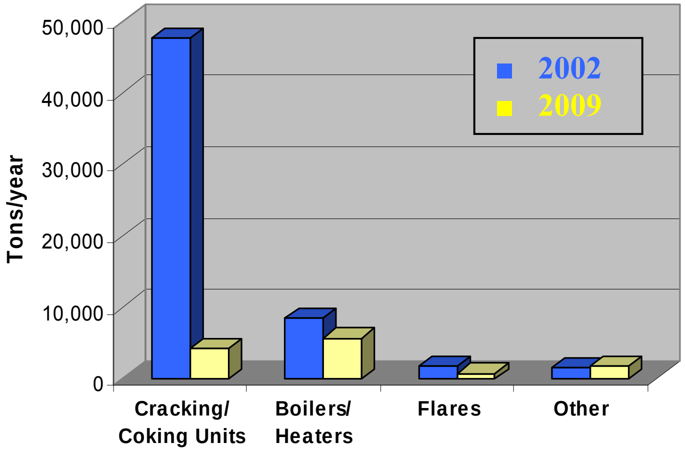


Figure 1-2c SO2 Emissions by Process

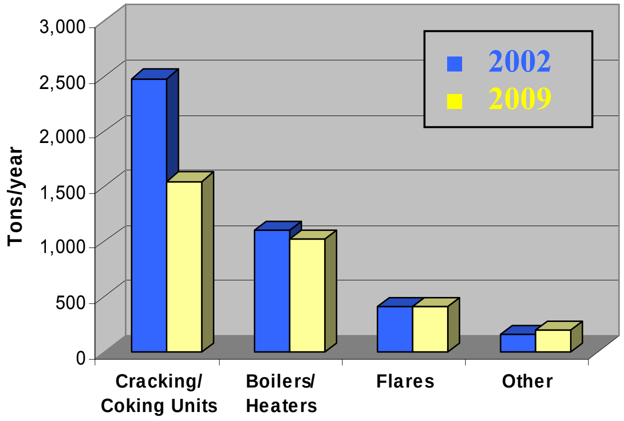


Figure 1-2b PM2.5 Emissions by Process

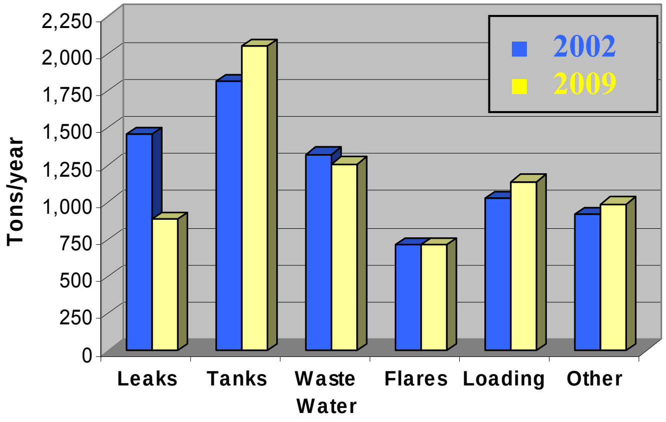


Figure 1-2d VOC Emissions by Process

1.1.3 Comparison of MARAMA Emissions to Other States

In addition to comparing emissions by refinery and process, we also compared emissions from all refineries in the MARAMA region to other areas of the country with large refining capacity. This was done to determine if there were any anomalies, unaccounted for sources, and unreasonable data in the MARAMA inventory.

Figure 1-3 compares capacity and emissions data for the 14 refineries in the MARAMA region to the 13 refineries in the Midwest Regional Planning Organization (MRPO) region, 21 refineries in California, 17 refineries in Louisiana, and 26 refineries in Texas. The capacity data was obtained from the Energy Information Administration, and the emissions data was obtained from the EPA's draft final version of the 2002 National Emission Inventory.

Figure 1-3 shows that emissions data for the refineries in the MARAMA region are generally consistent with the emissions data being reported for the refineries in CA, LA, and TX. For example, the 14 refineries in the MARAMA region have about the same crude distillation and catalytic cracking capacity as the 21 refineries in California. The NOx, CO, VOC, and PM2.5 emissions for these two areas are roughly the same. The exception is in the SO2 emissions. As mentioned previously, the Delaware City refinery was a very large source of SO2 in 2002 and is considered an outlier compared to other refineries. Once these emissions are controlled, this apparent anomaly in SO2 emissions will no longer exist.

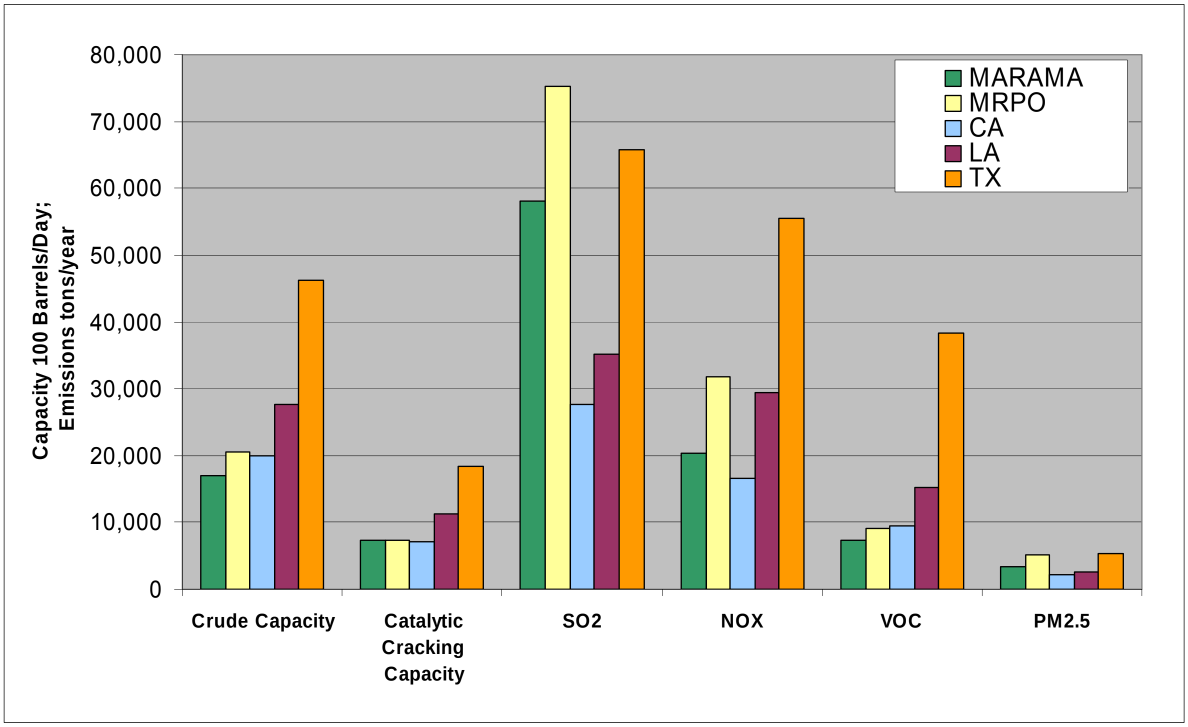


Figure 1-3 Comparison of 2002 MARAMA Refinery Capacity and Emissions with Other States

1.1.4 Emission Uncertainties

For some refinery sources, such as boilers and cracking units, emissions are monitored continuously using sophisticated equipment that provides a fairly accurate estimate of emissions. For other sources, emissions cannot easily be directly measured and the estimates of emissions from these sources are more uncertain. For example, VOC is emitted from small leaks in literally thousands of components (valve, flanges, pumps, seals, etc.). At present, it is not possible to continuously monitor each individual component to identify leaking equipment.

Recently, there has been an increased concern about the potential underestimation of emissions from certain sources at refineries. For example, there is some evidence that emissions from non-routine events (such as equipment breakdowns, startup, shutdown and maintenance) are not fully accounted for in the emission inventory, and that emissions from these events in some cases far exceed the annual emissions reported in the inventory. As the result of upsets, emissions are often routed to a flare or vented directly to the air and normal pollution controls are bypassed.

Of 18 refineries studied in Texas and Louisiana, 10 had unreported upset releases amounting to more than 25 percent of their emission inventory annual totals. The potential underestimation of emissions from non-routine events should be considered during the selection of refinery processes for detailed control measure analysis in the MARAMA region.

1.2 EXISTING REQUIREMENTS

Petroleum refineries are governed by multiple federal and state/local regulations under the Titles I and III of the Clean Air Act. Refineries are also subject to control technology assessments anytime they construct a new or modify an existing major source. Recently, refineries have been the subject of an enforcement initiative to ensure that the sources meet these regulatory and permitting requirements. Settlements from these enforcement actions will result in the installation of additional pollution control equipment. The following paragraphs generally describe the existing requirements for refineries in the Mid-Atlantic region. The specific requirements from each of these programs are discuss in detail in Sections 2-8 of this document.

1.2.1 Federal Regulations

Title I of the Clean Air Act imposes New Source Performance Standards (NSPS) on certain specified categories of new and modified large stationary sources. There are NSPS that affect the petroleum refining industry. Most of these standards were developed during the 1980s, and may or may not be applicable to a particular refinery depending on whether it has been modified since the adoption of the NSPS. The U.S. EPA is in the process of revising and updating NSPS standards. For example, in 2006 U.S. EPA finalized revisions to the NSPS for stationary combustion turbines and boilers.

EPA has also published several final rules under Title III of the CAA to substantially reduce emissions of toxic air pollutants from petroleum refineries. These Maximum Achievable Control Technology (MACT) standards apply to major sources of hazardous air pollutants (HAPs). The petroleum refinery MACT (Subpart CC) was promulgated in 1995, and most of its requirements affecting primarily organic HAP sources have already been implemented. Several other MACT standards became effective in the 1990s that affected specific refinery processes such as cooling towers and fuel storage/transfer.

Additional MACT standards may result in post-2002 emission reductions. These MACT standards include the petroleum refinery MACT II (Subpart UUU – catalytic cracking, catalytic reforming, sulfur plant units), industrial boilers and heaters, organic liquids distribution (non-gasoline), reciprocating engines, stationary combustion turbines, and remediation sites. While designed to reduce HAP emissions, the requirements of the post-2002 MACT standard may require control technologies that reduce both the level of HAP emitted from affected sources and also the VOC and PM, and to a lesser extent, SO2 emissions.

On June 15, 2005, EPA issued final amendments to its July 1999 regional haze rule. These amendments require emissions controls known as best available retrofit technology or BART for industrial facilities emitting air pollutants that reduce visibility. The BART requirements of the regional haze rule apply to facilities built between 1962 and 1977 that have the potential to emit more than 250 tons a year of visibility-impairing pollutants. Those facilities fall into 26 categories, including petroleum refineries. Some of these facilities previously have not been subject to pollution control requirements for these pollutants. Under the final BART guidelines, states are required to conduct source-by-source BART determinations to identify which facilities must install controls and the type of controls to be used.

A list is provided at the end of this section identifying the NSPS and NESHAP that are potentially applicable to a petroleum refinery.

1.2.2 State/local Regulations

Title I regulates criteria pollutants by requiring local governments to adopt State Implementation Plans (SIPs) that set forth their strategy for achieving reductions in the particular criteria pollutant(s) for which they are out of attainment. The SIP requirements includes Reasonably Available Control Technology (RACT) requirements, but more stringent requirements may be imposed depending on both the locale's degree of nonattainment with ambient air standards and the local air quality impacts. The MARAMA States have developed regulations limiting emissions from refineries based in part on the Control Technique Guidelines (CTGs) or Alternative Control Techniques (ACT) documents developed by EPA, or case-by-case RACT determinations. A list is provided at the end of this section identifying the CTGs and ACT documents that are potentially applicable to a petroleum refinery.

Another element of the SIP was finalized by EPA in the NOx SIP in 1998. The final version of the rule called for NOx emission reductions in twenty-two states that contributed to 1-hour ozone nonattainment in other states. The rule required affected states to amend their SIPs and limit NOx emissions. EPA set an ozone season NOx budget for each affected state, essentially a cap on emissions from May 1 to September 30 in the state. The cap results in about a 30 percent reduction from statewide baseline emissions. The first control period was scheduled for the 2004 ozone season. States adopted a NOx emissions trading program and assigned 5-month ozone season NOx allowances for large ICI boilers in the NOx SIP call region, including units at a few refineries in MARAMA region.

1.2.3 Permit Requirements

Title I of the Clean Air Act also subjects new and modified large stationary sources that increase their emissions to permitting requirements that impose control technologies of varying levels of stringency (known as New Source Review, or NSR). NSR requires a control technology assessment for new plants and for plant modifications that result in a significant increase in emissions, subjecting them to Best Available Control Technology (BACT) in attainment areas and to the Lowest Achievable Emission Rate (LAER) in nonattainment areas. The control strategies that constitute BACT and LAER evolve over time and are reviewed on a case-by-case basis in state/local permitting proceedings. Some states, such as Pennsylvania and Virginia, also have a minor source control technology evaluation requirement. New Jersey has a State-of-the-Art (SOTA) requirement for many types of modifications at refineries.

1.2.4 Requirements for Enforcement Settlements

EPA's national Petroleum Refinery Initiative is an integrated enforcement and compliance strategy to address air emissions from the nation's petroleum refineries. Since March 2000, the agency has entered into 17 settlements with U.S. companies that refine nearly 77 percent of the nation's petroleum. Both EPA and State/local agencies have negotiated settlements that will require significant investment in pollution control technology and will result in emission reductions in the future. The major refinery sources that are affected by the judicial settlements are: FCCUs/ (FCUs), process heaters and boilers, sulfur recovery plants, flare gas recovery, equipment leaks, and wastewater treatment.

Table 1-3 lists the recent enforcement settlements under EPA’s Petroleum Refinery Initiative that affect petroleum refineries in the MARAMA region. Ten of the 14 refineries in the MARAMA region have been included.

Table 1-3 – Recent Enforcement Settlements Under EPA's Petroleum Refinery Initiative

Settlement Company	**Lodging Date**	**Mid-Atlantic Refineries Affected by Action**
Sunoco	6/16/2005	Marcus Hook, PA/Claymont, DE Philadelphia, PA
Valero Refining	6/16/2005	Paulsboro, NJ
Conoco Phillips	1/27/2005	Linden (Bayway), NJ Trainer, PA
CITGO	10/6/2004	Paulsboro, NJ
Coastal Eagle Point	10/1/2003	Westville, NJ (purchased by Sonoco in 2004)
Ergon	10/1/2003	Newell, WV
Motiva Enterprises	3/21/2001	Delaware City, DE (purchased by Valero in 2005)
BP Amoco	1/19/2001	Yorktown, VA (purchased by Giant Industries in 2002)

The specific requirements from the enforcement settlements are discuss in detail in Sections 2-8 of this document.

1.3 SELECTION OF SOURCE CATEGORIES FOR FURTHER EVALUATION

The MARAMA Refinery Technical Oversight Committee reviewed the emission inventory, the existing requirements for each source category, and the resources available for this project. Based on that review, the following refinery processes were selected for further evaluation of candidate control measures:

- Catalytic and thermal cracking units
- Boilers and process heaters
- Flares
- Fugitive equipment leaks
- Wastewater treatment
- Storage Tanks
- Sulfur recovery units

The assessment of control technology options for these seven categories is presented in the remainder of this document.

1.4 REFERENCES

Energy Information Administration, June 2005, "Petroleum Supply Annual 2004: Table 38 Capacity of Operable Petroleum Refineries by State as of January 1, 2005".

Environmental Integrity Project, October 2002, "Accidents Will Happen: Pollution from Plant Malfunctions, Startups, and Shutdowns in Port Arthur, Texas".

Environmental Integrity Project, August 2004, "Gaming the System: How Off-the-Books Industrial Upset Emissions Cheat the Public of Clean Air".

Mid-Atlantic/Northeast Visibility Union (MANE-VU), 2006, Version 3 of the 2002 Point Source Emission Inventory, http://www.marama.org/visibility/Inventory%20Summary/2002EmissionsInventory.htm

MACTEC Federal Programs, Inc., 2006, Draft Technical Support Document: Development of Emission Projections for 2009/2012/2018 NonEGU Point, Area, and Nonroad Sources in the MANE-VU Region.

U.S. Environmental Protection Agency, 2005, Draft Final Version of the 2002 National Emission Inventory.

Visibility Improvement State and Tribal Association of the Southeast (VISTAS), 2005, Version Base 4f of the 2002, 2009, and 2018 Point Source Emission Inventory.

Attachment 1-1 – Potentially Applicable Requirements for the Petroleum Refining Industry

Name	Subpart	Effective Date
CONTROL TECHNOLOGY GUIDELINES (CTGs)		
Storage of Petroleum Liquids in Fixed Roof Tanks		1977
Refinery Vacuum Producing Systems, Wastewater Separators, and Process Unit Turnarounds		1977
Tank Truck Gasoline Loading Terminals		1977
Leaks from Petroleum Refinery Equipment		1978
Petroleum Liquid Storage in External Floating Roof Tanks		1978
SOCMI Air Oxidation Processes		1984
ALTERNATIVE CONTROL TECHNIQUES (ACT) DOCUMENTS		
Process Heaters		1993
Stationary Gas Turbines		1993
ICI Boilers		1994
Utility Boilers		1994
Internal Combustion Engines		1993
NEW SOURCE PERFORMANCE STANDARDS (NSPS) PART 60		
General Provisions	A	1970s
Sulfuric Acid Production Plants	Cd	1991
Fossil Fuel Fired Steam Generators Constructed After 8/17/71	D	1977
Electric Utility Steam Generating Units Constructed After 9/18/79	Da	1978
ICI Steam Generating Units	Db	1987
Small ICI Steam Generating Units	Dc	1990
Sulfuric Acid Plants	H	1977
Petroleum Refineries	J	1978
Storage Vessels for Petroleum Liquids Constructed Between 6/11/73 and 5/19/78	K	1977

Name	Subpart	Effective Date
NEW SOURCE PERFORMANCE STANDARDS (NSPS) PART 60 (continued)		
Storage Vessels for Petroleum Liquids Constructed Between 5/18/78 and 7/23/84	Ka	1980
Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) Constructed After 7/23/1984	Kb	1987
Stationary Gas Turbines	GG	1978
Asphalt Processing and Asphalt Roofing Manufacture	UU	1982
Equipment Leaks - SOCMI	VV	1983
Bulk Gasoline Terminals	XX	1983
Equipment Leaks of VOC in Petroleum Refineries	GGG	1984
VOC Emissions from SOCMI Air Oxidation Unit Processes	III	1990
VOC Emissions from SOCMI Distillation Operations	NNN	1990
VOC Emissions from Petroleum Refinery Wastewater Systems	QQQ	1988
VOC Emissions from SOCMI Reactor Processes	RRR	1993
Commercial and Industrial Solid Waste Incineration Units	CCCC	2001
NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP) PART 61		
General Provisions	A	1973
Equipment Leaks of Benzene	J	Mid-1980s
Asbestos	M	1984
Equipment Leaks	V	Mid-1980s
Benzene Storage Vessels	Y	Mid-1980s
Benzene Transfer Operations	BB	Mid-1980s
Benzene Waste Operations	FF	1993
NESHAP FOR SOURCE CATEGORIES PART 63		
General Provisions	A	1994
Control Technology Determinations	B	1994

Name	**Subpart**	**Effective Date**
SOCMI Industry	F	1994
SOCMI Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater	G	1994
Equipment Leaks	H	1994
Certain Processes Subject to the Negotiated Regulation for Equipment Leaks	I	1994
Industrial Cooling Towers	Q	1994
Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)	R	1994
Halogenated Solvent Cleaning	T	1994
Marine Tank Vessel Loading Operations	Y	1995
Petroleum Refineries (MACT I)	CC	1995
Hazardous Waste Combustors	EEE	1999
Petroleum Refineries (MACT II – catalytic cracking, catalytic reforming, sulfur plant units)	UUU	2002
Asphalt Processing and Asphalt Roofing Manufacturing	LLLLL	2003
ICI Boilers and Process Heaters	DDDDD	2004
Site Remediation	GGGGG	2003
Organic Liquids Distribution (non gasoline)	EEEE	2004
Misc. Organic Chemical Manufacturing	FFFF	2003
Reciprocating Internal Combustion Engines	ZZZZ	2004
Stationary Combustion Turbines	YYYY	2004

2.0 CATALYTIC AND THERMAL CRACKING UNITS

At many petroleum refineries, fluid catalytic cracking units (FCCU) and fluidized coking units (FCU) are among the largest air emission sources at the refinery. Numerous technologies have been developed over the years for pollution control at cracking units. In 1980's, the concern was primarily PM and SO_2. Today, there is concern with NOx, CO, and VOCs as well as further control of PM and SO_2. This Section presents an assessment of available control technology options for FCCUs and FCUs for states to consider as they undertake efforts to develop rules and State Implementation Plans (SIPs) for ozone, $PM_{2.5}$, and regional haze.

2.1 PROCESS DESCRIPTION

Cracking units convert middle distillate, gas oil and residuum into primarily gasoline, jet and diesel fuels by using a series of processing steps that literally "crack" large, heavy molecules into smaller, lighter ones. Heat and catalyst are used to convert the heavier oils to lighter products. With fluid catalytic cracking (FCC), a fluidized catalyst is used to optimize the cracking process. Thermal crackers, often called coking units, such as delayed and fluid coking units, rely on thermal energy to promote cracking without the use of a catalyst.

Typical FCC systems consist of a reactor, catalyst regenerator, and vent gas process equipment for energy recovery and/or emission control (see Figure 1-1). In the FCC process, preheated oil and oil vapors are introduced to the hot catalyst (usually zeolite supported by amorphous synthetic silica-alumina with metals) in the riser pipe. Due to the high reactivity of modern catalysts, most of the cracking takes place inside the riser pipe at temperatures between 880 and 980^{o}F. The fluidized catalyst and the reacted hydrocarbon vapor are then transferred to the reactor where they are separated mechanically in a cyclone system, sending the cracked oil vapors to a fractionation tower where desired fractions are separated, steam stripped, cooled, and collected. Slurry oil removed from the bottom of the fractionation tower is used either as wash oil and a quench for the hot reactor overhead vapors to prevent after-cracking, or filtered to remove catalyst fines, cooled, and sent to storage. The fluidized catalyst is transferred from the reactor to the catalyst regenerator. The catalytic cracking process deposits coke on the catalyst surface, reducing its effectiveness, therefore the coke is burned off at high temperatures in the regenerator, and then recycled back to the reactor.

Catalyst regenerators operate in either full (complete) or partial combustion mode. In the full combustion mode, the regenerator is operated at temperatures around 1300^{o}F to oxidize all coke carbon to CO_2 and not CO. In partial combustion mode, the regenerator is operated at lower temperatures, and CO oxidation is controlled by limiting the amount of combustion air available. The partial combustion mode avoids catalyst sintering problems with coke containing high metal content.

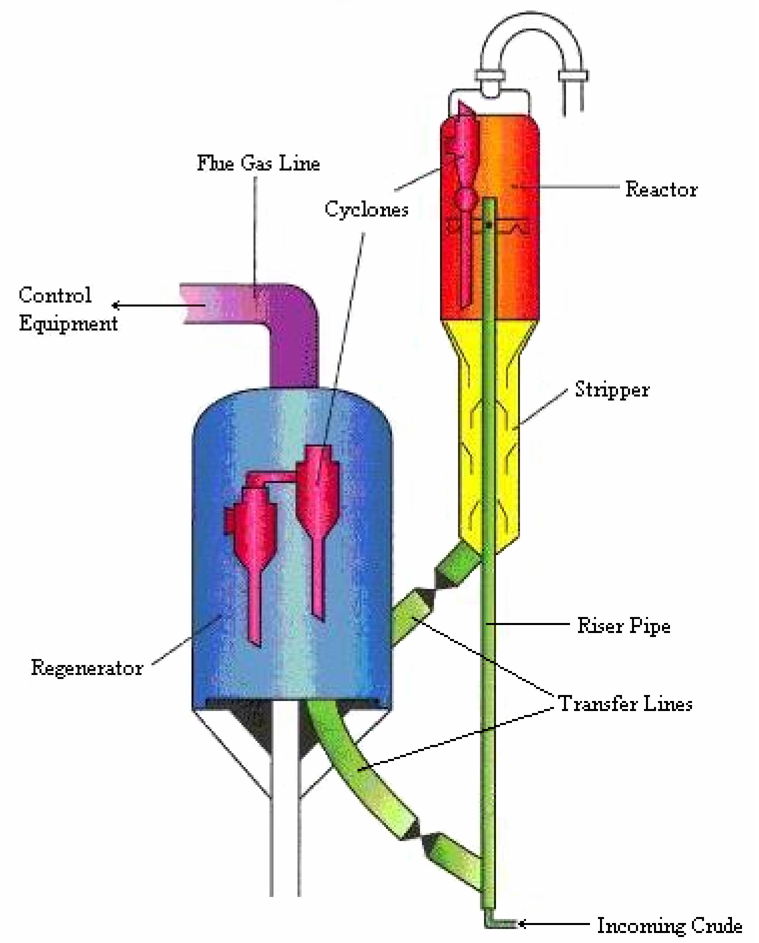


Figure 2-1. Diagram of a Fluidized Catalytic Cracking Unit

SOURCE: http://www.refractorydepot.com/FCCU.gif

FCCU systems are the most widely used cracking process in the MARAMA region. One facility (Delaware City) operates both a FCCU and a FCU. Another facility (Valero) uses a delayed coking thermal cracking unit in addition to a FCCU to further breakdown the heaviest fractions from distillation bottoms. Air pollution control issues for fluid coking units are similar to those for fluidized catalytic cracking units, while delayed coking units do not have process emissions. The only emissions from delayed coking units are from the combustion of fuel in the associated process heater that provides the energy required for the thermal cracking reaction.

2.2 EMISSION INVENTORY

Table 2-1 identifies the FCCUs and coking units in the MARAMA region, along with the capacity of each unit. Criteria pollutant emissions for each unit are shown for three years. The 2002 annual emissions serve as the baseline for future SIP development. The 2002 emissions were obtained from the 2002 inventories developed by MANEVU and VISTAS. The 2003 emissions were obtained directly from each state and represent the most currently quality assured data that is available.

The 2009 emissions were obtained from the MANEVU and VISTAS projection inventories that were developed to support modeling for SIP development. The 2009 inventories include the effects of anticipated growth as well as any planned controls that will result in emission reductions between 2002 and 2009 due to new regulations or enforcement settlements. The growth factors used for projecting emissions from 2002 to 2009 came from the U.S. Environmental Protection Agency's Economic Growth Analysis System (EGAS 5.0) and the U.S. Department of Energy's Annual Energy Outlook (2005) projections. The controls factors for 2009 were derived either from data supplied that the State/local agencies or from MACTEC's analysis of the requirements contained in the global enforcement settlements.

The 2009 projected emissions for the Marcus Hook FCCU were calculated assuming that controls required by the Consent Decree would be in place by 2009. While the controls in fact are not required until 2013 in the Consent Decree, there are stipulated penalties if the controls are not installed by 2010. It is unlikely that the controls will be installed by 2009, and the 2009 projected emissions will likely be higher than shown in Table 2-1.

The 1232 FCCU at the Philadelphia refinery (Girard Point) was issued a permit on February 28, 2006 to increase the daily feed rate to 100,000 barrels per any single day and 90,000 barrels per day on a rolling 365-day average while the 868 FCCU Philadelphia (Point Breeze) has a permit application under review to increase its daily feed rate to 58,000 barrels per any single day and 56,000 barrels per day on a rolling 365-day average. The emissions for 2009 for the 1232 FCCU and the 868 FCCU reflect the permit limits that are expected to be in place in 2009.

Table 2-1 shows that SO_2 emissions for several FCCUs/FCUs are projected to be reduced by 2009 as a result of the requirements of the enforcement settlements (to be discussed in more detail later), resulting in a region-wide reduction of about 90 percent for all units in the region. The region-wide NOx emission reductions are projected to be about 40 percent by 2009 as a result of the enforcement settlements and other on-the-books requirements. Smaller reductions in PM and VOC emissions are also projected as a result of compliance with the MACT standards.

Table 2-1 Emission Inventory for FCCUs and FCUs

State	Refinery/ Unit	Capacity BBL/day	Year	Annual Emissions (tons per year)					
				CO	NH_3	NOx	PM_{10}	SO_2	VOC
DE	Valero EUID = 011/012 FCCU w/ CO Boiler	82,000	2002	1,524	4	739	765	11,421	122
			2003	1,883	12	1,119	541	14,407	112
			2009	1,640	5	411	390	361	131
DE	Valero EUID = 001/002 Fluid Coker Unit w/CO Boiler	57,100	2002	1,209	3	624	496	19,461	97
			2003	996	7	557	403	17,752	72
			2009	1,291	4	690	334	174	100
NJ	Sunoco Eagle Point EUID = U9 FCCU	67,650	2002	83	0	103	69	91	41
			2003	93	0	58	62	68	37
			2009	95	0	47	35	5	6
NJ	Valero Refining EUID = U1 FCCU	55,000	2002	53	0	106	71	3,597	29
			2003	43	0	90	43	3,844	15
			2009	61	0	121	82	172	4
NJ	Amerada Hess EUID = U1 FCCU	65,000	2002	130	0	359	44	71	51
			2003	48	0	349	54	70	59
			2009	148	0	409	50	81	7
NJ	ConocoPhillips Bayway EUID = U4 FCCU w/ 2 CO Boilers	140,000	2002	99	0	1,036	128	65	12
			2003	105	0	1,341	205	37	5
			2009	113	0	475	128	75	2
PA	Sunoco Marcus Hook EUID = 101 PLT 10-4 FCC w/ CO Boiler	115,000	2002	514	0	1,489	209	4,374	10
			2003	453	0	1,651	217	5,246	4
			2009	484	0	184	105	824	1
PA	ConocoPhillips Trainer EUID = 101 FCC w/ CO Boiler	52,000	2002	.63	5	520	113	2,092	3
			2003	67	5	543	116	1,874	3
			2009	69	5	245	93	166	0
PA	Sunoco Philadelphia EUID = 019 GP 1232 w/ CO Boiler	73,500	2002	514	0	356	42	2,378	4
			2003	514	0	464	57	2,187	0
			2009	634	19	208	170	363	8
PA	Sunoco Philadelphia EUID = 539 PB 868 FCCU	47,500	2002	52	0	182	70	475	0
			2003	52	0	199	61	586	0
			2009	100	0	482	95	600	23
PA	United Refining Warren EUID = 101A FCCU	24,000	2002	43	0	29	43	1,091	0
			2003	41	0	39	41	1,074	0
			2009	49	0	33	49	1,245	0
VA	Giant Yorktown EUID = 6 FCCU	36,000	2002	140^e	0	210	428	477	3
			2003	44^e	0	212	428	629	3
			2009	140^e	0	233	53	106	3
	MARAMA Totals	864,650	2002	4,421	12	5,770	2,478	47,566	372
			2003	4,339	24	6,622	2,228	47,774	310
			2009	4,824	33	3,538	1,548	4,172	285

Notes: Dave Brown, PADEP indicates 2009 projections for Marcus Hook may be higher than shown since consent decree controls are not required until 2013; Keith Lemchak, AMS, provided revised 2009 emissions based on current permit limits and consent decree requirements.

2.3 EXISTING REQUIREMENTS

This section discusses the regulatory requirements which apply to cracking units. Four types of requirements are discussed: (1) Federal requirements such as the New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards; (2) State regulations for both the MARAMA states as well as other State agencies; (3) source-specific permit requirements; and (4) new requirements from recent enforcement settlements.

2.3.1 Federal Regulations

Performance standards under NSPS apply to emissions exiting the FCCU catalyst regenerator. Particulate matter discharged from the catalyst regenerator should not exceed 2.0 lb/ton of coke burn-off, as well as 30% opacity, except for one 6-minute average during any 1-hour period. In addition, for discharged flue gas that passes through an incinerator or waste heat boiler, which burns liquid or solid fossil fuel, incremental PM emissions are limited to 0.10 lb/MMBtu. As for SO_2 emissions, three options exist for compliance. First, if an add-on SO_2 control device is present, SO_2 emissions must be controlled by 90% or limited to 50 ppmv, whichever is less stringent. Second, if no control device is used, SO_2 emissions must be limited to 20 lb/ton coke burn-off. The third option limits the sulfur content of fresh feed to the FCCU to 0.30% by weight. Subpart J also limits CO emissions from the catalyst regenerator to 500 ppmvd on a 1-hour average.

National Emission Standards for Hazardous Air Pollutants (NESHAP) were developed as part of section 112(d) of the Clean Air Act, which requires that major sources of HAP, those that have the potential to emit at least 10 tpy of any single HAP or 25 tpy of any combination of HAPs, meet standards reflecting the application of the maximum achievable control technology (MACT). The first NESHAP for petroleum refineries (40 CFR 63, Subpart CC) commonly referred to as the MACT I standard, covered the following sources: miscellaneous process vents, storage vessels, wastewater collection/treatment, and equipment leaks. The second NESHAP applying to petroleum refineries is the MACT II standard (40 CFR 63, Subpart UUU), which applies to catalytic cracking units, catalytic reforming units, sulfur recovery units, and bypass vents.

Under Title 40, CFR, Part 63, Subpart UUU, for new and existing FCCUs subject to NSPS limits, PM emissions must not exceed 1.0 lb/1,000 lb of coke burn-off in the catalyst regenerator, and if the discharge gases pass through an incinerator or waste heat boiler, which burns liquid or solid fossil fuel, then the incremental rate of PM is limited to 0.10 lb/MMBtu, in addition to an opacity limit of 30%, except for a 6-minute average in any 1-hour period. For those FCCUs not subject to NSPS limitations, then four options exist for compliance with the MACT standard: (1) comply with the above stated PM emission limit, (2) limit PM emissions to 1.0 lb/1,000 lb coke burn-off, (3) limit Nickel emissions to 0.029 lb/hr, or (4) limit Nickel emissions to 0.001 lb/1,000 lb coke burn-off in the catalyst regenerator.

2.3.2 State Regulations

Table 2-2 lists the regulations for each of the MARAMA states for the control of PM, SO_2, and CO. Most states limit PM emissions using process weight rate calculations, while none of the MARAMA states had regulations limiting NOx emissions. In Table 2-3, the regulations are listed for Louisiana, Texas, and California (from the Bay Area Air Quality Management District – BAAQMD and the South Coast Air Quality Management District – SCAQMD). Regulations from these states are presented because these states have a large number of refineries and generally have stricter emission limitations than the MARAMA states and the federal government.

2.3.3 Permit Requirements

See Table 2-4 for a list of all current permit requirements for FCCUs at petroleum refineries in the MARAMA region. Many units have requirements that are more stringent than the Federal or State regulations discussed in the previous section as a result of New Source Review permitting that required the installation of best available control technology (BACT).

2.3.4 Requirements from Recent Enforcement Settlements

The EPA and State/local agencies recently undertook an initiative to investigate physical modifications to FCCUs. Capacity increases and modifications should have triggered NSR permitting and pollution control requirements. There have being several instances identified where refineries have failed to obtain pre-construction and operating permits for physical construction that increased their capacity and emissions. Consent Decrees require petroleum refineries to install continuous emissions monitoring equipment so that facilities, EPA, and States can access real time emissions data. More importantly, Consent Decrees also require facilities to install and implement a suite of controls to reduce NOX, SO2, and PM emissions. Table 2-5 provides a list of recent enforcement settlements for FCCUs and coking units at petroleum refineries in the MARAMA region.

For particulate emissions, the most stringent performance level specified in the Consent Decree requirements is 0.5 pounds PM per 1000 pounds coke burned on a 3-hour average basis. For SO2, the performance level is 25 ppmvd @ 0% oxygen based on 365-day rolling average 50 ppmvd @ 0% oxygen based on 7-day rolling average. For NOx, the most stringent performance level is 20 ppmvd, measured as a 365-day rolling average, and 40 ppmvd, measured as a 7-day rolling average, @ 0% oxygen. For CO, the performance level is 200 ppmvd @ 0% oxygen based on 1-hr block average and 100 ppmvd @ 0% oxygen based on 365-day rolling average

Table 2-2: Summary of MARAMA State Regulations for FCCUs/FCUs

Agency	PM	SO_2	CO
Delaware	Reg. 5, Section 5: Process Weight Rate based on coke burn-off rate (7,000 lb coke burn-off/hr is equivalent to 50 lb/hr PM, while 70,000 lb coke burn-off/hr is equivalent to 500 lb/hr PM for FCCUs and per Table 4 of Reg. 5 for coking units)	Reg. 8, Section 1: SO_2 emissions should meet ambient air quality standards (80 $\mu g/m^3$ on annual basis, 365 $\mu g/m^3$ on 24-hr basis, 1300 $\mu g/m^3$ on 3-hr basis)	Reg. 11, Section 2: In New Castle County, CO emissions must be burned at 1300°F for 0.3 seconds or greater in a direct flame afterburner or boiler
New Jersey	7:27-6.2: The maximum allowable PM emission rate varies depending on the size of the source	7:27-9.2: Maximum allowable % Sulfur in liquid fuels according to Table 1, or max sulfur emissions according to Table 2	
Pennsylvania	123.13: PM emissions shall not exceed the greater of 0.02 gr/dscf or the emissions calculated by $A=0.76\ (FxW)^{0.42}$, where A is the emissions limit (lb/hr), F is the Process Factor (40 lb/ton liquid feed for catalytic crackers), and W is the production rate (ton liquid feed/hr)	123.21: ≤ 500 ppmvd	
Philadelphia	Reg. 2, Section 7: PM emissions should not exceed those listed in Table I of the regulation, where process weight rate (lb/hr) is compared with maximum PM emissions (lb/hr). The maximum allowable PM emission rate is 40 lbs/hr.	Reg. 3, Section 2: (1) Emissions of SO_2 should not exceed ground level concentrations of 3ppmv, 0.5 ppmv for 15-min avg, and 0.1 ppmv for 8-hr avg. (2) SO_2 in exhaust streams ≤ 0.05% by volume	Reg. 8: Gases containing CO emissions should be incinerated at ≥ 1400°F for a period of not less than 0.5 seconds, or should be controlled by means of equal or greater efficiency:
Virginia	9 VAC 5-40-260: (AQCR 1-6) Process weight rate applies: (1) $E = 4.1(P^{0.67})$ for $P < 30$ tph; (2) $E = 55(P^{0.11})-40$ for $P > 30$ tph 9 VAC 5-40-270: (AQCR 7) Process weight rate applies according to Table 4-4B 9 VAC 5-40-1360: PM emissions from petroleum catalytic cracking units ≤ 0.05% of the rate of catalyst recirculation within the unit.	9 VAC 5-40-280: ≤ 2,000 ppmv	
West Virginia	45-7-4: Process Weight Rate according to Table 45-7A	45-10-4: ≤ 2,000 ppmv	

Table 2-3: Summary of Other State Regulations for FCCUs and FCUs

Agency	PM	SO_2	NOx	CO
Louisiana	Chapter 13, Subchapter A: PM emissions should follow the process weight rule; opacity ≤ 30% (except one 6-min avg. in a 1-hr period)	Chapter 15: ≤ 2,000 ppm at standard conditions (3-hr avg)		Chapter 17, Subchapter C: CO emissions must be burned in a direct flame afterburner or boiler (or other control method approved by the state)
Texas	111.151: $\leq 0.045(q^{0.62})$, where q is the stack effluent flow rate (acfm), however, if the effective stack height (H_E) < standard effective stack height (H_{SE}), then the allowable emission rate is multiplied by $(H_E/H_{SE})^2$; Formulas for H_E and H_{SE} are found in this rule.		117.206: In the Houston-Galveston ozone non-attainment area, catalytic cracking units (including CO boilers) must comply with one of the following: (1) ≤ 40 ppmvd @ 0% O_2; (2) 90% NOx reduction from calculated June-Aug. 1997 daily NOx emissions	
BAAQMD	6-310: (1) ≤ 0.15 gr/dscf and (2) follow process weight rate ($E = 4.1(P^{0.67}) \leq 40$ lb/hr)	9-1-310: ≤ 1,000 ppmv	9-10-304: (1) ≤ 150 ppmvd @ 3% O_2 (24-hr avg); OR (2) Operate an emissions control system that has a minimum control efficiency of 50% by wt.	9-10-305: ≤ 400 ppmvd @ 3% O_2 (24-hr avg)
SCAQMD	Rule 1105.1 Comply with one of the following: (1) 3.6 lb/hr; (2) 0.005 gr/dscf @ 3% O_2; (3) 2.8 lb/thousand barrel fresh feed	Rule 1105: 132 lb/thousand barrel feed charged to FCCU		

Table 2-4: Summary of Permit Requirements FCCUs and FCUs

Refinery & Unit	Required PM Control Technology or Emission Limitation	Required SO_2 Control Technology or Emission Limitation	Required NOx Control Technology or Emission Limitation	Required CO Control Technology or Emission Limitation
Valero Delaware City EUID = 011/012 FCCU w/ CO Boiler	TSP - 1 lb/1000 lb of coke burned Company shall propose lb/hr and tpy PM10 and H2SO4 emission limits	25 ppmvd or lower on a 365-day rolling avg, 50 ppmvd on a 7-day rolling avg basis, each corrected to 0% O_2, and 361 tpy	Reserved	CO emission limit 500 ppmv and 3,768 tpy CO burned at no less than 1300F for 0.3 seconds in the CO boiler
Valero Delaware City EUID = 001/002 Fluid Coker Unit w/CO Boiler	TSP - 47.1 lbs/hr and 206.3 tpy H2SO4 - 58 lbs/hr and 252.3 tpy PM10 - 133.1 lb/hr and 133.1 tpy	25 ppmvd or lower on a 365-day rolling avg, 50 ppmvd on a 7-day rolling avg basis, each corrected to 0% O_2, and 174 tpy	Not exceed level to be established in accordance with Consent Decree (i.e., SNCR optimization study) Emission limit 689.8 tpy	Company shall propose limit in conjunction with SNCR optimization study CO burned at no less than 1300F for 0.3 seconds in the CO boiler
Sunoco Eagle Point EUID = U9 FCCU	TSP - 11.4 lbs/hr H2SO4 - 15 lbs/hr PM10 - 30 lbs/hr	EDV-6000 scrubber - Permittee/DEP will decide on appropriate parameter for maximum feed sulfur content or barrel per day feed rate SO2 emission limit 75 lbs/hr	Emission limit 50 lbs/hr	Emission limit 75 lbs/hr
Valero Refining EUID = U1 FCCU	TSP – 120.4 tpy H2SO4 – 51.55 tpy PM10 – 120.4 tpy	BELCO wet scrubber SO2 emission limit 172 tpy	Emission limit 222.9 tpy	Emission Limit 150.5 tpy
Amerada Hess EUID = U1 FCCU	TSP – 0.02 gr/scf TSP – 22 lbs/hr H2SO4 – 12.86 lbs/hr PM10 – 36 lbs/hr	Wet gas scrubber Sulfur content of fresh feed < 1% by weight Emission limit 80 lbs/hr or 141 ppmvd at 0% oxygen, whichever is lower	Emission limit 160 lbs/hr or 328 ppmvd at 0% oxygen, whichever is lower	Emission limit 160 lbs/hr or 300 ppmvd at 0% oxygen, whichever is lower
ConocoPhillips Bayway EUID = U4 FCCU w/ 2 CO Boilers	PM10 – 59.9 lbs/hr TSP – 50.2 lbs/hr Particulate – 0.02 grains per scf H2SO4 – 150 lbs/hr	Sulfur content of fresh feed < 1% by weight Emission limit 25 ppm @ 7% oxygen Emission limit 77.6 lbs/hr Emission limit 261 tpy	Emission limit 334.7 lbs/hr Emission limit 1,127.8 tpy	Emission limit 872 lbs/hr and 500 ppmvd at 7% oxygen

Table 2-4: Summary of Permit Requirements FCCUs and FCUs (continued)

Refinery & Unit	Required PM Control Technology or Emission Limitation	Required SO_2 Control Technology or Emission Limitation	Required NOx Control Technology or Emission Limitation	Required CO Control Technology or Emission Limitation
Sunoco Marcus Hook EUID = 101 PLT 10-4 FCC w/ CO Boiler	0.02 grains per SCF	500 ppmv	0.0149 lbs/barrel of fresh feed	Two CO Boilers installed to control CO emissions from catalyst regenerator 500 ppm, dry basis
ConocoPhillips Trainer EUID = 101 FCC w/ CO Boiler	0.02 grains per SCF	500 ppmv	500 ppm	Nothing specified
Sunoco Philadelphia EUID = 019 GP 1232 w/ CO Boiler	Wet gas scrubber; Filterable PM/PM10 (0.30 lb/1000 lb coke burn-off, 365-day rolling average, 0.50 lb coke burn-off, 3-run average); Filterable PM10 (0.014 gr/dscf @ 3% O2, 3-run average), Total PM/PM10 Filterable and Condensable (40.0 lbs/hr, 960 lbs/day, 175 tons/yr)	Wet Gas Scrubber; 25 ppmvd @ 0% O2, 365-day rolling avg; 50 ppmdv @ 0% O2 based on 7-day rolling avg; (when CO boiler burns fuel with H2S>0.1 gr/dscf), 20 ppmdv @ 0% O2, 3-hr rolling avg.	SCR system; 20 ppmvd @ 0% O2, 365-day rolling avg; 40 ppmdv @ 0% O2, 7-day rolling avg	100 ppmdv @ 0% O2, 365-day roll avg; 500 ppmvd @ 0% O2, 1-hr avg
Sunoco Philadelphia EUID = 539 PB 868 FCCU	1 lb/1000 lb coke Comply with NSPS Subpart A and J	Comply with NSPS Subpart A and J	Comply with NSPS Subpart A and J	100 ppmdv @ 0% O2, 365-day roll avg; 500 ppmvd @ 0% O2, 1-hr avg
United Refining EUID 101A FCCU	0.04 grain per SCF	285 lbs/hr 1,248.3 tpy	71 lbs/1000 barrels FCC feed	Nothing specified
Giant Yorktown EUID = 6 FCCU	0.05% of the rate of catalyst recirculation within the unit, rolling 12-month basis COM measured opacity of 30% EPA Method 9 opacity of 20%	2,000 ppm by volume, rolling 12-month basis	Nothing specified	Nothing specified

Table 2-4: Summary of Recent Enforcement Settlements for FCCUs and FCUs

Refinery & Unit	Required PM Control Technology or Emission Limitation	Required SO_2 Control Technology or Emission Limitation	Required NOx Control Technology or Emission Limitation	Required CO Control Technology or Emission Limitation
Valero Delaware City EUID = 011/012 FCCU w/ CO Boiler	Comply with NSPS Subparts A and J	Wet gas scrubber; 25 ppmvd or lower on a 365-day rolling avg, 50 ppmvd on a 7-day rolling avg basis, each corrected to 0% O_2, and 361 tons/year	Original consent decree specified catalyst additive trials followed by optimization. A subsequent amendment specified optimization of key CO boiler operating parameters.	500 ppmv (dry bsis)
Valero Delaware City EUID = 001/002 Fluid Coker Unit w/CO Boiler	Nothing Specified	Wet gas scrubber; 25 ppmvd or lower on a 365-day rolling avg, 50 ppmvd on a 7-day rolling avg basis, each corrected to 0% O_2, and 174 tons/year	SNCR & NOx reducing catalyst additives; emission limits to be determined through optimization study	Nothing Specified
Sunoco Eagle Point EUID = U9 FCCU	0.50 lb/1,000 lb coke burned on a 3-hr rolling avg, 19 lbs/hr TSP, and 48 lbs/hr PM_{10} on a 1-hr block avg; wet gas scrubber upgrade, limit of 30 lbs/hr on 1-hr block avg.	25 ppmvd or lower on a 365-day rolling avg, 50 ppmvd on a 7-day rolling avg basis, each corrected to 0% O_2, and 67.4 lbs/hr on a 1-hr block avg	Continued use of low NOx promoter Eliminox ; 75 ppmvd on a 3-hr rolling avg @ 0% O_2 and 50 lbs/hr on a 1-hr block avg; Conduct NOx control technology study of SCR, LoTox, and others; install NOx controls by April 30, 2008	100 ppmvd @ 0% O_2 on a 365-day rolling avg basis and current NJDEP limit of 72.5 lbs/hr on a 1-hr block avg Install a CO & O_2 CEMS
Valero Refining EUID = U1 FCCU	Nothing Specified	Wet gas scrubber; 25 ppmvd @ 0% O_2 based on 365-day rolling avg or 50 ppmvd @ 0% O_2 based on 7-day rolling avg	Optimization study of existing control system; 20 ppmvd, measured as a 365-day rolling avg, and 40 ppmvd, measured as a 7-day rolling avg, @ 0% O_2	500 ppmvd (@ 0% O_2) measured as a 1-hr block avg
Amerada Hess EUID = U1 FCCU	Not included in national petroleum refinery initiative			
ConocoPhillips Bayway EUID = U4 FCCU w/ 2 CO Boilers	Wet gas scrubber (Continued Operation), 0.50 lb/1,000 lb coke burned on a 3-hr rolling avg	Wet gas scrubber (Continued Operation); 25 ppmvd or lower on a 365-day rolling avg basis and 50 ppmvd or lower on a 7-day rolling avg basis @ 0% O_2	Enhanced SNCR to reduce NOx as much as feasible	500 ppmvd on a 1-hr block avg @ 0% O_2

Table 2-5: Summary of Recent Enforcement Settlements (continued)

Refinery & Unit	Required PM Control Technology or Emission Limitation	Required SO_2 Control Technology or Emission Limitation	Required NOx Control Technology or Emission Limitation	Required CO Control Technology or Emission Limitation
Sunoco Marcus Hook EUID = 101 PLT 10-4 FCC w/ CO Boiler	If a wet gas scrubber is installed, then must comply with either (1) continued operation of the ESP, (2) install new ESP, or (3) accept emission limit of 0.5 lb/1,000 lb coke burned; Otherwise, PM limit is 1.0 lb/1,000 lb coke burned	Wet gas scrubber; 25 ppmvd @ 0% O_2 based on 365-day rolling avg or 50 ppmvd @ 0% O_2 based on 7-day rolling avg	SCR system; 20 ppmvd @ 0% O_2 based on 365-day rolling avg and 40 ppmvd @ 0% O_2 based on 7-day rolling avg	500 ppmvd on a 1-hr block avg @ 0% O_2 Install a CO & O_2 CEMS
ConocoPhillips Trainer EUID = 101 FCC w/ CO Boiler	Wet gas scrubber, 0.5 lb/1,000 lb coke burned on a 3-hr rolling avg.	Wet gas scrubber; 25 ppmvd @ 0% O_2 based on 365-day rolling avg or 50 ppmvd @ 0% O_2 based on 7-day rolling avg	Enhanced SNCR; emission limits to be determined through optimization study	500 ppmvd on a 1-hr block avg @ 0% O_2; Optional 100 ppmvd @ 0% O2 on a 1-hr block avg limit Install a CO & O_2 CEMS
Sunoco Philadelphia EUID = 019 GP 1232 w/ CO Boiler	If a wet gas scrubber is installed, then must comply with either (1) continued operation of the ESP, (2) install new ESP, or (3) accept emission limit of 0.5 lb/1,000 lb coke burned; Otherwise, PM limit is 1.0 lb/1,000 lb coke burned	Wet gas scrubber; 25 ppmvd @ 0% O_2 based on 365-day rolling avg or 50 ppmvd @ 0% O_2 based on 7-day rolling avg	SCR system; 20 ppmvd @ 0% O_2 based on 365-day rolling avg and 40 ppmvd @ 0% O_2 based on 7-day rolling avg	500 ppmvd on a 1-hr block avg @ 0% O_2 Install a CO CEMS
Sunoco Philadelphia EUID = 539 PB 868 FCCU	Nothing Specified	Nothing specified	Nothing specified	100 ppmvd on a 365-day rolling avg @ 0% O_2 Install a CO CEMS
United Refining EUID 101A FCCU	Not included in national petroleum refinery initiative			
Giant Yorktown EUID = 6 FCCU	ESP, 1 lb/1,000 lb coke burned	SO_2 Adsorbing Catalyst; 25 ppmvd (0% oxygen) 365-day rolling average; 80% reduction in uncontrolled SO2	Nothing specified	Nothing Specified

2.4 AVAILABLE CONTROL TECHNOLOGIES

Emissions from catalytic crackers are highly variable due to the wide variation of feed stocks, which contain varying amounts of nitrogen, sulfur, and metals, as well as operating conditions of the regenerator and waste heat boiler. A number of control technologies exist for controlling emissions from these units, and options include both process changes and add-on control equipment to target specific pollutants. The total emission contribution from a FCCU can comprise about 20 – 30% of SO_2, 15 – 30% of NOx, and 30 – 40% of PM emissions on a total refinery wide basis. Both process changes and add-on control equipment are discussed below for SO_2, NOx, and PM.

2.4.1 SO_2 Controls

The quantity of SO_2 emissions discharged from the FCCU depends upon the sulfur content of feed to the FCCU, as well as the applied control technology. In the FCCU reactor, about 70 – 95% of incoming sulfur in the feed is transferred to the cat cracker products. The remaining 5 – 30% is deposited along with coke on the catalyst surface, and is burned off during catalyst regeneration as SO_2. Control options for reducing SO_2 emissions include pre-treating the FCCU feed, applying specific additives to the catalyst regenerator, and the use of wet scrubbers.

2.4.1.1 Wet Scrubbing

Wet scrubbers have been successfully applied to many petroleum refinery FCCUs to control emissions of SO_2 and PM. Recent enforcement settlements will require several refineries in the MARAMA region to install wet gas scrubbers over the next several years. Several designs of wet scrubbers are available, such as packed towers, plate (or tray) towers, spray chambers, and venturi scrubbers, and emissions control levels of 95 – 99.9% have been achieved for SO_2 removal, and 85 – 95% for PM removal. With the inclusion of an additional treatment tower with the wet scrubber system, NOx emissions can also be controlled up to 70%, but may be cost-prohibitive in some cases. Examples of wet scrubbing systems are described below.

BELCO Technologies EDV® Wet Scrubbing (Eagleson, 1999)

The EDV® (electro-dynamic venturi) Wet Scrubbing system combines the techniques used in venturi scrubbers with electrostatic dust separation. The system houses a spray tower along with a set of filtering modules and set of droplet separators, as shown in Figure 1-2. The flue gas from the regenerator enters the spray tower and is immediately quenched to saturation by multiple levels of spray nozzles which remove coarse PM on impact with the water droplets, as well as removal of SO_2 through absorption with the use of a scrubbing reagent, such as caustic soda, lime, or a new regenerative LASORB^{TM} reagent (produced by BELCO). After leaving the spray tower, the flue gas is directed to the filtering module for removal of fine particulate through forced condensation and filtration with water sprays. Lastly, the flue gas passes through a set of cyclonic droplet separators, which removes any free water droplets from the gas before discharge out the stack.

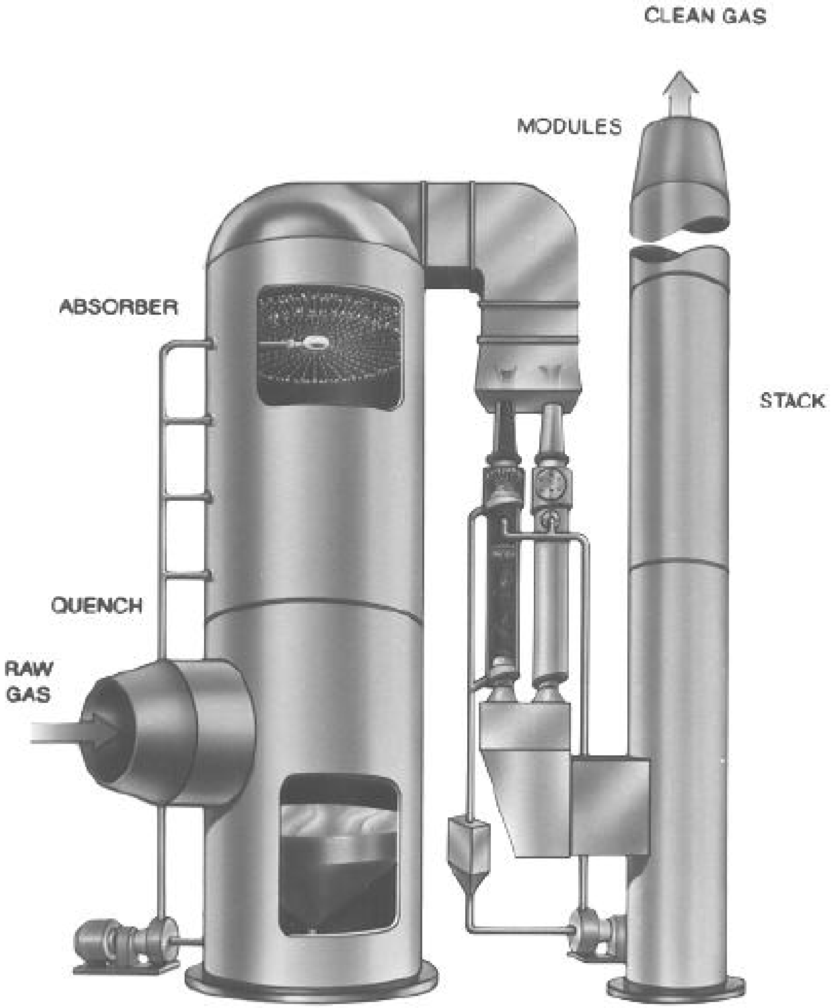
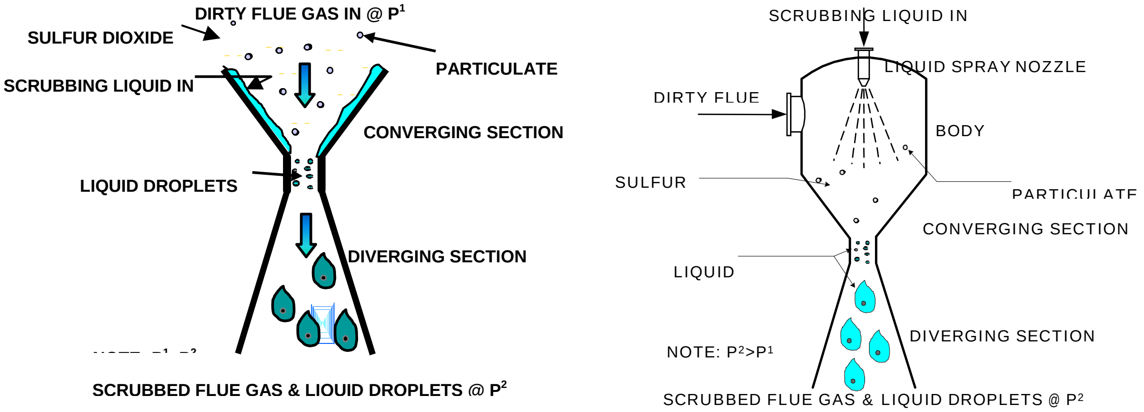


Figure 2-2. EDV-Wet Scrubbing System

SOURCE: Eagleson, S.T. and E.H. Weaver, 1999, "Controlling FCCU Emissions – EDV® Wet Scrubbing," 11th Refining Seminar, Dallas, TX.

ExxonMobil Wet Gas Scrubbers (Sapre, 2003)

The ExxonMobil Research and Engineering Company (EMRE) has developed two types of wet gas scrubbers, namely, the high-energy venturi (HEV) scrubber and the jet ejector venturi (JEV) scrubber. These two types of scrubbers are similar to traditional venturi scrubbers, in that water and a scrubbing liquid are introduced in the scrubber to collect PM and absorb SO_2 from the flue gas stream before discharge into the atmosphere. The HEV scrubber is used when the flue gas stream has adequate pressure to provide the motive force for moving the gas and liquid through the venturi. The scrubbing liquid enters at the converging section of the venturi, and the liquid is atomized by the high velocity gas. In contrast, the JEV scrubber is used for low pressure flue gas streams, and the scrubbing liquid is used to move the flue gas through the scrubber. The liquid is atomized due to shear forces at the top of the venturi, and impacts the PM and absorbs the SO_2 out of the gas phase. Figure 1-3 depicts the differences between these two scrubber systems.



HEV Scrubber **JEV Scrubber**

Figure 2-3. Diagrams of HEV & JEV Scrubbers

SOURCE: Sapre, A.V., D.S. McCaffrey Jr., R.B. Redich, J.N. Iyengar, and H.P. Singh, 2003, "Leading Edge Technology to Abate Air Emissions," Fairfax, Virginia.

Wellmann-Lord Flue Gas Desulfurization Process (DTI, 2003)

The Wellmann-Lord Flue Gas Desulfurization (FGD) process removes SO_2 from the flue gas with a control efficiency of about 98%. The flue gas enters the absorber and gas is scrubbed with an aqueous sodium sulfite solution. The clean flue gas exits the absorber, passes through a set of demisters, and is discharged to the atmosphere. A benefit of this process is that regeneration of the sodium sulfite solution produces concentrated SO_2 streams which can be converted and sold as liquid SO_2, sulfuric acid, or elemental sulfur. There are approximately forty Wellmann-Lord FGD units in Japan, the US, and Germany, however no new units have been built in recent years.

Sea Water Scrubbing (IPPC, 2003)

Sea Water Scrubbing takes advantage of the natural alkalinity of sea water to remove up to 99% of the SO_2 in flue gas. After scrubbing, the water can be treated with air, and discharged back into the sea. This process is feasible for sites near large bodies of sea water, which first treat the flue gas with a particulate abatement technique.

2.4.1.2 DeSOx Additives

DeSOx additives are typically metal oxide catalysts that convert SO2 to SO3 inside the catalyst regenerator. The SO3 is adsorbed to a sulfate and then recycled back to the reactor with the FCCU catalyst, where it is reduced in the reactor to H2S, which is controlled by the refinery's sulfur recovery plant. This three step process can remove between 20% and 60% of the SO_2 in the flue gas, depending on the mode of combustion and flue gas SO_2 concentration.

2.4.1.3 Feed Hydrotreatment

FCC feed hydrotreatment can significantly reduce inlet sulfur content to less than 0.1% to 0.5% by weight, depending on the initial feedstock concentration, which can in turn reduce SO_2 emissions from the FCCU catalyst regenerator by up to 90%. Reductions in nitrogen compounds (up to 75 – 85%) and trace metal impurities are also achieved with the use of feed hydrotreatment. The hydrotreatment process takes place over a metal catalyst in a hydrogen atmosphere. This process has advantages including reduction in the amount of sulfur in final refinery products, as well as improvement of final products, thereby requiring less final processing.

2.4.2 NOx Controls

The quantity of NOx emissions discharged from the FCCU depends upon the nitrogen content of feed due to crude type and upstream conditions, as well as the combustion conditions inside the catalyst regenerator or CO-boiler. NOx reductions from the FCCU process can be achieved by modifying the combustion zone to reduce the amount of thermal NOx formed, or through the use of add-on post-combustion control equipment, to remove NOx present in the flue gas that has already been formed. Examples of available control systems are described below.

BOC Gases' LoTOx Process (EPA, 2005)

BOC Gases' LoTOx process uses industrial-grade oxygen in a non-thermal plasma reactor to reduce pollutants by first converting them to a higher-oxidized state. After oxidation, the pollutants are hydrolyzed and removed with a caustic scrubber. BOC is marketing this process primarily as a NOx control technology, with achieved emission reductions of 80 – 95%. This technology has been reviewed by the California Air Resources Board, and according to the EPA RBLC Database, this process is to be installed on FCCUs located at petroleum refineries in Arkansas and Texas.

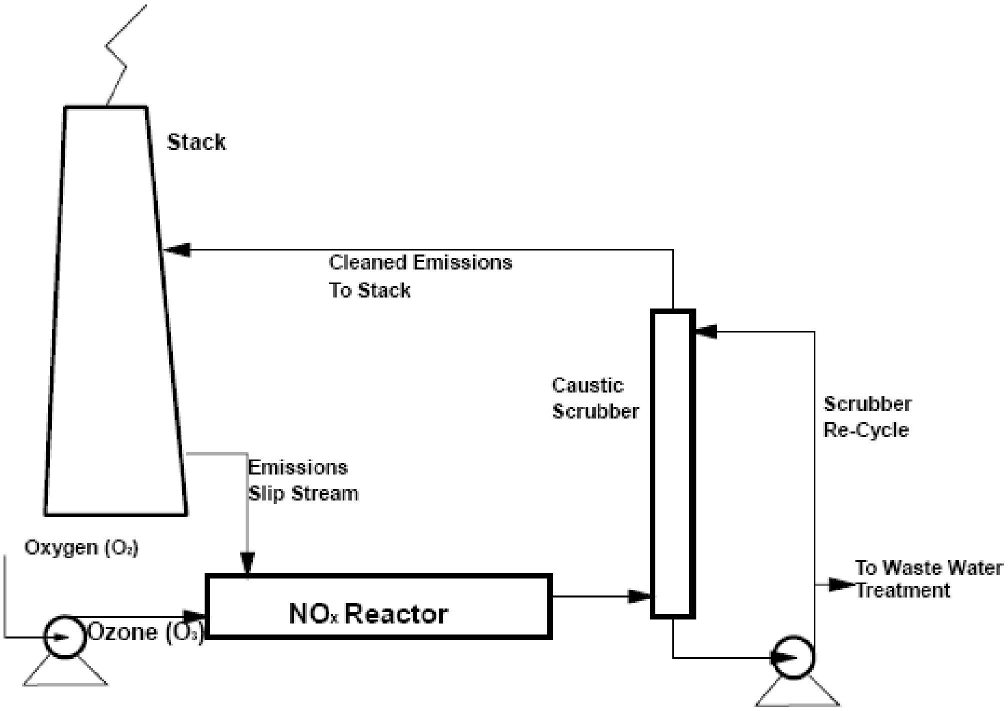


Figure 2-4. BOC Gases' LoTOx Process

SOURCE: United States Environmental Protection Agency, 2005, "Using Non-Thermal Plasma to Control Air Pollutants," EPA-456/R-05-001, Clean Air Technology Center, Research Triangle Park, North Carolina.

Grace Davison's XNOx & DENOX Promoters (Davey, 2000)

XNOx is a non-platinum combustion promoter used to control CO emissions and unit afterburn, as well as reduce NOx emissions up to 50 – 75%. The XNOx promoter was developed as an alternative to the conventional platinum-base CO promoter used to control afterburn. The XNOx technology has been successfully tested in ten FCCUs worldwide. For FCCUs that do not use CO promoters for afterburn control, Grace Davison developed the DENOX promoter. In commercial tests of the DENOX promoter, NOx reductions of up to 60% were achieved without an increase in regenerator afterburn.

Selective Non-Catalytic Reduction (SNCR)

The SNCR system is a post-combustion control technology that reacts ammonia or urea with flue gas to convert NOx compounds into nitrogen and water without the use of a catalyst. Without the use of a catalyst, high temperatures of 1600 and 2000^{o}F are required for NOx conversion. However, this temperature range is sensitive, as the reagents will produce additional NOx if the temperature is too high, and the reaction will proceed slowly and permit the escape of unreacted ammonia if the temperature is too low. Additives, such as hydrogen, and carrier gases can be added to enhance the SNCR, allowing the reaction to take place at temperatures as low as 1290^{o}F. These systems have been successfully applied to boilers and process heaters, as well as FCCU CO boilers. Retrofit applications on refinery CO boilers have achieved NOx control efficiencies in the 40-50% range..

Selective Catalytic Reduction (SCR)

The SCR system is a post-combustion control technology that injects ammonia in flue gas in the presence of a catalyst (e.g. titanium dioxide, vanadium pentoxide) to convert NOx compounds into nitrogen and water. The optimum operating temperature of SCR systems is between 480^{o}F and 800^{o}F, depending on the catalyst, for NOx conversion. These systems have be been successfully applied to refinery furnaces and FCCUs, and have achieved NOx control efficiencies of 80 - 95%.

ExxonMobil WGS+ (Sapre, 2003)

Another control device developed by EMRE is an additive for use in existing wet gas scrubbers that will reduce NOx emissions. The additive is introduced in the disengaging drum of the scrubber to form aqueous sodium nitrate. The effectiveness of the additive is dependent upon contacting efficiency and other factors. In recent lab and field tests, NOx reduction ranged from 40 – 60%. EMRE engineers indicate that with modifications to the wet gas scrubber in addition to using this additive, NOx reductions up to 90% can be achieved. The WGS+ technology was to be installed at an ExxonMobil refinery sometime in 2004; however no further information on

WGS+ is available. The only drawback to the use of this additive is the potential effect of increased nitrates to the wastewater treatment system.

2.4.3 PM Controls

The main source of PM_{10} and $PM_{2.5}$ emissions at petroleum refineries is FCCU catalytic regenerators because catalyst fines are released in the regenerator's exhaust. PM_{10} is easily controlled using common control devices such as wet scrubbers, electrostatic precipitators (ESP), and third stage separators/cyclones. However, fine particulates and condensables, such as sulfuric acid mist, can be more difficult to control due to the size limitations of these control devices. A patented SBS injection technology has been developed to prevent the formation of sulfuric acid mist. Properly designed control systems can be effective at controlling both PM_{10} and $PM_{2.5}$ size fractions. Specific performance data for particle size ranges in controlling FCCUs was not found.

2.4.3.1 Wet Scrubbing

As mentioned in section 2.4.1.1, wet scrubbers are capable or removing PM from flue gas, in addition to absorbing SO_2 with the use of additives. Venturi scrubbers with high pressure drops are most effective for removing up to 90% of PM from flue gas emitted from FCCU regenerators. In cases where fine particulates are an issue, a traditional high efficiency venturi scrubber can be placed in series with a wet ESP to remove sulfuric acid mist and other fine condensables. BELCO (Eagleson 1999) reports that their wet scrubbing systems can control particulate below 0.5 lbs/1,000 of coke burn-off.

2.4.3.2 Electrostatic Precipitators

In ESPs, flue gas is passed between a high-voltage electrode and a grounded electrode, where particulates in the flue gas becomes charged, and are attracted and collected on the grounded electrode. Particles are removed from the grounded electrode by vibration (dry ESPs) or washing (wet ESPs). ESPs have been applied to FCCUs, and have achieved PM reductions up to 95%.

2.4.3.3 SBS Injection Technology

Sulfuric acid mist contributes to fine particulate emissions from FCCU catalytic regenerators and can cause visible emissions and regional haze problems. Sulfuric acid mist is generated when SO_3 present in the flue gas is quenched in a wet scrubber. After the sub-micron aerosol mist is formed, only a portion of it can be removed in the scrubber, and the rest is released to the atmosphere. The SBS injection technology requires injecting a solution of sodium bisulfite (SBS) into the flue gas within a temperature range of 250 – 800°F upstream of the wet scrubber.

The SBS solution reacts quickly with SO_3 in a gas-solid reaction producing dry sodium sulfate and sodium bisulfate particles which can be removed by a downstream ESP or wet scrubber. A process diagram of this technology setup is shown in Figure 2-5.

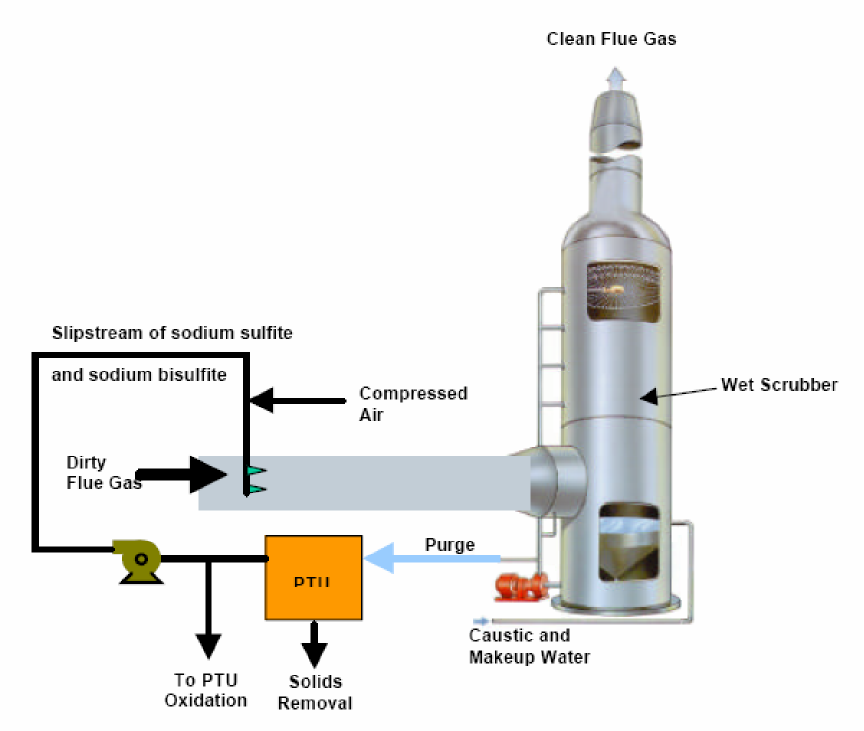


Figure 2-5. SBS Injection Technology Process Diagram

SOURCE: Weaver, Edwin H., and G.W. Billemeyer, 2003, “A Logical and Cost Effective Approach to the Reduction of Air Emissions from the FCCU Regenerator,” 5th Catalytic Cracking Conference, Sao Paulo, Brazil.

2.4.3.4 Third Stage Separators

Third Stage Separators (TSS) incorporate the basic principle of traditional PM cyclones by using multiple swirl tubes that are designed to separate catalyst fines and other PM from FCCU regenerator flue gas. Third stage separators are also sometimes paired with smaller fourth stage separators (FSS) or FSS filters to efficiently remove catalyst fines from the TSS underflow, as shown in Figure 2-6. Traditional cyclones are usually limited to removing larger particles, requiring the flue gas to be treated with a secondary control device, such as a scrubber or ESP. Testing of the TSS equipment has revealed that almost all PM above 2 μm has been removed, resulting in only fine particulates escaping the TSS.

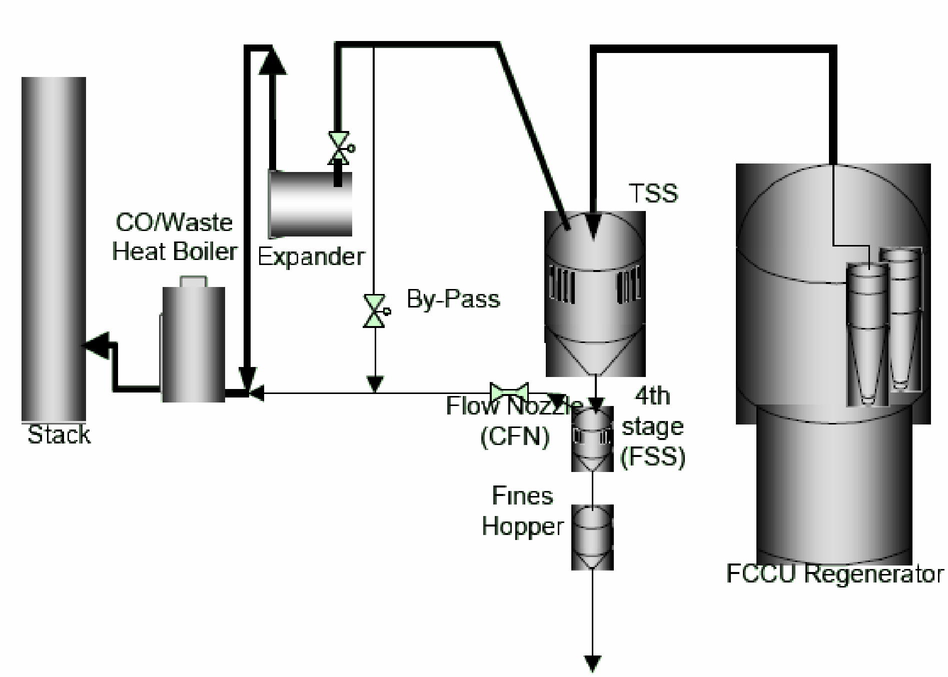


Figure 2-6. Typical TSS and FSS Arrangement

SOURCE: Weaver, Edwin H., and G.W. Billemeyer, 2003, "A Logical and Cost Effective Approach to the Reduction of Air Emissions from the FCCU Regenerator," 5th Catalytic Cracking Conference, Sao Paulo, Brazil.

2.4.4 CO Controls

CO emissions at petroleum refineries are mainly associated with partial combustion catalyst regenerators, FCCUs, and coking units. Full combustion catalyst regenerators are also a source of CO emissions; however due to complete regeneration of the catalyst, CO emissions are significantly less, and usually don't warrant CO emission controls. The most common control device is a CO boiler (or waste heat boiler) located after the FCCU regenerator. CO emissions can also be reduced by introducing CO combustion promoters in to the catalyst regenerator to oxidize CO to CO_2. Four refineries in New Jersey have CO ppm limits ranging from 50-300 ppmvd on an hourly basis, which is considerably lower than the 500 ppmvd limit specified in the recent Consent Decrees.

2.4.4.1 CO Boilers

CO boilers are used to combust the CO present in exhaust gases at high temperatures (approximately 1400^{o}F) in the presence of external combustion air, with the added advantage of generating steam for use at the petroleum refinery. CO boilers burn refinery fuel gas and/or natural gas to generate the necessary heat to oxidize CO to CO_2. CO boilers are capable of oxidizing at least 95% or more of CO emissions present in the exhaust stream to CO_2, while also oxidizing at least 90% of VOC emissions.

2.4.4.2 CO Combustion Promoters

CO combustion promoters are used in the catalyst regenerator primarily to oxidize CO to CO_2, while in some cases the promoter will also reduce NOx emissions and limit afterburn in the regenerator. Afterburn occurs when CO in the regenerator is not completely oxidized to CO_2 in the oxygen rich zone. When this happens, the oxidation of CO will continue into the oxygen deficient area of the regenerator, increasing the temperature of this area and potentially causing serious metallurgical damage to cyclones and flue-gas lines downstream. CO combustion promoters, such as Engelhard Corporation's OxyClean^{TM} and Grace Davison's XNOx (mentioned in section 2.4.2) are effective at reducing CO emissions while controlling NOx emissions at efficiencies greater than 45% and avoiding afterburn. Engelhard's ProCat$^{®}$ and USP^{TM} combustion promoters also reduce CO emissions, while controlling afterburn, however do not affect NOx emissions. These promoters contain platinum attached to a support made up of aluminum (USP^{TM}) or silica (ProCat$^{®}$) with strong chemical anchors to avoid afterburn while promoting CO combustion. The Albemarle Catalysts Company has also developed two types of CO promoters that reduce CO emissions while preventing afterburn. The first promoter, KOC, is a platinum additive on an alumina support, similar to Engelhard's USP^{TM}. Albemarle has also developed a CO combustion promoter called InSituPro, where platinum is impregnated onto the catalyst in varying concentrations to meet the needs of specific regenerators.

2.4.5 VOC Controls

VOC emissions at petroleum refineries are mainly associated with fugitive releases, however they are also emitted from partial combustion catalyst regenerators. VOCs can be reduced by various control measures, however a CO boiler after a partial burn regenerator can reduce VOC emissions up to 90%, as discussed in section 2.4.4.

2.5 COSTS AND AVAILABILITY

Feasible control technologies for FCCUs and FCCU catalyst regenerators are summarized in Table 2-6. The table includes

- Pollutant controlled
- Name of technology
- Origin for the level of control (rule, consent decree, permit)
- Range of potential emission reductions from applying those controls
- Performance level in terms of outlet concentration or emission rate
- Cost effectiveness of the controls
- Commercial status
- Reference

More detailed information on each technology was summarized in the previous sections and based on the information contained in the references for this Section.

The cost data presented in the Table were obtained from the published literature as referenced. In general, the percent reductions and cost effectiveness data represent data for uncontrolled sources. Incremental reductions will be lower and costs will be higher for sources already have some level of control and will be required to meet the performance levels shown in the Table. Also, site-specific factors greatly influence the actual achievable performance level and control costs at a particular facility. These considerations must be addressed in State and local rulemaking and permitting processes.

Table 2-6: Control Technology Options for FCCUs and FCUs

Pollutant	Technology	Origin of Requirement	Percent Reduction	Performance Level	Cost Effectiveness ($/ton)	Commercially Available?	Reference
SO2	Wet Scrubber	Consent Decree	95 to 99.9	25 ppmvd @ 0% O_2 based on 365-day rolling average or 50 ppmvd @ 0% O_2 based on 7-day rolling average	500 to 3,000	Yes	Weaver ,1999
	DeSOx Additives	NSPS	35 to 50	9.8 kg per 1000 kg of coke burned (normally translates to a FCC flue gas SOx concentration of approximately 300 ppmvd)	499 to 880	Yes	Davey, 2000
NOx	SCR	Consent Decree	85 to 90	20 ppmvd, measured as a 365-day rolling average, and 40 ppmvd, measured as a 7-day rolling average, @ 0% O_2	2,364 to 2,458	Yes	ECIPPC, 2003
	LoTOx	Consent Decree	80 to 95	20 ppmvd, measured as a 365-day rolling average, and 40 ppmvd, measured as a 7-day rolling average, @ 0% O_2	1,700 to 1,950	To be installed under consent decree	USEPA, 2005
	SNCR	Consent Decree	60 to 80	20 ppmvd, measured as a 365-day rolling average, and 40 ppmvd, measured as a 7-day rolling average, @ 0% O_2	1,520 to 1,985	Yes	ECIPPC, 2003
	Scrubber Based NOx Technology (SNERT)	Consent Decree	40 to 60	20 ppmvd, measured as a 365-day rolling average, and 40 ppmvd, measured as a 7-day rolling average, @ 0% O_2	Not available	To be installed under consent decree	
PM	Wet Scrubber	Consent Decree	85 to 95	0.5 pounds PM per 1000 pounds coke burned on a 3-hour average basis	Not available	Yes	
	Electrostatic Precipitator	Consent Decree or NSPS	>95%	1.0 pounds PM per 1000 pounds coke burned on a 3-hour average basis	3,500 to 6,600	Yes	ECIPPC, 2003
CO	CO Boiler	State Permits	95	200 ppmvd @ 0% O_2 based on 1-hr block average and 100 ppmvd @ 0% O_2 based on 365-day rolling average	Not available	Yes	Friedman (2006b)

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3.0 BOILERS AND PROCESS HEATERS

Boilers and process heaters are large sources of CO, NOx, PM, and SO_2 emissions at petroleum refineries. Numerous control strategies (including fuel switching, combustion modification, and add-on control equipment) have been developed over the years for reducing emissions from refinery boilers and heaters. Further reducing emissions of NOx and SO_2 from boilers and process heaters is the primary concern, as these pollutants are precursors for ozone and fine particulate formation. This Section presents an assessment of available control technology options for states to consider as they undertake efforts to develop rules and SIPs for ozone, $PM_{2.5}$, and regional haze.

3.1 PROCESS DESCRIPTION

Most refineries have a utilities plant that supplies the steam necessary for the refinery. Steam is primarily used for heating and separating hydrocarbon streams. When used for heating, the steam usually heats the petroleum indirectly in heat exchangers and returns to the boiler. In direct contact operations, the steam can serve as a stripping medium or a process fluid. Steam may also be used in vacuum ejectors to produce a vacuum. The steam can be used to produce electricity by expansion through a turbine (some refineries may receive electricity from outside sources.

Process heaters (furnaces) are used extensively in refineries to supply the heat necessary to raise the temperature of feed materials to reaction or distillation level. They are designed to raise petroleum fluid temperatures to a maximum of about 510°C (950°F). The fuel burned may be refinery gas, natural gas, residual fuel oils, or combinations, depending on economics, operating conditions, and emission requirements. Process heaters may also use CO-rich regenerator flue gas as fuel.

Boilers and process heaters are similar in that they are combustion devices which burn fuels such as natural gas, fuel oil, and refinery fuel gas (one refinery in northwestern Pennsylvania burns coal in one of its boilers). The main difference is that boilers are designed to burn fuels to generate steam for use throughout the refinery, while process heaters burn fuels to transfer heat directly to process materials. In the case of process heaters, combustion gases do not interact with process materials. Most control technologies developed for controlling emissions from boilers are also applicable to process heaters, and are discussed in the sections that follow.

3.2 EMISSION INVENTORY

Table 3-1 summarizes the emissions from petroleum refinery boilers and heaters in the MARAMA region. Criteria pollutant emissions for each refinery are shown for three years. The 2002 annual emissions serve as the baseline for future SIP development.

Table 3-1: Emission Inventory for Boilers/Heaters

State	Refinery	Year	Annual Emission (tons/year)						
			SO_2	NOx	VOC	CO	PM_{10}	$PM_{2.5}$	NH_3
DE	Valero Delaware City	2002	2,446	2,032	26	173	248	208	35
		2004	188	1,373	19	154	52	52	0
		2009	38	926	21	152	81	81	31
DE	SUNCO R M	2002	116	548	12	167	25	24	8
		2004	310	545	10	158	40	32	7
		2009	1	91	3	38	6	6	2
NJ	Sunoco Eagle Point	2002	26	741	13	27	54	53	0
		2003	24	660	52	81	59	59	0
		2009	1	334	11	26	61	61	0
NJ	Valero Refining	2002	688	814	49	165	94	93	0
		2003	916	1,059	16	146	117	117	7
		2009	952	539	57	225	120	119	0
NJ	CITGO Asphalt	2002	19	147	5	46	6	6	0
		2003	31	120	2	38	6	6	3
		2009	20	155	5	49	7	6	0
NJ	Amerada Hess	2002	1	41	1	16	3	1	0
		2003	2	60	2	34	3	3	0
		2009	2	59	1	24	4	1	0
NJ	Chevron Products	2002	11	137	1	7	6	6	0
		2003	10	129	1	3	13	13	3
		2009	14	178	2	8	7	7	0
NJ	ConocoPhillips Bayway	2002	526	1,123	13	42	47	47	0
		2003	454	1,157	1	19	55	44	0
		2009	552[a]	589	13	44	49	49	0
PA	Sunoco Marcus Hook	2002	18	796	29	433	57	48	0
		2004	2	514	21	298	36	36	0
		2009	7	510	39	586	74	62	0
PA	ConocoPhillips Trainer	2002	394	1,953	43	671	59	38	2
		2004	480	1,747	44	638	55	42	2
		2009	18	1,086	46	730	63	42	3
PA	American Refining	2002	1,294	229	2	90	13	6	0
		2003	1,269	245	2	95	13	6	0
		2009	1,334	256	2	98	10	4	0
PA	Sunoco Philadelphia	2002	913	2,498	90	1,381	108	108	0
		2003	992	2,495	87	1,319	128	128	0
		2009	521[b]	2,048[b]	74[b]	1,107[b]	84[b]	84[b]	0
PA	United Refining Warren	2002	1,808	355	12	193	137	88	4
		2004	1,795	543	14	209	114	89	4
		2009	2,191	437	15	247	156	96	4
VA	Giant Yorktown	2002	12	376	15	189	21	21	0
		2004	12	368	15	188	21	21	0
		2009	12	270	16	192	16	16	0
WV	Ergon	2002	31	179	11	125	11	11	5
		2003	28	184	12	138	11	11	5
		2009	34	94	12	136	12	11	6
	MARAMA Totals	2002	8,306	11,968	322	3,724	889	757	55
		2003/04	6,514	11,199	298	3,518	722	657	31
		2009	5,688	7,592	317	3,660	747	644	46

Notes: a) CD for Bayway requires large SO2 reductions by 2012; b) Keith Lemchak provided revised 2009 emissions based upon CD reductions; further reductions from the CD are schedule during 2010 and 2011.

The 2002 emissions were obtained from the 2002 inventories developed by MANEVU and VISTAS. The 2003 or 2004 emissions were obtained directly from each state and represent the most currently quality assured data that is available.

The 2009 emissions were obtained from the MANEVU and VISTAS projection inventories that were developed to support modeling for SIP development. The 2009 inventories include the effects of anticipated growth as well as any planned controls that will result in emission reductions between 2002 and 2009 due to new regulations or enforcement settlements. The growth factors used for projecting emissions from 2002 to 2009 came from the U.S. Environmental Protection Agency's Economic Growth Analysis System (EGAS 5.0) and the U.S. Department of Energy's Annual Energy Outlook (2005) projections. The controls factors for 2009 were derived either from data supplied that the State/local agencies or from MACTEC's analysis of the requirements contained in the global enforcement settlements.

Table 3-1 shows that SO2 emissions for a few refineries are projected to be reduced by 2009 as a result of the requirements of the enforcement settlements (to be discussed in more detail later). The region-wide NOx emissions in 2009 are projected to be about 10 percent lower than in 2002, and SO2 emissions in 2009 projected to be about 25 percent lower than in 2002. Further reductions in SO2 and NOx emissions are expected at the Philadelphia refinery beginning in 2011.

3.3 EXISTING REQUIREMENTS

This section discusses the regulatory requirements which apply to boilers and process heaters. Four types of requirements are discussed: (1) Federal requirements such as the New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards; (2) State regulations for both the MARAMA states as well as other State agencies; (3) source-specific permit requirements; and (4) new requirements from recent enforcement settlements.

3.3.1 Federal Requirements

The U.S. EPA has promulgated standards for emissions of PM, NOx, SO2, and CO, as well as toxic compounds from petroleum refinery boilers and heaters.

The New Source Performance Standards (NSPS) apply to boilers and process heaters at petroleum refineries. Several Subparts to Title 40 CFR Part 60 apply to boilers and/or process heaters depending on unit capacity and fuels burned, and are summarized in Table 3-2.

Table 3-2: Summary of NSPS Regulations for Boilers & Process Heaters

Heat Input (MMBtu/hr)	NSPS Subpart	Construction Date	Fuel Type	PM Emission Limit (lb/MMBtu)	SO_2 Emission Limit (lb/MMBtu)	NOx Emission Limit (lb/MMBtu)
Boilers > 250	D	8/17/1971	Gas	0.10	-	0.2
			Liquid	0.10	0.8	0.3
			Solid	0.10	1.2	0.7
ICI Boilers > 100	Db, J	6/19/1984	Gas	-	0.10 gr/dscf H_2S (162 ppm)	0.10 – 0.20
			Liquid	0.10		0.30 – 0.40
			Solid	0.051 – 0.20		0.5 – 0.8
	Db	7/9/1997	All Fossil	-	-	0.10 – 0.20
	Db	2/28/2005	All Fossil	0.03		
ICI Boilers 10 - 100	Dc	6/9/1989	Gas	-	-	-
			Liquid	-	0.50	-
			Solid	0.051 – 0.10	1.12 (+ 90% Controlled)	
Process Heaters All Sizes	J		All Fuels except natural gas	-	0.10 gr/dscf H_2S (162 ppm)	-

Subpart D applies to fossil-fuel-fired steam generators with heat input capacities greater than 250 MMBtu/hr that were constructed after August 17, 1971. Subpart Da applies to electric utility units and not to units at petroleum refineries. Subpart Db applies to industrial-commercial-institutional (ICI) steam generating units greater than 100 MMBtu/hour. According to section 60.40(c) of this subpart, only performance standards for PM and NOx from Subpart Db apply to boilers at petroleum refineries (SO2 emissions are subject to 40 CFR 60 Subpart J). Subpart Dc applies to small ICI steam generating units with heat input capacities between 10 and 100 MMBtu/hr. The last set of performance standards that apply is the SO_2 standards found in Subpart J, which apply to fuel gas combustion devices (boilers and process heaters) at petroleum refineries that were constructed or modified after June 11, 1973.

NSPS: Heat Input Capacity > 250 MMBtu/hr

Under Subpart D, for boilers with heat input capacities greater than 250 MMBtu/hr, PM emissions are limited to 0.10 lb/MMBtu burning fossil fuel, while opacity is limited to 20%, except for one 6-minute period per hour that is limited to 27% opacity. SO_2 emissions are limited to 0.80 lb/MMBtu when firing liquid fossil fuel and 1.2 lb/MMBtu when firing solid fossil fuel, while NOx emissions are limited to 0.20 lb/MMBtu when firing gaseous fossil fuels and 0.30 lb/MMBtu when firing liquid fossil fuels. When multiple fuels are fired simultaneous, an equation is used to determine the emission standards for SO_2 and NOx using the total heat input from each type of fuel fired.

NSPS: Heat Input Capacity Greater than 100 MMBtu/hr

For boilers greater than between 100 MMBtu/hour at petroleum refineries, performance standards from Subpart Db apply for emissions of PM and NOx, while performance standards from Subpart J apply for emissions of SO_2. Each of the following emission limits are based on the combination of fuels fired in the unit. For units firing coal or coal and other fuels, PM emissions are limited to 0.051 lb/MMBtu, or 0.10 lb/MMBtu if the facility combusts coal and other fuels with an annual capacity factor for the other fuels greater than 10%, or 0.20 lb/MMBtu if the facility combusts coal or coal and other fuels with an annual capacity factor of 30% or less and the unit began construction after June 19, 1984 and before November 25, 1986. NOx emissions from coal fired units vary between 0.50 and 0.80 lb/MMBtu depending on the type of boiler (e.g. mass-feed stoker, spreader stoker) and type of coal combusted (e.g. lignite, pulverized). For units firing oil, PM emissions are limited to 0.10 lb/MMBtu, while NOx emissions are limited to 0.30 lb/MMBtu with low heat release rates and 0.40 lb/MMBtu with high heat release rates. There is no PM emission limit for gas fired units, however, NOx emissions are limited to 0.10 lb/MMBtu with low heat release rates and 0.20 lb/MMBtu with high heat release rates. The SO_2 performance standards from Subpart J require the hydrogen sulfide (H_2S) concentration of fuel gas is limited to 0.10 gr/dscf (162 ppm).

In September 1998, the NOX emission limit was changed to 0.20 lb/MMBtu heat input from the combustion of natural gas, oil, coal, or a mixture containing any of these fossil fuels; however, for low heat release rate units firing natural gas or distillate oil, the current NOX emission limit of (0.10 lb/MMBtu heat input is unchanged. The revised NOx limit only applies to units for which construction, modification, or reconstruction commenced after July 9, 1997.

In February 2005, EPA revised the emission limits for SO2 and PM. For units at petroleum refineries, the Subpart J requirements still apply and have not been affected by the revised NSPS. The revised PM emission standard is consistent with the new source limits of 0.03 lb/MMBtu included in EPA's recently issued national air toxics standards for boilers. The revised PM limit only applies to units for which construction, modification, or reconstruction commenced after February 28, 2005.

NSPS: Heat Input Capacity between 10 and 100 MMBtu/hr

Subpart Dc, regulates boilers with heat input capacities greater than 10 MMBtu/hr, but less than 100 MMBtu. PM emissions for coal fired units are limited to 0.051 lb/MMBtu when burning coal or coal with other fuels with an annual capacity factor of 10% or less fuel or 0.10 lb/MMBtu when firing coal with other fuels with an annual capacity factor for the other fuels greater than 10%. Opacity is limited to 20%, except for one 6-minute period per hour that is limited to 27% opacity. SO_2 emissions from coal burning units should be 90% controlled and should not exceed 1.12 lb/MMBtu, while emissions from oil burning units are limited to 0.50 lb/MMBtu. For units that fire a combination of coal and oil with any other fuels, an equation is used to determine the emission limit based on the heat input from each fuel source. No NOx performance standards are listed under Subpart Dc.

National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart DDDDD applies to industrial, commercial, and institutional boilers and process heaters located at facilities which are major sources of HAPs (potential to emit at least 10 tpy of any single HAP or 25 tpy of any combination of HAPs). This Subpart applies to new (constructed after January 13, 2003), reconstructed (modified after January 13, 2003), and existing boilers and process heaters. Emission limits vary depending on size of the unit (large, limited use, and small) and type of fuel fired (solid, liquid, or gas).

Compliance with Title 40 CFR Part 63, Subpart DDDDD, can be achieved for boilers and process heaters by meeting limits set for PM or total selected metal emissions, in addition to meeting limits for hydrogen chloride (HCl), mercury (Hg), and carbon monoxide (CO). For new or reconstructed large, limited use, or small units firing solid fuel, emissions are limited to the following: PM of 0.025 lb/MMBtu (or total selected metals of 0.0003 lb/MMBtu), HCl of 0.02 lb/MMBtu, and Hg of 0.000003 lb/MMBtu. A CO limit of 400 ppmvd at 7% O_2 is also in effect, however, it does not apply to small units. For new or reconstructed large units firing liquid fuel, emissions are limited 0.03 lb/MMBtu for PM, 0.0005 lb/MMBtu for HCl, and 400 ppmvd at 3% O_2 for CO. For limited use and small units firing liquid fuel, PM and CO emissions are the same as for the large units, however, HCl emissions are limited to 0.0009 lb/MMBtu. For new or reconstructed units firing gaseous fuel, only a CO emission limit of 400 ppmvd at 3% O_2 applies. For existing large units firing solid fuels, PM is limited to 0.07 lb/MMBtu (or total selected metals of 0.001 lb/MMBtu), with HCl limited to 0.09 lb/MMBtu, and Hg limited to 0.000009 lb/MMBtu. For existing limited use units firing solid fuels, PM is limited to 0.21 lb/MMBtu (or total selected metals of 0.004 lb/MMBtu). Subpart DDDDD also specifies operating limits for control equipment used to demonstrate compliance with PM emission limits.

3.3.2 State Regulations

Table 3-3 lists the regulations for each of the MARAMA states for the control of PM, SO_2, and NOx. New Jersey is the only state with regulations for controlling CO and VOCs from boilers and process heaters. New Jersey limits CO emissions to 100 ppmvd @ 7% O_2, while VOCs are limited to 50 ppmvd @ 7% O_2 for units with heat inputs of 50 MMBtu/hr or more (NJDEP

Regulation 7:27-16.8). As part of the NOx SIP Call, States adopted a NOx emissions trading program and assigned 5-month ozone season NOx allowances for large boilers/heaters, including units at several refineries in MARAMA region.

Table 3-4 lists the regulations for other states the control of PM, SO_2, and NOx for refinery boilers and heaters. The regulations for the California air districts have more stringent requirements than the MARAMA state regulations, particularly for NOx.

3.3.3 Permit Requirements

Current permit requirements for boilers and process heaters at petroleum refineries vary widely in the MARAMA region depending on the size of the unit, date of construction, and type of fuel burned. For NOx, the emission limits range from 0.0033 lb/MMBtu for a 350MMBtu/hr unit burning refinery gas to 0.65 lbs/MMBtu for a 335 MMBtu/hr unit burning refinery fuel oil.

3.3.4 Requirements from Recent Enforcement Settlements

The EPA and state/local agencies recently undertook an initiative to investigate physical modifications to petroleum refineries. Capacity increases and modifications should have triggered NSR permitting and pollution control requirements. There have being several instances identified where refineries have failed to obtain pre-construction and operating permits for physical construction that increased their capacity and emissions. Consent Decrees require petroleum refineries to install continuous emissions monitoring equipment so that facilities, EPA, and States can access real time emissions data.

The enforcement settlements for petroleum refineries in the MARAMA region focused mainly on control strategies to limit emissions of SO_2 and NOx. Only the enforcement settlement for the Sunoco Eagle Point Facility included an emission limitation for PM, limiting emissions to 0.00427 lb/MMBtu based on a 1-hour average.

A listing of these requirements is found in Table 3-5. In general, the Consent Decrees require the refineries to select a qualifying control for NOx (SCR, SNCR, Ultra-low-NOx burners, any technology that can reduce NOx emissions to 0.04 lbs NOx / MMBtu). These requirements generally do not apply to all of a refinery's heaters and boilers but to a small subset of heaters and boilers. For SO2, the Consent Decrees generally require the elimination of fuel oil burning and compliance with Subpart J refinery gas H2S limits.

Table 3-3: Summary of MARAMA State Regulations

Agency	PM	SO_2	NO_x
Delaware Regulations	Reg. 4: ≤ 0.3 lb/MMBtu (max 2-hr avg.)	Reg. 8: Distillate oil should have a sulfur content ≤ 0.3% by weight	Reg. 12: 0.2 – 0.38 lb/MMBtu NOx depending on fuel type (gas, oil, coal) and firing type
New Jersey Regulations	7:27-4.2: PM emissions are extrapolated from a table that compares heat input (MMBtu) to maximum emission rates (lb/hr)	7:27-7.2: ≤ 2,000 ppm at standard conditions	7:27-19.7: Non-Utility Boilers and Process Heaters Emissions limits (lb/MMBtu) vary depending on type of boiler/heater (tangential, face, or cyclone) No. 2 Fuel Oil: 0.12 Other liquid fuel: 0.3 Refinery fuel gas: 0.20 Natural gas: 0.1
Pennsylvania Regulations	123.11: PM emissions from combustion units should comply with one of the following: (1) ≤ 0.4 lb/MMBtu for boiler heat input between 2.5 and 50 MMBtu/hr; (2) ≤ $3.6(E^{-0.56})$ for E between 50 and 600 MMBtu/hr; (3) ≤ 0.1 lb/MMBtu for E > 600 MMBtu/hr	123.21: % Sulfur in liquid fuels ≤ 0.5% for No. 2 and lighter oils, and ≤ 2.8% for No. 4, 5, 6, or heaver fuel oils.	129.201: For units with heat inputs between 100 and 250 MMBtu/hr Gas Fired: ≤ 0.10 lb/MMBtu Liquid or Solid Fuel Fired: ≤ 0.20 lb/MMBtu For units > 250 lb/MMBtu ≤ 0.17 lb/MMBtu
Philadelphia Regulations	Reg. 2, Section 5: (1) ≤ 0.20 lb/MMBtu for existing units; (2) ≤ 0.10 lb/MMBtu for units constructed or installed after April 10, 1970.	Reg. 3, Section 1: (1) % Sulfur in fuel oil ≤ 0.2% for No. 2 and lighter oils, ≤ 0.3% for No. 4, and ≤ 0.5% for No. 5, 6, or heavier fuel oils; (2) If the SO_2 emission limit of ≤ 0.30 lb/MMBtu firing No. 4, or 0.52 lb/MMBtu firing No. 5, 6, or heavier, then %S restrictions do not apply.	Reg. 7: NOx limits for combustion units with ≥ 250 MMBtu/hr heat input are (1) 0.20 lb/MMBtu (max 2-hr avg) when firing gaseous fuel; and (2) 0.30 lb/MMBtu (max 2-hr avg) when firing liquid or solid fuel
Virginia Regulations		9 VAC 5-40-280: (1) S = 2.64K (AQCR 1-6) S = allowable emission of sulfur dioxide (lb/hr) K = actual heat input at total capacity (MMBtu/hr)	9 VAC 5-40-310: ≤ 0.20 – 1.0 lb/MMBtu depending on fuel type (coal, oil, gas, combo) and firing method (face / tangential, cyclone, stoker)
West Virginia Regulations		45-10-3: (1) S = 3.1K (Priority I & II Regions); (2) S = 3.2K (Priority III Region) (3) S = 1.6K (Region IV), however must be ≤ 5,500 lb/hr. , where K is the heat input (MMBtu/hr), and the resultant number is SO_2 emissions (lb/hr)	

Table 3-4: Summary of Other State Regulations

Agency	PM	SO_2	NO_x	CO
Louisiana Regulations	Chapter 13, Subchapter C: ≤ 0.60 lb/MMBtu	Chapter 15: ≤ 2,000 ppm at standard conditions (3-hr avg)	Chapter 22: For Baton Rouge & the Region of Influence Process Heaters: ≤ 0.18 lb/MMBtu (40 – 80 MMBtu/hr); ≤ 0.08 lb/MMBtu (> 80 MMBtu/hr) Industrial Boilers: ≤ 0.20 lb/MMBtu (40 – 80 MMBtu/hr); ≤ 0.10 lb/MMBtu (> 80 MMBtu/hr)	
Texas Regulations	111.153: (1) ≤ 0.3 lb/MMBtu for solid fuel fired units (2-hr avg); (2) ≤ 0.1 lb/MMBtu for gas/oil fired units > 2,500 MMBtu/hr (2-hr avg)	112.8: ≤ 3.0 lb/MMBtu while burning solid fuels (3-hr avg) 112.9: ≤ 440 ppmv at actual stack conditions while burning liquid fuels (3-hr avg);	117.205b: (1) for gas fired boilers, NOx ≤ 0.10 – 0.28 lb/MMBtu depending on boiler heat release and preheat temp.; (2) for liquid fuel fired boilers, NOx ≤ 0.30 lb/MMBtu; 117.206: In the Houston-Galveston, catalytic cracking units (including CO boilers) must comply with: (1) ≤ 40 ppmvd @ 0% O_2; (2) 90% NOx reduction from calculated June-Aug. 1997 daily NOx emissions	117.205f ≤ 400 ppmvd @ 3% O_2 for gas or liquid fuel-fired boilers or process heaters
BAAQMD Regulations	6-310: (1) ≤ 0.15 gr/dscf and (2) follow process weight rate ($E = 4.1(P^{0.67}) \leq 40$ lb/hr)	9-1-304: Liquid fuels have a sulfur content of ≤ 0.5% by weight, while burning solid fuels results in ≤ 300 ppm SO_2 dry	9-10-301: Refinery Wide Standards (excluding CO Boilers): ≤ 0.033 lb/MMBtu (24-hr avg) 9-10-303: Refinery Wide Federal Requirements: ≤ 0.20 lb/MMBtu (24-hr avg) 9-10-304: Do not operate CO boilers unless NOx is controlled up to 50% or ≤ 150 ppmvd @ 3% O_2 (24-hr avg)	9-10-305: ≤ 400 ppmvd @ 3% O_2 based on 24-hr avg.
SCAQMD Regulations			Rule 1109: ≤ 0.03 lb/MMBtu @ max capacity	
SJV APCD Regulations	Rule 4301: < 0.10 gr/dscf @ 12% CO_2		Rule 4306: Refinery Units (1) Gas Fired: 5 – 65 MMBtu/hr: 30 ppmvd @ 3% O_2 or 0.031 lb/MMBtu 65 – 110 MMBtu/hr: 25 ppmvd @ 3% O_2 or 0.031 lb/MMBtu > 110 MMBtu/hr: 5 ppmvd @ 3% O_2 or 0.0062 lb/MMBtu (2) Liquid Fuel Fired: 40 ppmvd @ 3% O_2 or 0.052 lb/MMBtu Rule 4352: Solid Fuel Fired < 0.20 lb/MMBtu (24-hr avg)	Rule 4306: Refinery Units - 400 ppmvd @ 3% O_2 Rule 4352: Solid Fuel Fired Units: 400 ppmvd @ 3% O_2 or 310 ppmvd @ 12% O_2 or 310 ppmvd @ 12% CO_2

Table 3-5: Summary of Recent Enforcement Settlements

Refinery Unit	Required SO2 Control Technologies & Emission Limitations	Required NOx Control Technologies & Emission Limitations
Valero Delaware City	Cease burning liquid fuel in heaters and boilers except with NG supply is curtailed.	Complete a program to reduce overall NOx from controlled heaters and boilers; 3rd addendum to the consent decree apportions 1,794 tons reductions to Premcor to be obtained by Dec. 2008
Sunoco Eagle Point	Elimination/reduction of fuel oil burning	Implement a three-year program to reduce NOx emissions through the installation of NOx controls and the acceptance and establishment of federally-enforceable emission limits so that the weighted average of individual heater and boiler permitted emissions at the Refinery are $\leq$ 0.040 lb/MMBtu
Valero Refining Heaters/Boilers (>40 MMBtu/hr)	Discontinue burning fuel oil and comply with Subpart J	0.060 lbs/MMBtu (interim system-wide weighted avg) by Dec. 31, 2009; 0.044 lbs/MMBtu (final system-wide weighted avg) by Dec. 31, 2011
Citgo Asphalt	Burning of fuel oil with a sulfur content of 0.05% prohibited (except during gas curtailments; Subject to NSPS Subparts A and J	SCR, SNCR, Ultra-low-NOx burners, any technology that can reduce NOx emissions to 0.04 lbs NOx / MMBtu, single burner technology that can reduce emissions to 0.055 lbs/MMBtu if ultra-low-NOx burners are infeasible
ConocoPhillips Bayway	Upgrade refinery fuel gas system to ensure less than 0.1 grains of H2S per dscf of fuel gas	SCR, SNCR, Ultra-low-NOx burners, any technology that can reduce NOx emissions to 0.04 lbs NOx / MMBtu; install and operate SCR on crude pipestill heater to achieve at least a 90% control efficiency
Sunoco Marcus Hook	Elimination fuel oil burning	Select a "Qualifying Control" to reduce NO_x emissions from Refinery heaters and boilers greater than 40 mmBTU/hr through the installation of NO_x controls by June15, 2010
ConocoPhillips Trainer	Elimination fuel oil burning	SCR or SNCR; Current Generation or Next Generation Ultra-Low NOx Burners; other technology that reduces emissions to 0.040 lbs per MMBtu or lower; or permanent shutdown
Sunoco Philadelphia Heaters/Boilers (>40 MMBtu/hr)	Burning of fuel oil prohibited; Subject to NSPS 40CFR Part 60 Subparts A and J	Select a "Qualifying Control" to reduce NO_x emissions from Refinery heaters and boilers greater than 40 mmBTU/hr through the installation of NO_x controls by June15, 2010
Giant Yorktown Heaters and Boilers	Burning of fuel oil prohibited; Subject to NSPS 40CFR Part 60 Subparts A and J	SCR or SNCR or Ultra-low NOx burners or other technologies or permanent shutdown, or use only during emergencies; 0.04 lb/MMBtu
Ergon Refining Newell Boilers & Heaters	Eliminate/Reduce fuel oil burning and restrict necessary fuel oil combustion to <0.5% S;	Boiler A & B - Next generation ultra NOx burners Boiler C - 0.05 lb/MMBtu H-101 - 0.05 lb/MMBtu Vacuum Fraction Heater - Replace 4 conventional burners with ultra low NOx burners

3.4 AVAILABLE CONTROL TECHNOLOGIES

Emissions from boilers and process heaters vary depending on the unit size, burner configuration, and fuels combusted. A number of control technologies exist for controlling emissions from these units, and options include both combustion modifications and add-on control equipment to target specific pollutants. Both of these control options are discussed below for SO_2, NOx, and PM. Good combustion practice is the usual control method for CO and VOC emissions from boilers and process heaters, and therefore control devices for these emissions are not discussed in detail.

3.4.1 SO2 Controls

The quantity of SO_2 emissions discharged from boilers and heaters located at petroleum refineries depends upon the sulfur content of the fuels combusted. The bulk of SO_2 emissions from boilers and process heaters have been significantly reduced by limiting combustion units to burning low sulfur fuels, such as liquefied petroleum gas, natural gas, and refinery fuel gas. In the case of units permitted to burn coal and/or residual or distillate oils, usually the sulfur content of the fuel is limited, and in some cases, the annual capacity or operating hours of the boiler is limited. These limitations have come about from individual petroleum refinery permitting activities and/or from recent enforcement actions. In addition to limiting the fuels that can be burned, SO_2 emissions can be reduced using wet, spray dry, and dry scrubbers. These types of scrubbers are discussed in detail in the following sections.

3.4.1.1 Wet Scrubbers

In wet scrubber systems, flue gas enters a spray tower, where it is impacted with aqueous slurry made up of limestone, lime, or other proprietary sorbent. SO_2 is absorbed into slurry and falls to the bottom of the spray tower, where it is collected, then reacted and recycled back to the scrubber system or disposed of. The scrubbed flue gas is then processed by a mist-eliminator to remove any entrained water or slurry droplets. Wet scrubbers are capable of reducing SO_2 emissions from coal and oil fired boilers between 90 and 98% depending on the sorbent used. A common side effect in wet scrubbers is the formation of gypsum (calcium sulfate) scale on the absorber due to the oxidation of the slurry sorbent. A new process called limestone forced oxidation (LSFO) reduces gypsum by reacting it with air, then removing the gypsum prior to recycling the slurry back to the absorber. Once the gypsum is removed, it can be sold commercially, instead of sending it to a landfill.

3.4.1.2 Spray Dry Scrubbers

Spray dry scrubbers are similar in design to wet scrubbers, however, they use slurry with much higher sorbent concentrations. Lime is typically the sorbent of choice in the slurry, and is injected onto the flue gas using rotary atomizers or dual-fluid nozzles to create finer droplet sprays. When the flue gas interacts with the slurry solution, water is evaporated into the gas stream, while the SO_2 is absorbed into the slurry. The process produces a dry waste product of slurry reacted with SO_2 that is collected by conventional PM collection devices. The waste can be disposed of, sold as a by-product, or recycled back to the slurry. The lime spray dry scrubber is more sensitive to operating conditions and requires that the flue gas be within 20 to 50°F of the adiabatic saturation temperature in order to maximize SO_2 removal, as well as prevent deposits of wet solids on the absorber and downstream equipment caused by excess moisture. Application of spray dryer scrubbers to boilers can realize SO_2 removal efficiencies of 80 – 90%.

3.4.1.3 Dry Scrubbers

In dry scrubbers, powdered sorbent, typically consisting of calcium and sodium based alkaline reagents, is injected directly into the boiler or downstream ductwork. The injection location of the sorbent affects the ability of the sorbent to reduce SO_2 emissions. When injecting the dry sorbent into the boiler, temperatures of 1740 to 1830°F are needed to decompose the sorbent into porous solids with high surface area, while when injected into down stream ductwork, temperatures of 300 to 350°F are necessary. Typical configurations consist of several injection ports in the boiler or duct walls. In some cases, water is injected further downstream to help increase SO_2 removal. Dry scrubbers are usually followed by cyclones or ESPs to remove the dry waste product. These systems can achieve emission reductions of 50 – 80%, and are mostly applicable to small and medium sized boilers.

3.4.2 NOx Controls

The combustion of fuels results in two forms of NOx emissions: thermal NOx and fuel NOx. Thermal NOx is formed by the oxidation of nitrogen present in the combustion air, while fuel NOx is formed by oxidation of the nitrogen compounds in fuels such as coal and residual oils. Thermal NOx formation can be reduced by modifying the combustion zone through installation of low NOx burners, which can use air staging or fuel staging techniques to maximize NOx reduction. Fuel NOx can be reduced by burning fuels which don’t contain nitrogen, or through staging combustion air to limit the conversion of fuel nitrogen to NOx. If combustion modifications or fuel switching are not options for reducing NOx emissions, then post combustion controls such as SNCR, SCR, and flue gas recirculation can be used to reduce NOx already released in the flue gas.

3.4.2.1 Low NOx Burners

Low-NOx burners have been successfully applied to industrial boilers and process heaters and have achieved NOx reductions of 30% to 90%. Several low-NOx burner configurations are available to complement specific boilers and heaters which burn various fuels by using staged air, staged fuel, and flame shape techniques. The staged air technique first introduces a small quantity of air with all the fuel, creating a fuel rich reducing atmosphere which generates N_2 instead of fuel NOx due to the oxygen deficient conditions. Introduction of the rest of the combustion air down stream allows the combustion of the remaining fuel while limiting the formation of thermal NOx due to the presence of lower combustion temperatures. In staged-fuel designs, all of the combustion air is introduced in the primary combustion zone with a fraction of the fuel, and the remaining fuel is injected further downstream. This technique can only inhibit the formation of thermal NOx by combusting most of the fuel in an oxygen rich environment at lower temperatures. More recent low-NOx burner designs have incorporated changes to flame shape to accommodate various burner application, as well as further reduce NOx emissions. Several low-NOx burner configurations are discussed in more detail below.

Callidus Ultra Blue Burner (CB&I, 2000)

Callidus Technologies, Inc. has developed a new burner design applicable to gas-fired process heaters that will reduce NOx emissions at petroleum refineries. The Ultra Blue Burner uses reduced oxygen concentrations in the flame, which enables the flame to burn at a lower temperature without compromising burner efficiency. Testing of the burner resulted in measured NOx concentrations of less than 10 ppm, resulting in a 90% NOx reduction efficiency. This burner was scheduled to be installed at a major refinery in Houston in 2001 in response to stricter NOx SIPs in the Houston-Galveston area.

Hamworthy's Low-NOx Burners (Hamworthy)

Hamworthy Combustion Engineering has developed the Enviromix 2000 low-NOx burner for process and petrochemical heaters to meet the low NOx emissions standards imposed on petroleum refineries. The NOx reduction is achieved through air staging using a fully adjustable windbox assembly with individual manual dampers to allow for alterations according to site conditions. The windbox design was developed using extensive flow modeling to achieve optimum air distribution throughout the burner, without compromising burner efficiency or increasing NOx formation. Hamworthy claims that the Enviromix 2000 is highly versatile with models available in natural and forced draft burner designs and capable of firing a wide range of gases and oils.

Hamworthy has also developed a series of advance low-NOx burners, called Register Burners, to significantly reduce emissions of NOx and unburnt particles from boilers and process heaters with firing capacities between 17 and 307 MMBtu/hr. The DFL Range is a fixed geometry burner, which is internally staged, and operates in a low excess air environment, incorporating the air-staging techniques. This burner can be applied to most existing boiler designs and can fire liquid and gas fuels, including crude and heavy residual oils. NOx reductions of 60% are achievable using this burner configuration, while reduction efficiencies up to 80% are possible when paired with flue gas recirculation. The DF Range is another fixed geometry burner that is suited for burning natural gas, liquid petroleum gas, and liquid and waste fuels at petroleum refineries. This burner design incorporates the techniques of low excess air, air staging, and can accommodate combustion air preheat. The LNOG Range is a variable configuration burner designed for operational flexibility, which incorporates an adjustable air-staging slide and rotatable gas lances to ensure burner performance meets specific site requirements. NOx reductions from LNOG burners are similar to reductions achieved by the DFL Range burners. The final burner, the M Range, is another variable geometry burner which can combust a variety of fuels, from gases to heavy oils, and can be used in various applications, from water tube boilers to hot gas generators. In this burner, the flame is controlled by curved air vanes, and fuel atomization is completed by pressure jets, air, or steam.

A final set of burners, the Envirojet Series, has been developed by Hamworthy and fall under the category of new generation Ultra-low NOx burners, and are designed to provide the lowest possible emission levels. Envirojet burners were developed for industrial boilers firing oil and gas and have achieved NOx emissions of 45 – 160 mg/Nm^3 at 3% O_2. Traditionally low NOx burners use flue gas recirculation (FGR) to help reduce NOx emissions, however, the Envirojet does not use FGR, but instead incorporates a windbox that provides air distribution that enables the burner’s low excess air performance. Several burner configuration options, such as flame direction, ignition type, and burner performance monitoring, are available to customize the Envirojet burner to specific boilers.

Next Generation Ultra-low NOx Burners (John Zink Co., 2002)

The John Zink Company has recently developed three new ultra-low NOx burner designs in response to Texas air quality SIPs for the Houston-Galveston area to reduce NOx emissions by 90% at refineries and chemical plants, and to meet stricter NOx regulations in California. The burners were developed mainly for process heaters utilizing natural draft burners which burn various fuel compositions, often with high percentages of hydrogen. The first burner design, LM 300, was developed for “round flame” applications that are capable of firing refinery and petrochemical fuel gas compositions. The LM 300 burner design uses three stages of fuel injection combined with internal furnace gas recirculation and lean “lifted” flame technology. Testing indicated that this burner achieves NOx emissions as low as 10 – 20 ppm depending on fuels burned and operating conditions. A second burner design, FPM-F is for flat flame applications, and utilizes part of the fuel to supply all of the combustion air through high efficiency venturi eductors (produces a lean premix primary flame) and the remainder of the fuel is injected through staged fuel injection tips. With this burner configuration, the staged fuel oxidizes under high temperatures with minimal oxygen presence, and therefore significantly reduces both thermal and fuel NOx. Testing of this burner resulted in NOx concentrations of 9 – 16 ppm, achieving emission reductions of around 90%. The most recent burner design developed is for another round flame burner, however this burner's design is similar to the FPM-F model using a lean premix primary flame with staged combustion. During initial testing, this burner has achieved NOx emissions of 6 – 8 ppm.

Ultraclean, Low-Swirl Burner (Berkeley, 2003)

Resulting from a project with the U.S. Department of Energy (DOE) and several burner manufacturers (Coen, CMC Engineering, John Zink, Maxon Corp, etc.), work was initiated on the development of a low excess air, ultra-low NOx, natural gas fired industrial burner. The goal of the project was to incorporate an ultra-low NOx burner that will emit less than 5 ppm NOx without reducing burner efficiency. One outcome of the project was the development of the Ultraclean Low-Swirl Combustion (UCLSC) technology developed by Berkeley Lab and in production by the Maxon Corporation. This combustion technology can reduce average NOx emissions to below 10 ppm. The Ultraclean Low-Swirl Burner (UCLSB) combusts lean, premixed fuels, in a detached flame configuration. Previously, the detached flame was considered inherently unstable, but according to research at Berkeley, the USLSB provides the most stable platform for a stable flame because the flame can exist in its natural state without interference from interactions of the flame with the burner components. Also, because the flame does not touch the burner, no energy is lost to the burner, therefore enabling high energy conversion.

3.4.2.2 Combustion Air Modifications

Low Excess Air

Control systems that apply low excess air (LEA) techniques are able to optimize the amount of air available for combustion, while reducing fuel consumption and NOx formation. By decreasing the amount of oxygen available in the combustion zone, a reducing atmosphere is formed, which inhibits the formation of both thermal and fuel NOx. An additional benefit of this process is an increase in thermal efficiency because heat losses associated with pre-heating the excess air is eliminated, therefore allowing more heat to transfer to process fluids in process heaters per unit of energy input. The effectiveness of LEA systems depends on the long-term average maintained excess air level in the heater as well as the relationship between NOx emissions and oxygen in the heater. Previous testing has indicated that by reducing excess oxygen by 1% will result in a 6 – 9% decrease in the amount of NOx emitted from the heater. This technique is highly applicable to process heaters, however, it is considered impractical on packaged watertube and firetube boilers due to increased flame lengths and CO emissions, and can lead to rear wall flame impingement, especially when firing fuel oil.

Combustion Air Preheat

Combustion air preheat (CAP) in process heaters increases the thermal efficiency of the heater upwards of 92%. However, this technique is associated with increased levels of thermal NOx formation due to the presence of higher temperatures. On the flip side, this technique has been implemented on radiant burners, and has resulted in decreased NOx emissions.

3.4.2.3 SNCR

SNCR has be been successfully applied to boilers and process heaters, with NOx control efficiencies as high as 75%. NOx emissions from SNCR are controlled by injection of ammonia or urea solutions in the presence of high temperatures to convert flue gas NOx to N_2 and water. Differences between injection of ammonia urea are discussed below.

ExxonMobil Thermal DeNOx (Ammonia Injection)

The ExxonMobil Thermal DeNOx process has been installed on several process heaters and boilers since 1975. The DeNOx system uses either aqueous or anhydrous ammonia, which is reacted with air before passing into the firebox through a number of injection nozzles. The firebox temperature must be between 1600 and 2000^{o}F in order for the NOx conversion reaction to proceed. In more recent applications, hydrogen (H_2) may also be added to the ammonia to decrease the minimum operating temperature to 1400^{o}F. The process is highly temperature dependent; temperatures below 1400^{o}F can cause release of unreacted ammonia or ammonia slip, while temperatures above 2000^{o}F can cause increased NOx production.

Because SNCRs don’t use catalysts to increase the reaction rates between the ammonia and NOx, sufficient time for the reactants and flue gas to interact is necessary. Reaction rates and NOx conversion are also controlled by the ratio of ammonia injection to NOx present in the flue gas. This ratio should be 1 part ammonia to 1.5 parts NOx and must be consistent with flue gas temperature and residence time to achieve maximum NOx reduction. If too much ammonia is injected, the excess ammonia can create visible ammonia plumes and corrosive ammonium sulfite. Injection of the Thermal DeNOx reagent can reduce NOx emissions between 30% and 75%, with industry averages around 60%.

Nalco Fuel Tech NOxOUT (Urea Injection)

The urea injection based SNCR was developed in the early 1980s, and has been installed mainly on coal, oil, and gas fired boilers. The NOxOUT process involves direct injection of an aqueous urea solution using air or steam to distribute the solution throughout the firebox. Because urea is nonvolatile, as compared with ammonia, more energy is needed when injecting the urea solution to obtain adequate distribution of the reagent to maximize NOx conversion. The urea interacts with the flue gas and converts NO compounds to N_2, water. The balanced chemical reaction indicates that 2 moles of NO are converted per 1 mole of urea solution, however greater quantities of urea can be injected to improve NOx reduction and increase the speed of reaction kinetics, however, incomplete thermal decomposition of excess urea can increase emissions of CO and cause ammonia slip. Nalco has made modifications to the original process which minimizes the required minimum reaction temperature to $1200^{o}F$ by adding H_2, CO, and antifouling and storage stabilizing agents to the urea. As with ammonia injection, reaction temperature and residence time are the primary factors that influences NOx reduction. NOx reduction efficiencies vary 10 to 75%.

3.4.3 Selective Catalytic Reduction (SCR)

The SCR system, as discussed in section 2.3.2, can be applied to both boilers and process heaters, however application to process heaters is limited. SCR reductions can provide NOx reductions of 90% from boilers.

3.4.4 PM Controls

PM emissions are not of grave concern from boilers and process heaters at petroleum refineries, as most of these units burn natural gas and refinery fuel gas, which do not emit significant amounts of fine PM as a result of combustion. However, in the MARAMA region, there are still boilers and process heaters permitted to burn coal and oil, which emit PM as a result of fuel combustion. Common control devices used to reduce PM emissions from these units include wet scrubbers and electrostatic precipitators (ESP). Wet scrubbers are discussed in great detail in section 2.4.1, while benefits of ESPs are discussed in section 1.3.1.

3.5 COSTS AND AVAILABILITY

Feasible control technologies for FCCUs and FCCU catalyst regenerators are summarized in Table 3-6. The table includes

- Pollutant controlled
- Name of technology
- Origin for the level of control (rule, consent decree, permit)
- Range of potential emission reductions from applying those controls
- Performance level in terms of outlet concentration or emission rate
- Cost effectiveness of the controls
- Commercial status
- Reference

More detailed information on each technology was summarized in the previous sections and based on the information contained in the references for this Section.

The cost data presented in the Table were obtained from the published literature as referenced. In general, the percent reductions and cost effectiveness data represent data for uncontrolled sources. Incremental reductions will be lower and costs will be higher for sources already have some level of control and will be required to meet the performance levels shown in the Table. Also, site-specific factors greatly influence the actual achievable performance level and control costs at a particular facility. These considerations must be addressed in State and local rulemaking and permitting processes.

Table 3-6: Control Technology Options for Boilers and Process Heaters

Pollutant	Technology	Origin of Requirement	Percent Reduction	Performance Level	Cost Effectiveness ($/ton)	Commercially Available?	Reference
SO2	Fuel Switching	Consent Decree	>95	Eliminate the combustion of fuel oil (>0.05% sulfur by weight)		Yes	
	Fuel Processing	Consent Decree or NSPS Subpart J		Limit hydrogen sulfide content of refinery fuels to 0.10 gr/dscf (162 ppm)		Yes	
	Scrubbers		90 to 99.9	Not specified	7,674 to 45,384	Yes	MACTEC, 2005
NOx	Not Specified	San Joaquin Rule 4306	n/a	Gaseous Fuel: 0.0062 to 0.036 lb/MMBtu (depending on size) Liquid Fuel: 0.052 lb/MMBtu			Rule 4306
	Ultra-low NOx Burners	Consent Decree	75 to 85	0.02 to 0.04 lb/MMBtu	750 to 1,110	Yes	MACTEC, 2005
	SCR	Consent Decree	70 to 90	0.04 lb/MMBtu	2,444 to 7,402	Yes	MACTEC, 2005
	Low-NOx Burners Plus SNCR		50 to 89		1,560 to 7,101	Yes	MACTEC, 2005
	Low-NOx Burners		10 to 40		786 to 4,292	Yes	MACTEC, 2005
CO		NESHAP Subpart DDDDD		400 ppmvd @ 3% O_2			

3.6 REFERENCES

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4.0 FLARES

Petroleum refinery flares are used to safely dispose of flammable waste gases from emergency process upsets as well as during start-up, shut-down and turnaround operations. The combustion of these gases can emit large quantities of NOx, SO_2, and CO into the atmosphere. There is some uncertainty regarding the magnitude of emissions from flaring activities, as many refineries do not have formal flare monitoring and emissions recording procedures in-place. Based on data collected in California and Texas, there is a concern about the potential underestimation of reported emissions released during flaring events. There are opportunities to better quantify emissions from flaring events, as well as reducing emissions by safely limiting flare use or by installing a flare gas recovery unit. This Section presents a preliminary assessment of available control technology options for flaring activities for states to consider as they undertake efforts to develop rules and State Implementation Plans (SIPs) for ozone, $PM_{2.5}$, and regional haze.

4.1 PROCESS DESCRIPTION

Flares at petroleum refineries are intended to be last-resort control devices for the destruction of vent gases released under emergency conditions or during process start-ups, shut-downs, and turnarounds. Elevated flares are the most common type of flare used, as they can handle larger capacities than ground flares. In elevated flares, the waste gas stream is combusted at the tip of the flare stack, usually between 33 and 330 feet above the ground. The elevated flare system consists of five components: a gas collection header to collect gases from various process units, a knockout drum to remove entrained liquids and condensables from the vapor stream, a proprietary seal, water seal, or purge gas supply to prevent flash back, a single or multiple-burner unit in the flare stack, and gas pilots and igniter.

Figure 4-1 presents a schematic of a typical flare and the location of each of these components. In most cases, steam or blowing air is injected into the flare to create a smokeless flare. Without adequate steam, the presence of smoke is more likely. The presence of smoke usually arises from the combustion of heavy hydrocarbons, such as paraffins, olefins, and aromatics. Waste gases combusted at petroleum refineries usually consist of low molecular weight hydrocarbons, which burn without smoke, therefore not requiring steam injection. Flares normally dispose of low-volume continuous emissions but are designed to handle large quantities of waste gases that may be intermittently generated during plant emergencies. Flare gas volumes can vary from a few cubic meters per hour during regular operations up to several thousand cubic meters per hour during major upsets.

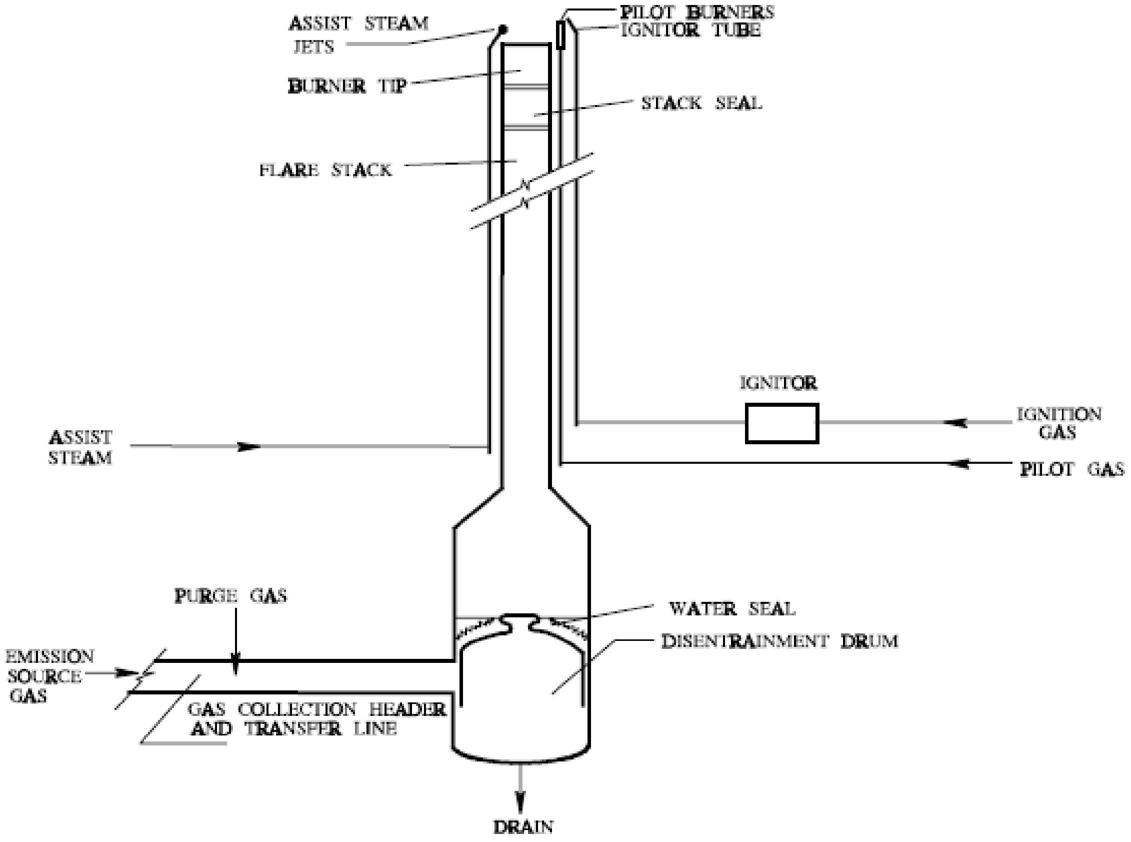

Figure 4-1. Diagram of a Typical Steam-Assisted Elevated Flare

SOURCE: United States Environmental Protection Agency, 1995, "Industrial Flares," Pages 13.5-1 – 13.5-5 in AP-42, Fifth Edition: Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, http://www.epa.gov/ttn/chief/ap42/ch13/final/c13s05.pdf.

4.2 EMISSION INVENTORY

Emissions from flaring include carbon particles (soot), unburned hydrocarbons, CO, and other partially burned and altered hydrocarbons. Also emitted are NO_x and, if sulfur-containing material such as hydrogen sulfide or mercaptans is flared, sulfur dioxide. The quantities of hydrocarbon emissions generated relate to the degree of combustion. The degree of combustion depends largely on the rate and extent of fuel-air mixing and on the flame temperatures achieved and maintained. Properly operated flares achieve at least 98 percent combustion efficiency in the flare plume, meaning that hydrocarbon and CO emissions amount to less than 2 percent of hydrocarbons in the gas stream.

Table 3-1 identifies the flaring units in the MARAMA region and criteria pollutant emissions for each unit for three years. The 2002 annual emissions serve as the baseline for future SIP development. The 2002 emissions were obtained from the 2002 inventories developed by MANEVU and VISTAS. The 2003 emissions were obtained directly from each state and represent the most currently quality assured data that is available.

The 2009 emissions were obtained from the MANEVU and VISTAS projection inventories that were developed to support modeling for SIP development. The 2009 inventories include the effects of anticipated growth as well as any planned controls that will result in emission reductions between 2002 and 2009 due to new regulations or enforcement settlements. The growth factors used for projecting emissions from 2002 to 2009 came from the U.S. Environmental Protection Agency's Economic Growth Analysis System (EGAS 5.0) and the U.S. Department of Energy's Annual Energy Outlook (2005) projections. The controls factors for 2009 were derived either from data supplied that the State/local agencies or from MACTEC's analysis of the requirements contained in the global enforcement settlements.

There is considerable uncertainty regarding the emissions from flaring activities, due to several factors. First, since flares are primarily designed to handle waste gases from process upsets, there is year-to-year and refinery-to-refinery variability in the number and duration of upsets. Another factor source of variability may be caused by the data available and methods used to estimate emissions. Accurate information on the amount and composition of the waste gas sent to the flare is necessary to accurately estimate emissions. Most refineries monitor the pilot gas flow rate, while the methods used to determine waste gas flow rates and composition vary widely. Finally, while properly operated flares achieve at least 98 percent combustion efficiency in the flare plume, there is some evidence that the actual efficiency may be less in practice.

Table 4-1: Emission Inventory for Flares

State	Refinery/ Unit	Year	Annual Emission (tons/year) CO	NOx	PM_{10}	$PM_{2.5}$	SO_2	VOC
DE	Valero Delaware City	2002	18.9	2.6	0.0	0.0	0.0	0.3
	EUID = 080	2003	19.2	2.7	0.0	0.0	0.0	0.3
	Flare System	2009	18.9	2.6	0.0	0.0	0.0	0.3
DE	Valero Delaware City	2002	112.4	2.1	0.0	0.0	222.5	0.6
	EUID = 530	2003	40.7	1.0	0.0	0.0	282.6	0.0
	Repower - Raw Gas Flare	2009	112.4	2.1	0.0	0.0	222.5	0.67
DE	Valero Delaware City	2002	798.3	20.2	0.0	0.0	15.5	13.4
	EUID = 532	2003	501.8	12.7	0.0	0.0	26.9	0.0
	Repower - Clean Gas Flare	2009	798.3	20.2	0.0	0.0	15.5	13.4
DE	SUNCO Inc Delaware	2002	15.5	62.0	1.3	1.3	765.2	1.2
	EUID = 005	2003	19.0	76.0	0.0	0.0	74.8	1.5
	Pipeline Flare	2009	16.5	66.2	1.4	1.3	817.2	0.5
NJ	Sunoco Eagle Point	2002	81.2	78.4	57.4	43.0	21.0	484.4
	EUID = U52	2003	49.9	48.9	33.9	33.9	12.6	294.2
	Refinery Plant Flare	2009	81.2	78.4	57.4	43.0	21.0	484.4
NJ	Valero Paulsboro	2002	2.3	8.5	0.7	0.5	5.6	0.1
	EUID = U21	2003	2.4	1.0	0.7	0.7	5.9	0.1
	South Plant Existing Flare	2009	2.3	8.5	0.7	0.5	5.6	0.1
NJ	Valero Paulsboro	2002	6.0	22.6	1.7	1.2	14.9	0.2
	EUID = U22	2003	6.3	23.8	1.8	1.8	15.7	0.2
	South Plant New Flare	2009	6.0	22.6	1.7	1.2	14.9	0.2
NJ	Valero Paulsboro	2002	2.5	9.3	0.7	0.5	61.3	0.1
	EUID = U25	2003	2.6	9.8	0.7	0.7	64.6	0.1
	North Plant Flare	2009	2.5	9.3	0.7	0.5	61.3	0.1
NJ	Citgo Asphalt	2002	4.8	0.7	0.2	0.1	0.0	0.1
	EUID = U14	2003	3.8	0.7	0.1	0.1	0.0	0.1
	Area 14 Emergency Flare	2009	4.8	0.7	0.2	0.1	0.0	0.1
NJ	Amerada Hess Port Reading	2002	11.1	2.1	0.2	0.2	1.3	4.2
	EUID = U9	2003	13.9	2.6	0.4	0.4	3.2	5.2
	Refinery Flare	2009	11.1	2.1	0.2	0.2	1.3	4.2
NJ	Chevron Products	2002	1.8	0.3	0.1	0.0	7.2	0.7
	EUID = U7	2003	0.1	0.1	0.0	0.0	1.0	0.0
	Area G Flares	2009	1.8	0.3	0.1	0.0	8.2	0.7
NJ	ConocoPhillips Bayway	2002	66.7	12.4	12.0	0.8	222.0	25.3
	EUID = U9	2003	75.3	13.8	1.5	1.2	252.7	28.5
	Flares	2009	66.7	12.4	12.0	0.8	10.8	2.5

Table 4-1: (continued)

State	Refinery/ Unit	Year	Annual Emission (tons/year)					
			CO	NOx	PM_{10}	$PM_{2.5}$	SO_2	VOC
PA	Sunoco Marcus Hook	2002	4.3	0.9	1.4	1.4	5.3	1.6
	EUID = 104	2003	5.3	0.5	1.7	1.7	6.2	0.3
	12 Plant Flare	2009	4.3	0.9	1.4	1.4	5.3	1.6
PA	Sunoco Marcus Hook	2002	3.0	1.0	1.0	1.0	4.7	2.0
	EUID = 105	2003	0.2	0.2	0.1	0.1	0.6	0.1
	10 Plant Flare	2009	3.0	1.0	1.0	1.0	4.7	2.0
PA	ConocoPhillips Trainer	2002	237.1	43.6	0.1	0.1	15.1	89.7
	EUID = 103	2003	210.0	38.6	0.1	0.1	10.5	79.5
	Main Flare	2009	237.1	43.6	0.1	0.1	15.1	89.7
PA	American Refining Bradford	2002	3.3	14.6	2.3	0.0	20.7	1.2
	EUID = 201	2003	3.3	14.6	2.3	0.0	20.7	1.2
	Refinery Gas Flare	2009	3.3	14.6	2.3	0.0	20.7	1.2
PA	Sunoco Philadelphia	2002	46.6	8.6	0.0	0.0	6.4	17.6
	EUID = 010, 014, 016	2003	54.0	9.9	0.0	0.0	4.4	20.5
	GP Flares 433, 1231, 1232	2009	46.6	8.6	0.0	0.0	6.4	17.6
PA	Sunoco Philadelphia	2002	10.5	2.0	0.0	0.0	26.2	17.7
	EUID = 523, 590, 591, 592, 600	2003	6.3	1.2	0.0	0.0	11.6	1.6
	PB Flares North, DEA, SWS, LPG	2009	10.5	2.0	0.0	0.0	26.2	17.7
PA	United Refining	2002	42.9	12.5	0.2	0.2	0.5	11.6
	EUID = 102	2003	46.6	14.1	0.2	0.2	0.6	13.0
	Blowdown System	2009	42.9	12.5	0.2	0.2	0.5	11.6
VA	Giant Yorktown	2002	0.0	1,042.7	340.7	327.0	984.3	49.5
	EUID = 26	2003	0.0	77.8	364.0	364.0	425.9	61.2
	Flare	2009	0.0	24.0	177.0	177.0	2.0	50.0
WV	Ergon West Virginia	2002	14.4	59.6	0.1	0.1	84.6	0.3
	EUID = 014	2003	14.5	57.3	0.1	0.1	81.3	0.4
	Plant Flares	2009	14.4	59.6	0.1	0.1	84.6	0.3
	MARAMA Totals	2002	1,483	1,406	420	377	2,484	729
		2003	1,075	408	408	405	1,302	510
		2009	1,485	392.2	257	227	1,336	699

Note 1: Flaring emissions in 2009 were originally projected using AEO2005 growth factors. These factors tended to overestimate the expected growth in emissions, so 2009 emission were calculated assuming no growth in flaring activity. MARAMA states are reviewing the latest guidance from EPA with respect to projecting emissions from nonEGU sources such as flares.

Note 2: Emissions from Giant Yorktown includes flaring emissions from sour water stripper gas flaring and vacuum tower vent gas flaring that have been eliminated as a result of the refinery's consent decree. The emissions also include process upset emissions from the SRU that will be corrected with the installation of a new SRU and sour water stripping system. Thus, emissions in 2009 will be substantially less than in 2002/2003.

4.3 EXISTING REQUIREMENTS

This section discusses the regulatory requirements which apply to flares. Four types of requirements are discussed: (1) Federal requirements such as the New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards; (2) State regulations for both the MARAMA states as well as other State agencies; (3) source-specific permit requirements; and (4) new requirements from recent enforcement settlements.

4.3.1 Federal Requirements

The U.S. EPA has promulgated standards for SO_2 emissions, in addition to establishing requirements for performance testing and compliance assessments, for flares at petroleum refineries.

New Source Performance Standards (NSPS) for refinery flares constructed or modified after June 11, 1973 are covered under 40 CFR Part 60, Subparts A and J. Subpart A applies to flares as general control devices, specifying design and operational criteria for new and modified flares. Requirements include operating the flare with no visible emission, monitoring the presence of the pilot flame with a thermocouple or equivalent device, and meeting heat content and maximum tip exit velocity specifications. Subpart J applies to flares at petroleum refineries, where flares are defined as fuel gas combustion devices, and are limited to burning fuel gas, for the maintenance of the pilot flame, containing hydrogen sulfide (H_2S) in excess of 0.10 gr/dscf. This limitation does not apply during process upsets, relief valve leakage, or other emergency malfunctions, where vent gases or fuel gas are released to the flare. This subpart also requires that a continuous monitoring and recording device be installed to track emissions of SO_2 or H_2S from the flare, in addition to the installation of an oxygen monitor for correcting the emissions data for excess air.

The National Emission Standards for Hazardous Air Pollutants (NESHAP) for flares are covered in 40 CFR Part 63, Subpart SS, which applies to closed vent systems, control devices, recovery devices and routing to a fuel gas system or process. Under the flare requirements of this subpart, flares are subject to compliance assessment and monitoring requirements. Compliance assessments include using EPA's Method 22 to determine measure opacity, using Equation 1 (of 40 CFR Part 63, Subpart SS) to determine the neat heating value of the gas being combusted, using EPA Method 2, 2A, 2C, 2D, 2F, or 2 G of 40 CFR Part 60 Appendix A to measure the volumetric flow rate, and using flame or pilot monitors during compliance assessments. Flare monitoring requirements indicate that a device (e.g. thermocouple, ultra-violet beam sensor, or infrared sensor) to detect the presence of the flare flame must be used at all times when the flare is in use.

4.3.2 State Regulations

In general, the state regulations in the MARAMA region do not specifically limit emissions or specifying monitoring requirements for flares at petroleum refineries. In some cases, such as the Bayway refinery in New Jersey, have requirements in their Title V permit to install flow monitoring equipment on each of the flares. Texas, the Bay Area (BAAQMD), South Coast (SCAQMD), and San Joaquin Valley (SJVQPCD) all have requirements governing the operation and emissions from flares. The Texas regulations are not as strict as those in California that lay out monitoring, testing, recordkeeping, and reporting requirements for flares at petroleum refineries, in addition to prohibiting flaring unless the situation is allowed according to the facility's flare minimization plan. Per the California regulations, each facility is required to have a flare minimization plan/monitoring and recording plan, which stipulates conditions for use of the flare, and what information must be reported after flaring events. Recent amendments to the BAAQMD and SCAQMD regulations are discussed further in section 4.4.2.

4.3.3 Requirements from Recent Enforcement Settlements

The EPA and state/local agencies recently undertook an initiative to investigate compliance with applicable Federal and State requirements for flaring. There have being several instances identified where refineries used flares for routine purposes instead of only to vent dangerous gases, as well as other problems with NSPS compliance. Consent Decrees have been developed to require facilities to: (1) meet new source standards at all flares (e.g. monitor all routinely generated refinery fuel gases that are combusted in a flare) and comply with applicable NSPS emission limits; (2) take action to reduce emissions from process upsets; and (3) implement a protocol to diagnose and prevent upsets that result in significant releases of SO_2 and other gases (flaring). Table 4-2 provides a list of recent enforcement settlements for flares at petroleum refineries in the MARAMA region.

Table 4-2: Summary of Recent Enforcement Settlements

State	Refinery Unit	Required Control Technology	Required Emission Limitation
DE	Valero Flares & Flaring	Meet "new source standards at all flares (e.g. monitor all routinely generated refinery fuel gases that are combusted in a flare) and comply with applicable NSPS emission limits. Take action to reduce emissions from process upsets. Reroute and eliminate sulfur pit emissions. Implement protocol to diagnose and prevent upsets that result in significant releases of SO_2 and other gases (flaring).	None Specified
NJ	Sunoco Eagle Point Flares & Flaring	Action to Reduce Emissions from Process Upsets, Reroute/Eliminate Sulfur Pit Emissions, & Prevent Upsets That Result in Flaring	Comply with NSPS Emission Limit
NJ	Valero Refining Flares & Flaring	Action to Reduce Emissions from Process Upsets, Reroute / Eliminate Sulfur Pit Emissions, & Prevent Upsets That Result in Flaring	Comply with NSPS Emission Limit
NJ	ConocoPhillips Bayway Flares & Flaring	Action to Reduce Emissions from Process Upsets, Reroute / Eliminate Sulfur Pit Emissions, & Prevent Upsets That Result in Flaring	Comply with NSPS Emission Limit
PA	Sunoco Marcus Hook Flares & Flaring	Action to Reduce Emissions from Process Upsets, Reroute / Eliminate Sulfur Pit Emissions, & Prevent Upsets That Result in Flaring	Comply with NSPS Emission Limit
PA	ConocoPhillips Trainer Flares & Flaring	Action to Reduce Emissions from Process Upsets, Reroute / Eliminate Sulfur Pit Emissions, & Prevent Upsets That Result in Flaring	Comply with NSPS Emission Limit
PA	Sunoco Philadelphia Flares & Flaring	Action to Reduce Emissions from Process Upsets, Reroute / Eliminate Sulfur Pit Emissions, & Prevent Upsets That Result in Flaring	Comply with NSPS Emission Limit
VA	Giant Yorktown Flares & Flaring	None Specified	None Specified
WV	Ergon Refining Newell F1-1 Flare & Sour Gas Flare	40 CFR Part 60 Subparts A & J	None Specified

4.4 AVAILABLE CONTROL OPTIONS

Under normal operating conditions, flares burn a small amount of gaseous fuel to keep the pilot flame lit in the event of an emergency waste gas release. Normal operations also include continuously burning sweep gas, which has a considerably greater flow rate than the pilot gas. Pressure relief valves, compressor seals, and analyzer purge lines also vent (either continuously or intermittently) to the flare. Emissions from flaring can include PM, CO, NOx, and SO_2 if sulfur containing vent gases are flared. Emissions from flaring events are released due to oxidation of vent gases and incomplete combustion of fuel. Since emissions from flares are unpredictable, the BAAQMD and SCAQMD amended previous regulations to include increased monitoring and reporting of process streams vented to flares in their Districts. A summary of the Texas flare rules are also provided for comparison to the California regulations to provide additional state control options. Add on control equipment is not practical for flares because gas combustion takes place in open air at the flare tip. In addition, most control devices are effective for steady state operations, a condition not found with the use of flares. Pollution control strategies for flares involve the installation of new equipment and/or physical changes to the flare system, such as adding flare gas recovery compressor systems, increasing gas storage capacity, and improving existing gas compressors and flare tip design.

4.4.1 Flare Gas Recovery Units

Flare gas recovery units reduce emissions from flares by recycling the gases vented during emergency releases instead of combusting them in flare. The vent gases are collected in the flare header, compressed, cooled, and returned for re-use in the refinery as fuel gas or process feedstock. The flare gas recovery system also has a safety feature built in that allows excess vent gas to be combusted in the flare in the event that the compressor system is at full capacity, but excess emissions are being vented. This incorporates the original safety features of the flare, limiting harmful gases that could be emitted into the atmosphere by combustion; however, the amount of emissions released due to flaring will be considerably reduced. Figure 3-2 shows the process diagram of a flare gas recovery system.

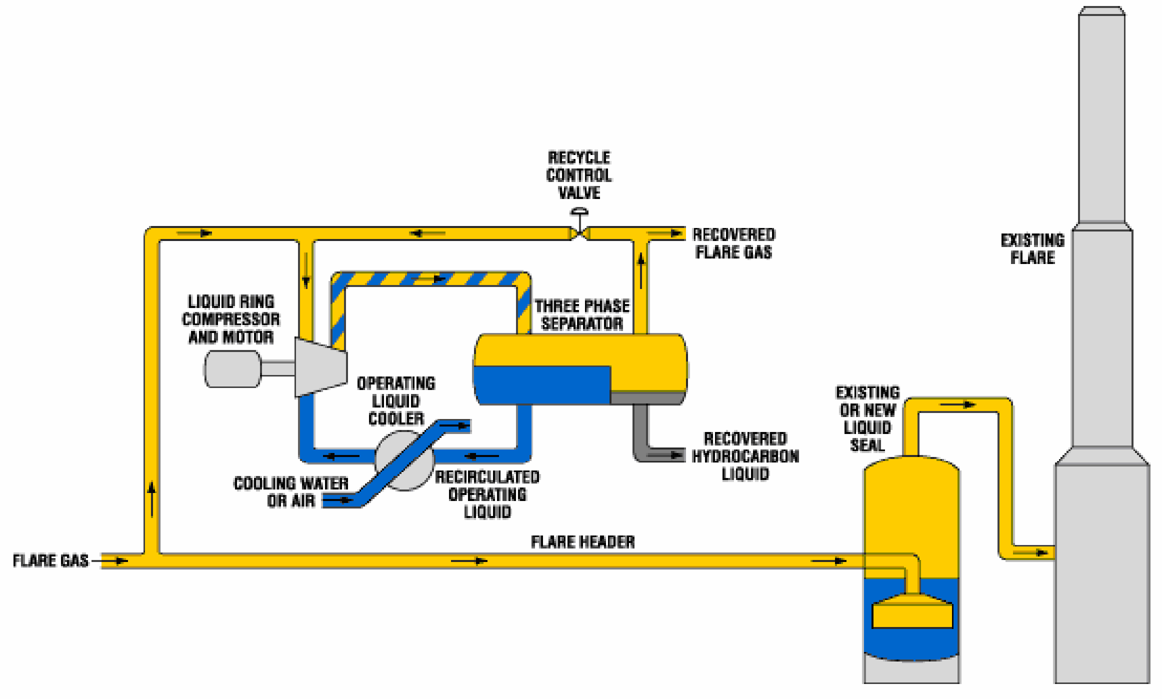

Figure 4-2. Process Flow Diagram of a Flare Gas Recovery Unit

SOURCE: http://www.johnzink.com/products/fgr/html/fgr_jz_procdiag.htm

4.4.2 California Regulations

In addition to implementation of control strategies at petroleum refineries, the BAAQMD and SCAQMD have recently updated their regulations to increase emission reductions from flares at petroleum refineries in California.

4.4.2.1 BAAQMD

On June 4, 2003, BAAQMD issued Rule 11 (part of Regulation 12: Miscellaneous Standards of Performance), which required monitoring and recording of emissions data for flares at petroleum refineries. This rule allowed the District to collect emissions data from refineries over the past two years to determine causes of specific flaring events, as well as estimate the quantity of emissions released during those events. The newest rule, Rule 12, was published on July 20, 2005 and will become effective November 1, 2006 in response to the District's findings under Rule 11. Rule 12 was created to reduce emissions from flares by minimizing the frequency and magnitude of flaring. The rule only allows flaring during emergency conditions and prohibits the use of refinery flares without the refinery first creating, following, and annually updating a Flare Minimization Plan (FMP) for each flare. It requires the submission of flaring reports when a flare releases more than 500,000 standard cubic feet of gas per calendar day (scf/day) and to identify the cause and to avoid flaring from that cause in the future, if possible. Also, the rule requires annual reports to the District evaluating flaring events that released less than 500,000 scf/day, where the amount of SO_2 emitted is more than 500 lbs. A final provision of this rule calls for continuous monitoring of the flare system's knock-out drum water seal for leaks. The knock-out drum is essential to reduce flaring at refineries, as this seal keeps liquid from entering the flare stack, provides a barrier between the flare gas header and flare stack preventing air from interacting with the vent gases and causing a potentially explosive environment, and provides backpressure on the flare gas header for operation of the flare gas recovery compressor.

4.4.2.2 SCAQMD

The SCAQMD has recently published (on November 4, 2005) its proposed amendments to Rule 1118, Emissions from Refinery Flares, that first adopted on February 13, 1998. Rule 1118 was originally promulgated to develop an accurate flare emission inventory and assess the need for requiring additional controls to minimize flare emissions. The emissions data collected between 1999 and 2003 as a result of this rule was analyzed by staff that made recommendations for further strengthening emissions data gathering, monitoring, and reporting procedures. The proposed amendments will be implemented starting January 2006 and be fully implemented by January 2012. The new amendments prohibit flaring of vent gases except in emergency situations, or during specific operational needs such as startups, shutdowns, and turnarounds. The new rule also establishes operational requirements and practices to minimize flaring events, sets specific annual SO_2 performance targets, requires that flares operate in a smokeless manner, and requires annual inspections of pressure relief devices directly connected to flares. New monitoring requirements call for the installation of analyzers to measure vent gas higher heating values, total sulfur concentration, and gas flow. The rule also contains provisions for refineries to give 24-hour advance notice for each large planned flaring activity, and to notify SCAQMD within 1-hour of unexpected flaring events, in addition to submitting quarterly reports detailing flow, emissions, and cause of each event. Refineries are also required to set up a 24-hour public telephone number for inquiries on flaring events.

4.4.3 Texas Regulations

The Texas Commission on Environmental Quality (TCEQ) has two air quality rules that pertain to the control of air emissions through flares. The first rule, found in Chapter 115, Subchapter D, Division 1, concerns the use of flares during process unit turnaround and on vacuum-producing systems at petroleum refineries. The rule requires that all vent gas streams controlled with a flare located in Beaumont/Port Arthur, Dallas/Fort Worth, El Paso, and Houston/Galveston areas, including Gregg, Nueces, and Victoria counties achieve 90% control efficiency or limit VOCs emitted to 20 ppmvd @ 3% O_2 with a smokeless flare.

The second TCEQ rule, Chapter 115, Subchapter H, Division 1, pertains to flares with the potential to emit highly-reactive VOCs (HRVOC) in the Houston/Galveston/Brazoria area. Each site located in this area is subject to a facility limit of 1,200 lbs HRVOC per 1-hr block period from any flare, vent, pressure relief valve, cooling tower, or any combination. This rule also outlines several monitoring specifications explicitly for flares. Each facility must install, calibrate, maintain, and operate a continuous flow monitoring system to measure the flow rate of gas to the flare and an on-line analyzer system capable of measuring the concentration of HRVOCs in addition to hydrogen, nitrogen, methane, carbon dioxide, and VOCs at least once every 15 minutes. Each monitoring system must operate at least 95% of the time the flare is operational, and if the continuous on-line analyzer is non-operational in excess of 8-hours, daily samples of vent gas sent to the flare must be taken and analyzed to determine all constituents. The average net heating value of combusted gas and the average actual exit velocity must be calculated for each 1-hr block and used in conjunction with the information collected by continuous monitors to calculate the hourly average HRVOC emission rate from the flare, assuming 99% control efficiency for ethylene and propylene, 98% control efficiency for all other HRVOCs, and 93% control efficiency when the calculated net heating value or exit velocity of the vent gas does not meet the limitations set forth by NSPS Subpart A. In addition, facilities must develop and implement a Quality Assurance Plan (QAP) and a Written Test Plan for the above monitoring requirements, in addition to maintaining records of all testing and monitored parameters.

4.5 COSTS AND AVAILABILITY

4.5.1 Flare Gas Recovery Unit

Based on cost estimates by SCAQMD and a plant-wide case study at the Houston Valero refinery, capital costs for flare gas recovery systems should range between $1.0 and $5.1 million, depending on needed system capacity. Even with the high capital investment, significant energy savings are realized from recycling vented gases for use as fuel or process feedstock. At the Houston refinery, the predicted fuel savings from the installation of a flare gas recovery unit amounts to about 130,000 MMBtu/yr heat input at a cost savings of $420,000/yr. At this rate, the flare gas recovery system pays for itself in two and a half years. The Shell Refinery in Martinez, California also installed a flare gas recovery system as part of an overall package of refinery improvements and expects a 2 year return on the recovery system. The typical payback period for flare gas recovery installations at other petroleum refineries is two to four years. Recently another flare gas recovery unit was installed at a refinery in Arkansas, which has resulted in reduced flaring and near-zero emission levels. No cost information was available for this installation.

4.5.2 Compliance with SCAQMD Rule 1118

The proposed amendments to Rule 1118 are expected to achieve emission reductions of 1.18 tons/day of SO_2 and 1.44 tons/day in total criteria pollutants (except CO) by December 31, 2012. According to estimates by SCAQMD staff, the cost effectiveness of the proposed amendments range from $5,524 to $8,620 per ton of SO_2 reduced and from $4,527 to $7,063 per ton SO_2, NOx, VOC, and PM_{10} reduced. These overall cost estimates include installation of flare gas recovery and treatment systems, installation of all required analyzers and flow meters, and the cost of man hours to produce annual surveys of all pressure relief devices and flaring events. Detailed cost analysis for these items can be found in Table 4-3.

4.5.3 Compliance with BAAQMD Rule 12

Estimated costs for implementing each requirement of Rule 12 at refineries in the Bay Area are summarized in Table 4-4. These estimates are conservative, as a few of the refineries have already installed control equipment to reduce flaring and many of the benefits of this rule have already been achieved, and therefore the associated costs have already been incurred by the refineries in the Bay Area. The BAAQMD staff determined the extremes of the expected costs, taking into account that some facilities had already taken steps to reduce flaring, while others have not made any changes to their systems. Overall cost effectiveness for implementation of Rule 12 is $818 - $1,298 on the low end, and $1,527 - $1,603 on the high end per ton of all pollutants reduced.

Table 4-4: Estimated Costs for Compliance with SCAQMD Rule 1118

Rule Requirement	Estimated Cost	Notes
Install Flare Gas Recovery & Treatment Systems	Capital: $20,400,000 O & M: $2,000,000 Permit Fees: $28,932 Annual Operating Fee: $2,950	Total cost for four separate units to be installed by January 1, 2009
Install Higher Heating Value (HHV) and Total Sulfur (TS) Analyzers	Capital: HHV - $71,000, TS - $79,000 O&M: HHV - $15,000, TS - $7,900 Installation Cost (total): $79,000 One-Time CEMS Certification: $7,693	Assumed that 22 HHV and 22 TS analyzers are needed to be installed at refinery flares; Costs presented are per flare.
Install Vent Gas Flow Meter	Capital: $10,000 Accuracy Verification: $10,500/yr	Assumed that 46 such meters and analyzers are needed to be installed by January 1, 2007 at refinery flares
Install 2 Purge/Pilot Gas Meters	Capital: $2,280 O&M: $126.50 Installation: $350	
Install Automated Sampler	Capital: $4,500 Installation: $500	
Annual Survey of Pressure Relief Devices	$68,000	Over all refineries, assumed 1,360 hours total at $50 per person hour, to be in effect the beginning of 2006.
Annual Flare Event Special Cause Analysis	$800,000/yr	Over all refineries, assumed 200 investigations at 80 hours per investigation and $50 per person hour, to be in effect the beginning of 2006.
Overall Cost Effectiveness: the cost effectiveness of the proposed amendments range from $5,524 to $8,620 per ton of SO_2 reduced and from $4,527 to $7,063 per ton SO_2, NOx, VOC, and PM_{10} reduced.		

SOURCE: Teszler, E., October 2005, "Final Staff Report for Proposed Rule 1118 – Control of Emissions from Refinery Flares," South Coast Air Quality Management District, Diamond, California.

Table 4-3: Estimated Costs for Compliance with BAAQMD Rule 12

Rule Requirement	Estimated Cost	Notes
Development of a Flare Minimization Plan	$100,000	Estimate for medium sized refinery
Implementation of FMP Low End: High End:	$120,000/yr $1,900,000/yr	Low: facility only needs to perform minor modifications High: facility needs to install all flare gas recovery controls ($20,000,000 project amortized over 20 years at 7%)
Flaring Notification to the District (High End)	$500/yr	Assumes 67 notifications (number derived from monthly reporting), where vent gas released was greater than 500,000 scf/day, assuming 15 minutes per phone call to the District at a rate of $30/person hour calling
Determination & Reporting of Cause (High End)	$40,200/yr	Assuming $50 per person hour at 12 hours per event for 67 flaring events
Annual Reports & FMP Updates	$30,000/yr	Less than $^1/_3$ the cost of developing the FMP
Water Seal Monitoring Low End: High End:	$3,000/yr $9,000/yr	Low: Accounts for annual maintenance costs High: Includes annual maintenance and partial upgrades amortized over 20 years at 7%
Overall Cost Effectiveness: The cost effectiveness for the high cost prevention measure would be $1,603 per ton for the first year for all pollutants, $1,527 per ton thereafter. For the low cost prevention measure the cost effectiveness would be $1,298 per ton for all pollutants, and $818 per ton thereafter.		

SOURCE: Ezersky, A., 2005, "Staff Report: Proposed Regulation: Regulation 12, Miscellaneous Standards of Performance, Rule 12, Flares at Petroleum Refineries," Bay Area Air Quality Management District, San Francisco, California.

Feasible control technologies for flares are summarized in Table 4-6. The table includes

- Pollutant controlled
- Name of technology
- Origin for the level of control (rule, consent decree, permit)
- Range of potential emission reductions from applying those controls
- Performance level in terms of outlet concentration or emission rate
- Cost effectiveness of the controls
- Commercial status
- Reference

More detailed information on each technology was summarized in the previous sections and based on the information contained in the references for this Section.

The cost data presented in the Table were obtained from the published literature as referenced. In general, the percent reductions and cost effectiveness data represent data for uncontrolled sources. Incremental reductions will be lower and costs will be higher for sources already have some level of control and will be required to meet the performance levels shown in the Table. Also, site-specific factors greatly influence the actual achievable performance level and control costs at a particular facility. These considerations must be addressed in State and local rulemaking and permitting processes.

Table 4-5: Control Technology Options for Flares

Pollutant	Technology	Origin of Requirement	Percent Reduction	Performance Level	Cost Effectiveness ($/ton)	Commercially Available?	Reference
All	Flare Gas Recovery Unit	Consent Decree	n/a	NSPS limit on hydrogen sulfide content of refinery fuels to 0.10 gr/dscf (162 ppm)	Cost Savings	Yes	
All	Requirements contained in BAAQMD Rule 12	BAAQMD Rule 12	65 to 86	Development and implementation of flare minimization plan, continuous monitoring of knock-out drum water seal for leaks, determine and report the causes of each reportable flaring incident	818 to 1,603	Yes	Ezersky, 2005
All	Requirements contained in SCAQMD Rule 1118	SCAQMD Rule 1118	53	Prohibits flaring except for emergencies, shutdowns and startups, turnarounds, and specific essential operational needs; establishes operational practices to minimize flaring events, sets annual SO2 performance targets, requires operation in a smokeless manner; increased inspections and monitoring	4,527 to 8,620	Yes	Wallerstein, 2005

4.6 REFERENCES

Ezersky, A., 2005, "Staff Report: Proposed Regulation: Regulation 12, Miscellaneous Standards of Performance, Rule 12, Flares at Petroleum Refineries," Bay Area Air Quality Management District, San Francisco, California.

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United States Environmental Protection Agency, 1995, "Industrial Flares," Pages 13.5-1 – 13.5-5 in AP-42, Fifth Edition: Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, http://www.epa.gov/ttn/chief/ap42/ch13/final/c13s05.pdf.

Wallerstein, B.R., 2005, "Final Environmental Assessment for Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares," SCAQMD No. 102605MK, October 2005.

Wallerstein, B.R., 2004, "Evaluation Report on Emissions from Flaring Operations at Refineries & Direct Staff to Initiate Amendment of Rule 1118," Board Meeting: September 3, 2004, Agenda No. 33.

5.0 FUGITIVE EQUIPMENT LEAKS

Equipment leaks contribute to plant-wide emission of fugitive VOCs at petroleum refineries. Equipment leaks are defined as emitters of organic hazardous air pollutants from pumps, compressors, pressure relief devices, sampling connection systems, open-ended or in-line valves, and instrumentation systems. Most petroleum refineries limit these fugitive emissions at their facilities by implementing leak detection and repair (LDAR) programs. Each refinery's LDAR program specifies the frequency of monitoring for VOC leaks from these components, as well as specifying testing methods, recordkeeping, and reporting requirements. Recently, there has been renewed interest in developing cost effective solutions to further reduce VOC emissions from equipment leaks as states undertake efforts to develop rules and State Implementation Plans (SIPs) for ozone, PM2.5, and regional haze.

5.1 PROCESS DESCRIPTION

Equipment leaks normally encountered in an oil refinery include pipe flanges, threaded pipe connections, pump seals, compressor seals and valve packing. There are literally thousands of such potential leak sources in a typical oil refinery. Reasons for leaks can include normal wear and tear, poor quality or design of components, poor maintenance or improper choice of materials. Volatile hydrocarbons can then be leaked from the processing units into the ambient environment from any of the above mentioned sources. Leak detection and repair programs can reduce but not eliminate these fugitive emissions.

5.2 EMISSION INVENTORY

Table 5-1 identifies the fugitive VOC emission releases from refineries in the MARAMA region. VOC emissions for each facility are shown for three years. The 2002 annual emissions serve as the baseline for future SIP development. The 2002 emissions were obtained from the 2002 inventories developed by MANEVU and VISTAS. The 2003 emissions were obtained directly from each state and represent the most currently quality assured data that is available.

The 2009 emissions were obtained from the MANEVU and VISTAS projection inventories that were developed to support modeling for SIP development. The 2009 inventories include the effects of anticipated growth as well as any planned controls that will result in emission reductions between 2002 and 2009 due to new regulations or enforcement settlements. The growth factors used for projecting emissions from 2002 to 2009 came from the U.S. Environmental Protection Agency's Economic Growth Analysis System (EGAS 5.0) and the U.S. Department of Energy's Annual Energy Outlook (2005) projections. The controls factors for 2009 were derived either from data supplied that the State/local agencies or from MACTEC's analysis of the requirements contained in the global enforcement settlements.

Table 5-1: Emission Inventory for Fugitive Equipment Leaks

State	Refinery/ Unit	Annual VOC Emissions (tons/year) 2002	2003	2009
DE	Valero Delaware City EUID = 083, 250	63.5	45.0	32.0
DE	SUNCO Inc Delaware EUID = 006, 007, 026, 027	1.9	2.6	1.8
NJ	Sunoco Eagle Point EUID = FG1 to FG28	41.6	63.9	21.0
NJ	Valero Paulsboro EUID = FG2 to FG7	65.6	63.9	33.0
NJ	Citgo Asphalt EUID = FG1 to FG4	10.0	10.0	5.0
NJ	Amerada Hess Port Reading EUID = FG0	13.5	13.5	13.5
NJ	Chevron Products EUID = FG0, FG1	9.5	11.5	9.5
NJ	ConocoPhillips Bayway EUID = FG0	233.0[a]	126.0	116.5
PA	Sunoco Marcus Hook EUID = 110, 114, 402	130.4	230.0	65.2
PA	ConocoPhillips Trainer EUID = 108, 112, 116, 118	63.4	53.0	31.7
PA	American Refining Bradford EUID = 206, 206A	129.9	129.9	129.9
PA	Sunoco Philadelphia EUID = over 40 separate IDs	175.6	183.4	88.0
PA	United Refining EUID = 109	167.0	176.4	167.0
VA	Giant Yorktown EUID= 25, 26, 27, 30-33	310.3	203.1	155.1
WV	Ergon West Virginia EUID = 017	45.4	44.3	22.7
	MARAMA Totals	**1,460.6**	**1,356.5**	**891.9**

a) ConocoPhillips Bayway initially estimated a VOC emissions of 1,629 tons/year from equipment leaks using the "leak/no leak" method and AP-42 emission factors consistent with the federal leak definition of 10,000 ppm. Emissions were recalculated using actual leak data and EPA correlation equations LeakDas software, resulting in a downward revision to 233 tons/year.

5.3 EXISTING REQUIREMENTS

This section discusses the regulatory requirements which apply to equipment leaks. Four types of requirements are discussed: (1) Federal requirements such as the New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards; (2) State regulations for both the MARAMA states as well as other State agencies; (3) source-specific permit requirements; and (4) new requirements from recent enforcement settlements.

5.3.1 Federal Regulations

New Source Performance Standards (NSPS) for equipment leaks of VOCs at petroleum refineries are covered by 40 CFR Part 60, Subpart GGG. This subpart applies to affected facilities (compressors, valves, pumps, pressure relief devices, sampling connection systems, open-ended and in-line valves, flanges, or other connector in VOC service) at petroleum refineries that have undergone construction or modification since January 4, 1983. This subpart refers to 40 CFR Part 60, Subpart VV for all applicable monitoring, testing, recordkeeping and reporting standards. Subpart VV indicates that a piece of equipment is leaking when an instrument reading of 10,000 ppm or greater is measured using EPA Method 21 or when a visual inspection uncovers liquid dripping from the equipment. When leaks are detected, a first attempt repair should be made within 5 days after the leak is detected, and final repairs should be made within 15 days, unless an equipment shutdown is warranted. The subpart also lists out specific standards for each type of equipment (pumps, compressors, pressure relief devices, sampling connection systems, values, etc.) Please refer to 40 CFR Part 60, Subpart GGG for all applicable NSPS requirements..

National Emission Standards for Hazardous Air Pollutants (NESHAP) for equipment leaks from process equipment components in organic HAP service at petroleum refineries are found in 40 CFR Part 63, Subpart CC, which indicates that the standards under 40 CFR Part 60 Subpart VV should be applied to existing sources, while the standards under 40 CFR Part 63 Subpart H should be applied to new sources. Subpart CC lists dates specific to petroleum refineries for owners/operators to demonstrate compliance specific emissions limit phases. Three phases were established, with the final phase taking effect on February 18, 2001, therefore the emission limit for leaks from new equipment should be consistent with Phase III. Just as defined in Subpart VV, Subpart H requires that an identification tag be affixed to leaking components upon detection, and stipulates that first attempt repairs to be made within 5 days after leak detection, while final repairs should be made within 15 days, unless an equipment shutdown is warranted. These subparts also identify specific standards for each type of equipment component. Please refer to 40 CFR Part 63, Subpart CC, 40 CFR Part 60 Subpart VV, and 40 CFR Part 63 Subpart H for all applicable NESHAP requirements.

Alternative Work Practices to Detect Leaks from Equipment were proposed by EPA on April 6, 2006. This action proposes a voluntary alternative work practice for finding leaking equipment using optical gas imaging instead of monitoring using EPA Reference Method 21. Although optical gas imaging can potentially be useful as a method of leak detection and repair when operated in conjunction with Federal Reference Method 21 ("Method 21"), commenters have raised enforcement and technical concerns that must be addressed before promulgation.

Revisions to the NSPS were proposed by EPA on November 7, 2006. These amendments increase the stringency of the leak definitions for pumps and valves. These amendments would increase the stringency of the leak definition for pumps in liquid service from 10,000 ppm to 2,000 ppm and increase the stringency of the leak definition for valves in gas/vapor service or light liquid service from 10,000 ppm to 500 ppm. The new leak definitions would apply only to new sources that began construction, reconstruction, or modification after November 7, 2006. EPA's analysis indicates that "even lower leak definitions would theoretically result in lower emissions, but available evidence to date does not support the selection of lower values". EPA's analysis indicates that lowering the leak detection definitions to 500 ppm for valves and 2,000 ppm for pumps for petroleum refineries would have a cost effectiveness of $3,100 per ton removed.

5.3.2 State Regulations

Most states have detailed monitoring, testing, recordkeeping, and reporting requirements, with the exception of Virginia, which mimic the federal regulations. Please refer to the applicable state/local rules for applicable requirements:

- Delaware Regulation No. 24, Section 29: Leaks from Petroleum Refinery Equipment
- Philadelphia Regulation V, Section XIII: Process Equipment Leaks
- Pennsylvania Section 129.58: Petroleum Refineries – Fugitive Sources
- New Jersey 7:27-16.18: Leak Detection and Repair
- Virginia 9 VAC 5-40-1420: Standard for Fugitive Dust/Emissions

The regulations for other states (Louisiana, Texas) and California districts (Bay Area Air Quality Management District – BAAQMD, South Coast Air Quality Management District – SCAQMD, and San Joaquin Valley Air Pollution Control District - SJVAPCD) are generally more stringent (more frequent monitoring, lower leak definitions) than the MARAMA states and the federal government.

5.3.3 Permit Requirements

The permit requirements for most of the facilities follow the NSPS, NESHAP, or the state LDAR requirements.

5.3.4 Requirements from Recent Enforcement Settlements

The EPA and state/local agencies recently undertook an initiative to investigate physical modifications to petroleum refineries. Capacity increases and modifications should have triggered NSR permitting and pollution control requirements. There have being several instances identified where refineries have failed to obtain pre-construction and operating permits for physical construction that increased their capacity and emissions. Consent Decrees require petroleum refineries to implement enhanced leak detection and repair systems to reduce fugitive VOC emissions. In general, the enforcement settles require leak detection and repair program enhancements, including the following:

- Written refinery-wide LDAR program description
- Training for any person (employee or contract employee) assigned LDAR program responsibilities
- LDAR audits, including an initial compliance audit, third-party audits, and internal audits
- Actions necessary to correct noncompliance resulting from audits
- More stringent leak definitions for valves and pumps
- Increased LDAR monitoring frequency
- Electronic monitoring, storing, and reporting of LDAR data
- QA/QC of LDAR data
- Establish and maintain an LDAR coordinator with responsibility for LDAR management and authority to implement LDAR improvements
- Establish a tracking program to ensure new valves and pumps are integrated into the LDAR program
- Verification of "delay of repair" determinations
- Calibration/calibration drift assessments
- Chronic leaker identification and repair program
- Recordkeeping and reporting requirements

5.4 AVAILABLE CONTROL TECHNOLOGIES

Fugitive VOC emissions from equipment leaks at petroleum refineries are difficult to cost-effectively monitor and prevent using current LDAR methods given that emissions from these sources are highly random. Two new LDAR approaches have been recently introduced in an effort to reduce fugitive emissions from petroleum refineries.

5.4.1 Enhanced LDAR

Implementation of an enhanced LDAR program is required by the recent enforcement settlements enacted at the refineries in the MARAMA region. According to the individual Consent Decrees, several conditions are to be added to the current LDAR program in order to reduce fugitive VOC emissions from each facility. The Shell Oil Company has already enforced an enhanced LDAR program at its Deer Park Manufacturing Complex (TX) which has resulted in a 1,200,000 pound (600 ton) reduction in toxic emissions released to the atmosphere. Enhanced LDAR program improvements include:

- Training: Implement an annual training program for personnel assigned to LDAR responsibilities, including a separate training program for all other refinery personnel with instruction on relative aspects of the LDAR program, providing refresher courses on a 1-year or 3-year schedule.
- LDAR Personnel: Establish a program to hold LDAR personnel accountable for LDAR performance at the refinery.
- QA/QC: Develop and implement a QA/QC procedure for reviewing all monitoring data daily, including the number of components monitored per technician, time between monitoring events, and abnormal data patterns.
- Leak Definition: The VOC leak detection limits are reduced from 10,000 ppm to 500 ppm for valves, and 2,000 ppm for pumps.
- Monitoring Frequency: Pumps should be monitored monthly, while valves should be monitored either quarterly with no ability to skip monitoring periods or according to the sustainable skip period program.
- Data Collection: Requires use of dataloggers and/or electronic data collection devices to maintain an electronic database of LDAR monitoring results.
- Calibration Drift Assessment: At the end of each monitoring shift, a calibration drift assessment should be conducted. If any drift after the initial calibration shows a negative drift of more than 10% from the previous calibration, then all valves with monitoring concentrations greater than 100 ppm and all pumps with concentrations greater than 500 ppm should be retested.
- Repairs: New repair regulations vary by consent decree, including regulations for "first-attempt" repairs to be made within 1-day of leak detection (Sunoco), and a 30-day limit to make repairs and re-monitor pumps and valves (Delaware City). The Consent Decrees also call for pumps and valves to be placed on a "Delay of Repair" list under proper documentation. Some Consent Decrees also allow refineries to monitor affected pumps and valves at process units after completing maintenance, startup, or shutdown activities without having to submit the results to the state.
- Tracking Program: Establish a program to ensure that new valves and pumps installed during maintenance and construction projects are implemented into the LDAR program.
- Recordkeeping & Reporting Requirements: Regular reports written to the state should include addition information on the new additions to the LDAR program (training program, audits, monitoring, QA/QC, etc.).
- Audits: Requires alternating third-party and internal audits every two years. Audits include comparative monitoring of valves and pumps, review of records, tagging, and data management, and observation of LDAR technicians' calibration and monitoring techniques.

5.4.2 Smart LDAR

Both the current and enhanced LDAR programs require regular inspections of equipment using EPA Method 21 by placing a gas sampling probe at the surface of all piping component seals. This procedure requires extensive man hours to check every potential leaking source, and requires checking many sources whose fugitive emissions usually range from non-detect to 100 ppm. According to a study conducted by the American Petroleum Institute (API), only 0.13% of the total sources monitored at petroleum refineries account for the largest source of fugitive emissions (leaks measured at concentrations greater than 10,000 ppm). The majority of the sources monitored indicated zero emissions when tested, while only 5% of the sources with initial leak concentrations greater than 1,000 ppm were found to repeatedly leak. This evidence suggests that more emphasis should be placed on the detection and repair of sources measured with high leak concentrations rather than using the EPA Method 21 to monitor all refinery components with the potential to develop an equipment leak. This can be accomplished using the second LDAR approach, called Smart LDAR, which seeks to efficiently locate and repair the small number of leaky components using visual imaging equipment. Several camera systems have been developed for this sort of task and employ detection methods such as infrared spectrometry, backscatter absorption, and lasers to pictorially represent major leaks from equipment as plumes of smoke on a portable screen. Listed below are some examples of the types of cameras available.

Infrared Imaging Spectrometer (Pacific Advanced Technology, 2000)

Pacific Advanced Technologies (PAT), under contract to the Department of Defense, developed a field portable infrared imagining spectrometer for defense related applications, such as detection of chemical weapons and missile plumes. This imaging system combines a diffractive optical system with state of the art image processing technology to allow real-time viewing of fugitive gas leaks. Recently, PAT has applied this technology to environmental monitoring for fugitive gas leaks, smoke stack emissions, and flares and has demonstrated this device can measure multiple species simultaneously, as well as handle the effects of atmospheric absorption and scattering. An added benefit of this instrument is its ability to identify elemental species present in the equipment leak without the use of an artificial illumination source.

Backscatter Absorption Gas Imaging (Goers, Kulp, and McRae, 2000)

The Backscatter Absorption Gas Imaging (BAGI) instrument uses an infrared laser to direct specific wavelengths of light towards suspected gas leaks. The gas will absorb the light and appear as a dark cloud on the screen of the imaging equipment. The BAGI instrument allows the simultaneous viewing of many potential emission points, while also being able to focus in on a single leaking source and estimate the leak flux more accurately than from single point concentration measurements. The first field test of this equipment involved using a vehicle-mounted BAGI instrument, which was found to be impractical due to the need to test areas of the refinery that had limited accessibility. Since the field test, work has been underway to develop a hand-held portable imaging device.

Pulsed Laser Imager (US DOE, 2002)

The Pulsed Laser Imager (PLI) developed by LaSen Inc. also uses infrared spectroscopy to detect and measure fugitive VOC leaks from refinery equipment. The main advantage of this imager is its ability to detect hydrocarbon leaks at a safe distance away (between 328 ft and 1.5 miles), without requiring an air sample. Two versions of PLI have been developed, the Lidar and the NICE, and initially operate by firing an invisible pulsed laser towards a suspected leak. Then, the radiation is backscattered to a telescope and a sensor measures the hydrocarbon concentration in the Lidar imager, whereas the NICE imager converts the backscattered radiation into a false color image using video processing technology.

5.5 COSTS AND AVAILABILITY

A cost effective LDAR program should both maximize emission reductions while minimizing equipment and labor costs. Current LDAR programs requiring quarterly monitoring of primary pump seals and valves in liquid and gas service can cost between $54,000 and $1,075,000 per year depending on plant size and the number of required-to-monitor components. With an 80% VOC reduction, cost savings of $215/ton VOC abated can be achieved. Cost effectiveness of LDAR programs for pumps and compressors can range from $1,950 to $2,787 per ton VOC (ECIPPC, 2003).

The smart LDAR option doesn't include changing the defined leak emission limit, but instead changing the method of detecting leaks. Instead of using a hydrocarbon gas analyzer and following EPA Method 21 to determine leak concentrations at all applicable process components, it suggests using a gas imaging instrument that can visually located VOC leaks, so that refineries can focus on the major equipment leaks which contribute the most to high fugitive emissions. Gas imaging equipment, such as the Pulsed Laser Imager, costs between $1,500 to $25,000 for short range devices, and up to $100,000 for long range devices. Even though the upfront cost of the equipment is high, significant savings in labor costs can be attained, as the typical refinery spends approximately $1,000,000 a year on the manpower alone to support their LDAR programs. As part of a consent decree, the ExxonMobil refinery in Baytown, Texas has plans to implement a Smart LDAR program by December 31st, 2007, in order to demonstrate and evaluate gas imaging equipment, at an estimated cost of $250,000. No cost effectiveness data for this option is available at this time.

Revisions to the NSPS were proposed by EPA on November 7, 2006. These amendments would increase the stringency of the leak definition for pumps in liquid service from 10,000 ppm to 2,000 ppm and increase the stringency of the leak definition for valves in gas/vapor service or light liquid service from 10,000 ppm to 500 ppm. EPA's analysis indicates that lowering the leak detection definitions to 500 ppm for valves and 2,000 ppm for pumps for petroleum refineries would have a cost effectiveness of $3,100 per ton removed.

Several of the refineries in the MARAMA region already have leak definitions that are more stringent than the NSPS for some process units. An enhanced LDAR program with a leak definition of 500 ppm will be less effective at reducing the emissions from refineries where the starting leak definition is 1,000 ppm than where the leak definition is 10,000 ppm. The cost-effectiveness is likely to be high for refineries where the current leak definition is already lower than the Federal leak definition. We recognize that it's the emission reduction estimates and cost-effectiveness will vary by refinery due to the differences in the current leak definitions at a particular refinery. We recommend that State's further evaluate the refinery-specific baseline emissions, leak definitions, and potential emission reductions from lowering the leak definitions.

Feasible control technologies for equipment leaks are summarized in Table 5-2, including::

- Pollutant controlled
- Name of technology
- Origin for the level of control (rule, consent decree, permit)
- Range of potential emission reductions from applying those controls
- Performance level in terms of outlet concentration or emission rate
- Cost effectiveness of the controls
- Commercial status
- Reference

The cost data presented in the Table were obtained from the published literature as referenced. In general, the percent reductions and cost effectiveness data represent data for uncontrolled sources. Incremental reductions will be lower and costs will be higher for sources already have some level of control and will be required to meet the performance levels shown in the Table. Also, site-specific factors greatly influence the actual achievable performance level and control costs at a particular facility. These considerations must be addressed in State and local rulemaking and permitting processes.

Table 5-2: Control Technology Options for Fugitive Equipment Leaks

Pollutant	Technology	Origin of Requirement	Percent Reduction	Performance Level	Cost Effectiveness ($/ton)	Commercially Available?	Reference
VOC	Enhanced LDAR	Consent Decrees	50	Program enhancements beyond requirements of NSPS, NESHAP, and State Rules: Training of LDAR personnel; enhanced QA/QC; low leak definitions; electronic recording of LDAR monitoring results; third-party audits; chronic leaker identification and repair; other operational improvements	1,300	Yes	Coburn, 2002
VOC	Lower Leak Definitions	Proposed Revisions to NSPS	Not Quantified	Increase the stringency of the leak definitions for pumps and valves; for pumps in liquid service from 10,000 ppm to 2,000 ppm and increase the stringency of the leak definition for valves in gas/vapor service or light liquid service from 10,000 ppm to 500 ppm.	$3,100	Yes	USEPA Nov. 7 2006
VOC	Gas Imaging Technology	EPA's proposed alternative work standards	Unknown	Unknown	Unknown	Currently Being Demonstrated	USEPA Apr. 6 2006

5.6 REFERENCES

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6.0 WASTEWATER TREATMENT

The process of petroleum refining generates a significant amount of wastewater, contributing to emissions released to the atmosphere, nearby water bodies and the production of solid waste. This wastewater is then either recycled for specific use in the petroleum refinery or processed through a series of on-site collection and treatment units to reduce air and water emissions, as well as solid waste. Emissions to the air consist mainly of volatile organic carbons (VOCs) and hazardous air pollutants (HAPs) from wastewater collection and treatment units which are open to the atmosphere. Contaminants released into the water include hydrocarbons, organic, sulfur, and ammonia based compounds, and heavy metals. Solid waste generated from wastewater treatment systems is in the form of sludge, which can contain phenols, metals, oil, chemical coagulants, suspended solids, and spent lime. Owners of wastewater treatment systems are required to meet federal and state standards for controlling the release of contaminants into air, water, and solid waste. This section will only focus on air emissions from petroleum refinery wastewater collection and treatment systems, and provide control strategies to reduce VOC emissions from these facilities. Current state and federal standards require some of these collection and treatment systems to be covered and or controlled to minimize VOC releases to the atmosphere, however, not all systems are covered and/or controlled. Both equipment covers and pollution control equipment can be employed to further reduce VOC emissions from the wastewater treatment facilities at petroleum refineries in the MARAMA region.

6.1 PROCESS DESCRIPTION

Wastewater treatment systems at petroleum refineries treat cooling water, process water, storm water, and sanitary sewage water before discharging the treated water to a public owned treatment works (POTW) facility or to a nearby receiving water body. Wastewater treatment systems are divided into two sections; first a collection system followed by a treatment system. Collection systems consist of some or all of the following: process drains, manholes, reaches, junction boxes, weirs, trenches, sumps, and lift stations, while treatment system consist of some or all of the following: oil-water separators, equalization basins, dissolved air floatation (DAF)/dissolved nitrogen floatation (DNF) tanks, clarifiers, biological treatment basins, sludge digesters, treatment tanks, surface impoundments, and air and steam strippers. Figure 6-1 depicts a typical refinery wastewater collection and treatment system.

Collection system components are designed to collect wastewaters from various process units throughout the petroleum refinery and transport them to the treatment facility. Collection system components are defined as follows: Process drains are the connecting point between process sources and sewer lines, trenches, sumps, or ditches. Manholes provide entrances to sewer lines for sewer inspection and cleaning. Reaches are the lengths of sewer pipe between each manhole or between other sewer components, such as lift stations or junction boxes. Junction boxes are the meeting points for several process sewer lines to combine the streams into one stream. Weirs act as dams in open channels to maintain constant water levels upstream. Trenches are an alternative to process drains and accommodate pad water runoff, water from equipment washes, and spill cleanups. Sumps are used for collection and equalization of wastewater flow from trenches. Lift stations provide sufficient pressure to transport collected wastewaters to the treatment system.

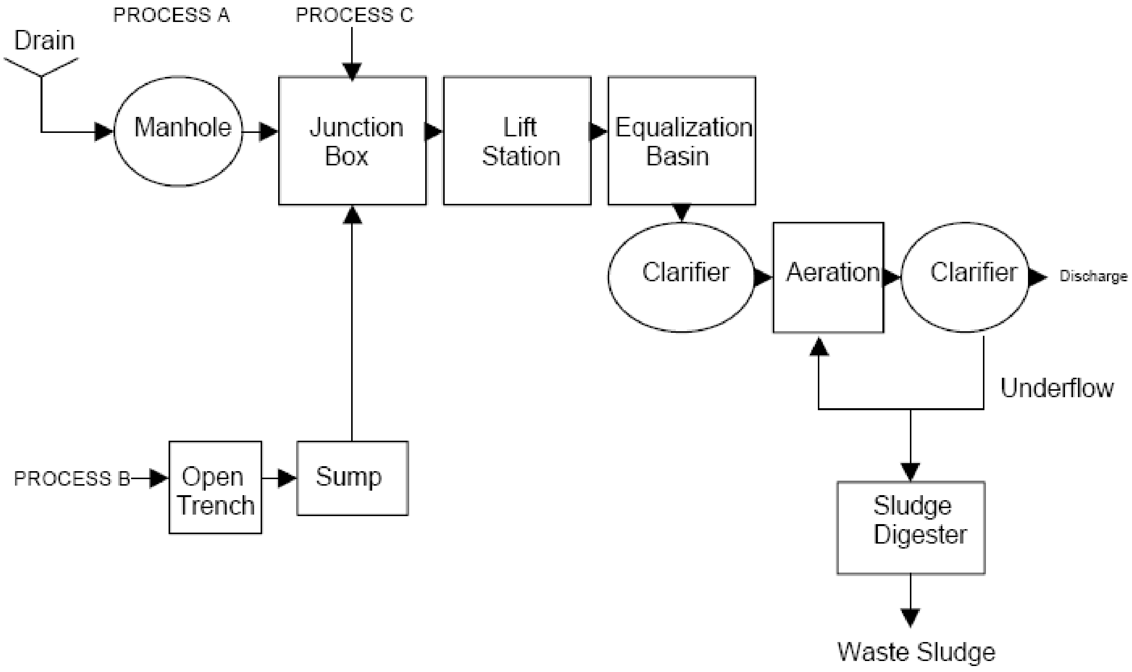


Figure 6-1. Typical Refinery Wastewater Collection & Treatment System

SOURCE: Dunn, T.X., D.M. Breen, and C. Pham, 2004, "Draft Technical Assessment Document: Potential Control Strategies to Reduce Emissions from Refinery Wastewater Collection and Treatment Systems," California Air Resources Board and the Bay Area Air Quality Management District.

Treatment system components are responsible for removing oil, sludge, and other hazardous components from the wastewater stream before discharging the stream to a receiving body of water or other POTWs. Oil-water separators (also known as API separators) are the first step in wastewater treatment, which separates oil and suspended solids from wastewater based on the specific gravity of each liquid. Equalization basins are used to prevent fluctuations in the wastewater flow rate to downstream treatment processes. DAF/DNF tanks use floatation to separate oils, grease, scum and solids remaining in the wastewater, removing these pollutants using a surface skimmer. Clarifiers are used to remove sludge from wastewaters. Biological treatment basins are large aeration basins where microorganisms metabolize organic compounds through the use of mechanical aeration. Sludge digesters treat organic sludge through aeration with conventional air diffusers or surface aeration equipment. Treatment tanks, including biological treatment tanks and pH adjustment tanks, are used to treat wastewater before and/or after biological treatment. Surface impoundments are used for evaporation, polishing, equalization, storage, leachate collection, and as emergency surge basins. Air and steam stripping can be used to remove organic constituents in wastewater streams prior to secondary or tertiary treatment devices. Air stripping involves contacting wastewater with air to strip out VOCs, while steam stripping involves distillation of the wastewater through contact with steam to provide the necessary heat to vaporize VOCs present.

6.2 EMISSION INVENTORY

Table 6-1 identifies the wastewater treatment systems in the MARAMA region, along with the capacity of each unit. Criteria pollutant emissions for each unit are shown for three years. The 2002 annual emissions serve as the baseline for future SIP development. The 2002 emissions were obtained from the 2002 inventories developed by MANEVU and VISTAS. The 2003 emissions were obtained directly from each state and represent the most currently quality assured data that is available. The 2009 emissions were obtained from the MANEVU and VISTAS projection inventories that were developed to support modeling for SIP development. The 2009 inventories include the effects of anticipated growth as well as any planned controls that will result in emission reductions between 2002 and 2009 due to new regulations or enforcement settlements.

Table 6-1: Emission Inventory for Wastewater Treatment

State	Refinery/ Unit	Annual VOC Emissions (tons/year) 2002	2003	2009
DE	Valero Delaware City			
	EUID = 050 CPI&API Separator, Tanks	199.5	209.1	184.0
	EUID = 051 Wastewater Treatment Plant	167.3	4.2	154.3
DE	SUNCO Inc Delaware			
	None listed in Inventory	0.0	0.0	0.0
NJ	Sunoco Eagle Point			
	EUID = U53 API System	60.6	64.8	69.2
	EUID = U55 Aeration Basin	55.8	59.6	63.6
NJ	Valero Paulsboro			
	EUID = U53 Wastewater Treatment Plant	272.0	283.7	393.9
NJ	Citgo Asphalt			
	EUID = U9 Area 9 Waste Water Treatment	4.7	2.3	5.3
NJ	Amerada Hess Port Reading			
	EUID = U6 Waste Water Treatment	1.4	3.1	1.6
NJ	Chevron Products			
	EUID = U10 Area J Effluent Treatment Plant	41.2	24.6	47.0
NJ	ConocoPhillips Bayway			
	EUID = U10	35.1	50.5	51.0
PA	Sunoco Marcus Hook			
	EUID = 112 Process Drains	37.0	281.4	42.2
PA	ConocoPhillips Trainer			
	EUID = 106 Process Drains and Separator	18.6	16.3	21.2
PA	American Refining Bradford			
	EUID = 302/303 Oil/Water Separators	0.2	0.2	0.2
PA	Sunoco Philadelphia			
	EUID = 046 GP Separator 2	7.6	22.8	8.7
	EUID = 047 GP Separator 4	7.5	15.5	8.6
	EUID = 556 PB Wastewater Operations	24.4	24.4	27.8
	EUID = 745 PB LDAR Process Drains	72.9	72.9	10.5
	EUID = 905 GP LDAR Process Drains	49.9	49.9	7.2
PA	United Refining			
	EUID = 110 Wastewater Fugitive Emissions	184.4	191.6	72.3
VA	Giant Yorktown			
	EUID = 029 Below Grade Sewer	1.5	1.2	1.6
WV	Ergon West Virginia			
	EUID = 017 Waste Water Treatment	83.2	56.8	89.0
	MARAMA Totals	**1,324.8**	**1,433.7**	**1,259.2**

6.3 EXISTING REQUIREMENTS

This section discusses the regulatory requirements which apply to wastewater treatment systems at petroleum refineries. Four types of requirements are discussed: (1) Federal requirements such as the New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards; (2) State regulations for both the MARAMA states as well as other State agencies; (3) source-specific permit requirements; and (4) new requirements from recent enforcement settlements.

6.3.1 Federal Requirements

The U.S. EPA has promulgated standards to limit emissions of VOCs from petroleum refinery wastewater treatment facilities.

New Source Performance Standards (NSPS) for wastewater treatment systems constructed or modified after May 4, 1987 are covered under 40 CFR Part 60, Subpart QQQ. This subpart applies to individual drain systems, oil-water separators, and aggregate wastewater treatment facilities at petroleum refineries. For individual drain systems, each drain should be equipped with water seal controls and be visually or physically inspected monthly for low water levels. Each drain system's junction box should be equipped with a cover and tight seal around the edges and should be inspected semiannually for broken seals. In addition, sewer lines should be covered or enclosed with no visible gaps or cracks in joints, seals, or other emission interfaces and inspected semiannually. Alternative standards allow for the owner or operator to construct and operate a closed drain system with a control device with the Administrator's approval.

For oil-water separators, each oil-water separator tank, slop oil tank, storage vessel, and any other auxiliary equipment subject to this subpart should be equipped and operated with a fixed roof and visually inspected semiannually for cracks or gaps in the roof and wall, access doors, and roof seals. In addition, oil-water separator tanks or auxiliary equipment with a design capacity to treat more than 250 gallons of refinery wastewater per minute are also required to be equipped with a closed vent system and control device. Closed vent systems should be designed and operated with no detectable emissions (measured emissions less than 500 ppm) and be equipped with a flow indicator to ensure that all vapors are routed to the control device. Control device options include enclosed combustion devices with a 95% VOC control efficiency and a minimum residence time of 0.75 seconds at a minimum temperature of 1,500^{o}F, vapor recovery stems with a minimum 95% VOC control efficiency, and flares. Alternative standards allow the use of floating roof tanks on oil-water separators, slop oil tanks, storage vessels, and other auxiliary equipment with approval from the Administrator. As for monitoring requirements, Subpart QQQ requires using a temperature monitoring device for thermal or catalytic incinerators to ensure proper VOC combustion, while carbon adsorption systems should be equipped with continuous emissions monitors to record VOC emissions in the exhaust.

The National Emission Standards for Hazardous Air Pollutants (NESHAP) for wastewater treatment systems are covered in 40 CFR Part 63, Subpart CC, which applies to petroleum refinery wastewater streams and treatment operations. Under this subpart, wastewater treatment systems with an annual benzene loading of 11 tons/yr or greater are required to comply with the requirements of 40 CFR Part 61, Subpart FF (NESHAP for Benzene Waste Operations), which requires the removal of benzene from the wastewater stream by 99% or more on a mass basis, meet a 10 ppmw on a flow-weighted annual average basis final benzene concentration, or incinerate the waste in a combustion unit that achieves 99% destruction efficiency.

6.3.2 State Regulations

Table 6-2 lists the regulations for each of the MARAMA states for the control of VOCs from wastewater treatment systems. All regulatory agencies in the MARAMA region have regulations limiting the emissions of VOCs except for New Jersey. In Table 6-3, the regulations are listed for Louisiana, Texas, and California (from the Bay Area Air Quality Management District – BAAQMD, the South Coast Air Quality Management District – SCAQMD, and the San Joaquin Valley Air Pollution Control District – SJVAPCD). Regulations from these states are presented because these states tend to enforce stricter emission limitations than the MARAMA states and the federal government.

6.3.3 Requirements from Recent Enforcement Settlements

The Consent Decrees addressed noncompliance with the benzene waste (40 CFR Part 61, Subpart FF). The Consent Decrees require increased monitoring, regular laboratory and program audits, quarterly benzene balances, and replacement of carbon emission filters as soon as monitoring detects any benzene emissions above background levels. In general, the Consent Decrees require program benzene waste NESHAP enhancements, including the following:

- Review and verification of compliance status
- Implementation of corrective action plants to correct noncompliance
- Requirements for use of carbon canister systems
- Annual review of process information to ensure that all new benzene waste streams are included in the waste stream inventory
- Audits of laboratories that perform analyses of NESHAP samples
- Review of benzene spill data
- Benzene waste sampling plans and training of technicians
- Recordkeeping and reporting requirements

The Consent Decrees required covering of the API separators in some cases.

Table 6-2: Summary of MARAMA State Regulations

Agency	**Emission Standards**
Delaware	**Reg. 24, Section 28** The owner or operator of any wastewater (oil/water) separator at a petroleum refinery shall: 1. Provide covers and seals on all separators and forebays. 2. Equip all openings in covers, separators, and forebays with lids or seals and keep the lids or seals in the closed position at all times except when in actual use.
New Jersey	**7:27-16.27** The provisions of this subchapter shall not apply to the emissions of VOC from the following source operations: 4. Industrial wastewater treatment systems until November 15, 1994; 5. All other wastewater treatment facilities until November 15, 1994: and
Pennsylvania	**§ 129.55.** No person may permit the use of a compartment of a single or multiple compartment volatile organic compound wastewater separator which compartment receives effluent water containing 200 gallons a day or more of any volatile organic compound from equipment processing, refining, treating, storing or handling volatile organic compounds unless the compartment is equipped with one of the following vapor loss control devices—properly installed, in good working order, and in operation—as follows: 1. A container having openings sealed and totally enclosing the liquid contents. Gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place. 2. A container equipped with a floating roof—consisting of a pontoon type roof, double-deck-type roof or internal floating cover—which will rest on the surface of the contents and be equipped with a closure seal or seals to close the space between the roof edge and container wall. Gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.
Philadelphia	**Reg. 5, SECTION III.** No person shall use any compartment of any single or multiple compartment oil-effluent water separator which may receive 200 gallons a day or more of organic materials or mixture of organic materials consisting of kerosene or more volatile organic materials unless one of the following organic material vapor control devices properly installed and well maintained, is in operation: 1. A solid cover sealed and totally enclosing the liquid contents, and in addition, all gauging and sampling devices shall be gas-tight except when in use, or 2. A floating roof resting on the surface of the liquid contents equipped with a closure seal or seals to close the space between the roof edge and wall, and in addition, all tank gauging and sampling devices shall be gas-tight except when in use, or 3. A vapor recovery system capable of collecting the organic materials emitted from the separator and disposing of these emissions so as to prevent their emission to the atmosphere, and in addition, all tank gauging and sampling devices shall be gas-tight except when in use, or 4. Other equipment equal or greater in efficiency to those devices listed above, and approved by the Department
Virginia	**9 VAC 5-40-1390.** No owner or other person shall use or permit the use of any wastewater separator unless such separator is equipped with a vapor control system that will remove, destroy or prevent the discharge into the atmosphere of at least 95% by weight of volatile organic compound emissions. **9 VAC 5-40-1400.** The control system (for wastewater separators) should consist of one of the following: 1. A solid cover with all openings sealed and totally enclosing the liquid contents of that compartment; 2. A floating pontoon or double-deck type cover, equipped with closure seals to enclose any space between the cover's edge and compartment wall; or 3. Any system of equal or greater control efficiency to the system mentioned in this section, provided such system is approved by the board.
West Virginia	**§45-21-25. Petroleum Refinery Sources.** The owner or operator of any wastewater (oil/water) separator at a petroleum refinery shall: 1. Provide covers and seals on all separators and forebays; and 2. Equip all openings in covers, separators, and forebays with lids or seals and keep the lids or seals in the closed position at all times except when in actual use.

Table 6-3: Summary of Other State Regulations

Agency	Emission Limitations
BAAQMD	**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. **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. **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.
Louisiana	**Section 2153 Subchapter M**. 1. The wastewater component shall meet the following requirements: a. all components shall be fully covered or be equipped with water seal controls; b. all openings shall be closed and sealed, except when the opening is in actual use for its intended purpose or the component is maintained at a pressure less than atmospheric pressure; c. all liquid contents shall be totally enclosed; d. for junction boxes and vented covers, the vent shall be equipped with either a control device or a vapor recovery system that maintains a minimum control efficiency of 90 percent VOC removal or a VOC concentration of less than or equal to 50 parts per million by volume (ppmv) (whichever is less stringent) or a closed system which prevents the flow of VOC vapors from the vent during normal operation; e. all gauging and sampling devices shall be vapor tight except during gauging or sampling; 2. Any wastewater tank equipped with a floating roof or internal floating cover shall meet the following requirements: a. all openings in an internal or external floating roof shall provide a projection below the liquid surface and be equipped with a cover, seal, or lid. b. automatic bleeder vents shall be closed at all times except when the roof is floated off or landed on the roof leg supports; c. rim vents, if provided, shall be set to open only when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting; d. any emergency roof drain shall be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening; e. there shall be no visible holes, tears, or other openings in any seal or seal fabric; f. secondary seals shall be the rim-mounted type (i.e., the seal shall be continuous from the floating roof to the tank wall). The accumulated area of gaps that exceed 1/8 inch (0.32 cm) in width between the secondary seal and tank wall shall be no greater than 1.0 $inch^2$ per foot (21 cm^2 per meter) of tank diameter 3. A properly operated biotreatment unit and wet weather retention basin shall meet the following requirements: a. the VOC content of the wastewater shall be reduced by 90 percent; and b. the average concentration of suspended biomass maintained in the aeration basin of the biotreatment unit shall equal or exceed 1.0 kilogram per cubic meter (kg/m^3), measured as total suspended solids, or an

	alternate parameter, as approved by the administrative authority, may be measured to ensure proper operation of the biotreatment unit.
SCAQMD	**Rule 1176.** 1. Wastewater System Emissions: Wastewater systems and closed vent systems, except sump and wastewater separator covers shall not emit VOC emissions greater than 500 ppm above background levels 2. Sumps and Wastewater Separators : A. Sumps and Wastewater Separators shall be provided with one of the following: i. A floating cover equipped with seals. ii. A fixed cover, equipped with a closed vent system vented to an APC device. iii. Any other alternate control measure which is demonstrated by the facility operator to be equivalent to, or more effective in reducing VOC emissions, and approved in writing by the Executive Officer. B. Sump and Wastewater Separator Covers, both fixed and floating, shall meet all of the following requirements: i. The cover material shall be impermeable to VOCs, and free from holes, tears, or openings. ii. Drains on covers shall be provided with a slotted membrane fabric cover, or equivalent, over at least 90 percent of the open area. iii. Gauging or sampling openings on the separator shall be covered. iv. A floating cover shall be designed and maintained so that the gap between the separator or sump wall and the seal does not exceed 1/8 inch for a cumulative length of 97 percent of the perimeter of the separator. No gap between the wall and the seal shall exceed 1/2 inch. 3. Sewer lines: All sewer lines shall be completely enclosed so that no liquid surface is exposed to the atmosphere, and all openings in the sewer line manhole covers shall be completely sealed. 4. Process drains: Any new process drain installed after September 13, 1996, shall be equipped with water seal controls or any other alternative control measure which is demonstrated by the applicant to be equivalent, or more effective than water seal controls in reducing VOC emissions, as approved in writing by the Executive Officer. 5. Junction boxes: Junction boxes shall be totally enclosed with a solid, gasketed, fixed cover or a manhole cover. Each fixed cover shall be allowed to have an open vent pipe no more than four inches in diameter and at least three feet in length. Each manhole cover on junction boxes shall be allowed to have openings totaling no more than 12 square inches. The manhole cover shall remain fully closed, except when opened for active inspection, maintenance, sampling, or repair. 6. APC Devices shall meet one of the following requirements: A. An APC device receiving vapors from a closed vent system shall achieve a control efficiency of 95 percent by weight or greater of VOC. B. The outlet of the APC device shall not emit VOC emissions greater than 500 ppm above background. The frequency of monitoring shall be at least monthly
SJV APCD	**Rule 4625** 1. A person shall not use any compartment of any vessel or device operated for the recovery of oil or tar from effluent water, from any equipment which processes, refines, stores or handles petroleum or coal tar products unless such compartments are equipped with one of the following vapor loss control devices, except when gauging or sampling is taking place: A. A solid cover with all openings sealed and totally enclosing the liquid contents of the compartment, except for such breathing vents as are structurally necessary; or B. A floating pontoon or double-deck type cover, equipped with closure seals that have no holes or tears, installed and maintained so that gaps between the compartment wall and seal shall not exceed one-eighth (1/8) inch for an accumulative length of 97 percent of the perimeter of the tank, and shall not exceed one-half (1/2) inch for an accumulative length of the remaining three (3) percent of the perimeter of the tank. No gap between the compartment wall and the seal shall exceed one-half (1/2) inch; or C. A vapor recovery system with a combined collection and control efficiency of at least 90 percent by weight. 2. Any gauging and sampling device in the compartment cover shall be equipped with a cover or lid. The cover shall be in a closed position at all times, except when the device is in actual use. 3. All wastewater separator forbays shall be covered. 4. Skimmed oil or tar removed from wastewater separating devices shall be either charged to process units with feed or transferred to a container with a control system with at least 90 percent control efficiency by weight. A control device must be under District permit.

Texas	**Rule 115.142** 1. For wastewater treatment components, including storage tanks, surface impoundments, drains, junction boxes, lift stations, weirs, and oil-water separators: A. All components shall be fully covered or be equipped with water seal controls B. For junction boxes and vented covers in the Dallas/Fort Worth and El Paso areas, vents shall be equipped with either a vapor control system which maintains a minimum control efficiency of 90% or a closed system which prevents the flow of VOC vapors from the vent during normal operation. In the Beaumont/Port Arthur and Houston/Galveston areas, vents shall be equipped with either a vapor control system which maintains a minimum control efficiency of 90% or a closed system which prevents the flow of VOC vapors from the vent during normal operation. C. All gauging and sampling devices shall be vapor-tight except during gauging or sampling. D. Any loading or unloading to or from a portable container by pumping shall be performed with a submerged fill pipe. 2. If a wastewater component is equipped with an internal or external floating roof: A. All openings in an internal or external floating roof except for automatic bleeder vents and rim space vents shall provide a projection below the liquid surface or be equipped with a cover, seal, or lid. B. Automatic bleeder vents (vacuum breaker vents) shall be closed at all times except when the roof is being floated off or landed on the roof leg supports. C. Rim vents, if provided, shall be set to open only when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting. D. Any roof drain that empties into the stored liquid shall be provided with a slotted membrane fabric cover that covers at least 90% of the area of the opening. E. There shall be no visible holes, tears, or other openings in any seal or seal fabric. F. For external floating roof storage tanks, the secondary seals shall be the rim-mounted type. The accumulated area of gaps that exceed 1/8 in. in width between the secondary seal and tank wall shall be no greater than 1.0 in^2/ft of tank diameter. 3. In the Beaumont/Port Arthur and Houston/Galveston areas, each properly operated biotreatment unit shall meet the following requirements. A. The VOC content of the wastewater shall be reduced by 90% by weight; and B. The average concentration of suspended biomass maintained in the aeration basin of the biotreatment unit shall equal or exceed 1.0 kilogram per cubic meter (kg/m^3), measured as total suspended solids.

6.4 AVAILABLE CONTROL TECHNOLOGIES

Wastewater treatment systems mainly emit VOCs through volatilization of organic compounds at the liquid surface of uncovered wastewater collection and treatment units. The main strategies employed to limit VOC emissions from these primary treatment units include installing covers or seals over existing collection equipment, and using control devices to destroy VOCs that are released. A third, less researched, method includes reducing the available VOC in the wastewater stream before the wastewater enters collection and treatment systems. These strategies are discussed below, with several control options available to reduce VOC emissions from primary treatment units. For secondary treatment, proven control technologies include steam stripping, liquid phase carbon adsorption units, and doming tanks. These control technologies are discussed in Section 6.4.4.

6.4.1 Equipment Covers

Controlling VOCs from wastewater collection systems can be achieved by various methods, including installing water seals on process drains and junction box vents, sealing manholes, enclosing open weirs, hard piping, and installing domed roofs on sludge storage tanks. Installation of these types of seals and covers on collection units currently open to the atmosphere will prevent volatilized emissions in the sewer lines from escaping.

6.4.1.1 Water Seals on Drains and Junction Box Vents

Water seals create a liquid barrier between the sewer line and the atmosphere to prevent air flow through the system. Water levels within the seal should be kept constant, as evaporation of the water will result in emissions of VOCs similar to the previously uncontrolled levels. There are two types of water seal configurations, the P-leg seal and the liquid seal inserts placed inside existing process drains or junction box vents (Figure 6-3). By installing these seals on drains and vents, VOC emissions can be reduced on average by 65%, which varies depending on the maintenance of the seal.

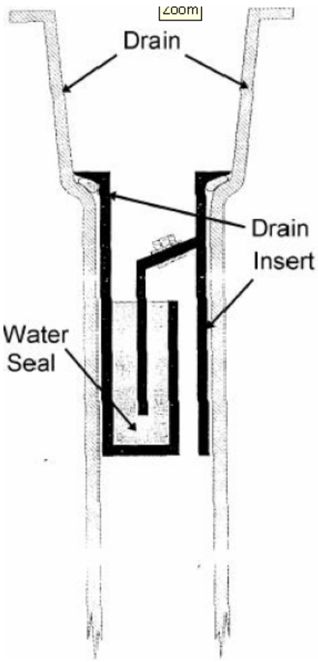


Figure 6-2. Liquid Seal Insert for Process Drain

SOURCE: Dunn, T.X., D.M. Breen, and C. Pham, 2004, "Draft Technical Assessment Document: Potential Control Strategies to Reduce Emissions from Refinery Wastewater Collection and Treatment Systems," California Air Resources Board and the Bay Area Air Quality Management District.

6.4.1.2 Sealing Manholes

VOC emissions can be reduced an average of 65% by installing gasket seals on manholes and plugging holes in manhole covers. Although, by installing these seals, VOC emissions are still reported from manhole covers through cracks and gaps in the manhole chimney seal or cover ring. Figure 6-3 shows a typical design of a refinery sewer manhole.

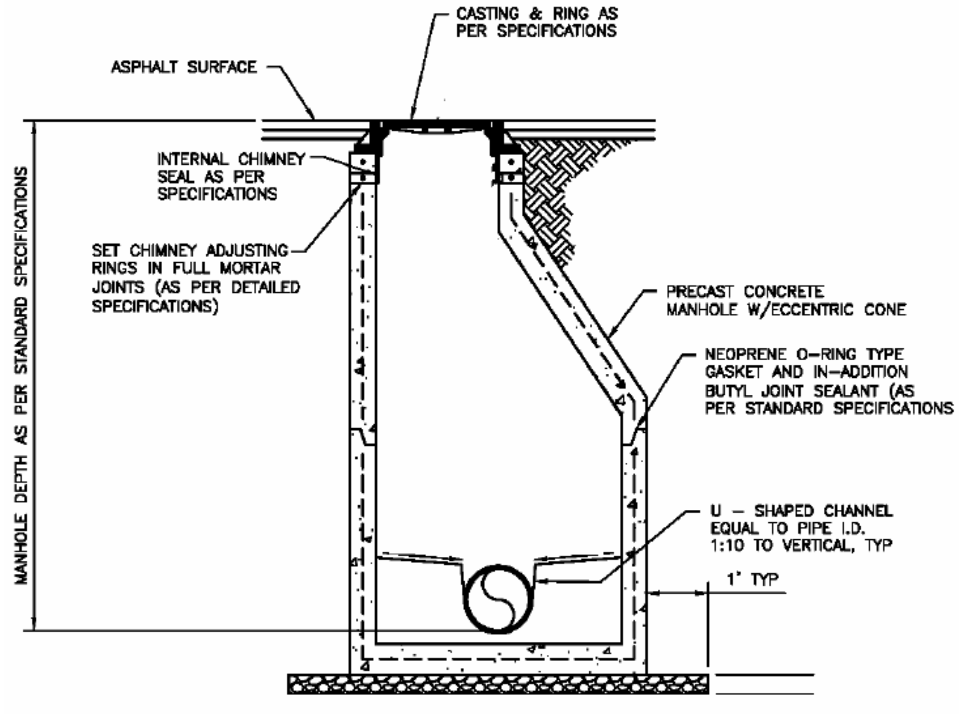


Figure 6-3. Design of Refinery Manhole

SOURCE: Dunn, T.X., D.M. Breen, and C. Pham, 2004, "Draft Technical Assessment Document: Potential Control Strategies to Reduce Emissions from Refinery Wastewater Collection and Treatment Systems," California Air Resources Board and the Bay Area Air Quality Management District.

6.4.1.3 Enclosing Weirs and Hard Piping

Enclosing open weirs and lines with direct piping, a process referred to has hard piping, is considered one of the most stringent control options and could effectively eliminate VOC emissions from weirs and sewer lines. Enclosing weirs and lines with direct piping involves (1) hard piping process units to the wastewater separator and cap all process drains, (2) hard pipe process units to a drain box enclosure, (3) hard piping the process units that contribute the largest emissions to process drains, and (4) hard pipe covered and sealed junction boxes. This control option may eliminate VOC emissions, however, by enclosing all air emissions, there is an increased likeliness of safety issues from the trapped combustible VOCs. It is also unlikely that all components of the wastewater collection system will be enclosed due to the complexity of reconstructing the sewer system.

6.4.1.4 Installing Domed Roofs on Sludge Tanks

For refineries with activated sludge tanks, in some cases domed aluminum roofs can be installed to reduce VOC emissions from escaping by up to 95%. Domed roofs allow sufficient head space above the tanks liquid level for volatized organics to collect. These VOCs must then be piped to a control device for destruction.

6.4.2 Pollution Control Equipment

In addition to installing covers and seals to prevent the release of VOCs from the wastewater collection equipment, control equipment can be installed to reduce the VOCs released during collection and/or treatment operations. The common control devices used to reduce VOCs include air or steam strippers, gas or liquid phase carbon adsorption, and combustion devices. These control devices are discussed in detail below.

6.4.2.1 Air & Steam Stripping

Air strippers contact wastewater with large amounts of air in order to transfer VOCs from the water to the air. Steam stripping is similar to air stripping, but the wastewater is contacted with steam to distill the wastewater and remove VOCs. Removal efficiencies for both stripping processes vary between 50% and 99% depending on the volatility and solubility of the organic material in the wastewater. After the VOCs are stripped from the wastewater, the contaminated air stream must then be vented to a secondary control device, such as a combustion device (flare, incinerator, boiler, etc) or gas phase carbon adsorber.

These stripping processes also hold some safety and equipment concerns. Concerns over air stripping include safety during refinery upsets when there is a potential for large amounts of hydrocarbons to be released to the wastewater treatment system resulting in explosive conditions, and equipment concerns due to fouling of the packing material due to oil and grease, compounds that precipitate when reacted with oxygen, and fouling of carbon by hydrogen sulfide, thereby decreasing the VOC capture and destruction. Texaco developed an improvement to the air stripping process to address these safety and equipment concerns, which involves using nitrogen as the stripping gas, thus eliminating the presence of oxygen and the safety and equipment concerns. The main downside to this improvement, known as the AMCEC BRU (benzene recovery unit, depicted in Figure 6-4), is the high cost of nitrogen, however the gas can be recycled after it is cleaned by carbon adsorption. Concerns over steam stripping are similar and include equipment fouling due to oil and grease, fouling of packing material with salts, as well as high costs due to energy consumption.

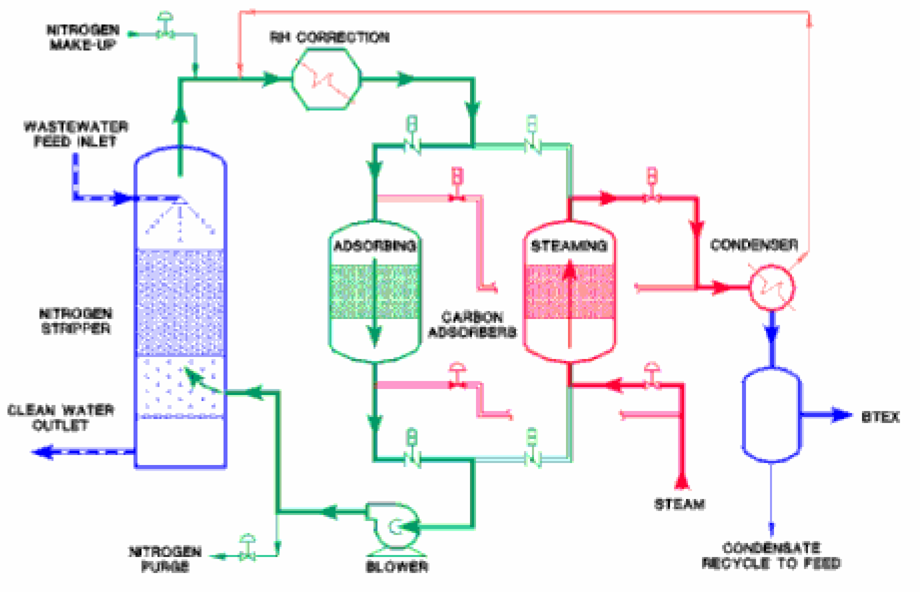


Figure 6-4. Diagram of the Air Stripping Improvement, AMCEC BRU

SOURCE: Worrall, M. and I. Zuber, 1998, “Case Studies: Control VOCs in Refinery Wastewater,” Process Optimization Conference, Houston, TX.

6.4.2.2 Carbon Adsorption

Both gas phase and liquid phase carbon adsorption take advantage of compound affinities for activated carbon, however gas phase systems are used to treat contaminated air emissions from wastewater control equipment, whereas liquid-phase systems are used to remove VOCs from the wastewater. The most common gas phase carbon adsorption systems are fixed-bed carbon adsorbers and carbon canisters. Fixed-bed carbon adsorbers are used to remove VOCs from large contaminated air flows between 30 and 3,000 m^3/min, while carbon canisters are usually installed to control air flows less than 3 m^3/min.

Control efficiencies vary between 90 and 99% depending on the types of VOCs being removed, and in some cases using pollutant specific activated carbon. There are also two types of liquid phase carbon adsorbers, including fixed-bed and moving-bed systems. The fixed-bed system operates in batch mode, processing mainly low flow wastewater streams. The moving-bed system operates continuously allowing wastewater to flow countercurrent to regenerated carbon. Liquid phase carbon adsorbers are mainly used for wastewater streams with low concentrations of non-volatile components and for high concentrations of non-degradable compounds. They achieve control efficiencies between 90 and 99%, with efficiency varying with the contaminant's affinity for the activated carbon.

6.4.2.3 Combustion Devices

VOC emission releases collected from wastewater collection and treatment systems can be vented to a combustion device for destruction. Common combustion devices include flares (discussed in Section 4.0), thermal or catalytic incinerators, and boilers (discussed in Section 3.0). These devices can reduce VOCs by combusting them at a specified minimum temperature for a specified residence time to ensure complete destruction. Typically vented gases can be combined with natural gas or fuel oil to supplement the fuel or used as an alternate fuel in cases where the vent gas has a high fuel value. However, in cases where the fuel value of the vented gases is very low, vent gases can be mixed with other fuels or combustion air.

6.4.3 Reduce VOCs from Wastewater

Several potential control measures have been identified by the BAAQMD as ways to reduce the concentration of VOCs entering the wastewater collection and treatment system. These measures include the following list.

- Reduce the generation of tank bottoms
- Minimize solids leaving the desalter unit
- Minimize and/or segregate cooling tower blowdown condensate
- Minimize fluid catalytic cracking unit decant oil sludge
- Control heat exchanger cleaning solids and sludge
- Minimize discharge of surfactants into wastewater collection system
- Reduce use of open pits, tanks, and ponds
- Remove unnecessary storage tanks from service
- Segregate storm, process, and septic wastewater collection
- Improve recovery of petroleum product from wastewater collection systems
- Identify VOC sources and install upstream water treatment and/or separation
- Use oily sludges as feedstock
- Control and reuse FCCU and coke fines
- Train personnel to reduce solids in sewers from sludge treatment

6.4.4 Secondary Treatment Control Options

The approaches for controlling VOC emissions from secondary treatment units either remove VOCs from the wastewater stream prior to its entry to secondary treatment or reduce the stream's exposure to the atmosphere. The BAAQMD recently completed a study to evaluate the VOC emission reductions to be achieved from control of secondary wastewater treatment components at refineries. The BAAQMD identified three control options:

- Steam stripping is a proven technology to remove VOCs prior to secondary treatment. It requires proper venting to a secondary control device and monitoring to insure optimal operation. The BAAQMD estimates that the total cost to install, inspect and maintain a steam stripper at each refinery over a ten-year period ranges between $7.1 million and $17.9 million. The estimated VOC emission reductions are 0.14 tons per day (tpd) based on a 90% removal efficiency if the steam stripper is installed to treat wastewater that enters the biological treatment unit and channel/weir.
- Liquid phase carbon adsorption may be used as a stand alone control device, but is also suitable as a secondary control device to reduce VOC emissions from gas phase vent streams from a steam stripper. The BAAQMD estimates that the total annual costs are comparable to that of a steam stripper. The BAAQMD estimates VOC emission reductions to be 0.14 tpd based on a 90% removal efficiency. Total annual costs for this technology are estimated to be $6.7 million to $24 million. A number of factors may limit the equipment's effectiveness. For example, high suspended solids and oil and grease can foul the carbon and require extensive pretreatment. Refineries must continuously monitor the equipment to ensure that the carbon beds are regenerated.
- Some activated sludge tanks may accommodate domed aluminum roofs to contain VOC emissions. The BAAQMD assumed a 95% VOC removal efficiency and estimated a total of 0.025 tpd reductions from two refineries' activated sludge units. The District estimated that the total cost to install, operate and maintain the aluminum domes over a ten year period would range from $100,000 to $900,000 at the two refineries. This estimated cost does not include additional expenses to install and operate VOC abatement equipment. The BAAQMD also determined that two refineries have bermed aeration lagoons and ponds that cannot accommodate a dome. These refineries would have to install foundations and support structures to contain them or replace the lagoons and ponds with tanks.

The BAAQMD concluded these measures decided not to implement these technologies because of the relatively small emission reductions compared to the present cost of implementing these known technologies. The BAAQMD estimated the cost-effectiveness to be over $1 million per ton for either a steam stripper or liquid phase carbon adsorption, and $25,000 per ton for enclosing the treatment tanks.

6.5 COSTS AND AVAILABILITY

Feasible control technologies for primary and secondary wastewater treatment units are summarized in Table 6-4. The table includes

- Pollutant controlled
- Name of technology
- Origin for the level of control (rule, consent decree, permit)
- Range of potential emission reductions from applying those controls
- Performance level in terms of outlet concentration or emission rate
- Cost effectiveness of the controls
- Commercial status
- Reference

More detailed information on each technology was summarized in the previous sections and based on the information contained in the references for this Section.

The cost data presented in the Table were obtained from the published literature as referenced. In general, the percent reductions and cost effectiveness data represent data for uncontrolled sources. Incremental reductions will be lower and costs will be higher for sources already have some level of control and will be required to meet the performance levels shown in the Table. Also, site-specific factors greatly influence the actual achievable performance level and control costs at a particular facility. These considerations must be addressed in State and local rulemaking and permitting processes.

Table 6-4: Control Technology Options for Wastewater Treatment

Pollutant	Technology	Origin of Requirement	Percent Reduction	Performance Level	Cost Effectiveness ($/ton)	Commercially Available?	Reference
Primary Treatment Processes							
VOC	Install water seals on drains	BAAQMD Rule 8	65	n/a	1,900 to 4,200	Yes	Dunn, 2004
	Install water seals on junction box vents	BAAQMD Rule 8	65	n/a	1,900 to 4,200	Yes	Dunn, 2004
	Sealing manholes	BAAQMD Rule 8	65	n/a	1,900 to 4,200	Yes	Dunn, 2004
	Enclosing open weirs and lines with direct piping	BAAQMD Rule 8	100	n/a	1,900 to 4,200	Yes	Dunn, 2004
	Reduce VOCs to Wastewater	BAAQMD Rule 8	Depends on Prevention Measures Implemented	n/a	Cost Savings	Yes	Dunn, 2004
Secondary Treatment Processes							
VOC	Install domed roofs on activated sludge tanks	n/a	95	n/a	25,000	Yes	Broadbent, 2005
	Air or Steam Stripper	n/a	90 to 99	n/a	1.35 to 1.42 million	Yes	Broadbent, 2005
	Liquid Phase Carbon Adsorption	n/a	90 to 99	n/a	1.35 to 1.42 million	Yes	Broadbent, 2005

6.6 REFERENCES

Broadbent, J.P., 2005, Memorandum to Chairperson Townsend and Members of the Board of Directors, November 9, Bay Area Air Quality Management District, San Francisco, California.

European Commission, Integrated Pollution Prevention & Control (ECIPPC), 2003, "Reference Document on Best Available Techniques for Mineral Oil and Gas Refineries."

Dunn, T.X., D.M. Breen, and C. Pham, 2004, "Draft Technical Assessment Document: Potential Control Strategies to Reduce Emissions from Refinery Wastewater Collection and Treatment Systems," California Air Resources Board and the Bay Area Air Quality Management District.

Lau, V., 2005, "Workshop Staff Report: Further Study Measure 9 Refinery Wastewater Treatment Systems," Bay Area Air Quality Management District, San Francisco, California.

United States Environmental Protection Agency, 1995, "Waste Water Collection, Treatment, and Storage," Pages 4. 3-1 – 4. 3-46 in AP-42, Fifth Edition: Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources.

Worrall, M. and I. Zuber, 1998, "Case Studies: Control VOCs in Refinery Wastewater," Process Optimization Conference, Houston, Texas.

7.0 STORAGE TANKS

Storage tanks at petroleum refineries containing volatile organic liquids (VOLs) such as petroleum and petroleum derivatives can emit up 40 percent of a refinery's total VOCs emissions. These tanks emit fugitive volatile organic carbon (VOC) emissions as a result of vapor expansion and contraction due to changes in temperature and barometric pressure, vapor losses due to filling and emptying tanks, and vapor losses at tank roof seals. These types of losses can not be completely eradicated, however, various control devices can be implemented to limit the amount of VOCs released from storage tanks.

7.1 PROCESS DESCRIPTION

The level of VOC emissions escaping from storage tanks containing organic liquids varies depending on the tank's roof design and vapor pressure of the stored liquid. There are six types of tank roofs, namely the fixed roof, external floating roof, domed external (or covered) floating roof, internal floating roof, variable vapor space, and pressure tanks. Each of these roof designs are discussed in detail below, including information on the specific mechanisms involved in VOC release.

7.1.1 Fixed Roof Tanks

Fixed roof tanks can be situated vertically or horizontally. The vertical fixed roof tank, as shown in Figure 7-1, is a cylindrical steel shell with a permanent fixed flat, dome, or cone shaped roof. Vertical fixed roof tanks can either be vented to the atmosphere or equipped with a pressure/vacuum vent to prevent vapor releases. Horizontal fixed roof tanks are constructed out of steel, steel with a fiberglass overlay, or fiberglass-reinforced polyester, and are usually equipped with pressure/vacuum vents, gauge hatches, sample wells, and manholes to provide access to the tank. These tanks can be built either above or below ground. Below ground tanks generally have storage capacities not exceeding 40,000 gallons, while aboveground fixed roof tanks can be in excess of 1,000,000 gallons. Vapor losses from fixed roof vertical and above-ground horizontal tanks are mainly due to changes in atmosphere temperature and pressure as well as liquid levels changes inside the tank. As for underground fixed roof tanks, changes in the stored liquid level have the largest effect on VOC emissions because the earth limits the effect of atmospheric temperature and pressure changes on these tanks.

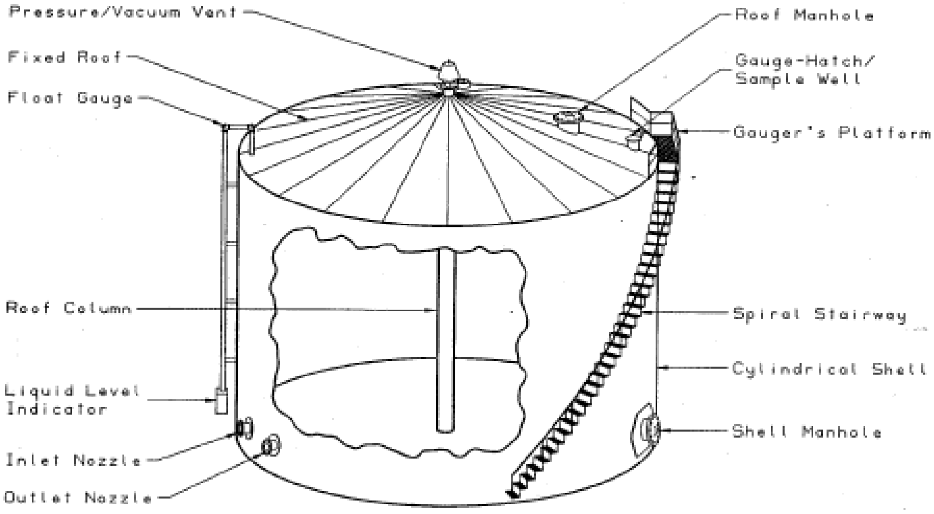


Figure 7-1. Vertical Fixed Roof Tank

SOURCE: U.S. EPA, 1997, "Organic Liquid Storage Tanks," Pages 7.1-1 – 7.1-102 in AP-42, Fifth Edition: Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources.

7.1.2 External Floating Roof Tanks

External floating roof tanks consist of an open cylindrical steel shell fitted with a roof that floats on the surface of the stored liquid. There are two types of floating roofs, also known as decks: the pontoon roof, shown in Figure 7-2 and the double-deck roof shown in Figure 7-3. Both types of floating decks rise and fall with the liquid level in the tank. This process is designed to reduce evaporative tank losses due to fluctuations in the stored liquid level and is facilitated through the use of a rim seal system which is attached to the deck perimeter and contacts the tank wall. Emissions associated with external floating roof tanks are due to standing storage losses from the rim seal system and deck fittings and withdrawal losses from the evaporation of exposed liquid on the tank walls.

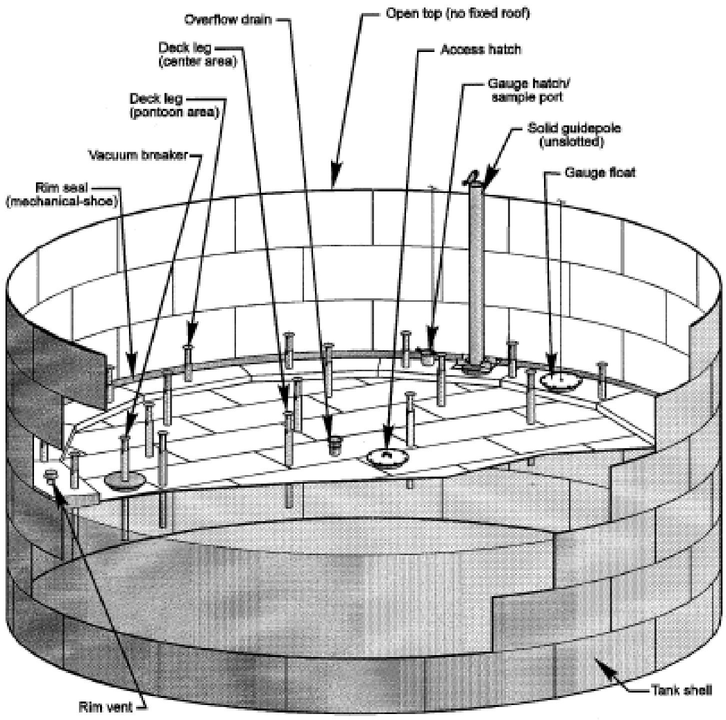


Figure 7-2. Pontoon External Floating Roof Tank

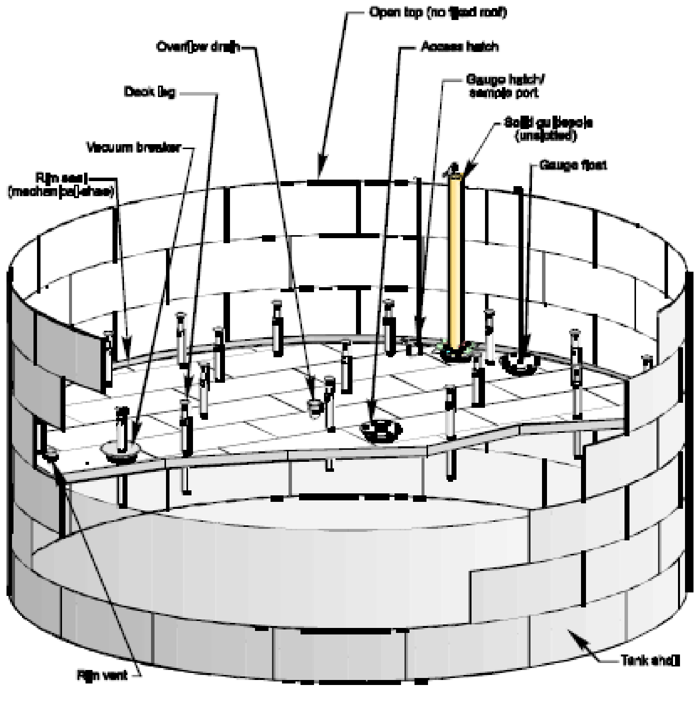


Figure 7-3. Double-Deck External Floating Roof Tank

SOURCE: U.S. EPA, 1997, "Organic Liquid Storage Tanks," Pages 7.1-1 – 7.1-102 in AP-42, Fifth Edition: Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources.

7.1.3 Internal Floating Roof Tanks

Internal floating roof tanks have two roofs, a permanent fixed roof above a floating roof. The fixed roof portion of the internal floating roof tank can be supported either by vertical columns within the tank or by a self-supporting system without internal support columns. The internal floating roof rises and falls with the stored liquid level, just as in the case of the external floating roof tank, and either rests directly on the liquid surface (known as a contact deck) or rests on pontoons a few inches above the liquid surface (known as a non-contact deck). A typical internal floating roof tank is shown in Figure 7-4. The majority of vapor losses from these tanks comes from deck fittings, non-welded deck seems, and the space between the deck and tank walls. Internal floating roof tanks are usually vented to the atmosphere at the top of the fixed roof portion of the tank, preventing build-up of combustible vapors.

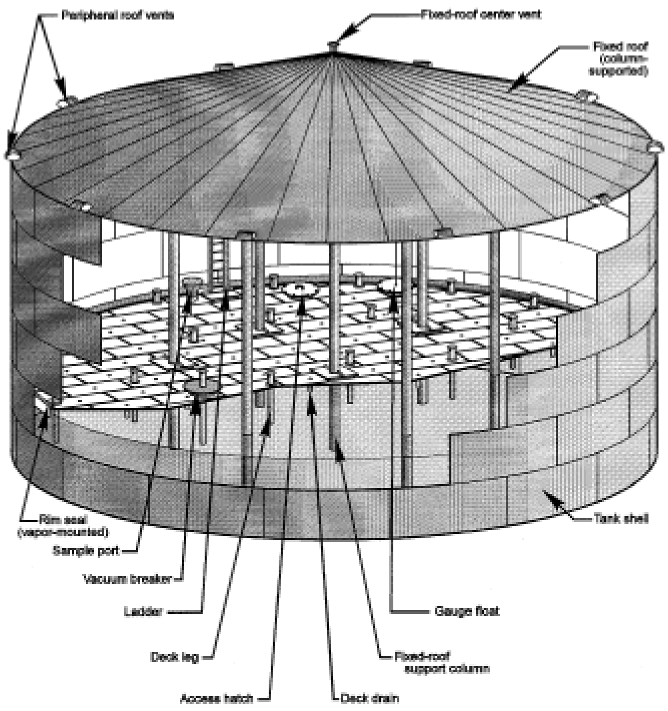


Figure 7-4. Internal Floating Roof Tank

SOURCE: United States Environmental Protection Agency, 1997, "Organic Liquid Storage Tanks," Pages 7.1-1 – 7.1-102 in AP-42, Fifth Edition: Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources.

7.1.4 Domed External Floating Roof Tanks

Domed external floating roof tanks are a combination of the external and internal floating roof tanks. This type of tank is equipped with a floating roof similar to those used in external floating roof tanks which is covered by a fixed roof similar to those used for internal floating roofs, as seen in Figure 7-5. These tanks are usually the result of retrofitting an external floating roof tank with a fixed roof. The fixed roof is usually a self supporting aluminum dome roof, whose function is to block the wind from causing evaporative losses.

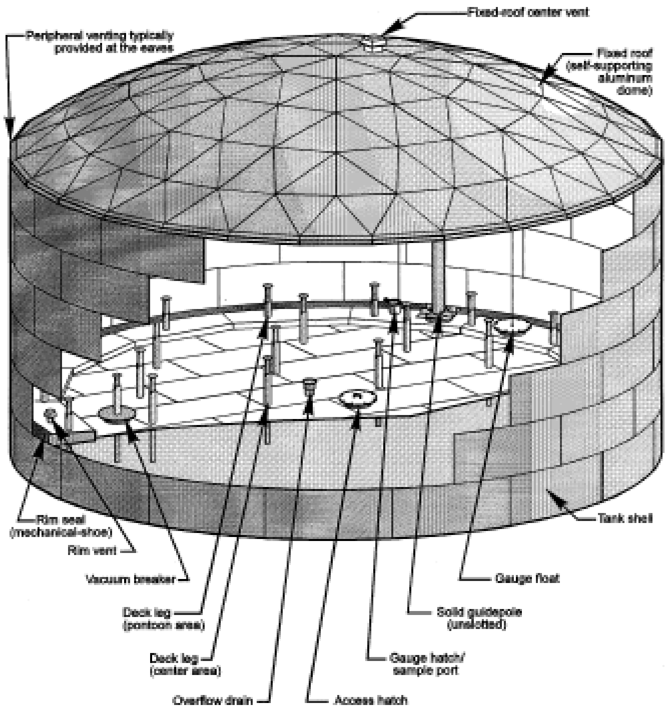


Figure 7-5. Domed External Floating Roof Tank

SOURCE: United States Environmental Protection Agency, 1997, "Organic Liquid Storage Tanks," Pages 7.1-1 – 7.1-102 in AP-42, Fifth Edition: Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources.

7.1.5 Variable Vapor Space Tanks

Variable vapor space tanks are equipped with expandable vapor reservoirs to accommodate vapor fluctuations due to atmosphere temperature and pressure changes. The most common types of variable vapor space tanks are the lifter roof tank and the flexible diaphragm tank. The lifter roof tank has a telescoping roof that loosely fits the outside of the main tank wall. The space between the roof and tank wall is filled with either a wet or dry seal. Flexible diaphragm tanks use flexible membranes, and can either be separate gas holder units or use a flexible coated fabric. The vapors collected in variable vapor space tanks are usually connected to the vapor space of fixed roof tanks.

7.1.6 Pressure Tanks

Pressure tanks are designed to store either low pressure (2.5 to 15 psig) or high pressure (greater than 15 psig) organic liquids and gases and equipped with a pressure/vacuum vent that is designed to prevent venting losses from daily atmospheric temperature and pressure changes. Tanks storing high-pressure liquids and gases can be operated so that virtually no evaporative losses (emissions due to temperature or pressure changes) or working losses (emissions due to changes in liquid levels) occur. However, low pressure tanks can have release VOCs atmospheric venting during tank filling.

7.2 EMISSION INVENTORY

Table 7-1 identifies the fugitive VOC emissions from storage tanks in the MARAMA region for each of the three years, along with the storage capacity of each unit. The 2002 annual emissions serve as the baseline for future SIP development. The 2002 emissions were obtained from the 2002 inventories developed by MANEVU and VISTAS. The 2003 emissions were obtained directly from each state and represent the most currently quality assured data that is available. The 2009 emissions were obtained from the MANEVU and VISTAS projection inventories that were developed to support modeling for SIP development. The 2009 inventories include the effects of anticipated growth as well as any planned controls that will result in emission reductions between 2002 and 2009 due to new regulations or enforcement settlements.

Table 7-1: Emission Inventory for Storage Tanks

	Refinery/	**Annual VOC Emissions (tons/year)**		
State	**Unit**	**2002**	**2003**	**2009**
DE	Valero Delaware City	124.0	119.3	114.3
DE	SUNCO Inc Delaware	1.6	1.6	1.5
NJ	Sunoco Eagle Point	216.0	198.6	240.6
NJ	Valero Paulsboro	389.0	387.9	416.1
NJ	Citgo Asphalt	17.0	16.3	19.5
NJ	Amerada Hess Port Reading	235.8	203.1	252.3
NJ	Chevron Products	77.9	69.2	83.3
NJ	ConocoPhillips Bayway	325.7	266.1	347.2
PA	Sunoco Marcus Hook	151.0	152.6	172.0
PA	ConocoPhillips Trainer	76.7	74.7	87.6
PA	American Refining Bradford	12.5	12.5	13.3
PA	Sunoco Philadelphia	145.9	140.1	163.3
PA	United Refining	23.4	25.3	25.7
VA	Giant Yorktown	97.1	130.6	107.6
WV	Ergon West Virginia	23.7	21.4	8.7
	MARAMA Totals	**1,793.3**	**1,700.0**	**2,053.0**

Note: Storage tank emissions in 2009 were projected using EGAS growth factors; these factors may tend to overestimate the expected growth in emissions. MARAMA states are reviewing the latest guidance from EPA with respect to projecting emissions from nonEGU sources such as storage tanks.

7.3 EXISTING REQUIREMENTS

This section discusses the regulatory requirements which apply to storage tanks at petroleum refineries. Four types of requirements are discussed: (1) Federal requirements such as the New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards; (2) State regulations for both the MARAMA states as well as other State agencies; (3) source-specific permit requirements; and (4) new requirements from recent enforcement settlements.

7.3.1 Federal Requirements

The U.S. EPA has promulgated standards for emissions of VOCs from petroleum refinery storage vessels.

<u>New Source Performance Standards (NSPS)</u> for petroleum liquid storage vessels are covered by three separate subparts of 40 CFR Part 60. Subpart K pertains to storage vessels constructed or modified after June 11, 1973 but before May 19, 1978, Subpart Ka pertains to storage vessels constructed or modified after May 19, 1978 but before July 23, 1984, and Subpart Kb pertains to storage vessels constructed or modified after July 23, 1984. Requirements under each of these subparts are discussed below.

Subpart K applies to petroleum liquid storage vessels with storage capacities greater than 40,000 gallons, as well as storage vessels with capacities between 40,000 and 65,000 gallons that were constructed or modified after March 8, 1974 and before May 19, 1978. Storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer are exempt from this subpart. Subpart K requires storage vessels that store petroleum liquids with true vapor pressures between 1.5 and 11.1 psia to be equipped with a floating roof and a vapor recovery system, or other equivalent equipment. For petroleum liquids with a true vapor pressure greater than 11.1 psia, a vapor recovery system or equivalent equipment is required.

Subpart Ka applies to petroleum liquid storage vessels with storage capacities greater than 40,000 gallons, however storage vessels with storage capacities less than 420,000 gallons used for petroleum or condensate stored, processed or treated prior to custody transfer are exempt. Storage vessels containing petroleum liquids with true vapor pressures between 1.5 and 11.1 psia should be equipped with either an external floating roof, a fixed roof with an internal floating type cover, a vapor recovery system that collects all VOC vapors and discharged gases, or an equivalent system. Storage vessels containing petroleum liquids with true vapor pressures greater than 11.1 should be equipped with a vapor recovery system to collect all discharged gases and a vapor return or disposal system to reduce VOC emissions by at least 95% by weight.

Subpart Kb applies to volatile organic liquid (VOL) storage vessels, which includes petroleum liquid storage vessels, with capacities greater than or equal to 75 m^3. However, this subpart excludes storage vessels with capacities greater than 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kPa or vessels with capacities between 75 and 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa. For storage vessels greater than 151 m^3 in size containing a VOL with a maximum true vapor pressure between 5.2 and 76.6 kPa and vessels sized between 75 and 151 m^3 storing a VOL with a maximum true vapor pressure between 27.6 and 76.6 kPa should be equipped with either a fixed roof with an internal floating roof, an external floating roof, a closed vent system and control device, or an equivalent system. Storage vessels with capacities greater than 75 m^3 containing a VOL with a maximum true vapor pressure greater than or equal to 766 kPa should be equipped with a closed vent system and control device or equivalent system.

The National Emission Standards for Hazardous Air Pollutants (NESHAP) for storage vessels are covered in 40 CFR Part 63, Subpart CC, which applies to petroleum refinery storage vessels. Under this subpart, Group 1 storage vessels (defined in Table 7-2) are required to comply with the requirements of 40 CFR Part 63, Subpart G (NESHAP for the synthetic organic chemical manufacturing industry for process vents, storage vessels, transfer operations, and wastewater) sections 63.119 through 63.121. These sections provide control technology requirements, compliance procedures, and alternative emission limits, respectively.

Table 7-2: Properties of Group 1 Storage Vessels

Facility	Design Capacity	Stored-Liquid Maximum true vapor pressure	Annual average HAP liquid concentration
Existing Source	≥ 177 m^3	≥ 10.4 kPa ≥ 8.3 kPa (annual)	> 4% by wt.
New Source	≥ 151 m^3	≥ 3.4 kPa	> 2% by wt.
New Source	76 – 151 m^3	≥ 77 kPa	> 2% by wt.

Section 63.119 requires that Group 1 storage vessels containing liquids with a maximum true vapor pressure less than 76.6 kPa be equipped with either a fixed roof and internal floating roof, an external floating roof, an external roof converted to an internal roof, a closed vent system and control device, route emissions to a process or fuel gas system, or perform regular vapor balances. On the other hand, those tanks containing liquids with a maximum true vapor pressure greater than or equal to 76.6 kPa must be equipped with either a closed vent system and control device, route emissions to a process or fuel gas system, or perform regular vapor balances. Specific requirements for each of these controls are also spelled out in this regulation. A range of compliance procedures are identified depending on the type of control technology used to control emissions from the storage vessels, including visual inspections, gap measurements, design evaluations, performance tests, etc. Control devices which perform equal to or better than the required control technology are also allowed under Administrative approval.

7.3.2 State Regulations

Table 7-3 lists the regulations for each of the MARAMA states for the control of VOCs from petroleum refinery storage tanks. In Table 7-4, the regulations are listed for Louisiana, Texas, and California (from the Bay Area Air Quality Management District – BAAQMD, the South Coast Air Quality Management District – SCAQMD, and the San Joaquin Valley Air Pollution Control District - SJVAPCD). Regulations from these states are presented because these states tend to enforce stricter emission limitations than the MARAMA states and the federal government.

7.3.3 Requirements from Recent Enforcement Settlements

There are no enforcement settlements for storage tanks at petroleum refineries in the MARAMA region.

Table 7-3: Summary of MARAMA State Regulations

Agency	**Emission Limitations**
Delaware	**Regulation No. 24, Section 30:** This Section applies to any petroleum liquid storage tank that is equipped with an external floating roof and that has a capacity greater than 40,000 gallons. No owner of a petroleum liquid storage vessel subject to this Section shall store a petroleum liquid in that tank unless: 1. The tank has been fitted with a continuous secondary seal extending from the floating roof to the tank wall or a closure or other device that controls VOC emissions with an effectiveness equal to or greater than a secondary seal 2. All seal closure devices meet the following requirements: (a) There are no visible holes, tears, or other openings in the seal(s) or seal fabric; (b) The seal(s) are intact and uniformly in place around the circumference of the floating roof between the floating roof and the tank wall; and (c) For vapor-mounted primary seals, the accumulated area of gaps exceeding 0.125 in. in width between the secondary seal and the tank wall shall not exceed 1.0 in.^{2}/ft of tank diameter 3. All openings in the external floating roof, except for automatic bleeder vents, rim space vents, and leg sleeves, are equipped with: (a) Covers, seals, or lids in the closed position except when the openings are in actual use; and (b) Projections into the tank that remain below the liquid surface at all times 4. Automatic bleeder vents are closed at all times except when the roof is being floated off or being landed on the roof leg supports. 5. Rim vents are set to open when the roof is being floated off the leg supports or at the manufacturer's recommended setting. 6. Emergency roof drains are provided with slotted membrane fabric covers or equivalent covers that cover at least 90 percent of the area of the opening. **Regulation No. 24, Section 31:** This Section applies to any fixed roof petroleum liquid storage tank with a capacity greater than 40,000 gal. No owner or operator of a petroleum liquid storage tank subject to this Section shall store petroleum liquid in that tank unless: 1. The tank is equipped with an internal floating roof equipped with a closure seal or seals to close the space between the roof edge and tank wall or an equally effective alternative control, approved by the Administrator of the U.S. EPA as part of a State Implementation Plan (SIP) or Federal Implementation Plan (FIP) revision. 2. The tank is maintained such that there are no visible holes, tears, or other openings in the seal or any seal fabric or materials. 3. All openings, except stub drains, are equipped with covers, lids, or seals such that: (a) The cover, lid, or seal is in the closed position at all times except when in actual use; (b) Automatic bleeder vents are closed at all times except when the roof is being floated off or being landed on the roof leg supports; and (c) Rim vents, if provided, are set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.
New Jersey	**7:27-16.2 Storage of volatile organic compounds** a. The provisions of this section shall apply to stationary storage tanks. b. No person shall cause, suffer, allow, or permit the following:

	1. The storage of any applicable VOC in any stationary storage tank that has a maximum capacity of 2,000 gallons or greater and is exposed to the rays of the sun unless**:** i. The external surface of the tank is painted and maintained white, except that this provision shall not apply to words and logos applied to the external surface of the storage tank for purposes of identification provided such symbols do not cover more than 20 percent of the external surface area of the tank's sides and top or more than 200 ft^2, whichever is less ; or ii. An equivalent method of emission control approved by the Department is used; or 2. The storage of any applicable VOC in any stationary storage tank having a maximum capacity of 10,000 gallons or greater unless such stationary storage tank is equipped with control apparatus as determined in accordance with the procedures for using Table 2A or as approved by the Department as being equally or more effective in preventing the emission of a VOC into the outdoor atmosphere. [Table 2A indicates type of control apparatus required (Range I: No control apparatus required under this subsection, Range II: Conservation vent required, or Range III: Floating roof required) depending on the stored liquid's vapor pressure and the tank capacity.] c. No person shall cause, suffer, allow, or permit the storage of any VOC having a vapor pressure of greater than 13.0 psia at the actual temperature existing at or near the liquid surface in any stationary storage tank having a maximum capacity of 1,000 gallons or greater unless such tank is equipped with a vapor control system to reduce the rate of VOC emissions to the outdoor atmosphere by at least 90% by weight of the uncontrolled VOC emissions from the tank. d. No person shall cause, suffer, allow, or permit the storage of any VOC in any stationary storage tank equipped with gauging and/or sampling systems unless such systems are vapor-tight except when gauging or sampling is taking place. e. Any stationary storage tank in Range III as determined from Table 2A, constructed or installed on or after December 17, 1979, shall be provided with a double seal floating roof or other control apparatus approved by the Department as being equally or more effective in preventing the emission of any VOC into the outdoor atmosphere. f. No person shall cause, suffer, allow, or permit the storage of any VOC in any stationary storage tank equipped with an external floating roof, unless any such storage tank containing a VOC having a vapor pressure of 1.0 psia or greater at standard conditions and having a maximum capacity of 20,000 gallons or greater is equipped with a double seal-envelope combination or equipment approved by the Department as being equally or more effective in preventing the emission of any VOC into the outdoor atmosphere. For the secondary seal, the gap area of gaps exceeding 1/8-inch in width between the seal and the tank wall shall not exceed 1.0 square inch per foot of tank diameter. Any secondary seal shall be intact, with no visible holes, tears or other openings. g. No person shall cause, suffer, allow, or permit the storage of any VOC in any stationary storage tank equipped with an external floating roof unless all openings in such roof, excluding emergency roof drains, are covered when not in active use. h. Any person responsible for the emission of any applicable VOC from any storage tank pursuant to this section shall maintain, for each tank, records specifying each VOC stored and the vapor pressure of each VOC at standard conditions.
Pennsylvania	**§ 129.56. Storage tanks greater than 40,000 gallons capacity containing VOCs.** a. No person may permit the placing, storing or holding in a stationary tank, reservoir or other container with a capacity greater than 40,000 gallons of volatile organic compounds with a vapor pressure greater than 1.5 psia (10.5 kPa) under actual storage conditions unless the tank, reservoir or other container is a pressure tank capable of maintaining working pressures sufficient at all times to prevent vapor or gas loss to the atmosphere or is designed and equipped with one of the following vapor loss control devices: 1. *An external* or *an internal floating roof.* This control equipment may not be permitted if the volatile organic compounds have a vapor pressure of 11 psia (76 kPa) or greater under actual storage conditions. 2. *Vapor recovery system.* A vapor recovery system, consisting of a vapor gathering system capable of collecting

	the volatile organic compound vapors and gases discharged and a vapor disposal system capable of processing such volatile organic vapors and gases so as to prevent their emission to the atmosphere. Tank gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place. The vapor recovery system shall be maintained in good working order and recover at least 80% of the vapors emitted by such tank. b. An external floating roof shall be fitted with a primary seal and a continuous secondary seal extending from the floating roof to the tank wall (rim-mounted secondary seal). The external floating roof shall meet the following equipment requirements: 1. Seal closure devices shall meet the following requirements: (a) There are no visible holes, tears or other openings in the seals or seal fabric; (b) The seals are intact and uniformly in place around the circumference of the floating roof between the floating roof and the tank wall; and (c) For tanks with vapor-mounted primary seals, the accumulated area of gaps exceeding 1/8 inch in width between the secondary seal and the tank wall shall not exceed 1 in^2/ft of tank diameter. 2. Openings in the external floating roof, except for automatic bleeder vents, rim space vents and leg sleeves, are as follows: (a) Equipped with covers, seals or lids in the closed position except when the openings are in actual use, and (b) Equipped with projections into the tank which remain below the liquid surface at all times. 3. Automatic bleeder vents are closed at all times except when the roof is floated off or landed on the roof leg supports. 4. Rim vents are set to open when the roof is being floated off the leg supports or at the recommended setting of the manufacturer. 5. Emergency roof drains are provided with slotted membrane fabric covers or equivalent covers which cover at least 90% of the area of the opening. c. An internal floating roof shall be fitted with a primary seal and shall comply with the following equipment requirements: 1. A closure seal or seals, to close the space between the roof edge and tank wall is used. 2. There are no holes, tears or other openings in the seal or a seal fabric or materials. 3. Openings except stub drains are equipped with covers, lids or seals such that: (a) The cover, lid or seal is in the closed position at all times except when in actual use; (b) Automatic bleeder vents are closed at all times except when the roof is floated off or landed on the roof leg supports; and (c) Rim vents, if provided are set to open when the roof is being floated off the roof leg supports or at the recommended setting of the manufacturer. d. For the purposes of this section, the petroleum liquid storage vessels listed in this subsection comply with the equipment requirements of this section. These tanks shall comply with the maintenance, inspection and reporting requirements of this section. These petroleum liquid storage vessels are those either (a) Which contain a petroleum liquid with a true vapor pressure less than 4 psia (27.6 kPa) and which are of welded construction and which presently possess a metallic-type shoe seal, a liquid-mounted foam seal, a liquid mounted liquid filled type seal or other closure device of demonstrated equivalence approved by the Department; or (b) Which are of welded construction, equipped with a metallic-type shoe primary seal and has a secondary seal from the top of the shoe seal to the tank wall (shoe-mounted secondary seal). f. The owner or operator of a petroleum liquid storage vessel with a floating roof subject to this regulation shall: 1. Perform routine inspections annually. The inspection shall include a visual inspection of the secondary seal gap when inspecting external floating roof tanks. 2. For external floating roof tanks, measure the secondary seal gap annually when the floating roof is equipped with a vapor-mounted primary seal. 3. Maintain records of the types of volatile petroleum liquids stored, the maximum true vapor pressure of the liquid as stored, and the results of the inspections performed. Copies of the records shall be retained by the owner or operator for a period of 2 years after the date on which the record was made and shall be made available to the Department upon written or verbal request at a reasonable time. g. For volatile organic compounds whose storage temperature is governed by ambient weather conditions, the

	vapor pressure under actual storage conditions shall be determined using a temperature which is representative of the average storage temperature for the hottest month of the year in which the storage takes place. **§ 129.57. Storage tanks less than or equal to 40,000 gallons capacity containing VOCs.** The provisions of this section apply to above ground stationary storage tanks with a capacity equal to or greater than 2,000 gallons which contain volatile organic compounds with vapor pressure greater than 1.5 psia (10.5 kPa) under actual storage conditions. Storage tanks covered under this section shall have pressure relief valves which are maintained in good operating condition and which are set to release at no less than 0.7 psig (4.8 kPa) of pressure or 0.3 psig (2.1 kPa) of vacuum or the highest possible pressure and vacuum in accordance with state or local fire codes or the National Fire Prevention Association guidelines or other national consensus standards acceptable to the Department.
Philadelphia	**Reg. 5, Section II. STORAGE TANKS** A. No person shall place or store in any stationary storage tank or container of 40,000 gallon capacity or greater, any organic material having a vapor pressure of 1.5 psia or greater at actual storage conditions unless one of the following organic material vapor control devices properly installed and well maintained is in operation: 1. A floating roof resting on the surface of the liquid contents equipped with a closure seal, or seals, to close the space between the roof edge and tank wall, and in addition, all tank gauging and sampling devices shall be gas tight except when in use, or 2. A pressure tank system maintaining a pressure at all times so as to prevent organic material loss to the atmosphere, or 3. A vapor recovery system capable of collecting the organic materials emitted from the tank and disposing of these emissions so as to prevent their emission to the atmosphere, and in addition, all tank gauging and sampling devices shall be gas-tight except when is use, or 4. Other equipment equal or greater in efficiency to those devices listed above, and approved by the Department. B. No person shall place, or store in any stationary storage tank or container of 40,000 gallon capacity or greater, any organic material having a vapor pressure of 11.0 psia or greater at actual storage conditions unless one of the following organic material vapor control devices properly installed and well maintained, is in operation: 1. A pressure tank system maintaining a pressure at all times so as to prevent organic material loss to the atmosphere, or 2. A vapor recovery system capable of collecting the organic materials emitted from the tank and disposing of these emissions so as to prevent their emission to the atmosphere, and in addition, all tank gauging and sampling devices shall be gas-tight except when in use, or 3. Other equipment equal or greater in efficiency to those devices listed above, and approved by the Department.
Virginia	**9 VAC 5-40-5220.** Standard for volatile organic compounds. A. Petroleum liquid storage ─ fixed roof tanks. 1. No owner or other person shall use or permit the use of any fixed roof tank of more than 40,000 gallons capacity for storage of petroleum liquids, unless such tank is equipped with a control method which will remove, destroy or prevent the discharge into the atmosphere of at least 90% by weight of volatile organic compound emissions. 2. The owner of a fixed roof tank subject to these provisions shall: a. When the fixed roof tank is equipped with an internal floating roof, perform a visual inspection annually of the floating cover through roof hatches. (1) The cover should be uniformly floating on or above the liquid and there should be no visible defects in the surface of the cover or liquid accumulated on the cover, and (2) The seal must be intact and uniformly in place around the circumference of the cover between the cover and tank wall.

	b. Perform a complete inspection of the cover and seal and record the condition of the cover and seal when the tank is emptied for non-operational reasons such as maintenance, an emergency, or other similar purposes. c. Maintain records of the throughput quantities and types of petroleum liquids stored, the average monthly storage temperature and true vapor pressure of the liquid as stored, and the results of the inspections. B. Petroleum liquid storage ─ floating roof tanks. 1. No owner or other person shall use or permit the use of any floating roof tank of more than 40,000 gallons capacity for storage of petroleum liquids, unless such tank is equipped with a control method which will remove, destroy or prevent the discharge into the atmosphere of at least 90% by weight of volatile organic compound emissions. 2. The owner of a floating roof tank subject to these provisions shall: a. Perform routine inspections annually which shall include a visual inspection of the secondary seal gap, and b. When the floating roof is equipped with a vapor-mounted primary seal, measure the secondary seal gap annually: (1) Physically measuring the length and width of all gaps around the entire circumference of the secondary seal in each place where a 1/8-inch uniform diameter probe passes freely (without forcing or binding against the seal) between the seal and tank wall; and (2) Summing the area of the individual gaps. c. Maintain records of the types of petroleum liquids stored, the maximum true vapor pressure of the liquid as stored, and the results of the inspections performed.
West Virginia	**§45-21-27. Petroleum Liquid Storage in External Floating Roof Tanks.** This section applies to any petroleum liquid storage tank that is equipped with an external floating roof and that has a capacity greater than 40,000 gallons. No owner of a petroleum liquid storage vessel subject to this section shall store a petroleum liquid in that tank unless: a. The tank has been fitted with either a continuous secondary seal extending from the floating roof to the tank wall (rim-mounted secondary seal); or a closure or other device that controls VOC emissions with an effectiveness equal to or greater than a secondary seal, and is approved by the Director and the U.S. EPA; and b. All seal closure devices meet the following requirements: (1) There are no visible holes, tears, or other openings in the seal(s) or seal fabric; (2) The seal(s) are intact and uniformly in place around the circumference of the floating roof between the floating roof and the tank wall; and (3) For vapor-mounted primary seals, the accumulated area of gaps exceeding 0.125 in. in width between the secondary seal and the tank wall shall not exceed 1.0 in^2/ft of tank diameter; and c. All openings in the external floating roof, except for automatic bleeder vents, rim space vents, and leg sleeves, should be equipped with covers, seals, or lids in the closed position except when the openings are in actual use; and equipped with projections into the tank that remain below the liquid surface at all times; d. Automatic bleeder vents are closed at all times except when the roof is being floated off or being landed on the roof leg supports; e. Rim vents are set to open when the roof is being floated off the leg supports or at the manufacturer's recommended setting; and f. Emergency roof drains are provided with slotted membrane fabric covers or equivalent covers which cover at least 90 percent of the area of the opening. Inspections. -- The owner or operator of a petroleum liquid storage tank with an external floating roof subject to this section shall perform routine inspections semiannually in order to ensure compliance (the inspections shall include a visual inspection of the secondary seal gap); and measure the secondary seal gap annually when the floating roof is equipped with a vapor mounted primary seal. **§45-21-28. Petroleum Liquid Storage in Fixed Roof Tanks.**

	This section applies to any fixed roof petroleum liquid storage tank with a capacity greater than 40,000 gallons. No owner or operator of a petroleum liquid storage tank subject to this section 28. shall store petroleum liquid in that tank unless: a. The tank is equipped with either an internal floating roof equipped with a closure seal or seals to close the space between the roof edge and tank wall; or an equally effective alternative control, approved by the Director and the U.S. EPA; b. The tank is maintained such that there are no visible holes, tears, or other openings in the seal or any seal fabric or materials; and c. All openings, except stub drains, are equipped with covers, lids, or seals such that: (1) The cover, lid, or seal is in the closed position at all times except when in actual use; (2) Automatic bleeder vents are closed at all times except when the roof is being floated off or being landed on the roof leg supports; and (3) Rim vents, if provided, are set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting. Inspections. -- The owner or operator of a petroleum liquid storage tank with a fixed roof subject to this section shall: (1) Perform routine, semi-annual, visual inspections of the internal floating roof and its closure seal or seals through roof hatches; and (2) Perform a complete inspection of cover and seal whenever the tank is emptied for non-operational reasons or at least every 5 years, whichever is more frequent.

Table 7-4: Summary of Other State Regulations

<table>
<tr><th>Agency</th><th>Emission Limitations</th></tr>
<tr><td>**BAAQMD**</td><td>
Reg. 8, Rule 5

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.

<table>
<tr><th rowspan="2">Tank Capacity</th><th colspan="3">True Vapor Pressure of Tank Organic Contents</th></tr>
<tr><th>> 0.5 to ≤ 1.5 psia</th><th>> 1.5 to < 11 psia</th><th>≥ 11 psia</th></tr>
<tr><td>≥ 264 gallons to ≤ 9,906 gallons, aboveground only</td><td>Submerged fill pipe, internal floating roof, external floating roof, or approved emission control system</td><td>Pressure vacuum valve, internal floating roof, external floating roof, or approved emission control system</td><td>Pressure tank or approved emission control system</td></tr>
<tr><td>> 9,906 gallons to < 19,803 gallons, aboveground only</td><td>Submerged fill pipe, internal floating roof, external floating roof, or approved emission control system</td><td>Pressure vacuum valve, internal floating roof, external floating roof, or approved emission control system</td><td>Pressure tank or approved emission control system</td></tr>
<tr><td>≥ 19,803 gallons to < 39,626 gallons</td><td>Submerged fill pipe, internal floating roof, external floating roof, or approved emission control system</td><td>Internal floating roof, external floating roof, or approved emission control system</td><td>Pressure tank or approved emission control system</td></tr>
<tr><td>≥ 39,626 gallons</td><td>Internal floating roof, external floating roof, or approved emission control system</td><td>Internal floating roof, external floating roof, or approved emission control system</td><td>Pressure tank or approved emission control system</td></tr>
</table>
8-5-304 Requirements for External Floating Roofs: All external floating roofs must be equipped with a primary and secondary seal. The floating roof must rest on the surface of the liquid tank contents, must be properly installed and maintained, 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.

8-5-305 Requirements for Internal Floating Roofs: An internal floating roof must meet the following requirements:

1. For a tank with seals installed on or before February 1, 1993, the tank must be equipped with either a liquid mounted primary seal, mounted in full contact with the liquid in the annular space between the tank shell and floating roof, a metallic shoe primary seal, or 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
</td></tr>
</table>

	subsection 2. 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 and a secondary seal. 3. Internal floating roof tanks which are placed into service or de-gassed after February 1, 1993 shall be equipped with at least 3 viewing ports in the fixed roof of the tank. 4. The floating roof must rest on the surface of the liquid tank contents, must be properly installed and maintained, 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. **8-5-306 Requirements for Approved Emission Control Systems:** An Approved Emission Control System must be gas tight. It must also provide an abatement efficiency of at least 95% by weight. **8-5-320 Tank Fitting Requirements:** The fittings on any floating roof storage tank subject to Section 8-5-304 or 305 shall meet the following conditions: 1. All openings through the floating roof, except pressure-vacuum valves and vacuum breaker vents, shall provide a projection below the liquid surface to prevent belching of liquid and reduce escaping organic vapors. 2. All openings through the floating roof, except floating roof legs, shall be equipped with a gasketed cover, seal or lid, which shall at all times be in a closed position and either (a) the gasketed cover, seal or lid shall have no measurable gap exceeding 1/8 in., except when the opening is in use, or for inaccessible openings on internal floating roof tanks, there shall be no visible gaps as viewed from the fixed roof man way or view ports, except when the opening is in use. 3. Solid sampling or gauging wells, and similar fixed projections through a floating roof such as an anti-rotational pipe, shall: (a) the well shall provide a projection below the liquid surface; (b) 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 1/8 in., except when the well is in use, and (c) 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 1/2 in. 4. Slotted sampling or gauging wells, and similar fixed projections through a floating roof such as an anti-rotational pipe, shall: (a) The well shall provide a projection below the liquid surface, (b) the well 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 1/2 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, and (c) 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.). 5. 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. **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: 1. There shall be no holes, tears, or other openings in the primary seal fabric which allow the emission of organic vapors. 2. The seal shall be either a metallic shoe or a liquid mounted type. 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 24 in. for external floating roofs and 18 inches for internal floating roofs above the stored liquid surface. a. 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 18 in. in the vertical plane above the liquid surface. b. For welded tanks, no gap between the tank shell and the primary seal shall exceed 1-1/2 in. No continuous gap greater than 1/8 in. shall exceed 10% of the circumference of the tank. The cumulative

	length of all primary seal gaps exceeding 1/2 in. shall be not more than 10% of the circumference, and the cumulative length of all primary seal gaps exceeding 1/8 in. shall be not more than 40% of the circumference. c. For riveted tanks, no gap between the tank shell and the primary seal shall exceed 2-1/2 in. The cumulative length of all primary seal gaps exceeding 1-1/2 in. shall be not more than 10% of the circumference. 4. For resilient-toroid-seal equipped tanks, no gap between the tank shell and the primary seal shall exceed 1/2 in. The cumulative length of all gaps exceeding 1/8 in. shall be not more than 5% of the circumference. **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 conditions: 1. There shall be no holes, tears, or other openings in the secondary seal fabric which allow the emission of organic vapors. 2. The secondary seal shall allow easy insertion of probes up to 1-1/2 in. in width in order to measure gaps in the primary seal. 3. No gap between the tank shell and the secondary seal shall exceed 1/2 in. The cumulative length of all secondary seal gaps exceeding 1/8 in. shall be not more than 5% of the circumference of the tank. 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 6 in. 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 0.06 in. The cumulative length of all secondary seal gaps exceeding 0.02 in. shall be not more than 5% of the circumference of the tank excluding gaps less than 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. 6. The secondary seal shall extend from the roof to the tank shell and shall not be attached to the primary seal.
Louisiana	**Section 2103.** **§2103. Storage of Volatile Organic Compounds** A. No person shall place, store, or hold in any stationary tank, reservoir, or other container of 250 – 40,000 gallons nominal capacity any volatile organic compound, having a maximum true vapor pressure ≥ 1.5 psia at storage conditions, unless such tank, reservoir, or other container is designed and equipped with a submerged fill pipe or a vapor loss control system, or is a pressure tank capable of maintaining working pressures sufficient at all times under normal operating conditions to prevent vapor or gas loss to the atmosphere. B. No person shall place, store, or hold in any stationary tank, reservoir, or other container > 40,000 gallons nominal capacity any volatile organic compound having a maximum true vapor pressure ≥ 1.5 psia at storage conditions unless such tank, reservoir, or other container is a pressure tank capable of maintaining working pressures sufficient at all times under normal operating conditions to prevent vapor or gas loss to the atmosphere or is designed and equipped with a submerged fill pipe and one or more of the vapor loss control devices described in Subsections C, D, and E of this Section. C. Internal Floating Roof. An internal floating roof consists of a pontoon type roof, double deck type roof, or internal floating cover which will rest or float on the surface of the liquid contents and is equipped with a closure seal to close the space between the roof edge and tank wall. All tank gauging and sampling devices shall be gas tight except when gauging or sampling is taking place. If the organic compounds have a vapor pressure ≥ 11.0 psia under actual storage conditions, the requirements of Subsection F of this Section shall

supersede the requirements of this Subsection. *In the parishes of Ascension, Calcasieu, East Baton Rouge, Iberville, Livingston, Pointe Coupee, and West Baton Rouge, the following additional requirements apply.*

1. The closure seal shall consist of either: (a) a liquid mounted seal consisting of a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank; (b) a mechanical shoe seal (metallic-type shoe seal) consisting of a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof; or (c) two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

2. Each opening in the internal floating roof (except rim space vents and automatic bleeder vents) shall be provided with a projection below the liquid surface. In addition, each opening (except for leg sleeves, bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains) shall be provided with a cover equipped with a gasket. Automatic bleeder vents and rim space vents shall be gasketed and ladder wells shall be equipped with a sliding cover.

D. External Floating Roof. An external floating roof consists of a pontoon type roof, double deck type roof, or external floating cover which will rest or float on the surface of the liquid contents and is equipped with a primary closure seal to close the space between the roof edge and tank wall and a continuous secondary seal (a rim mounted secondary) extending from the floating roof to the tank wall. In the parishes of Ascension, Calcasieu, East Baton Rouge, Iberville, Livingston, Pointe Coupee, and West Baton Rouge, the primary closure seal shall consist of a liquid mounted seal or a mechanical shoe seal

1. A secondary seal is not required if (a) the tank is a welded tank storing a VOC with a vapor pressure at storage conditions < 4.0 psia and is also equipped with a liquid mounted seal, a mechanical shoe seal, or a seal deemed equivalent by the administrative authority; (b) the storage vessels are external floating roof tanks having nominal storage capacities ≤ 420,000 gallons used to store produced crude oil or condensate prior to lease custody transfer; (c) a mechanical shoe seal is used in a welded tank which also has a secondary seal from the top of the shoe seal to the tank wall (i.e., a shoe-mounted secondary); or (d) an alternate seal or seals can be used in lieu of the primary and secondary seals required herein provided the resulting emission is not greater than that which would have resulted if the primary and secondary seals were installed.

2. The required seal closure devices shall: (a) have no visible holes, tears, or other openings in the seal(s) or seal(s) fabric; (b) be intact and uniformly in place around the circumference of the floating roof and the tank wall; (c) not have gap areas, of gaps exceeding 1/8 inch in width between the secondary seal and the tank wall, in excess of 1.0 in^2/ft of tank diameter; (d) not have gap areas, of gaps exceeding 1/8 inch in width between the primary seal and the tank wall, in excess of 10.0 in^2/ft of tank diameter; and (e) the secondary seals shall be visually inspected at least semiannually. The secondary seal gap measurements shall be made annually at any tank level provided the roof is off its legs. The primary seal gap measurements shall be made every five years at any tank level provided the roof is off its legs.

3. Requirements for Covering Openings. All openings in the external floating roof, except for automatic bleeder vents, rim space vent, and leg sleeves, are to provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents must be closed at all times except when the roof is floated off or landed on the roof leg supports. Rim vents must be set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting. Any emergency roof drain must be equipped with a slotted membrane fabric cover or equivalent cover that covers at least 90 percent of the opening. In the parishes of Ascension, Calcasieu, East Baton Rouge, Iberville, Livingston, Point Coupee, and West Baton Rouge, all covers, seals, lids, automatic bleeder vents, and rim space vents are to be gasketed.

4. Requirements for Guide Poles and Stilling Well Systems. Emissions from guide pole systems must be controlled for external floating roof storage tanks with a capacity > 40,000 gallons and which store a

	liquid having a total vapor pressure ≥ 1.5 psia. *The requirements of this Paragraph shall only apply in the parishes of Ascension, Calcasieu, East Baton Rouge, Iberville, Livingston, Pointe Coupee, and West Baton Rouge.* a. Controls for non-slotted guide poles and stilling wells shall include pole wiper and gasketing between the well and sliding cover. Controls for slotted guide poles shall include a float with wiper, pole wiper, and gasketing between the well and sliding cover. b. Alternate methods of controls are acceptable if demonstrated to be equivalent and approved by the administrative authority. c. Control systems required by Paragraph D.4 of this Section shall be inspected semiannually for rips, tears, visible gaps in the pole or float wiper, and/or missing sliding cover gaskets. Any rips, tears, visible gaps in the pole or float wiper, and/or missing sliding cover gaskets shall be repaired in accordance with this Paragraph in order to avoid noncompliance. E. Vapor Loss Control System. A vapor loss control system consists of a gathering system capable of collecting the VOC vapors and a vapor disposal system capable of processing such organic vapors. All tank gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place. 1. The vapor loss control system shall reduce inlet emissions of total volatile organic compounds by 95 percent or greater. 2. If the vapor loss control system was installed on or before December 31, 1992, then the vapor loss control system shall reduce inlet emissions of total volatile organic compounds by 90 percent or greater. 3. These specifications and requirements do not apply during periods of planned routine maintenance. Periods of planned routine maintenance of the vapor loss control system shall not exceed 240 hours per year. F. No person shall place, store or hold in any stationary tank, reservoir or other container > 40,000 gallons nominal capacity any VOC having a true vapor pressure ≥ 11 psia at storage conditions unless such tank, reservoir or other container is a pressure tank capable of maintaining working pressures sufficient at all times under normal operating conditions to prevent vapor or gas loss to the atmosphere or is designed and equipped with a submerged fill pipe and vapor loss control system.
SCAQMD	**Rule 1178** The rule applies to all aboveground storage tanks that have capacity ≥ 19,815 gallons, are used to store organic liquids with a true vapor pressure > 0.1 psia under actual storage conditions, and are located at any petroleum facility that emits > 20 tons per year of VOC in any emission inventory year starting with the emission inventory year 2000. **External Floating Roof Tanks** A. The operator of an external floating roof tank containing organic liquids having true vapor pressure of < 3 psia at any petroleum facility with annual VOC emissions > 20 tons for emission inventory year 2000 shall: (1) Equip each access hatch and gauge float well with a cover that is gasketed and bolted; (2) Equip each gauge hatch/sample well with a cover that is gasketed; (3) Gasket or cover each adjustable roof leg with a VOC impervious sock at all times when the roof is floating; (4) Gasket each rim vent; (5) Gasket each vacuum breaker; (6) Equip each open floating roof drain with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening; (7) Equip each unslotted guidepole well with a gasketed sliding cover and a flexible fabric sleeve or wiper; (8) Equip each unslotted guidepole with a gasketed cover at the end of the pole; (9) Equip each slotted guidepole with a gasketed cover, a pole wiper and a pole sleeve extended into the stored liquid, (10) Equip each slotted guidepole having a pole float with a gasketed cover, a pole wiper, and a pole float wiper; (11) Cover each slotted guidepole opening with a gasketed cover at all times; (12) Maintain the pole float in a condition such that it floats within the guidepole; (13) Except for vacuum breakers and rim vents, ensure that each opening in the external floating roof shall provide a projection below the liquid surface; and (14) Except for vacuum breakers, rim vents, roof drains, and leg sleeves, equip all other openings in the roof with a gasketed cover or seal which is closed at all

times, with no visible gaps, except when the cover or seal must be opened for access.

B. The operator of an external floating roof tank containing organic liquids having true vapor pressure of < 3 psia at any petroleum facility with annual VOC emissions > 20 tons for emission inventory year 2000 shall equip the tank with a rim seal system meeting the following requirements:

1. The primary seal shall be a mechanical shoe or liquid mounted.
2. The secondary seal shall be rim mounted and shall not be attached to the primary seal.
3. Gaps between the tank shell and the primary seal shall not exceed 1/2 inch for a cumulative length of 30% of the circumference of the tank, and 1/8 inch for 60% of the circumference of the tank. No gap between the tank shell and the primary seal shall exceed 1-1/2 inches. No continuous gap between the tank shell and the primary seal greater than 1/8 inch shall exceed 10% of the circumference of the tank.
4. Gaps between the tank shell and the secondary seal shall not exceed 1/8 inch for a cumulative length of 95% of the circumference of the tank. No gap between the tank shell and the secondary seal shall exceed 1/2 inch.
5. Mechanical shoe primary seals shall be installed so that one end of the shoe extends into the stored organic liquid and the other end extends a minimum vertical distance of 24 inches above the stored organic liquid surface.
6. 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 18 inches in the vertical plane above the liquid surface.
7. The primary seal envelope shall be made available for unobstructed inspection by the Executive Officer along its circumference. In the case of riveted tanks with resilient filled primary seals, at least 8 such locations shall be made available; for all other types of seals, at least 4 such locations shall be made available. If the Executive Officer deems it necessary, further unobstructed inspection of the primary seal may be required to determine the seal's condition along its entire circumference.
8. The secondary seal shall be installed in a way that permits the Executive Officer to insert probes up to 1-1/2 inches in width to measure gaps in the primary seal.
9. There shall be no holes, tears or openings in the secondary seal or in the primary seal envelope surrounding the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal.
10. Except during the preventive maintenance, repair, or inspection periods that do not exceed 72 hours with prior notification to the Executive Officer, both the primary seal and the secondary seal shall cover the annular space between the external floating roof and the wall of the storage tank in a continuous fashion, with no visible gaps.
11. The operator shall use a rim seal system that is identified on the current list of seals approved by the Executive Officer.

C. In lieu of complying with the requirement of no visible gap, the operator of an external floating roof tank shall maintain all roof openings in a vapor tight condition at all times except during preventive maintenance, repair, or inspection periods.

Domed External Floating Roof Tanks

A. Phase I: The operator at any petroleum facility with annual VOC emissions > 20 tons for emission inventory year 2000 shall install domed roofs on all external floating roof tanks that contain organic liquids having true vapor pressure ≥ 3 psia for the emission inventory year 2000 according to the following schedule:

1. All tanks subject to this provision by January 1, 2008.
2. As an alternative, an operator may submit a compliance plan demonstrating that 75% of the tanks subject to this provision have domes installed by December 31, 2006, and 100% of such tanks shall have domes installed by December 31, 2008.

B. Phase II: For additional external floating roof tanks that are not identified under Phase I but contain organic liquids having true vapor pressure ≥ 3 psia for any emission inventory year after 2000, the operator who is subject to Phase I shall comply with these requirements no later than 2 years after becoming subject to the rule.

C. In lieu of complying with the requirements in subparagraph B., the operator who is subject to Phase I shall accept permit conditions to limit the true vapor pressure of the organic liquids stored in the tanks to < 3 psia by the end of Phase I.

D. The operator of a domed external floating roof tank shall equip the tank with a rim seal system consisting of a primary and a secondary seal

E. The operator shall ensure that the concentration of organic vapor in the vapor space above a domed external floating roof shall not exceed 30% of its lower explosive limit (LEL) by the applicable compliance

F. The operator shall submit to the Executive Officer an annual status report including at a minimum all of the following:

1. A list of all external floating roof tanks subject to these requirements;
2. A general description of each tank including information such as tank identification, District permit number or District device identification, tank type, tank capacity, type of liquid stored, and if applicable, number of representative samples, frequency of sampling, averaging method used to determine the monthly average true vapor pressure of waste stream or recovered oil tanks, and the results.
3. A compliance status for each tank; and
4. An estimated compliance date for each external floating roof tank that is not yet in compliance.

Internal Floating Roof Tanks

When an internal floating roof tank is scheduled for emptying and degassing, but no later than January 1, 2007, the operator of an internal floating roof tank at any petroleum facility with annual VOC emissions > 20 tons for emission inventory year 2000 shall:

A. Equip each fixed roof support column and well with a sliding cover that is gasketed or with flexible fabric sleeves;

B. Equip each ladder well with a gasketed cover.

C. Equip the tank with a rim seal system consisting of either a primary seal, or a primary and a secondary seal; and

D. Ensure that the concentration of organic vapor in the vapor space above the internal floating roof shall not exceed 50% of its lower explosive limit (LEL) for those installed prior to June 1, 1984 and 30% of its LEL for those installed after June 1, 1984.

Fixed Roof Tanks

A. No later than January 1, 2007, the operator of a fixed roof tank at any petroleum facility with annual VOC emissions > 20 tons for emission inventory year 2000 shall equip each fixed roof tank containing organic liquids with true vapor pressure > 0.1 psia with an emission control system meeting the following requirements:

1. The tank emissions are vented to an emission control system with an overall control efficiency ≥ 95% by wt or the tank emissions are vented to a fuel gas system.
2. Any tank gauging or sampling device on a tank shall be equipped with a vapor tight cover which shall be closed at all times, with no visible gaps, except during gauging or sampling.
3. All openings on the roof shall be properly installed and maintained in a vapor tight condition at all times.
4. The operator shall equip each fixed roof tank with pressure vacuum vents that shall be set to the lesser of 10% below the maximum allowable working pressure of the roof or 0.5 psig.
5. The operator shall maintain pressure-vacuum vents in a vapor tight condition at all times except when the

operating pressure of the fixed roof tank exceeds the manufacturer's recommended setting.

B. In lieu of complying with the requirement in subparagraph A., the operator may choose to convert the fixed roof tank to an external floating roof tank or an internal floating roof tank and meet the requirements for those types of roofs.

General Tank Compliance Requirements

The operator of any petroleum facility with annual VOC emissions > 20 tons for any emission inventory year subsequent to 2000 shall:

A. Comply with the requirements for external floating roof tanks no later than 1 year after becoming subject to this rule.

B. Comply with the requirements for domed external floating roof tanks no later than 6 years after becoming subject to this rule. Any external floating roof tank that later becomes subject to this requirement based on any subsequent emission inventory year, shall comply with the requirements no later than 2 years after becoming subject to this rule.

C. Comply with the requirements for internal floating roof tanks when the tanks are scheduled for emptying and degassing, but no later than 5 years after becoming subject to this rule.

D. Comply with the requirements for fixed roof tanks no later than 5 years after becoming subject to this rule.

SJV APCD

Rule 4623

This rule applies to any tank with a capacity ≥ 1,100 gallons in which any organic liquid is placed, held, or stored.

VOC Control System Requirements

A. General VOC Control System Requirements: Except for small producers, an operator shall not place, hold, or store organic liquid in any tank unless such tank is equipped with a VOC control system identified in Table 1.

Table 1 – General VOC Control System Requirements

Tank Capacity (Gallons)	True Vapor Pressure (TVP) of Organic Liquid		
	0.5 psia to < 1.5 psia	**1.5 psia to < 11 psia**	**≥ 11.0 psia**
(Group A) 1,100 – 19,800	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system.	Pressure vessel or vapor recovery system
(Group B) > 19,800 – 39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system.	Internal floating roof, or external floating roof, or vapor recovery system.	Pressure vessel system or vapor recovery system.
(Group C) > 39,600	Internal floating roof, or external floating roof, or vapor recovery system.	Internal floating roof, or external floating roof, or vapor recovery system.	Pressure vessel or vapor recovery system.

B. Small Producer VOC Control System Requirements: A small producer shall not place, hold, or store crude oil in any tank unless such tank is equipped with a VOC control system identified in Table 2.

Table 2 – Small Producer VOC Control System Requirements for Crude Oil Storage Tanks

Tank Capacity (Gallons)	**True Vapor Pressure (TVP) of Organic Liquid**		
	0.5 psia to < 11 psia and a tank throughput of > 50 to < 150 barrels of crude oil per day	**0.5 psia to < 11 psia and a tank throughput of ≥ 150 barrels of crude oil per day**	**≥ 11.0 psia and regardless of crude oil tank throughput**
(Group A) 1,100 – 39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system.	Pressure vessel or vapor recovery system
(Group B) > 39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system.	Internal floating roof, or external floating roof, or vapor recovery system.	Pressure vessel system or vapor recovery system.

C. All tanks subject to the control requirements of this rule shall be maintained in a leak-free condition, except for (a) Primary seals and secondary seals of external floating roof tanks; (b) Primary seals and secondary seals of internal floating roof tanks; (c) Floating roof deck fittings; and (d) Floating roof automatic bleeder

Specifications for External Floating Roof Tanks

A. An external floating roof tank shall be:

1. Equipped with a floating roof consisting of a pan type that is installed before December 20, 2001, pontoon-type, or double-deck type cover, that rests on the surface of the liquid contents; and
2. Equipped with a closure device between the tank shell and roof edge consisting of two seals, one above the other; the one below shall be referred to as the primary seal, and the one above shall be referred to as the secondary seal.
3. The floating roof shall be floating on the surface of the stored liquid at all times except during the initial fill until the roof is lifted off the leg supports and when the tank is completely emptied and subsequently refilled.

B. Seal designs shall be submitted to the APCO and shall not be installed or used unless they are approved by the APCO as meeting the following criteria:

1. Welded Tanks with Primary Metallic-Shoe Type Seal
   a. No gap between the tank shell and the primary seal shall exceed 1-1/2 inches. The cumulative length of all gaps between the tank shell and the primary seal > 1/2 inch shall not exceed 10% of the circumference of the tank. The cumulative length of all primary seal gaps >1/8inch shall not exceed 30% of the tank circumference. No continuous gap > 1/8 inch shall exceed 10% of the tank circumference.

	b. No gap between the tank shell and the secondary seal shall exceed 1/2 inch. The cumulative length of all gaps between the tank shell and the secondary seal, > 1/8 inch shall not exceed 5% of the tank circumference. c. 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 24 inches above the stored liquid surface. d. The geometry of the metallic-shoe type seal 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 18 inches in the vertical plane above the liquid surface. e. There shall be no holes, tears, or openings in the secondary seal or in the primary seal envelope that surrounds the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal. f. The secondary seal shall allow easy insertion of probes up to 1-1/2 inches in width in order to measure gaps in the primary seal. g The secondary seal shall extend from the roof to the tank shell and shall not be attached to the primary seal. 2. Riveted Tank with Primary Metallic-Shoe Type Seal a. No gap between the tank shell and the primary seal shall exceed 2-1/2 inches. The cumulative length of all primary seal gaps > 1-1/2 inches shall be not exceed 10% of the circumference of the tank. The cumulative length of all gaps between the tank shell and the primary seal > 1/8 inch shall not exceed 30% of the circumference of the tank. No continuous gap > 1/8 inch shall exceed 10% of the tank circumference. b. No gap between the tank shell and the secondary seal shall exceed 1/2 inch. The cumulative length of all gaps between the tank shell and the secondary seal > 1/8 inch shall not exceed 5% of the tank circumference. c. 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 24 inches above the stored liquid surface. d. There shall be no holes, tears, or openings in the secondary seal or in the primary seal envelope that surrounds the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal. e. The secondary seal shall allow easy insertion of probes up to 2-1/2 inches in width in order to measure gaps in the primary seal. f. The secondary seal shall extend from the roof to the tank shell and shall not be attached to the primary seal. 3. Tanks with Primary Resilient Toroid Seal: a. The primary resilient toroid seal shall be mounted on the perimeter of the roof such that it is in contact with the tank's liquid contents at all times while the roof is floating. b. No gap between the tank shell and the primary seal shall exceed 1/2 inch. The cumulative length of all primary seal gaps > 1/8 inch shall not exceed 5% of the tank circumference. No continuous gap > 1/8 inch shall exceed 10% of the tank circumference. c. No gap between the tank shell and the secondary seal shall exceed 1/2 inch. The cumulative length of all gaps between the tank shall and the secondary seal, > 1/8 inch shall not exceed 5% of the tank circumference. d. There shall be no holes, tears, or openings in the secondary seal or in the primary seal envelope that surrounds the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal. e. The secondary seal shall allow easy insertion of probes up to 1/2 inch in width in order to measure gaps in the primary seal. f. The secondary seal shall extend from the roof of the tank to the shell and not be attached to the primary

seal.

4. The following seal designs have been found to be equivalent to seals meeting the criteria set forth in Sections B.1 through B.3:

   a. When installed and maintained with zero gap:

Manufacturer	Model
Republic Fabricators	WeatherGuard Seal

5.3.2.4.2 When installed and maintained to meet the gap criteria for primary and secondary seals set forth in Sections B.1 through B.3:

Manufacturer	Model
"HMT"	Dual/Multi Blade Wiper Seals

Specifications for Internal Floating Roof Tanks

A. Internal floating roof tanks shall be equipped with seals that meet the criteria set forth for external floating roof tanks, except for complying with the requirement specified metallic-shoe type seals. For internal floating roof, the 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 18 inches above the stored liquid surface.

B. The following seal designs have been found to be equivalent to seals meeting the criteria set forth for external floating roof tanks:

1. When installed and maintained with zero gap:

Manufacturer	Model
Ultraflote	Single Ultraseal

2. When installed and maintained to meet the gap criteria for primary and secondary seals:

Manufacturer	Model
Ultraflote	Dual Ultraseal
Altech	Double Wiper Seal

C. The operator shall comply with the floating roof landing requirements

Floating Roof Deck Fitting Requirements

A. All openings in the roof used for sampling or gauging, shall provide a projection below the liquid surface to prevent belching of liquid and to prevent entrained or formed organic vapor from escaping from the liquid contents of the tank and shall be equipped with a cover, seal, or lid. The cover, seal, or lid shall at all times be in a closed position, with no visible gaps and leak-free, except when the device or appurtenance is in use for sampling or gauging.

B. Tanks shall meet the following requirements:

1. Requirements for Internal Floating Roof Deck Fittings

   a. Each opening in a non-contact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and rim space vents shall provide a projection below the liquid surface.

  b. Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, combination man way/vacuum breakers, and stub drains shall be equipped with a cover, or a lid shall be maintained in a closed position at all times (i.e., no visible gap) except when the device is in use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted in place except when they are in use.

  c. Automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the leg roof supports.

  d. Rim vents shall be equipped with a gasket and shall be set to open only when the internal floating roof is not floating or set to open at the manufacturer's recommended setting.

  e. Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The well shall have a slit fabric cover that covers at least 90% of the opening. The fabric cover must be impermeable.

  f. Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover. The fabric sleeve must be impermeable.

2. Requirements for External Floating Roof Deck Fittings

  a. Except for automatic bleeder vents, rim vents, and pressure vacuum relief vents, each opening in a non-contact external floating roof shall provide a projection below the liquid surface.

  b. Except for automatic bleeder vents and rim vents, roof drains, and leg sleeves, each opening in the roof shall be equipped with a gasketed cover, seal, or lid that shall be maintained in a closed position at all times (i.e., no visible gap) except when in actual use.

  c. Automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

  d. Rim vents shall be equipped with a gasket and shall be set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.

  e. Each emergency roof drain shall be provided with a slotted membrane fabric cover that covers at least 90% of the area of the opening. The fabric cover must be impermeable if the liquid is drained into the contents of the tanks.

  f. External floating roof legs shall be equipped with vapor socks or vapor barriers in order to maintain a leak-free condition so as to prevent VOC emissions from escaping through the roof leg opening.

3. Solid Guidepole: Solid sampling or gauging wells, and similar fixed projections through a floating roof such as an anti- rotational pipe, shall meet the following requirements:

  a. The well shall provide a projection below the liquid surface.

  b. The well shall be equipped with a pole wiper and a gasketed cover, seal or lid which shall be in a closed position at all times (i.e., no visible gap) except when the well is in use.

  c. The gap between the pole wiper and the guidepole shall be added to the gaps measured to determine compliance with the secondary seal requirement, and in no case shall exceed 1/2 inch.

4. Slotted Guidepole: Slotted sampling or gauging wells shall meet the following requirements:

  a. The well shall provide a projection below the liquid surface.

  b. The well on external floating roof shall be equipped with the following: a sliding cover, a well gasket, a pole sleeve, a pole wiper, and an internal float and float wiper designed to minimize the gap between the float and the well, and provided the gap shall not exceed 1/8 inch; or shall be equipped with a well gasket, a zero gap pole wiper seal and a pole sleeve that projects below the liquid surface.

  c. The gap between the pole wiper and the guidepole shall be added to the gaps measured to determine

	compliance with the secondary seal requirement, and in no case shall exceed 1/8 inch. **Specifications for Vapor Recovery Systems** A. Fixed roof tanks shall be fully enclosed and shall be maintained in a leak-free condition. An APCO-approved vapor recovery system shall consist of a closed system that collects all VOCs from the storage tank, and a VOC control device. The vapor recovery system shall be maintained in a leak-free condition. The VOC control device shall be one of the following: 1. A condensation or vapor return system that connects to one of the following: a gas processing plant, a field gas pipeline, a pipeline distributing Public Utility Commission quality gas for sale, an injection well for disposal of vapors as approved by the California Department of Conservation, Division of Oil Gas, and Geothermal Resources, or 2. A VOC control device that reduces the inlet VOC emissions by at least 95% by wt B. Any tank gauging or sampling device on a tank vented to the vapor recovery system shall be equipped with a leak-free cover which shall be closed at all times except during gauging or sampling. C. All piping, valves, and fittings shall be constructed and maintained in a leak-free condition.
Texas	**§115.112. Control Requirements.** A. For all persons in the Beaumont/Port Arthur, Dallas/Fort Worth, El Paso, and Houston/Galveston, the following requirements shall apply: 1. No person shall place, store, or hold in any stationary tank, reservoir, or other container any VOC unless such container is capable of maintaining working pressure sufficient at all times to prevent any vapor or gas loss to the atmosphere, or is equipped with at least the control device specified in Table I(a) for VOC other than crude oil and condensate, or Table II(a) for crude oil and condensate. 2. For floating roof storage tanks subject to the provisions this subsection, the following requirements shall apply: a. All openings in an internal or external floating roof except for automatic bleeder vents (vacuum breaker vents) and rim space vents must provide a projection below the liquid surface or be equipped with a cover, seal, or lid. Any cover, seal, or lid must be in a closed (i.e., no visible gap) position at all times except when the device is in actual use. b. Automatic bleeder vents (vacuum breaker vents) are to be closed at all times except when the roof is being floated off or landed on the roof leg supports. c. Rim vents, if provided, are to be set to open only when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting. d. Any roof drain that empties into the stored liquid shall be equipped with a slotted membrane fabric cover that covers at least 90% of the area of the opening. e. There shall be no visible holes, tears, or other openings in any seal or seal fabric.

Table I(a). REQUIRED CONTROL DEVICES FOR STORAGE TANKS FOR VOC OTHER THAN CRUDE OIL AND CONDENSATE

True Vapor Pressure of Compound at Storage Conditions	Nominal Storage Capacity	Emission Control Requirements
< 1.5 psia (10.3 kPa)	Any	None
≥ 1.5 psia (10.3 kPa) and < 11 psia (75.8 kPa)	≤ 1,000 gal	None
	> 1,000 gal and ≤ 25,000 gal	Submerged fill pipe or vapor recovery system
	> 25,000 gal and ≤ 40,000 gal	Internal or external floating roof (any type) or vapor recovery system
	> 40,000 gal	Internal floating roof or External floating roof with primary seal (any type) and secondary seal or vapor recovery system
≥ 11 psia (75.8 kPa)	≤ 1,000 gal	None
	> 1,000 gal and ≤ 25,000 gal	Submerged fill pipe or vapor recovery system
	> 25,000 gal	Submerged fill pipe and vapor recovery system

Table II(a). REQUIRED CONTROL DEVICES FOR STORAGE TANKS FOR CRUDE OIL AND CONDENSATE

True Vapor Pressure of Compound at Storage Conditions	Nominal Storage Capacity	Emission Control Requirements
< 1.5 psia (10.3 kPa)	Any	None
≥ 1.5 psia (10.3 kPa) and < 11 psia (75.8 kPa)	≤ 1,000 gal	None
	> 1,000 gal and ≤ 40,000 gal	Submerged fill pipe or vapor recovery system
	> 40,000 gal	Internal floating roof or External floating roof with primary seal (any type) and secondary seal or vapor recovery system
≥ 11 psia (75.8 kPa)	≤ 1,000 gal	None
	> 1,000 gal and ≤ 40,000 gal	Submerged fill pipe or vapor recovery system
	> 40,000 gal	Submerged fill pipe and vapor recovery system

Table I(b). REQUIRED CONTROL DEVICES FOR STORAGE TANKS FOR VOC OTHER THAN CRUDE OIL AND CONDENSATE

True Vapor Pressure of Compound at Storage Conditions	Nominal Storage Capacity	Emission Control Requirements
< 1.5 psia (10.3 kPa)	Any	None
≥ 1.5 psia (10.3 kPa) and < 11 psia (75.8 kPa)	≤ 1,000 gal	None
	> 1,000 gal and ≤ 25,000 gal	Submerged fill pipe or vapor recovery system
	> 25,000 gal	Internal or external floating roof (any type) or vapor recovery system
≥ 11 psia (75.8 kPa)	≤ 1,000 gal	None
	> 1,000 gal and ≤ 25,000 gal	Submerged fill pipe or vapor recovery system
	> 25,000 gal	Submerged fill pipe and vapor recovery system

f. For external floating roof storage tanks, secondary seals shall be the rim-mounted type (the seal shall be continuous from the floating roof to the tank wall). The accumulated area of gaps that exceed 1/8 inch in width between the secondary seal and tank wall shall be no greater than 1.0 in^2/ft of tank diameter.

3. Vapor recovery systems used as a control device on any stationary tank, reservoir, or other container shall maintain a minimum control efficiency of 90%.

B. For all persons in Gregg, Nueces, and Victoria Counties, the following requirements shall apply:

1. No person shall place, store, or hold in any stationary tank, reservoir, or other container any VOC, unless such container is capable of maintaining working pressure sufficient at all times to prevent any vapor or gas loss to the atmosphere, or is equipped with at least the control device specified in Table I(a) for VOC other than crude oil and condensate or Table II(a) for crude oil and condensate.

2. For floating roof storage tanks subject to the provisions of this subsection, the following requirements shall apply:

a. All openings in an internal or external floating roof, except for automatic bleeder vents (vacuum breaker vents) and rim space vents, must provide a projection below the liquid surface or be equipped with a cover, seal, or lid. Any cover, seal, or lid must be in a closed (i.e., no visible gap) position at all times, except when the device is in actual use.

b. Automatic bleeder vents (vacuum breaker vents) are to be closed at all times except when the roof is being floated off or landed on the roof leg supports.

c. Rim vents, if provided, are to be set to open only when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.

d. Any roof drain that empties into the stored liquid shall be equipped with a slotted membrane fabric cover that covers at least 90% of the area of the opening.

e. There shall be no visible holes, tears, or other openings in any seal or seal fabric.

f. For external floating roof storage tanks, secondary seals shall be the rim-mounted type (the seal shall be continuous from the floating roof to the tank wall). The accumulated area of gaps that exceed 1/8 inch in width between the secondary seal and tank wall shall be no greater than 1.0 in^2/ft of tank diameter.

	C. For all persons in Aransas, Bexar, Calhoun, Matagorda, San Patricio, and Travis Counties, the following requirements shall apply. 1. No person may place, store, or hold in any stationary tank, reservoir, or other container any VOC, other than crude oil or condensate, unless such container is capable of maintaining working pressure sufficient at all times to prevent any vapor or gas loss to the atmosphere, or is designed and equipped with at least the control device specified in Table I(b) for VOC other than crude oil and condensate. 2. For floating roof storage tanks subject to the provisions of paragraph (1) of this subsection, the following requirements shall apply: a. There shall be no visible holes, tears, or other openings in any seal or seal fabric. b. All tank gauging and sampling devices shall be vapor-tight except when gauging and sampling is taking place. 3. No person in Matagorda or San Patricio Counties shall place, store, or hold crude oil or condensate in any stationary tank, reservoir, or other container, unless such tank, reservoir, or other container is a pressure tank capable of maintaining working pressures sufficient at all times to prevent vapor or gas loss to the atmosphere or is equipped with one of the following vapor-loss control devices, properly maintained and operated: a. An internal floating cover or external floating roof. This control equipment shall not be permitted if the VOC has a true vapor pressure ≥ 11.0 psia (75.8 kPa). All tank-gauging and tank-sampling devices shall be vapor-tight, except when gauging or sampling is taking place; or b. A vapor recovery system.

7.4 AVAILABLE CONTROL TECHNOLOGIES

The main mechanisms of evaporative VOC losses from storage tanks at petroleum refineries are breathing loss, standing storage loss and working loss. Breathing losses are due to fluctuations in atmosphere temperature and pressure causing the organic liquid to volatilize. Standing storage losses are a result of evaporative losses through rim seals, deck fittings, and/or deck seams. Working losses are due to changes in the stored liquid levels caused by to filling and draining operations. Emissions from each of the types of tanks mention in Section 7.2 can vary. Emissions from fixed roof tanks are a result of breathing and standing storage losses, with emissions from external and internal floating roof tanks resulting from standing storage and working losses, and variable vapor space tanks result from working losses. Because tank emissions vary based on the tank's roof design and the mechanism of evaporative loss, controls for each of these types of tanks will be discussed separately below.

7.4.1 Controls for Fixed Roof Tanks

Several control techniques are available to limit emissions due to standing storage and working losses from fixed roof tanks. Control techniques include retrofitting the fixed tank to an internal floating roof tank and vapor balancing, as well as implementing a vapor recovery system or thermal oxidation system (discussed in Section 7.4.3).

7.4.1.1 Install an Internal Floating Roof and Seals

Installation of an internal floating roof with seals inside a fixed roof tank will result in emission reductions in standing evaporative losses. Depending on the type of roof and seals installed and liquid stored, control efficiencies of 60% to 99% can be achieved.

7.4.1.2 Vapor Balancing

Vapor balancing is a method of collecting the vapors that are displaced when a tank is filled liquid. This emission control technique is most common for filling tanks at gasoline stations. As the storage tank is filled, the expelled vapors are collected in the tanker truck and are then transported to a vapor recovery system or combustion device. If the collected vapors are subsequently controlled, control efficiencies of 90% to 98% can be achieved.

7.4.1 Floating Roof Tanks

Floating roof tanks experience most of their vapor losses through working losses and standing storage losses. In floating roof tanks, working losses occur when the floating roof is lowered, and residual liquid on the tank's inner walls evaporate. The standing storage losses originate from rim seals and deck seems and fittings, and are highly affected by wind. Options to reduce these vapor losses from floating roof tanks include installing weather shields and/or secondary seals.

7.4.1.3 Weather Shields

Weather conditions can be harsh on floating roof tank rims seals and cause deterioration of the fabric seal. Weather shields can provide protection to these rim seals, reducing the amount of VOCs released from standing storage losses.

7.4.1.4 Secondary Seals

Rim seals on floating roof tanks can consist of either a primary seal or a primary and secondary seal. Secondary seals can provide further protection from evaporative losses through the primary rim seal. For external floating roofs, secondary seals can either be shoe mounted or rim mounted. Rim mounted secondary seals cover the entire rim vapor space, while the shoe mounted secondary seal is held against the tank using a mechanical device. For internal floating roof tanks, the secondary seal is mounted to an extended vertical rim plate above the primary seal. Even though secondary seals can help reduce VOC emissions from floating roof tanks, a secondary seal can also limit the tank's operating capacity in order to prevent the seal from interfering with the fixed roof.

7.4.2 Vapor Recovery Systems

The function of vapor recovery systems is to collect VOC emissions from storage tanks that can be routed to a fuel gas system for combustion as fuel. Vapor recovery can be achieved either through condensation, carbon adsorption, or absorption. Depending on the procedure used, the design of the vapor recovery unit, and composition of the vapors recovered, control efficiencies vary between 90% and 98%. An alternative to vapor recovery is to destroy the vapors in a thermal oxidation system, where the air/vapor mixture is combusted in an incinerator, with the ability to reduce VOCs 95% to 99%.

7.4.2.1 Condensation

Condensation is performed by chilling or pressurizing VOC vapors to return them to their liquid state. This process is most effect with VOCs whose boiling points are above 40^{o}C (104^{o}F) and whose vapor concentrations are greater than 5000 ppm. Due to the nature of VOCs ability to combust, safety precautions must be implemented to prevent explosions.

7.4.2.2 Carbon Adsorption

Carbon adsorption, as discussed in Section 6.4.2, is a common emission control technique for waste gas streams contaminated with VOCs. The VOCs in the waste gas become physically bound to the activated carbon, effectively removing it from the air stream. In multi carbon bed systems, once the first carbon bed becomes saturated with VOCs that bed is taken off-line and regenerated and the next bed will adsorb any VOCs. The downside to activated carbon adsorption systems is that activated carbon is a flammable substance, thus fire suppression systems are needed in the recovery system, and/or the activated carbon in these systems has been replaced with a hydrophobic zeolite.

7.4.2.3 Absorption

In absorption systems, the contaminated air stream is contacted with a liquid solvent in an absorber tower, where VOCs are absorbed by the solvent. The absorber tower is designed to provide the necessary liquid-vapor contact area to facilitate mass transfer. Packed bed towers and mist scrubbing systems are two types of absorber towers that can remove 95% to 98% of the incoming VOCs from the waste gas stream. One advantage of absorber systems is its ability to handle fluctuations in incoming VOC concentrations, which can vary between 500 and 5000 ppm.

7.4.2.4 Incinerators

One of the most popular control devices for destroying collected VOCs is an incinerator, either thermal or catalytic. Thermal incinerators combust VOCs at temperatures between 1400^{o}F and 2000^{o}F for a required minimum residence time to oxidize 95 to 99% of the VOCs present in waste gas stream. They are most effective at reducing VOCs from waste gas streams with a VOC concentration between 100 and 2000 ppm. Catalytic oxidizers are similar to thermal oxidizers, however they use a catalyst in the presence of lower combustion temperatures, between 600^{o}F and 900^{o}F, to oxidize VOCs in the waste gas stream.

7.4.3 More Stringent Standards

The Bay Area Air Quality Management District (BAAQMD) in California is currently studying applicable control measures to further reduce VOC emissions from organic liquid storage tanks. Proposed changes to BAAQMD Regulation 8, Rule 5 include:

(1) Applying tank standards to storage tanks containing liquids with true vapor pressures less than or equal to 0.5 psia.
(2) Retrofit external floating roof tanks to internal floating roof tanks or domed external floating roof tanks
(3) Implement more stringent tank cleaning standards
(4) Vent vapor recovery systems to fuel gas systems
(5) Include a maintenance program

Of these proposed changes, only items (1), (3), and (5) have yet to be discussed, and are discussed in more detail below.

7.4.3.1 Vapor Pressure Criteria

Currently, BAAQMD's Regulation 8, Rule 5 does not address storage tanks containing liquids with true vapor pressures less than or equal to 0.5 psia. By applying the current tank standards to these tanks, VOC emissions would be reduced. Tanks storing low vapor pressure liquids inevitably generate fewer VOC emissions than tanks storing high vapor pressure liquids. For this reason, to implement control devices on storage tanks containing low vapor pressure emissions would not be cost effective.

7.4.3.2 Tank Cleaning

Current tank cleaning standards require that the insides of tanks be cleaned when either the accumulation of sludge inside the tank causes an unacceptable loss of tank capacity or when the sludge affects product quality. Given this guideline, most tanks are cleaned every 5 to 10 years, or prior to decommissioning. Tank cleaning first involves draining the tank, then removing any remaining product with a vacuum truck. After removing most of the liquid, the tank is degassed to lower the organic vapor concentration, and then the tank is ready to be cleaned. Under current standards, only tanks with storage capacities greater than 19,803 gallons are required to be degassed prior to tank cleaning and/or opening. Degassing is to be performed by liquid balancing (the opposite of vapor balancing) until the resulting liquid vapor pressure is less than 0.5 psia or by venting the tank to a control device with a 90% minimum control efficiency until the residual VOC concentration is less than 10,000 ppm. Under these regulations, the remaining 10,000 ppm of organics can be released to the atmosphere. Also under the current BAAQMD regulations, the control device must be tested annually, and tank sludge removal is not regulated.

More stringent tank cleaning/degassing standards proposed by the BAAQMD include:

- Lower the tank capacity (currently 19,803 gallons) which triggers required tank degassing
- Reduce the current 10,000 ppm residual organic standard to 5,000 ppm
- Increase the required minimum control efficiency of the control device from 90% to 95%
- Increase control device monitoring from an annual test to continuous real-time monitoring during venting
- Regulate the handling of sludge removal from tanks

7.4.3.3 Maintenance Programs

No provisions currently exist under Regulation 8 Rule 5 requiring a maintenance program for tanks. Implementation of such a program would result in more frequent inspections and repairs of tank roof seals, similar to standards implemented for equipment leaks.

7.5 COSTS AND AVAILABILITY

Feasible control technologies for storage tanks are summarized in Table 7-5. The table includes

- Pollutant controlled
- Name of technology
- Origin for the level of control (rule, consent decree, permit)
- Range of potential emission reductions from applying those controls
- Performance level in terms of outlet concentration or emission rate
- Cost effectiveness of the controls
- Commercial status
- Reference

More detailed information on each technology was summarized in the previous sections and based on the information contained in the references for this Section.

The cost data presented in the Table were obtained from the published literature as referenced. In general, the percent reductions and cost effectiveness data represent data for uncontrolled sources. Incremental reductions will be lower and costs will be higher for sources already have some level of control and will be required to meet the performance levels shown in the Table. Also, site-specific factors greatly influence the actual achievable performance level and control costs at a particular facility. These considerations must be addressed in State and local rulemaking and permitting processes.

7.6 REFERENCES

Elliot, J., 2004, “Draft Technical Assessment Document: Further Study Measure 10, Organic Liquid Storage Tanks,” Bay Area Air Quality Management District, San Francisco, California.

European Commission, Integrated Pollution Prevention & Control (ECIPPC), 2003, “Reference Document on Best Available Techniques for Mineral Oil and Gas Refineries.”

van den Braken, A.M., “VOC Treatment: Don’t Change an Environmental Problem into a Safety Problem,” Akzo Nobel Safety Research Department, Deventer, The Netherlands.

Table 7-5: Control Technology Summary for Storage Tanks

Pollutant	Technology	Origin of Requirement	Percent Reduction	Performance Level	Cost Data	Commercially Available?	Reference
VOC	Install internal floating roof in fixed roof tank	NSPS/ NESHAP/ State Rule	60 to 99	See applicable rule	Investment: $240,000 - $480,900 Operating: minor	Yes	ECIPPC, 2003
	Install domed fixed roof on a external floating roof tank	NSPS/ NESHAP/ State Rule	96	See applicable rule	Avg. cost: $21,640 – $240,500	Yes	ECIPPC, 2003
	Replace a vapor-mounted primary seal with a liquid-mounted primary seal	NSPS/ NESHAP/ State Rule	30 to 70 EFRT[1] 43 to 45 for IFRT[1]	See applicable rule	Avg. cost: $5,530 - $18,155	Yes	ECIPPC, 2003
	Install secondary seals on floating roof tanks	NSPS/ NESHAP/ State Rule	75 – 95%	See applicable rule	Investment: $60,000 - $120,000 Avg. cost: $4090 – $13,590	Yes	ECIPPC, 2003
	Vapor Balancing	NSPS/ NESHAP/ State Rule	80%	See applicable rule	Investment: $96,000/tank	Yes	ECIPPC, 2003
	Vapor Recovery Systems	NSPS/ NESHAP/ State Rule	80 – 99%	See applicable rule	Investment: $337,000 – $2,164,000 Operating: $60,000 – $144,300	Yes	ECIPPC, 2003
	Incineration	NSPS/ NESHAP/ State Rule	95 – 99%	See applicable rule	Investment: $2.4 - $30 million Operating: $24,100 - $1,320,000	Yes	ECIPPC, 2003
	Apply tank standards to tanks storing organic liquids with vapor pressures 0.1 – 0.5 psia		Varies		$20,500 - $34,000 per ton VOC reduced (potential reduction of 100 – 160 tons/yr)	Yes	Elliot, 2004

[1] EFRT = external floating roof tank; IFRT = internal floating roof tank

8.0 SULFUR RECOVERY UNITS

As discussed in the previous sections, SO_2 is released from petroleum refinery FCCUs, boilers/process heaters, and flares as a result of firing fuels containing sulfur compounds. These emission units comprise approximately 81% of the total SO_2 emissions from petroleum refineries, while emissions from sulfur recovery units (11%) and miscellaneous process equipment make up the remaining 19%. Typical sulfur recovery configurations at petroleum refineries entail the use of the Claus sulfur recovery process followed by a tail gas clean-up unit (TGCU) to maximize removal of H_2S. Several process modifications are available to increase sulfur recovery from this process, however, they result in increased emissions of CO_2 to the atmosphere.

8.1 PROCESS DESCRIPTION

Claus sulfur recovery units convert hydrogen sulfide (H_2S), a by-product of refining crude oils to elemental sulfur through multistage catalytic oxidation. Each catalytic stage can only recover half to two-thirds of the incoming sulfur, therefore multiple stages (usually two or three) consisting of a gas reheater, catalyst chamber, and condenser are used to achieve about 95 – 97% sulfur recovery. The Claus reaction proceeds in two exothermic steps. The first reaction occurs in the reactor furnace, where a portion of the H_2S reacts with air to form SO_2. The second reaction takes place in catalytic reactors where the remaining H_2S reacts with the SO_2 produced in the first reaction to form elemental sulfur and water. Side reactions also occur, producing carbonyl sulfide (COS) and carbon disulfide (CS_2). After the process stream passes through the final catalytic stage condenser, a tail gas treatment system is employed to recover any remaining sulfur. Figure 8-1 is a process flow diagram of the typical Claus sulfur recovery unit.

8.2 EMISSION INVENTORY

Table 8-1 identifies the sulfur recovery units in the MARAMA region, along with the capacity of each unit. Criteria pollutant emissions for each unit are shown for three years. The 2002 annual emissions serve as the baseline for future SIP development. The 2002 emissions were obtained from the 2002 inventories developed by MANEVU and VISTAS. The 2003 emissions were obtained directly from each state and represent the most currently quality assured data that is available. The 2009 emissions were obtained from the MANEVU and VISTAS projection inventories that were developed to support modeling for SIP development. The 2009 inventories include the effects of anticipated growth as well as any planned controls that will result in emission reductions between 2002 and 2009 due to new regulations or enforcement settlements.

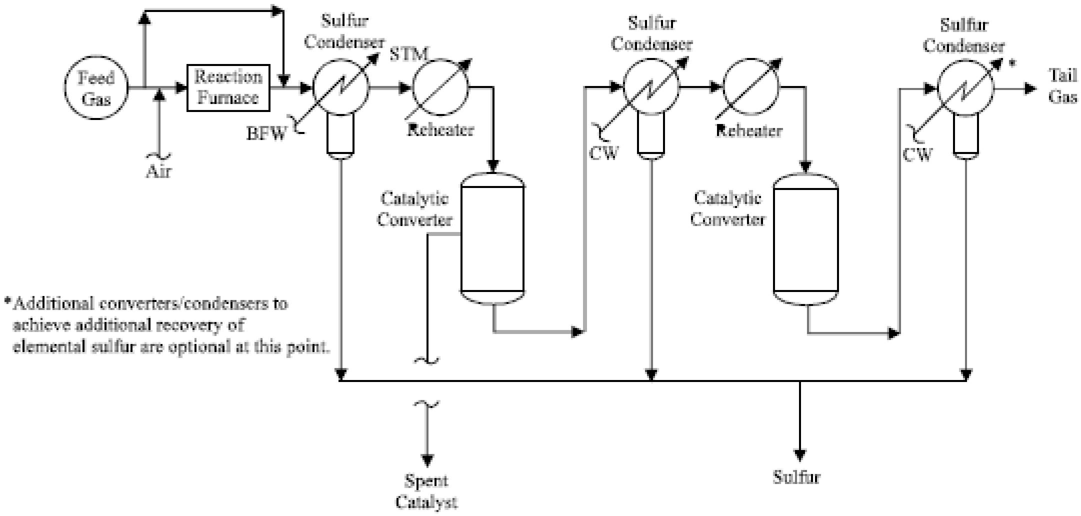


Figure 8-1. Typical Claus Sulfur Recovery Unit Process Flow Diagram

SOURCE: United States Environmental Protection Agency, 1995, "Sulfur Recovery," Pages 8.13-1 – 8.13-5 in AP-42, Fifth Edition: Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, http://www.epa.gov/ttn/chief/ap42/ch08/final/c08s13.pdf.

Table 8-1: Emission Inventory for Sulfur Recovery Units

State	Refinery/ Unit	Annual SO2 Emissions (tons/year) 2002	2003	2009
DE	Valero Delaware City			
	EUID = 010 Gasoline MEROX Plant	13.1	13.1	12.1
	EUID = 016 Alkylation MEROX Plant	113.9	113.9	105.4
	EUID = 017 Polymerization MEROX Plant	74.5	74.5	69.0
	EUID = 027 Sulfur Recovery Unit 1	20.9	58.5	19.3
	EUID = 028 Sulfur Recovery Unit 2	26.7	74.8	24.7
DE	SUNCO Inc Delaware			
	None Listed in Inventory	0.0	0.0	0.0
NJ	Sunoco Eagle Point			
	EUID = U48 SRU Thermal Oxidizer	12.9	22.6	14.7
NJ	Valero Paulsboro			
	EUID = U7 SRU Complex	0.1	0.1	0.1
	EUID = U56 SRU Thermal Oxidizer	18.0	12.0	23.9
NJ	Citgo Asphalt			
	None Listed in Inventory	0.0	0.0	0.0
NJ	Amerada Hess Port Reading			
	None Listed in Inventory	0.0	0.0	0.0
NJ	Chevron Products			
	None Listed in Inventory	0.0	0.0	0.0
NJ	ConocoPhillips Bayway			
	EUID = U5 Sulfur Recovery Units	142.0	0.1	0.1*
PA	Sunoco Marcus Hook			
	None listed in 2002/2003 inventory; installed in 2004 and located in Delaware	0.0	0.0	0.0
PA	ConocoPhillips Trainer			
	EUID = 102 Claus Sulfur Recov. Plt.	34.8	25.6	32.7
PA	American Refining Bradford			
	None Listed in Inventory	0.0	0.0	0.0
PA	Sunoco Philadelphia			
	EUID = 013 GP 532 SRU Incinerator	0.0	0.0	0.0
	EUID = 522 PB 867 Unit SRU	9.9	11.5	9.3
PA	United Refining			
	EUID = 108 Claus Sulfur Plant #2	12.0	12.0	13.7
VA	Giant Yorktown			
	EUID = 7 Gas Treat/Sulfur Recovery	676.7	1,609.3	24.7*
WV	Ergon West Virginia			
	EUID = 025 Sulferox Unit	0.0	0.0	0.0
	MARAMA Totals	**1,155.5**	**2,028.0**	**353.6**

* Bayway Claus units will be shut down and the refinery acid gas will be treated by the Spent Acid Regeneration Plant; Giant will have a new SRU and TGU.

8.3 EXISTING REQUIREMENTS

This section discusses the regulatory requirements which apply to sulfur recovery units. Four types of requirements are discussed: (1) Federal requirements such as the New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards; (2) State regulations for both the MARAMA states as well as other State agencies; (3) source-specific permit requirements; and (4) new requirements from recent enforcement settlements.

8.3.1 Federal Requirements

The U.S. EPA has promulgated standards for emissions of SO_2 from petroleum refinery Claus sulfur recovery units.

New Source Performance Standards (NSPS) for Claus sulfur recovery units constructed or modified after October 4, 1976 are covered under 40 CFR Part 60, Subpart J. This subpart applies to Claus sulfur recovery plants with capacities greater than 20 long tons per day at petroleum refineries. For units with an oxidation or reduction control system followed by incineration, SO2 emissions are limited to 250 ppmvd at 0% O_2. For units with a reduction control system not followed by incineration, emissions of reduced sulfur compounds are limited to 300 ppmvd at 0% O_2 and emissions of H_2S are limited to 10 ppmvd at 0% O_2, each calculated as SO_2. Monitoring requirements are also specified under this subpart, requiring instruments to continuously monitor and record the concentration of SO_2 emissions and O_2 levels for data correction.

The National Emission Standards for Hazardous Air Pollutants (NESHAP) for sulfur recovery units are covered in 40 CFR Part 63, Subpart UUU, which applies to petroleum refinery catalytic cracking units, catalytic reforming units, sulfur recovery units, and associated by-pass lines. Under the requirements of this subpart, new or existing Claus sulfur recovery units subject to NSPS requirements must comply with the emission limits set under NSPS. For new or existing units not subject to NSPS, units must comply with either the emission limits specified under NSPS or a total reduced sulfur (TRS) limit of 300 ppmvd at 0% O_2.

8.3.2 State Regulations

Table 8-2 lists the regulations for each of the MARAMA states for the control of SO_2 from sulfur recovery units. All regulatory agencies in the MARAMA region have regulations limiting the emissions of SO_2 except for Philadelphia. In Table 8-3, the regulations are listed for Louisiana, Texas, and California which tend to have stricter emission limitations than the MARAMA states and the federal government.

Table 8-2: Summary of MARAMA State Regulations

<table>
<tr><th>Agency</th><th>Emission Limitations</th></tr>
<tr><td>Delaware</td><td>
<p>Regulation No. 9, Section 3</p>
<p>3.1 No person shall cause or allow the emission of sulfur dioxide in the tail gases from existing sulfur recovery operations to exceed either a concentration of 2,000 parts per million by volume or a mass emission rate as specified in Table 2.</p>
<p>Table 2</p>
<p>Allowable Mass Emission Rate of Sulfur Dioxide from Sulfur Recovery Operations</p>
<table>
<tr><th>Production Rate
(tons/day)</th><th>Mass Emission Rate
(pounds/hr)</th></tr>
<tr><td>50</td><td>425</td></tr>
<tr><td>100</td><td>550</td></tr>
<tr><td>200</td><td>800</td></tr>
<tr><td>300</td><td>1050</td></tr>
<tr><td>400</td><td>1300</td></tr>
<tr><td>500</td><td>1550</td></tr>
<tr><td>600</td><td>1800</td></tr>
<tr><td>700</td><td>2050</td></tr>
<tr><td>800</td><td>2300</td></tr>
<tr><td>900</td><td>2550</td></tr>
<tr><td>1000</td><td>2880</td></tr>
</table>
<p>3.2 Except as provided in Section 11 of Regulation No. 20, NSPS, no person shall cause or allow the emission of sulfur dioxide in the tail gases from new sulfur recovery operations to exceed either a concentration of 2,000 parts per million by volume or a mass emission rate as specified in Table 2.</p>
</td></tr>
<tr><td>New Jersey</td><td>7:27-7.2. Sulfur recovery plants which are engaged in recovering elemental sulfur from hydrogen sulfide. For such plants the concentration of SO_2 in the gases being discharged from a stack or chimney shall not exceed 15,000 ppm by volume at standard conditions.</td></tr>
<tr><td>Pennsylvania</td><td>
<p>129.13.</p>
<p>(a) No person may permit the emission into the outdoor atmosphere, at any time, from a plant used for recovering elemental sulfur from gases containing sulfur compounds, of sulfur oxides, expressed as SO_2, in excess of the rate determined by the formula:</p>
<p>$A = 0.32E^{-.5}$</p>
<p>where: A = Allowable emissions in pounds of sulfur oxides per pound of sulfur compounds, expressed as S, in the feed gases, and E = Recovery plant rating in long tons of sulfur per day.</p>
<p>(b) Allowable emissions under this section are graphically indicated in Appendix A.</p>
</td></tr>
</table>

<table>
<tr><th>Agency</th><th>Emission Limitations</th></tr>
<tr><td>Virginia</td><td>Rule 4-22. No owner or other person shall cause or permit to be discharged into the atmosphere from any sulfur recovery operation any sulfur dioxide emissions in excess of a concentration of 8000 parts per million by volume and in excess of the mass emission rate specified in Table 4-22.

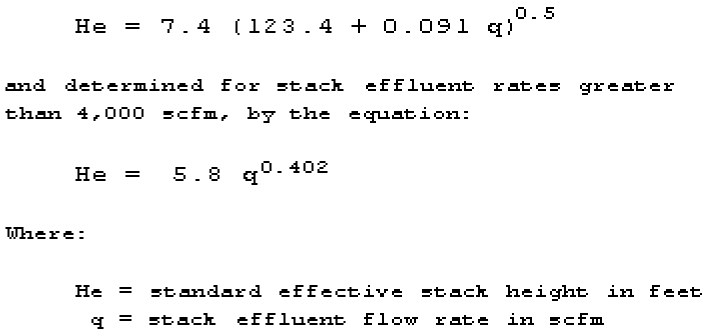
Table 4-22

Sulfur Maximum Allowable SO₂

<table>
<tr><th>Production Rate
(tons/day)</th><th>Mass Emission Rate
(lbs/hr)</th></tr>
<tr><td>≤ 50</td><td>415</td></tr>
<tr><td>100</td><td>830</td></tr>
<tr><td>200</td><td>1660</td></tr>
<tr><td>300</td><td>2490</td></tr>
<tr><td>400</td><td>3320</td></tr>
<tr><td>≥ 500</td><td>4150</td></tr>
</table>
</td></tr>
<tr><td>West Virginia</td><td>45-10-4, 4.1.b. No person shall cause, suffer, allow or permit the emission of sulfur oxides, calculated as sulfur dioxide, from a sulfur recovery plant to exceed 0.06 pounds per pound of sulfur processed.</td></tr>
</table>

Table 8-3: Summary of Other State Regulations

Agency	Emission Limitations
BAAQMD	**9-1-307** 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.
Louisiana	**Chapter 15, Rule 1503 B.** The emission of sulfur oxides calculated as sulfur dioxide from a new sulfur recovery plant that commences construction or modification after October 4, 1976, shall be limited to that specified in 40 CFR 60.104(a)(2), as incorporated by reference in LAC 33:III.Chapter 30. The emission of sulfur oxides calculated as sulfur dioxide from an existing plant shall be limited to a sulfur dioxide concentration of not more than 1,300 ppm by volume (three-hour average).
SCAQMD	Subject to the requirements of Amended Rule 1118 as discussed in Section 3.4.2.2 and summarized in Appendix B.
SJV APCD	**Rule 4801.** 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

Agency	**Emission Limitations**
	point of discharge: two-tenths (0.2) percent by volume calculated as sulfur dioxide (SO2), on a dry basis averaged over 15 consecutive minutes.
Texas	**Rule 112.7** **(a)** No person may cause, suffer, allow, or permit emissions of sulfur dioxide (SO_2) from any sulfur recovery plant to exceed the emission limits specified for stack effluent flow rates less than or equal to 4,000 standard cubic feet per minute (scfm) as determined by the equation: $E = 123.4 + 0.091\ q$ and the emission limits, specified for stack effluent flow rates in excess of 4,000 scfm, as determined by the equation: $E = 0.614\ q^{0.8042}$ Where: E = allowable emission rate in pounds per hour, and q = stack effluent flow rate in scfm **(b)** If a source has an effective stack height less than the standard effective stack height determined for stack effluent rates less than or equal to 4,000 scfm by the equation:  $He = 7.4\ (123.4 + 0.091\ q)^{0.5}$ and determined for stack effluent rates greater than 4,000 scfm, by the equation: $He = 5.8\ q^{0.402}$ Where: He = standard effective stack height in feet q = stack effluent flow rate in scfm then, the allowable emission limit in subsection (a) of this section must be reduced by multiplying it by the short-stack reduction factor.

8.3.3 Requirements from Recent Enforcement Settlements

The enforcement settlements for sulfur recovery units at petroleum refineries in the MARAMA region generally require compliance with NSPS Subpart J. Specific requirements are shown in Table 8-4.

Table 8-4: Summary of Recent Enforcement Settlements

State	Refinery	Required Control Technology
DE	Valero	Comply with NSPS Subparts A and J Route all sulfur pit emissions so that sulfur pit emissions either are eliminated or are included and monitored as part of the Sulfur Recovery Plant tail gas emissions
NJ	Sunoco Eagle Point	Comply with NSPS Subparts A and J by no later than December 31, 2006 Route all sulfur pit emissions so that sulfur pit emissions either are eliminated or are included and monitored as part of the Sulfur Recovery Plant tail gas emissions
NJ	Valero Refining	Comply with NSPS Subparts A and J By December 31, 2006, Valero shall replace the two existing Bevon-Stretford tail gas treatment units at the Paulsboro refinery with amine based tail gas treatment units.
NJ	ConocoPhillips Bayway	Comply with NSPS Subparts A and J Eliminate, control, and/or monitor sulfur pit emissions Conduct optimization study of the Claus trains and implement recommendations
PA	Sunoco Marcus Hook	Comply with NSPS Subparts A and J
PA	ConocoPhillips Trainer	Comply with NSPS Subparts A and J Eliminate, control, and/or monitor sulfur pit emissions
PA	Sunoco Philadelphia	Comply with NSPS Subparts A and J
VA	Giant Yorktown	Install a TGU or equivalent control technology to ensure continuous compliance with the NSPS emission standards by no later than the planned refinery turnaround in 2006
WV	Ergon Refining Newell	Nothing specified

8.4 AVAILABLE CONTROL TECHNOLOGIES

Sulfur recovery units mainly emit SO_2 and other sulfur containing compounds, in addition to CO_2 and small quantities of NOx. The two main strategies employed to limit sulfur emissions from these units include increasing the capacity of the Claus unit to recover more sulfur and improving the efficiency of the tail gas scrubber. These two strategies are discussed below, with several control options available to improve sulfur recovery and reduce SO_2 emissions.

8.4.1 Increase Claus Unit Capacity

The amount of sulfur recovered in a Claus unit varies based on the number of catalytic stages of the Claus unit, feed composition, stoichiometric balance of gaseous components at the inlet, operating temperature, and catalyst maintenance. The conversion of H_2S to elemental sulfur is limited by the equilibrium reaction of H_2S with SO_2, which only recovers 90 – 96% with a two-stage unit and 95 – 98% with a three-stage unit of the incoming sulfur. The NSPS regulations require limiting SO_2 emissions to 250 ppmv at 0% O_2, which is equivalent to 99.8 – 99.9% control level of reduce sulfur compounds. These higher sulfur recoveries can be achieved by expanding the capacity of the existing sulfur recovery unit through the methods discussed below.

8.4.1.1 Oxygen Enrichment

For many petroleum refineries, it is considered cost effective to increase the capacity of the sulfur recovery unit by applying oxygen enrichment. Varying levels of oxygen enrichment are available depending on the desired capacity increase. The low-level oxygen enrichment design can increase capacity 20 – 25% of the original design of the sulfur recovery unit, and is accomplished by injecting pure oxygen or oxygen-rich air into the combustion air upstream of the reaction furnace burner. The medium-level oxygen enrichment design can increase capacity up to 75% of the unit's original design, through direct injection of oxygen through separate nozzles into the furnace. This design calls for use of special burners designed to handle direct oxygen injection. The high-level oxygen enrichment design can increase capacity up to 150% of the unit's original design. This design requires modification or replacement of the thermal section of the sulfur recovery unit. Three technologies exist which incorporate high-level oxygen enrichment, the "SURE" Double Combustion process, the Lurgi process, and the COPE process. The "SURE" Double Combustion process divides the combustion air into two stages with intermediate cooling of the combustion product, the Lurgi process uses a multi-staged burner to maintain the furnace temperature low enough for about 60% oxygen enrichment, and the COPE process, developed by GAA/Air Products, recycles cooled acid gas from the first sulfur condenser to the furnace. Oxygen enrichment has several advantages including reducing the gas volume sent to the tail gas treatment system, keeping the combustion temperatures high, shortening the gas residence time requirements, ensuring complete destruction of undesired heavy hydrocarbons and ammonia, and reducing formation of the unwanted side products, COS and CS_2, from the Claus reaction.

8.4.1.2 Selectox Catalyst

Use of the selectox catalyst was designed for systems with low H_2S concentration acid gas streams (5 – 25 mole % H_2S), and can handle acid gas concentrations up to 50 – 60 mole % H_2S. The selectox catalyst is used in the first catalytic stage of the Claus sulfur recovery unit to promote selective oxidation of H_2S to SO_2 without the use of a flame. The selectox catalyst also promotes the reaction between H2S and SO_2 to form elemental sulfur, recovering between 90 and 97%. Overall recovery is affected by the H2S concentration in the feed and the specific sulfur recovery process in place. Higher recovery efficiencies can be achieved using a tail gas cleanup unit.

8.4.1.3 SUPERCLAUS®

The Superclaus sulfur recovery unit is similar to the Claus unit. It contains a thermal stage, followed by three to four catalytic reaction stages. The first two or three catalytic reactors use the Claus catalyst, while the last reactor uses a selective oxidation catalyst. The catalyst in the last reactor oxidizes the H2S to sulfur at a very high efficiency, recovering 99% of the incoming sulfur. The use of this catalyst doesn't allow the oxidation of H_2S to SO_2, as occurs in the Claus reaction. Using this process on rich H_2S feed gas results in high sulfur recovery and reductions of current SO_2 emissions by 50 – 90%.

8.4.2 Tail Gas Treatment

Emissions of SO_2 from sulfur recovery units can be reduced by treating the emissions from the Claus unit with a tail gas treatment unit. Several types of treatment processes have been developed that provide process variations to treat the specific conditions of the exhaust from the sulfur recovery unit. The expected sulfur recovery of using any of these tail gas treatment technologies is 98 – 99.99%.

8.4.2.1 SCOT Tailgas Unit

The Shell Claus Off-gas Treating (SCOT) unit is one of the most common tail gas treatment systems and uses a hydrotreating reactor followed by amine scrubbing to recover and recycle sulfur to the Claus unit. Tail gas from the Claus unit is contacted with hydrogen and reduced in a hydrotreating reactor to form H_2S and water in the presence of a cobalt/molybdenum on alumina catalyst. The gas is then cooled in a water contactor and enters an amine absorber where it is contacted with a MDEA or diisopropyl amine, generating a rich amine stream. The rich amine stream is then desorbed in a stripper, where a lean amine stream is generated and recycled to the absorber, while an H_2S gas stream is sent back to the Claus unit.

8.4.2.2 Sulfreen

The Sulfreen process is a catalytic tail gas process that extends the Claus reaction with the addition of two or three Sulfreen reactors at the end of the Claus unit. An activated alumina catalyst is used to remove additional sulfur. A regenerator is used to remove accumulated sulfur from the catalyst, achieving sulfur recoveries up to 99.0%. Variations on the Sulfreen process include the Maxisulf, HydroSulfreen, and DoxoSulfreen. The Maxisulf design incorporates a one-stage (includes only one absorber and one regenerator) Sulfreen unit with an open regeneration loop. Instead of recycling the regeneration gas, it is fed together with the Claus tail gas to the absorber. The Maxisulf can achieve sulfur recoveries up to 98.5%. The HydroSulfreen process includes an additional catalyst stage upstream of the Sulfreen unit. The additional stage uses an activated titanium oxide Claus catalyst to hydrolyze COS and CS_2 to increase sulfur recovery to 99.7%. The DoxoSulfreen process combines the HydroSulfreen process with a direct oxidation step. The goal of this process is to operate with an excess of H_2S in the system to convert all the SO_2 using the Sulfreen catalyst. The excess H_2S leaving the Sulfreen unit is then oxidized in the final stage, recovering 99.9% of the incoming sulfur. A similar Sulfreen process known as Cold Bed Absorption (CBA) uses hot process steam from the first Claus reactor to regenerate the catalyst and recover more sulfur. The CBA process recovers about 99 – 99.5% of the incoming sulfur. Figure 4-3 shows the typical configuration of these Sulfreen processes.

8.4.2.3 Beaven Process

The Beaven process uses a quinone solution to absorb the remaining H_2S contained in the exhaust gas from the Claus sulfur recovery unit. The absorbed H_2S is then oxidized to form a mixture of elemental sulfur and hydro-quinone. Air or oxygen is injected into this mixture to oxidize the hydro-quinone back to quinone. The remaining solution is then filtered to remove the sulfur, while the quinone is re-used. The Beaven process is can also eliminate SO_2, COS, and CS_2 in the exhaust by first converting the Claus reaction side-products into H_2S using a cobalt molybdate catalyst in the presence of high temperatures before processing the exhaust in the Beaven unit. Sulfur recoveries achieved using the Beaven process range from 99 to 99.9%.

8.4.2.4 Stretford Process

The Stretford Process (also referred to as the Beavon-Stretford Process) uses a hydrotreating reactor to first convert off-gas SO_2 to H_2S, and then contacts the H_2S with Stretford solution in a liquid-gas absorber. The Stretford solution contains a mixture of vanadium salt, anthraquinone disulfonic acid (ADA), sodium carbonate, and sodium hydroxide. The vanadium salt acts as a catalyst to react the H2S stepwise with the sodium carbonate and ADA to produce elemental sulfur. Oxygen is then added to the solution to regenerate the reactants. The solution is then sent to one or more froth/slurry tanks where the sulfur product is skimmed from the solution.

8.4.2.5 Clauspol

The Clauspol process treats the Claus unit's tail gas by first contacting the gas stream with a polyethylene glycol solvent, and then passing it over a dissolved catalyst of the sodium salt of an inorganic acid. The H_2S and SO_2 present in the tail gas are absorbed by the solvent and catalyst. Liquid sulfur is not soluble under these conditions and is separated from the mixture. This process is effective at recovering 99.5 – 99.9% of the incoming sulfur.

8.4.2.6 PROClaus

The Parsons RedOx Claus (PROClaus) unit is a dry catalytic process that proceeds in three steps, using the traditional first or second Claus stage followed by a selective reduction stage and a selective reduction stage. As in the traditional Claus process, the petroleum refinery's acid gas is fed to the Claus unit and mixed with air or oxygen which converts a portion of the inlet H_2S to SO_2. The remaining inlet H_2S is then reacted with the converted SO_2 to produce elemental sulfur. The gases are then processed in a second converter where the remaining SO_2 is reduced to elemental sulfur through a reaction with H_2 and CO in the presence of a highly selective SO_2 reduction catalyst developed by Lawrence Berkeley National Laboratory. This reaction is equivalent to the equilibrium reaction that takes place in a 2-stage Claus unit. After each converter, the process gases are cooled and elemental sulfur is removed before the gas phase is reheated. Finally, the gas enters a third converter where the remaining H_2S is oxidized to form elemental sulfur in the presence of a Parsons Hi-Activity selective oxidation catalyst. After this stage, the remaining elemental sulfur is recovered, and the tail gas is sent to a thermal oxidizer. An overall sulfur recovery of 99.5% is possible utilizing the 3-stage PROClaus unit as depicted in Figure 4-4.

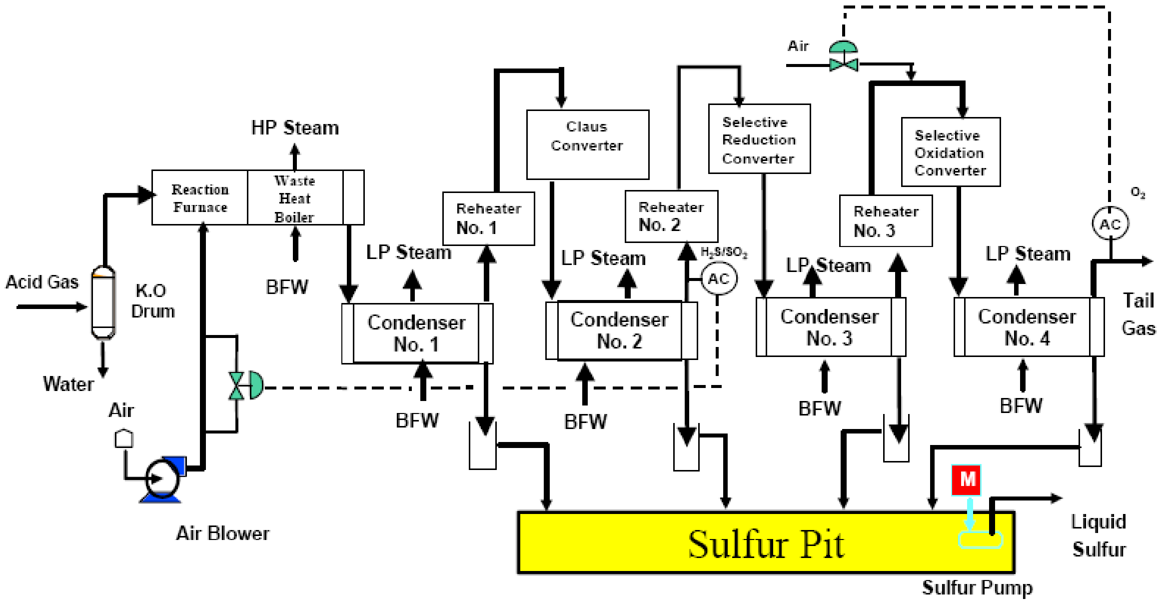


Figure 8-4. Diagram of a 3-stage PROClaus Process

SOURCE: Rameshni, M. and R. Street, 2001, "PROClaus: The New Standard for Claus Performance," Sulfur Recovery Symposium, Canmore, Alberta.

8.4.2.7 LO-CAT®

LO-CAT is a liquid redox tail gas treatment system capable of achieving sulfur recoveries of 99.9+% with or without the use of a hydrogenation/hydrolysis reactor. The direct LO-CAT tail gas method employs a proprietary Mobile Bed Absorber (MBA) where H_2S and SO_2 leaving the Claus system are absorbed into a circulating solution and the sulfide ions are converted to elemental sulfur in the presence of a chelated-iron catalyst. The solution leaving the MBA is then processed by an oxidizer where air is injected to regenerate the catalyst. Exhaust gas from the MBA is vented to the atmosphere with H2S concentrations below 10 ppm. The indirect LO-CAT tail gas method follows the same process steps as the direct method, however, the indirect method first passes the tail gas from the Claus system through a hydrogenation/hydrolysis catalytic reactor to convert all sulfur compounds to H_2S. Figures 4-5a and 4-5b depict the equipment layout for these two LO-CAT systems.

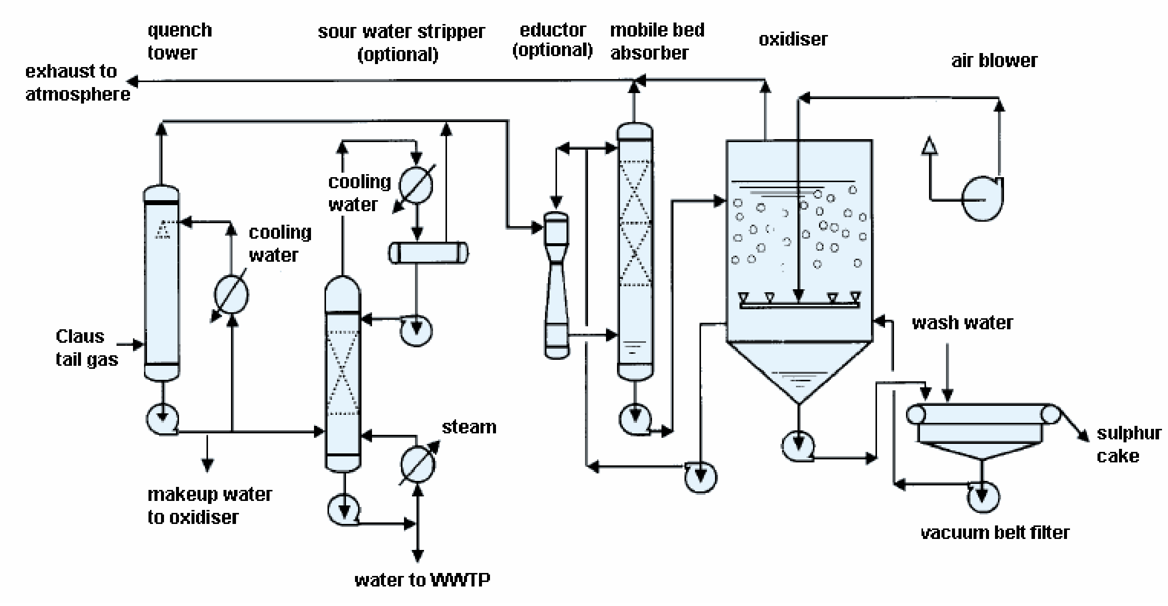


Figure 8-5a. Direct LO-CAT Tail Gas System

SOURCE: Nagl, G.J., 2001, "Liquid Redox Enhances Claus Process," Sulfur, Vol. May-June, No. 274.

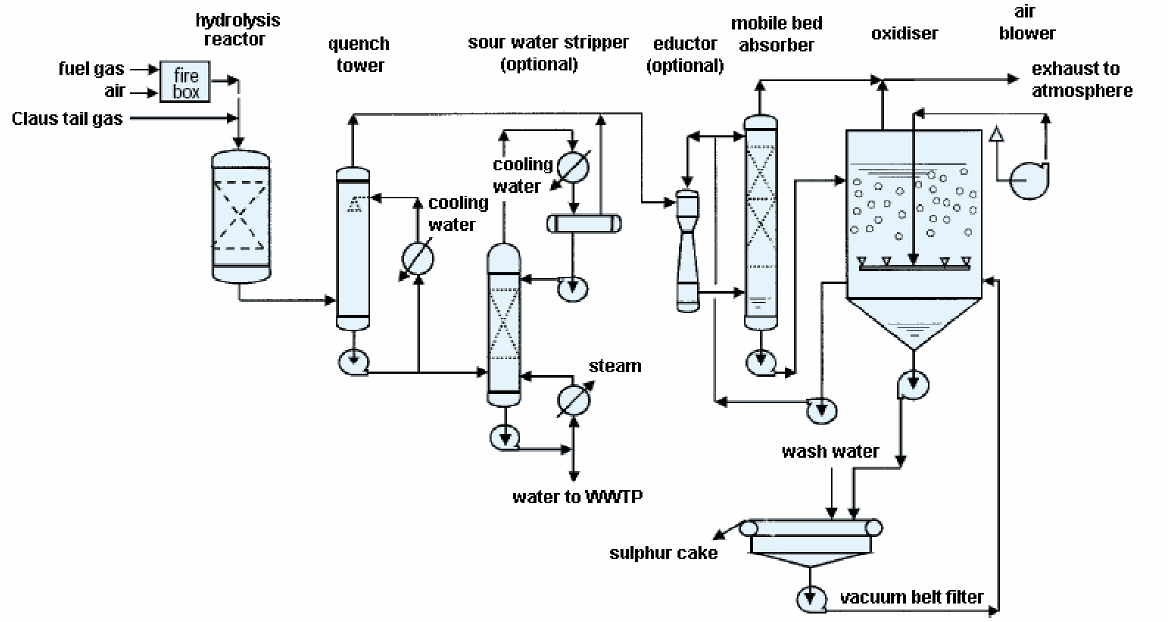


Figure 8-5b. Indirect LO-CAT Tail Gas System

SOURCE: Nagl, G.J., 2001, "Liquid Redox Enhances Claus Process," Sulfur, Vol. May-June, No. 274.

8.4.2.8 FLEXSORB®

A number of FLEXSORB solvents were developed by the ExxonMobil Research and Engineering Co. as alternatives to the traditional MDEA amine used in tail gas treatment units. These solvents were designed for a broad range of natural gas and refinery applications and are capable of being used in new or retrofit units, as well as to help in debottlenecking tail gas units. The family of FLEXSORB solvents includes the SE, SE Plus, SE hybrid, and the PS solvents. These solvents are designed to provide the following characteristics: the SE solvent is designed to provide high H_2S selectivity in the presence of CO_2, the SE Plus solvent improves H_2S selectivity by enhancing the solvent's ability to regenerate, the SE hybrid solvent is used for H_2S and organic sulfur removal, and the PS solvent is designed to remove all CO_2, H_2S and organic sulfur compounds from exhaust gases. The SE and SE Plus solvents are best for selective H_2S removal from refinery tail gas treatment systems. In one refinery application, replacing the MDEA solvent used in the tail gas treatment system of a US refinery with the SE Plus solvent allowed the refinery to discontinue use of the Stretford tail gas unit providing annual savings in operating and maintenance costs. Use of these solvents in the proper application can result in sulfur recoveries of 99.9+%.

8.4.2.9 Emission Free Claus Unit

Catalytic tail gas treatment systems are only good for sulfur recoveries up to 99.9%. To achieve recovery efficiencies greater than 99.9%, selective chemical absorption is necessary to remove any remaining H_2S and recycle it to the Claus feed gas. Lurgi Oel-Gas-Chemie (Lurgi) has designed a few of these systems, which increase sulfur recovery and reduce exhaust gas H_2S levels prior to incineration. One such design is an Emission-free sulfur recovery unit. This process first cools the process gases leaving the Claus unit which results in hydrolyzing sulfur compounds to H_2S and the precipitation of elemental sulfur. The gas stream goes through an absorber stage where the H_2S in the stream is reduced to less than 10 ppm, and then recycled to the combustion chamber, where it is oxidized. Since the H_2S is recycled and converted to other compounds within the system, the system is considered a flue gas-free process. Figure 4-5 gives the basic configuration of all equipment used in this process.

8.4.2.10 Tail Gas Scrubbers & Incinerators

Sulfur emissions from sulfur recovery units can be reduced by installing a scrubber or an incinerator at the end of the Claus unit. In general, there are two types of scrubbing processes: oxidation tail gas scrubbers and reduction tail gas scrubbers. The Wellman-Lord Scrubber is an oxidation tail gas scrubber. The scrubber uses a wet generative

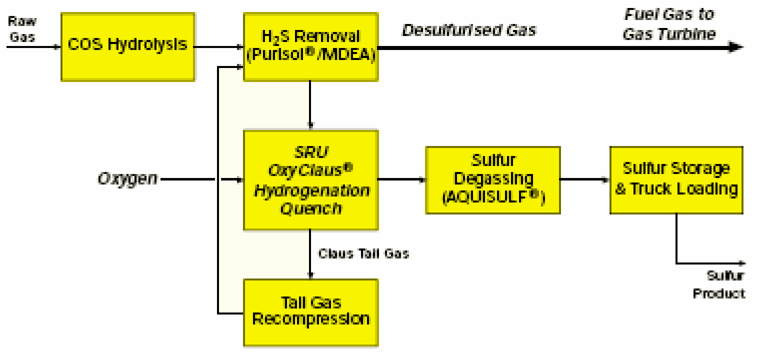


Figure 8-5. Lurgi Emission Free Sulfur Recovery Unit

SOURCE: Lurgi Oel-Gas-Chemie GmbH, "Lurgi Sulfur Management,"
www.lurgi.de/deutsch/nbsp/main/infomaterial/lurgi_sulfur_management.pdf

process to reduce SO_2 concentrations in the flue gas to levels below 250 ppmv. In the Wellman-Lord process, the tail gas is incinerated to oxidize all sulfur species to SO_2. The concentrated SO_2 stream is then reacted with a solution of sodium sulfite (Na_2SO_3) forming sodium bisulfite (Na_2HSO_3). The off-gas is vented to the atmosphere, while the sodium bisulfite still in solution is boiled in an evaporator-crystallizer, where sodium sulfite is crystallized and SO_2 is released with water. The crystallized sodium sulfite is reused in the scrubber while the SO_2 is recycled back to the Claus unit for further conversion to elemental sulfur.

In reduction tail gas scrubbers, sulfur in the tail gas is converted to H_2S by hydrogenation, and then the tail gas is cooled and sent to a scrubber to remove the H_2S. The removed H2S can be recycled back to the Claus unit for further sulfur removal. In addition to scrubbers, incinerators can be employed to destroy sulfur containing compounds, with the side-effect of emitting SO_2. In order to effectively reduce sulfur compounds, incinerators must operate at temperatures of 1,200°F or higher. Incinerator stacks should have proper monitoring in place to measure SO_2 emission levels.

8.5 COSTS AND AVAILABILITY

Numerous technologies are available for controlling sulfur emissions from sulfur recovery units at petroleum refineries. Table 8-5 summarizes the relevant information about these control techniques. More detailed information on each technology was summarized in the previous sections and based on the information contained in the references for this Section.

The cost data presented in the Table were obtained from the published literature as referenced. In general, the percent reductions and cost effectiveness data represent data for uncontrolled sources. Incremental reductions will be lower and costs will be higher for sources already have some level of control and will be required to meet the performance levels shown in the Table. Also, site-specific factors greatly influence the actual achievable performance level and control costs at a particular facility. These considerations must be addressed in State and local rulemaking and permitting processes.

Table 8-5: Control Technology Summary for Sulfur Recovery Units

Pollutant	Technology	Origin of Requirement	Percent Reduction	Performance Level	Cost Effectiveness ($/ton)	Commercially Available?	Reference
SO2	Various Technologies described in Section 8.4	Consent Decree/ NSPS/ NESHAP	97 to 99.9	NSPS: For units with an oxidation or reduction control system followed by incineration, SO2 emissions are limited to 250 ppmvd at 0% O_2. For units with a reduction control system not followed by incineration, emissions of reduced sulfur compounds are limited to 300 ppmvd at 0% O_2 and emissions of H_2S are limited to 10 ppmvd at 0% O_2, each calculated as SO_2. MACT: for units not subject to NSPS, emission limit specified under NSPS or a total reduced sulfur (TRS) limit of 300 ppmvd at 0% O_2	167 to 449	Yes	ECIPPC, 2003

8.6 REFERENCES

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APPENDIX A
METHODOLOGY FOR ESTIMATING EMISSION REDUCTIONS FROM CONSENT DECREES AND MODEL RULES

INTRODUCTION

Through its refinery initiative, EPA and the States have established Consent Decrees with most of the refineries in the MARAMA region to reduce their air pollution emissions. The Consent Decrees are expected to produce significant criteria pollutant emission reductions by 2009. States in the MARAMA region are also considering model rules to obtain further emission reductions in and around their nonattainment areas. This Appendix describes how the provisions of the Consent Decrees provisions were translated into refinery and unit-specific emission reductions for fluid catalytic cracking units, flares, and equipment leaks.

The general procedures for projecting emissions for refineries involved the application of growth factors (to account for changes in economic activity) and control factors (to account for emission reductions anticipated from the Consent Decrees and model rules). The procedures used are fully documented in *Draft Final Technical Support Document: Development of Emission Projections for 2009, 2012, and 2018 for NonEGU Point, Area, and Nonroad Sources in the MANE-VU Region*, December 7, 2006. These procedures were agreed to by the MARAMA states as part of the development of emission projections to support regional air quality modeling.

We started with the 2002 emission inventories developed by the MANEVU and VISTAS states. The base year of 2002 was chosen since that is the base year States are required by EPA to use in developing State Implementation Plans for attaining the 8-hour ozone standard. The 2002 inventories are based almost exclusively on data submitted by industry to fulfill their Emission Statement reporting obligations. We recognize that there are year-to-year variations in emissions (due to variations in capacity utilization, availability and costs of fuels, etc.). However, it was beyond the scope of this study to develop a “typical year” inventory to account for fluctuations in emissions from year to year. The MARAMA States may consider more recent inventories (2003-2006) during their rulemaking process.

We also recognize that, for some refinery processes, that there is considerable uncertainty in the baseline emission estimates. For example, the methods used to calculate flaring emissions are not consistent across the industry, resulting in a wide variations in the emissions reported at each refinery. Recent studies in Texas and California suggest the emissions from flaring activities at refineries may be significantly underestimated. Also, the various mass emission estimating methodologies for equipment leaks yield approximations that vary by an order of magnitude for the same components. The MARAMA States would like to work with industry to improve the emission estimates from flaring activities and equipment leaks as time permits.

The growth factors for refinery operations were developed using three sets of data:

- The U.S. EPA's Economic Growth and Analysis System Version 5.0 (EGAS 5.0);
- The DOE's Annual Energy Outlook 2005 (AEO2005) fuel consumption forecasts;
- State-supplied employment and other emission projection data.

The priority for applying these growth factors was to first use the state-supplied projection data (if available). If no state-supplied data are available, then we used the AEO2005 projection factors for fuel consumption sources. If data from these two sources were not available, we used the EGAS 5.0 default SCC configuration.

The EPA, as well as many states, uses the EGAS model to forecast emissions because it provides a consistent economic-based approach for develop growth factors for projecting emissions inventories. The EPA's EGAS model estimated about a 14 percent growth in activity at refineries, which was applied to estimate 1 14 percent growth in emissions at non-fuel burning sources. For fuel-burning sources, Table 24 of the AEO2005 provides the following forecasts for energy consumption in the refining industry:

Excerpts for AEO2005 Table 24: Refining Industry Energy Consumption

Parameter	**2002**	**2009**	**% Change**
Value of Shipments	163.66	195.71	19.6
Energy Consumption (trillion Btu)			
Still Gas	1399.4	1898.1	35.6
Oil	2008.7	2670.0	32.9
Natural Gas	807.8	862.8	6.8
Other	185.7	271.6	46.3
Total	3002.2	3804.4	26.7

The growth procedures were chosen to represent anticipated growth in the refining industry across a broad geographic area for regional air quality modeling purposes. As such, they were not intended to represent particular changes at a specific process at a specific refinery for permitting purposes. We recognize that the use of these growth factors may over predict emissions for a given refinery process since a particular process may be constrained by existing permit limits and would have to undergo NSR review to increase capacity. In cases where existing permit limits constrained emissions at large sources; we attempted to take into account those constraints. However, it was not feasible (given time and resource constraints) to account for permit limits at each of the thousands of emission points at the refineries being studied.

Next, we reviewed the Consent Decrees and coordinated with State and local agencies to develop estimates of future year emission reduction based upon the settlements and recent permits that implement the provisions of those settlements. We focused on the controls that are likely to be in place by 2009 since that is the SIP attainment planning year. The controls factors for 2009 were derived either from data supplied that the State/local agencies or from MACTEC's analysis of the requirements contained in the global enforcement settlements. The specific timing and extent of emission reductions resulting from the Consent Decrees are evolving over time as the specific implementation requirements and schedules are being developed. Thus, there remains some uncertainty regarding the time and extent of emission reductions associated with the Consent Decrees.

FLUID CATALYTIC CRACKING UNITS

For FCCUs/FCUs, the control requirements generally require the installation of wet gas scrubbers for SO2 control. Some of the units have already been permitted to include the control requirements. In those cases, specific emission limits for SO2 have already been established and were used as the best estimate of emission in 2009. In cases where specific emission limitation have not yet been specified in permits, a 90 percent SO2 control efficiency was assumed as a conservative estimate of the SO2 reductions from the installation of a wet gas scrubber. For units not affected by a Consent Decree, MACTEC assumed that the Model Rule would require a wet gas scrubber (or equivalent) that would result in a 90 percent reduction of SO2 emissions. Table A-1 shows the unit-by-unit emission reductions anticipated after implementation of the Consent Decrees and Model Rule.

For NOx control, the Consent Decrees require selective catalytic reduction (SCR), selective non-catalytic reduction (SCNR), or optimization studies to reduce NOx emissions. Some of the units have already been permitted to include the control requirements. In those cases, specific emission limits for NOx have already been established and were used as the best estimate of emission in 2009. In cases where specific emission limitation have not yet been specified in permits, a 90 percent NOx control efficiency was assumed for SCR, and a 60 percent reduction was assumed from the installation of SNCR. For units not affected by a Consent Decree, MACTEC assumed that the Model Rule would require SNCR-type controls, and the emission reduction was conservatively estimated to 60 percent. Table A-2 shows the unit-by-unit emission reductions anticipated after implementation of the Consent Decrees and Model Rule.

For PM control, reductions from the model rule were calculated by comparing the unit's permitted emission limitation (in lbs/1000 lbs coke burned) or limitation contained in the Consent Decree to the model rule emission limitation (0.5 lbs/1000 lbs coke burned). If the unit's current limit is at or below 0.5 lbs/1000 lbs coke burned, no additional emission reductions were assumed. Table A-3 shows the unit-by-unit emission reductions anticipated after implementation of the Consent Decrees and Model Rule.

For CO control, reductions from the model rule were calculated by comparing the unit's emission limitation (in ppm) to the model rule emission limitation (200 ppm hourly average). If the unit's current limit is below 200 ppm, no additional emission reductions were assumed. Table A-4 shows the unit-by-unit emission reductions anticipated after implementation of the Consent Decrees and Model Rule.

Table A-1 Emission Reductions from Consent Decrees and Model Rules: SO2 Emissions from Catalytic Cracking Units

		SO2 Emissions (tons/year)				
State	**Refinery**	**2002**	**2009 with CDs**	**2009 With Model Rules**	**Model Rule Reductions**	**Emission Calculation Assumptions**
DE	Premcor FCCU	11,421	361	361	0	Permit APC-81/0981 limit with Wet Gas Scrubber
DE	Premcor FCU	19,461	174	174	0	Permit APC-81/0829 limit with Wet Gas Scrubber
NJ	Sunoco Eagle Point	91	5	5	0	CD specifies Wet Gas Scrubber Upgrade; assume 90% reduction
NJ	Valero	3,597	172	172	0	Permitted emission limit after installation of BELCO scrubber
NJ	Amerada Hess	71	81	8	73	Not affected by a CD; assume 90% reduction from Wet Gas Scrubber
NJ	ConocoPhillips/Bayway	65	75	75	0	Existing Wet Gas Scrubber in 2002; no additional reductions
PA	Sunoco Marcus Hook	4,374	824	824	0	CD specifies Wet Gas Scrubber; assume 80% reduction
PA	ConocoPhillips Trainer	2,063	166	166	0	CD specifies Wet Gas Scrubber; new permit limit is 165.8 tons per year
PA	Sunoco Phila. GP 1232	2,378	363	363	0	Permit limit with Wet Gas Scrubber required by CD
PA	Sunoco Phila. PB 868	475	600	120	480	Not affected by CD, assume 80 percent reduction from Wet Gas Scrubber
PA	United Refining	1,091	1,245	125	1,121	Not affected by a CD; assume 90% reduction from Wet Gas Scrubber
VA	Giant Yorktown	477	106	106	0	CD specifies Wet Gas Scrubber; assume 80% reduction
	MARAMA Region	**47,566**	**4,172**	**2,499**	**1,673**	

Table A-2 Emission Reductions from Consent Decrees and Model Rules: NOx Emissions from Catalytic Cracking Units

		NOx Emissions (tons/year)				
State	**Refinery**	**2002**	**2009 with CDs**	**2009 With Model Rules**	**Model Rule Reductions**	**Emission Calculation Assumptions**
DE	Premcor FCCU	739	411	411	0	2009 emissions estimated by DNREC
DE	Premcor FCU	624	690	690	0	Permit APC-81/0829 limit based on Consent Decree
NJ	Sunoco Eagle Point	103	47	47	0	CD specifies NOx study; assume 60% control
NJ	Valero	106	121	121	0	CD requires optimization study of existing control system; no additional reductions assumed
NJ	Amerada Hess	359	409	164	245	Not affected by a CD; assume 60% reduction from SNCR-type controls
NJ	ConocoPhillips/Bayway	1,036	475	475	0	CD specifies enhanced SNCR; assume 60% control;
PA	Sunoco Marcus Hook	1,489	184	184	0	CD specifies SCR; assume 90% control
PA	ConocoPhillips Trainer	537	245	245	0	CD specifies enhanced SNCR; assume 60% control;
PA	Sunoco Phila. GP 1232	356	208	208	0	Permit limit with SCR required by CD
PA	Sunoco Phila. PB 868	182	482	193	289	Not affected by CD; assume 60% reduction from NOx control
PA	United Refining	29	33	13	20	Not affected by a CD; assume 60% reduction from SNCR-type controls
VA	Giant Yorktown	210	233	93	140	Nothing specified in CD; assume 60% reduction from SNCR-type controls
	MARAMA Region	**5,770**	**3,538**	**2,844**	**694**	

Table A-3 Emission Reductions from Consent Decrees and Model Rules: PM Emissions from Catalytic Cracking Units

		PM Emissions (tons/year)				
State	**Refinery**	**2002x**	**2009 with CDs**	**2009 With Model Rules**	**Model Rule Reductions**	**Emission Calculation Assumptions**
DE	Premcor FCCU	765	390	390	0	No limit specified in permit; no reductions assumed
DE	Premcor FCU	496	334	167	167	Current limit is 1 lb/1000 lbs coke; model rule limit is 0.5 lbs/1000 coke; assume 50% reduction from model rule
NJ	Sunoco Eagle Point	69	35	35	0	CD required 0.5 lbs/1000 lbs coke; assume 50 % reduction from CD
NJ	Valero	71	82	82	0	No limit specified in permit; no reductions assumed
NJ	Amerada Hess	44	50	50	0	No limit specified in permit; no reductions assumed
NJ	ConocoPhillips/Bayway	128	128	128	0	Existing permit limit is equivalent to 0.5 lbs/1000 lbs coke
PA	Sunoco Marcus Hook	209	105	105	0	CD required 0.5 lbs/1000 lbs coke; assume 50 % reduction from CD
PA	ConocoPhillips Trainer	113	93	93	0	Permit limit
PA	Sunoco Phila. GP 1232	42	170	170	0	Permit limit, CD required 0.5 lbs/1000 lbs coke
PA	Sunoco Phila. PB 868	70	95	48	47	Not affected by CD; current limit is 1 lb/1000 lbs coke; model rule limit is 0.5 lbs/1000 lbs coke; assume 50% reduction from model rule
PA	United Refining	43	49	25	25	Current limit is 1 lb/1000 lbs coke; model rule limit is 0.5 lbs/1000 lbs coke; assume 50% reduction from model rule
VA	Giant Yorktown	428	53	26.5	26.5	Current limit is 1 lb/1000 lbs coke; model rule limit is 0.5 lbs/1000 lbs coke; assume 50% reduction from model rule
	MARAMA Region	**2478**	**1548**	**1283.5**	**265.5**	

This table shows reductions of total suspended particulate emissions; reductions in PM2.5 are not available.

Table A-4 Emission Reductions from Consent Decrees and Model Rules: CO Emissions from Catalytic Cracking Units

		CO Emissions (tons/year)				
State	**Refinery**	**2002**	**2009 with CDs**	**2009 With Model Rules**	**Model Rule Reductions**	**Emission Calculation Assumptions**
DE	Premcor FCCU	1,524	1,640	656	984	No ppm limit specified in permit; assume 60% reduction
DE	Premcor FCU	1,209	1,291	516	775	Current limit is 500 ppm; model rule limit is 200 ppm; assume 60% reduction
NJ	Sunoco Eagle Point	83	95	95	0	Current limit is 127 ppm; no additional reductions since current limit is lower than Model Rule limit
NJ	Valero	53	61	61	0	Current limit is 50 ppm; no additional reductions since current limit is lower than Model Rule limit
NJ	Amerada Hess	130	148	99	49	Current limit is 300 ppm; model rule limit is 200 ppm; assume 33% reduction
NJ	ConocoPhillips/Bayway	99	113	113	0	Current limit is 200 ppm; no additional reductions since current limit is lower than Model Rule limit
PA	Sunoco Marcus Hook	514	484	194	290	Current limit is 500 ppm; model rule limit is 200 ppm; assume 60% reduction
PA	ConocoPhillips Trainer	60	69	28	41	Current limit is 500 ppm; model rule limit is 200 ppm; assume 60% reduction
PA	Sunoco Phila. GP 1232	514	634	254	380	Current limit is 500 ppm (1-hr avg) 100 ppmvd (365-day rolling avg.); model rule limit is 200 ppm; assume 60% reduction
PA	Sunoco Phila. PB 868	52	100	40	60	Current limit is 500 ppm (1-hr avg) 100 ppmvd (365-day rolling avg.); model rule limit is 200 ppm; assume 60% reduction
PA	United Refining	43	49	20	29	Current limit is 500 ppm; model rule limit is 200 ppm; assume 60% reduction
VA	Giant Yorktown	140	140	56	84	Current limit is 500 ppm; model rule limit is 200 ppm; assume 60% reduction
	MARAMA Region	**4,421**	**4,824**	**2,130**	**2,694**	

EQUIPMENT LEAKS

Substantial emission reductions are achievable by enhanced LDAR programs (e.g., reducing the defined leak concentration, increasing the monitoring frequency, other requirements). Our best estimate is a 50% reduction in VOC emissions as a result of implementing enhanced LDAR programs similar to those required in the recent Consent Decrees and the MARAMA model rule.

Several of the refineries in the MARAMA region already have leak definitions that are more stringent than the NSPS for some process units. Thus, the emission reductions expected from lower leak definitions will vary by refinery due to the differences in the current leak definitions. Resource constraints did not allow us to make emission reduction estimates on a process unit by process unit basis. We recommend that State's further evaluate the refinery-specific baseline emissions, leak definitions, and potential emission reductions from lowering the leak definitions.

It should be noted that both the baseline VOC emissions from equipment leaks, as well as the estimated emission reductions, are highly uncertain. On-going research and field studies suggest that VOC emissions could be much higher than currently estimated. The MARAMA States should monitor on-going and imminent national and state studies to better quantify baseline emissions and potential emission reductions.

FLARES

The MARAMA model rule contains similar requirements to the recently amended SCAQMD Rule 1118. In the "Final Environmental Assessment for Proposed Amended Rule 1118", SCAQMD estimated a 53% reduction in all vent gases, and the concurrent combustions emissions (e.g., NOx, VOC, CO, and PM10) will also be reduced by 53%. A similar reduction in SO2 emissions is anticipated. Since the MARAMA model rule is similar to SCAQMD Rule 1118, similar reductions would be expected from implementation of the MARAMA model rule.

It should be noted that both the baseline emissions from flares, as well as the estimated emission reductions, are highly uncertain. On-going research and field studies suggest that emissions could be much higher than currently estimated. The MARAMA States should monitor on-going and imminent national and state studies to better quantify baseline emissions and potential emission reductions.

Table A-5 Emission Reductions from Consent Decrees and Model Rules: VOC Emissions from Equipment Leaks

State	**Refinery**	**VOC Emissions (tons/year)**				**Emission Calculation Assumptions**
		2002	**2009 with CDs**	**2009 With Model Rules**	**Model Rule Reductions**	
DE	Premcor	64	32	32	0	Enhanced LDAR in CD; assume 50% control
NJ	Sunoco Eagle Point	42	21	21	0	Enhanced LDAR in CD; assume 50% control
NJ	Valero	66	33	33	0	Enhanced LDAR in CD; assume 50% control
NJ	CITGO Asphalt	10	5	5	0	Enhanced LDAR in CD; assume 50% control
NJ	Amerada Hess	14	14	7	7	No CD; assume Model Rule's enhanced LDAR requirements achieve a 50% reduction
NJ	Chevron	9.5	9.5	4.7	4.8	No CD; assume Model Rule's enhanced LDAR requirements achieve a 50% reduction
NJ	ConocoPhillips/Bayway	233	117	117	0	Enhanced LDAR in CD; assume 50% control
PA	Sunoco Marcus Hook	130	65	65	0	Enhanced LDAR in CD; assume 50% control
PA	ConocoPhillips Trainer	63	32	32	0	Enhanced LDAR in CD; assume 50% control
PA	American Refining	130	130	65	65	No CD; assume Model Rule's enhanced LDAR requirements achieve a 50% reduction
PA	Sunoco Philadelphia	176	88	88	0	Enhanced LDAR in CD; assume 50% control
PA	United Refining	167	167	84	84	No CD; assume Model Rule's enhanced LDAR requirements achieve a 50% reduction
VA	Giant Yorktown	310	155	155	0	Enhanced LDAR in CD; assume 50% control
WV	Ergon Newell	45	23	23	0	Enhanced LDAR in CD; assume 50% control
	MARAMA Region	**1,459**	**889**	**729**	**160**	

ConocoPhillips Bayway initially estimated a VOC emissions of 1,629 tons/year from equipment leaks using the "leak/no leak" method and AP-42 emission factors consistent with the federal leak definition of 10,000 ppm. Emissions were recalculated using actual leak data and EPA correlation equations LeakDas software, resulting in a downward revision to 233 tons/year.

Table A-6 Emission Reductions from Consent Decrees and Model Rules: SO2 Emissions from Flares

		SO2 Emissions (tons/year)				
State	**Refinery**	**2002**	**2009 with CDs**	**2009 With Model Rules**	**Model Rule Reductions**	**Emission Calculation Assumptions**
DE	Premcor	238	238	112	126	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	Sunoco Eagle Point	21	21	10	11	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	Valero	82	82	38	43	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	CITGO Asphalt	0	0	0	0	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	Amerada Hess	1	1	1	1	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	Chevron	7	7	3	4	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	ConocoPhillips/Bayway	222	222	104	118	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
PA	Sunoco Marcus Hook	10	10	5	5	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
PA	ConocoPhillips Trainer	15	15	7	8	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
PA	American Refining	21	21	10	11	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
PA	Sunoco Philadelphia	33	33	15	17	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
PA	United Refining	1	1	0	0	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
VA	Giant Yorktown	984	2	2	2	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
WV	Ergon Newell	85	85	40	45	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
	MARAMA Region	**1,719**	**737**	**347**	**391**	

Table A-7 Emission Reductions from Consent Decrees and Model Rules: NOx Emissions from Flares

		NOx Emissions (tons/year)				
State	**Refinery**	**2002**	**2009 with CDs**	**2009 With Model Rules**	**Model Rule Reductions**	**Emission Calculation Assumptions**
DE	Premcor	25	25	12	13	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	Sunoco Eagle Point	78	78	37	42	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	Valero	40	40	19	21	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	CITGO Asphalt	1	1	0	0	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	Amerada Hess	2	2	1	1	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	Chevron	0	0	0	0	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	ConocoPhillips/Bayway	12	12	6	7	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
PA	Sunoco Marcus Hook	2	2	1	1	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
PA	ConocoPhillips Trainer	44	44	20	23	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
PA	American Refining	15	15	7	8	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
PA	Sunoco Philadelphia	11	11	5	6	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
PA	United Refining	13	13	6	7	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
VA	Giant Yorktown	1,043	24	11	11	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
WV	Ergon Newell	60	60	28	32	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
	MARAMA Region	**1,345**	**326**	**153**	**173**	

Table A-8 Emission Reductions from Consent Decrees and Model Rules: VOC Emissions from Flares

		VOC Emissions (tons/year)				
State	**Refinery**	**2002**	**2009 with CDs**	**2009 With Model Rules**	**Model Rule Reductions**	**Emission Calculation Assumptions**
DE	Premcor	7	7	3	4	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	Sunoco Eagle Point	484	484	228	257	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	Valero	0	0	0	0	
NJ	CITGO Asphalt	0	0	0	0	
NJ	Amerada Hess	4	4	2	2	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	Chevron	1	1	0	0	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
NJ	ConocoPhillips/Bayway	25	25	12	13	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
PA	Sunoco Marcus Hook	4	4	2	2	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
PA	ConocoPhillips Trainer	90	90	42	48	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
PA	American Refining	1	1	1	1	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
PA	Sunoco Philadelphia	35	35	17	19	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
PA	United Refining	12	12	5	6	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
VA	Giant Yorktown	50	50	23	26	SCAQMD estimated 53% reduction in vent gases from recent Rule 1118 amendments; similar reductions for MARAMA model rule
WV	Ergon Newell	0	0	0	0	
	MARAMA Region	**713**	**713**	**335**	**378**	