

**OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION**

MEMORANDUM

August 28, 2003

TO: Dawson Lasseter, P.E., Chief Engineer, Air Quality Division

THROUGH: Phillip Fielder, P.E., Engineer Manager, Engineering Section
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THROUGH: Peer Review

FROM: Eric L. Milligan, P.E., Engineering Section

SUBJECT: Evaluation of Construction Permit Application No. **98-172-C (M-11) (PSD)**
Valero Energy Corporation
TPI Petroleum, Inc.
Valero Ardmore Refinery – 130 Long Ton per Day (LTPD) Sulfur Recovery Unit (SRU), 200 LTPD Tail Gas Treating Unit (TGTU), & 200 LTPD Amine Recovery Unit (ARU)
Ardmore, Carter County
Directions from I-35: east three miles on Highway 142

SECTION I. INTRODUCTION

TPI Petroleum, Incorporated (TPI), a company of Valero, currently operates the Valero Ardmore Refinery located in Carter County, Oklahoma. This Prevention of Significant Deterioration (PSD) construction permit addresses the proposed construction and installation of a 130 long ton per day (LTPD) new sulfur recovery unit, a 200 LTPD tail-gas treating unit, and a 200 LTPD amine regeneration unit to operate in addition to the existing sources at the refinery. Several changes to the existing refinery operations are also proposed. The proposed construction includes:

1. Installation of a 130 LTPD sulfur recovery unit (SRU) and associated vessels;
2. Installation of a 40.4 MMBTUH incinerator and a 20.0 MMBTUH hot oil heater;
3. Installation of a 200 LTPD amine regeneration unit (ARU) and associated vessels;
4. Installation of a 200 LTPD tail-gas treating unit (TGTU) and associated vessels;
5. Installation of one cat-feed hydrotreater (CFHT) reactor;
6. Installation of two naphtha hydrotreater (NHT) reactors;
7. Installation of a 1,000 barrels (bbl) regenerated amine storage tank;
8. Installation of a 3,300 bbl molten sulfur storage tank; and
9. Installation of new piping peripheral equipment.

The new equipment and units will operate in addition to the refinery's existing source operations and limitations. Permit No. 98-172-C (PSD) established throughput limitations for most processes at the facility and this project will not increase the facility's processing limits. All other contemporaneous changes and associated emissions from the hydrogen plant heater were incorporated into or were covered under Permit No. 98-172-C (PSD).

SECTION II. PROCESS DESCRIPTIONS

The Valero Ardmore Refinery's primary standard industrial classification (SIC) code is 2911. The refinery processes medium and sour crude oils from both the domestic and foreign markets. Major production and processing units include the following: an 85 thousand barrels per day (MBPD) crude unit, a 26.2 MBPD vacuum-tower unit, a 12 MBPD asphalt blow-still unit, a 10.4 MBPD polymer modified asphalt unit, a 32 MBPD distillate heavy-oil hydrotreater (DHDS) unit, a 32 MBPD CFHT unit, a 30 MBPD fluid catalytic cracker unit with two-stage regeneration, a 26 MBPD NHT unit, a 23 MBPD catalytic reformer unit, a 12.5 MBPD Sat-Gas Unit, a 7.5 MBPD alkylation unit, a 7.5 MBPD isomerization unit, a 98 LTPD sulfur recovery unit, and a 26 MMSCFD hydrogen production unit. The majority of raw crude oil is received on-site through utilization of an integrated pipeline system.

To effect operations, the refinery's process heaters, steam boilers, compressors, and generators are capable of producing approximately 1.6 billion BTU/hr of energy transfer. The refinery has approximately 2.4 million barrels of refined product storage capability. Products include conventional and reformulated low sulfur gasoline, diesel fuel, asphalt products, propylene, butane, propane, and sulfur. Refined products are transported via pipeline, railcar, and tank truck.

1- - General Function Of Petroleum Refining

Basically, the refining process does four types of operations to crude oil:

1. Separation: Liquid hydrocarbons are distilled by heat separation into gases, gasoline, diesel fuel, fuel oils, and heavier residual material.
2. Conversion:
 - i. *Cracking*: This process breaks or cracks large hydrocarbons molecules into smaller ones. This is done by thermal or catalytic cracking.
 - ii. *Reforming*: High temperatures and catalysts are used to rearrange the chemical structure of a particular oil stream to improve its quality.
 - iii. *Combining*: Chemically combines two or more hydrocarbons such as liquid petroleum gas (LPG) materials to produce high grade gasoline.
3. Purification: Converts contaminants to an easily removable or an acceptable form.
4. Blending: Mixes combinations of hydrocarbon liquids to produce a final product(s).

1- - Description of Affected Units

NHT Unit

The purpose of this unit is to remove the sulfur, nitrogen, and water from the Platformer and Penex (Isomerization) charge stocks. These are contaminants to the Platformer and Penex catalysts. This is accomplished by passing the naphtha feed stocks over hydrotreating catalyst at elevated temperatures in the presence of hydrogen at high pressures. Under these conditions, the sulfur and nitrogen components are converted to H₂S and ammonia (NH₃), which are then easily removed from the liquid effluent by distillation stripping. Removal of the contaminants provides clean charge stocks to the Platformer and Penex units, which increases the operational efficiency of both units.

The equipment to be installed per this construction permit, two additional reactors and the supporting peripheral fugitive equipment sources, will reduce the space velocity by a factor of four and thus enable more intimate catalyst contact in the presence of hydrogen. This will enable more efficient removal of sulfur from the platformer feedstock.

CFHT

Hydrotreating is a process to remove impurities present in hydrocarbons and/or catalytically stabilize petroleum products by reacting them with hydrogen. The CFHT has two primary functions: 1) improve the quality of the feed to the FCCU by removing impurities (metals, sulfur, and nitrogen), and 2) increasing the hydrogen content by saturating the aromatics in the gas oils and light cycle oil feedstocks.

Feed to the CFHT enters the unit from several sources: high sulfur diesel from Tank T-1081; light cycle oil from the FCCU; gas oil from the Crude Unit; either vacuum or atmospheric residue from the Crude Unit; and hydrogen from the Hydrogen Unit. The combined liquid feed is filtered and then heated in a series of exchangers before entering the feed surge drum. Liquid feed from the surge drum is pumped to the reaction section of the unit through the multistage charge pump. Hydrogen feed is compressed to the unit operating pressure by two reciprocating compressors. The fresh hydrogen feed along with recycled hydrogen from a steam turbine driven centrifugal compressor combines with the liquid feed in the reaction section of the unit.

Combined feed to the unit is heated in the reactor charge heater and then enters the first of three reactors in series. The reactors each contain a different type of catalyst with a very specific, but complementary role. The primary role of the catalyst in the first two reactors is to remove metals contained in the feed such as nickel and vanadium. The catalyst in the third reactor is primarily designed to convert sulfur and nitrogen species into a form in which they can be removed. The effluent from the reactors then enters a series of separators.

There are four separators in the CFHT: Hot High Pressure Separator, Hot Flash Drum, Cold High Pressure Separator, and Cold Flash Drum. The primary function of these vessels is to separate the oil from the hydrogen-rich gas in the reactor effluent. Each vessel is operated at different conditions (temperature and pressure) to allow certain components in the reactor effluent to vaporize. Hydrogen recovered in the cold high-pressure separator is routed to the recycle gas amine treater. Light ends, such as methane and ethane, are sent to the refinery sour fuel gas system. Water recovered is sent to a sour water stripper. All of the remaining oil is then combined and sent to the fractionation section of the unit.

Hydrogen recovered from the reactor effluent contains H₂S. The unit is designed to have 0.5-1.0% H₂S in the recycle gas. To control the H₂S at the desired level, a portion of the recycle gas is amine treated. Recycle gas enters the bottom of the amine absorber and is contacted by a counter-current flow of amine across trays. The H₂S is absorbed by the amine and sweet hydrogen exits the top of the absorber. Amine exits the bottom of the absorber and is regenerated in the ARU in the refinery.

The oil from the separators is routed to the fractionation section of the unit. The oil is heated in the fractionator charge heater and then enters the fractionator. The fractionator is a trayed tower. The fractionator separates the oil into three streams: overhead naphtha product; diesel product; and FCCU feed. The diesel product is stripped of light ends and H₂S in the distillate stripper before being sent to storage.

The equipment to be installed per this construction permit, an additional reactor and the supporting peripheral fugitive equipment source, will enable more efficient sweetening of the FCCU feedstock and is a step toward complying with the proposed Tier II sulfur standards in 2006 & 2007.

Sour Water Strippers

The purpose of the sour water strippers is to remove H₂S and ammonia from the total sour water inlet stream. The H₂S and ammonia are stripped from the sour water feed as the water travels down the column. Rising steam strips out the H₂S and ammonia gases. These gases are routed to the SRU/SCOT Unit to convert the H₂S gas stream to sulfur and to destroy the ammonia gas in the thermal section of the SRU.

MDEA Unit

Methyldiethanolamine is used to recover CO₂ and H₂S to form a weak and unstable salt. These processes take place in the fuel gas absorber and amine contactors. Once this weak and unstable amine salt solution is formed, the reaction must be reversed to clean up or regenerate the amine solution. This reaction takes place in the ARU. The new amine unit will increase the CO₂ and H₂S removal efficiency of the refinery.

The MDEA solution is fed to the tower from the MDEA Flash Drum. As the solution travels down the tower, the acid gases are stripped as the salt solution is broken down by heat, which is supplied by two steam reboilers at the base of the tower. The lean regenerated MDEA is then pumped back to the Lean MDEA Surge Drum where the low- and high-pressure MDEA charge pumps charge the regenerated amine solution back to the fuel gas absorber and amine contactors.

SRU / SCOT Process

The SRU converts the H₂S stream from the ARU to liquid elemental sulfur to be loaded out by rail car or truck. This process takes place in two general sections: 1) H₂S is converted to sulfur at high temperatures without the aid of catalytic conversion; and 2) sulfur is formed at much lower temperatures with the aid of catalytic conversion.

In section one, high thermal temperatures are maintained by using liquid oxygen, which also aids in the destruction of ammonia contained in the sour water gases which are destroyed in the thermal section of the SRU. In section two, unconverted sulfur is processed through two successive catalytic stages. Each stage consists of process gas reheating, sulfur conversion over an activated alumina catalyst and then cooling to condense and recover the sulfur formed.

The SCOT Unit operation is much the same as the MDEA Unit operation. Unprocessed tail gas from the SRU is heated and mixed with a hydrogen rich reducing gas stream. This heated tail gas stream passes through a catalytic reactor where the sulfur compounds are reconverted back to H₂S. Once the tail gases are converted back into a H₂S gas stream, these gases are routed to a quench system where the gases are cooled and the condensed water from the reactor product is routed to the sour water system. The cooled reactor effluent is then fed to an absorber/stripper section where the acid gas comes in contact with an amine solution and is absorbed, regenerated, and reprocessed by the SRU.

The new SRU and the TGTU will increase the refinery's sulfur recovery capacity. The new units will be able to handle the additional H₂S generated in the new reactors for the NHT and the CFHT.

SECTION III. AFFECTED EQUIPMENT - EMISSION UNIT (EU) GROUPS

EUG 115 Process Flare (East)

EU	Point	Description	MMBTUH	Const. Date
crude unit flare	P-116	Process Flare	27.0	1976 Mod. 2004

EUG 170 SRU Incinerator

EU	Point	Description	MMBTUH	Const. Date
SBH-001	P-170	SRU Incinerator	40.4	2004

EUG 171 Hot Oil Heater

EU	Point	Description	MMBTUH	Const. Date
SBH-002	P-171	Hot Oil Heater	20.0	2004

EUG 172 Regenerated Amine Storage Tank TK-AB001

EU	Point	Roof Type	Contents	Barrels	Const. Date
TK-AB001	P-172	Cone	Amine	895	2004

EUG 173 Liquid Sulfur Storage Tank TK-SB001

EU	Point	Roof Type	Contents	Barrels	Const. Date
TK-SB001	P-171	Cone	Sulfur	3,300	2004

EUG 174 Molten Sulfur Railcar Loading Rack

EU	Point	Loading Rack	Loading Arm
LR-SB001	P-171	1	1
			2
			3

EUG 210 Cat Feed Hydrotreater Unit Fugitive VOC Emissions

EU	Point	Number Items	Type of Equipment
Area 650	F-110	4	Valves
		6	Flanges

EUG 220 Naphtha Hydrotreater (NHT) Fugitive VOC Emissions

EU	Point	Number Items	Type of Equipment
Area 400	F-107	8	Valves
		22	Flanges

EUG 230 Amine Regenerator / SRU Unit #2 Wastewater Processing

EU	Point	Number Items	Type of Equipment
WWAB-001	F-AB001	12	P-Trap
		2	Junction Boxes

EUG 231 SCOT Unit #2 Wastewater Processing

EU	Point	Number Items	Type of Equipment
WWSB-001	F-SB001	9	P-Trap
		1	Junction Box

EUG 530 SCOT Unit #2 Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 530	F-530	282	Valves
		499	Flanges
		4	Other
		6	Pumps

EUG 560 Amine Regeneration Unit #2 Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 560	F-560	314	Valves
		630	Flanges
		8	Other
		6	Pumps

EUG 570 SRU Tail Gas Treating Unit #2 Fugitive Sources

EU	Point	Number Items	Type of Equipment
Area 570	F-570	252	Valves
		560	Flanges
		3	Other
		7	Pumps

SECTION IV. EMISSIONS

The table on the following page provides a list of active permits, registrations, and applicability determinations affected by this permit. This permit will supercede any conditions of the previous permits that affect the EUs incorporated into this permit.

List of Affected Air Quality Permits and Determinations

74-171-C	95-506-O (M-1)	98-172-C (PSD)
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Emissions from the East Flare from Permit No. 98-172-C (PSD)

The table below details the emissions for the east flare after the PSD/BACT review.

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1.84	8.04	9.99	43.76	0.25	1.10	0.91	3.97	3.78	16.56

Potential emissions are based on a 27 MMBTUH flare operating at 100% capacity 8,760 hours per year with a maximum sulfur content of 159 ppm H₂S (NSPS, Subpart J limitation) and AP-42 (1/95), Section 13.5.

Emissions from the SRU Incinerator SBH-001

The new SRU will vent to the incinerator along with the displaced vapors from the railcar loading operations and the storage tank. Emission estimates assume 100% conversion of H₂S to SO₂. The table below shows the emission estimates for the SRU Incinerator.

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
4.0	17.4	1.1	4.6	0.3	1.3	26.2	114.7	0.2	1.0

Emissions from the incinerator are based on the following:

NO_x – For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 27.7 MMBTUH, a heat content of 867 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98); For emissions from combustion of the waste gas, emissions were based on a flow rate of

552,396 SCFH of waste gas, a heat content of 23 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98);

CO – For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 27.7 MMBTUH, a heat content of 867 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98); For emissions from combustion of the waste gas, emissions were based on a flow rate of 552,396 SCFH of waste gas, a heat content of 23 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98);

PM₁₀ – For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 27.7 MMBTUH, a heat content of 867 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98); For emissions from combustion of the waste gas, emissions were based on a flow rate of 552,396 SCFH of waste gas, a heat content of 23 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98);

SO₂ – Based on the NSPS, Subpart J, SO₂ emission limit of 250 ppm_{dv} and a flow rate of 630,000 DSCFH @ 0% O₂;

VOC – For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 27.7 MMBTUH, a heat content of 867 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98); For emissions from combustion of the waste gas, emissions were based on a flow rate of 552,396 SCFH of waste gas, a heat content of 23 BTU/SCF, and the emission factor from AP-42, Section 1.4 (7/98).

Emissions from the Hot Oil Heater SBH-002

The table below shows the estimated emissions for heater SBH-002 and assumes 100% conversion of H₂S in the fuel gas to SO₂.

NO _x		CO		PM ₁₀		SO ₂		VOC	
lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1.0	4.3	1.7	7.2	0.2	0.7	0.6	2.7	0.1	0.5

Emissions from the heater are based on a heat rating of 20 MMBTUH, continuous operation, and the emission factors shown below:

NO_x – AP-42, Section 1.4 (7/98), Low NO_x burner factor;

CO – AP-42, Section 1.4 (7/98);

PM₁₀ – AP-42, Section 1.4 (7/98);

SO₂ – A fuel-gas H₂S concentration of 159 ppm_v;

VOC – AP-42, Section 1.4 (7/98).

Emissions from the Regenerated Amine Storage Tank TK-AB001

The table below shows the estimated emissions from the regenerated amine storage tank. Emissions are based on TANKS4.0, a throughput of 12,463,046 bbl/yr, and a H₂S concentration of 0.1% by weight.

	VOC		H ₂ S	
	lb/hr	TPY	lb/hr	TPY
Emissions	<0.1	<0.1	0.1	0.5

Emissions from the Liquid Sulfur Storage Tank TK-SB001

The table below shows the estimated emissions from the liquid sulfur storage tank. Emissions are based on a H₂S concentration of 8,000 ppm_v (based on historical analyses of sulfur pit sweep vapors ~2,000 ppm_v plus a safety factor of four), the run-down rate of 12,100 lb/hr of molten sulfur (130 LTD), and the density of molten sulfur (124.8 lb/SCF). These emissions are vented to the SRU incinerator and are incorporated into that limit as SO₂.

	H ₂ S	
	lb/hr	TPY
Emissions	0.1	0.3

Emissions from the Molten Sulfur Railcar Loading Rack LR-SB001

The table below shows the estimated emissions from the molten sulfur railcar loading rack. Emissions are based on a H₂S concentration of 8,000 ppmv (based on historical analyses of sulfur pit sweep vapors ~2,000 ppmv plus a safety factor of four), a loading rate of 100,000 lb/hr of molten sulfur per railcar, three loading stations, and the density of molten sulfur (124.8 lb/SCF). These emissions are vented to the SRU incinerator and are incorporated into that limit as SO₂.

	H ₂ S	
	lb/hr	TPY
Emissions	1.7	7.6

Cat Feed Hydrotreater Unit Equipment Leaks – Fugitive Emissions

The table below summarizes the fugitive emissions from the Cat Feed Hydrotreater equipment leaks. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC		H ₂ S	
	lb/hr	TPY	lb/hr	TPY
Emissions	<0.1	<0.1	<0.1	<0.1

Naptha Hydrotreater (NHT) Equipment Leaks – Fugitive VOC Emissions

The table below summarizes the fugitive emissions from the NHT equipment leaks. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC		H ₂ S	
	lb/hr	TPY	lb/hr	TPY
Emissions	<0.1	0.1	<0.1	<0.1

Amine Regenerator/SRU/TGTU Unit #2 Wastewater Processing Fugitive VOC Emissions

Added emissions from the wastewater processing due to the new amine regeneration unit, SRU, and TGTU were estimated using a continuous flow of 0.0315 and WATER9.

	VOC		H ₂ S		NH ₃	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Emissions	0.8	3.6	0.2	0.8	0.1	0.5

SRU #2 Equipment Leaks – Fugitive VOC Emissions

The table below summarizes the fugitive emissions from the SRU #2 equipment leaks. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC		H ₂ S		SO ₂		NH ₃	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Emissions	0.7	2.9	0.6	2.4	0.1	0.4	0.1	0.3

Amine Regeneration Unit #2 Equipment Leaks – Fugitive VOC Emissions

The table below summarizes the fugitive emissions from the Amine Regeneration Unit #2 equipment leaks. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC		H ₂ S		SO ₂	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Emissions	0.4	1.6	0.1	0.4	0.8	3.5

SRU Tail Gas Treating Unit #2 Equipment Leaks – Fugitive VOC Emissions

The table below summarizes the fugitive emissions from the SRU Tail Gas Treating Unit #2 equipment leaks. Potential emissions are based on estimated equipment counts and the average refinery emission factors.

	VOC		H ₂ S		SO ₂	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Emissions	0.6	2.5	0.1	0.4	0.3	1.3

TOTAL EMISSION INCREASES

EU	NO _x		CO		PM ₁₀		SO ₂		VOC		H ₂ S	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
SBH-001	4.0	17.4	1.1	4.6	0.3	1.3	26.2	114.7	0.2	1.0	----	----
SBH-002	1.0	4.3	1.7	7.2	0.2	0.7	0.6	2.7	0.1	0.5	----	----
TK-AB001	----	----	----	----	----	----	----	----	<0.1	<0.1	0.1	0.5
CFHT	----	----	----	----	----	----	----	----	<0.1	<0.1	<0.1	<0.1
NHT	----	----	----	----	----	----	----	----	<0.1	0.1	<0.1	<0.1
WWTP	----	----	----	----	----	----	----	----	0.8	3.6	0.2	0.8
SRU #2	----	----	----	----	----	----	0.1	0.4	0.7	2.9	0.6	2.4
ARU #2	----	----	----	----	----	----	0.8	3.5	0.4	1.6	0.1	0.4
TGTU #2	----	----	----	----	----	----	0.3	1.3	0.6	2.5	0.1	0.4
TOTALS	5.0	21.7	2.8	11.8	0.5	2.0	27.7	122.6	3.1	12.4	1.3	4.7

SECTION V. PSD REVIEW

Emission increases of SO₂ are greater than the Prevention of Significant Deterioration (PSD) significance level (40 TPY). Therefore, the requirements of the PSD program must be addressed for this modification. Full PSD review of emissions consisted of the following:

1. A determination of best available control technology (BACT);
2. An evaluation of existing air quality and a determination concerning monitoring requirements;
3. An analysis of compliance with National Ambient Air Quality Standards (NAAQS);
4. An evaluation of PSD increment consumption;
5. An evaluation of source-related impacts on growth, soils, vegetation, and visibility;
6. And a Class I area impact evaluation.

A. Best Available Control Technology

A BACT analysis is required for all pollutants emitted above PSD-significance levels. Economic as well as energy and environmental impacts are considered in a BACT analysis. BACT is generally defined as “an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any...source...which on a case-by-case basis is determined to be achievable taking into account energy, environmental, and economic impacts and other costs.” The EPA-required top-down BACT approach must look not only at the most stringent emission control technology previously approved, but it also must evaluate all demonstrated and potentially applicable technologies, including innovative controls, lower polluting processes, etc. The five basic steps of the top-down procedure are:

- Step 1. Identify all control technologies
- Step 2. Eliminate technically infeasible options
- Step 3. Rank remaining control technologies by control effectiveness
- Step 4. Evaluate most effective controls and document results
- Step 5. Select BACT

The first step is to identify all "available" control options for each modification/EU which triggering PSD for each pollutant under review. Available control options are those technologies or techniques with a practical potential for application to the EU. During the course of the BACT analysis, one or more control options may be eliminated from consideration. However, at the outset, a comprehensive list must be compiled. This list should include potentially applicable Lowest Achievable Emission Rate (LAER) technologies, innovative technologies, and controls applied to similar source categories.

The second step of the top-down analysis is to arrange the comprehensive list, created in Step 1, based on technical feasibility. The technical evaluation should clearly document the difficulties based on source-specific factors and physical, chemical, and engineering principles that preclude the safe and successful use of the control option. Technically infeasible control technologies are removed from further evaluation.

In the third step, all remaining control alternatives not eliminated in Step 2 are ranked and listed in descending order of control effectiveness. A list should be prepared for each emissions unit for each pollutant subject to BACT review. If the top ranked control option is proposed as BACT, other considerations need not be detailed.

In the fourth step, energy, environmental, and economic impacts are considered in order to arrive at the level of control. Beginning with the most stringent control option, both beneficial and adverse impacts are discussed and quantified. This process continues until the technology under consideration cannot be eliminated by any source-specific adverse impacts.

The final step is the selection of the most effective control option not eliminated by the four preceding steps as BACT for the pollutant and EU under review.

The EPA has consistently interpreted statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available control technologies (i.e., those which provide the "maximum degree of emissions reduction"). Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of energy, environmental, and economic impacts.

The BACT analysis evaluates control technologies/techniques for the following pollutants emitted from the sources identified above:

1. SO₂ emissions from the SRU tail gases,
2. SO₂ emissions from the hot oil heater, and
3. SO₂ emissions from the fugitive equipment leaks.

All proposed and applied BACT must meet, at minimum, all applicable New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP). In some cases, technologies not sufficiently effective by themselves can be used in tandem to achieve BACT emission reduction levels.

Selected BACT

Source	Pollutant	Selected BACT
SRU Exhaust	SO ₂	MDEA Regenerative Absorber TGTU & Incinerator
Heaters	SO ₂	Refinery Fuel Gas w/H ₂ S concentration of 160 ppmv or less
Equipment Leaks	SO ₂	LDAR

SO₂**SRU**

The SRU will be subject to NSPS, Subpart J. The applicable NSPS maximum allowable emissions from an SRU are listed below:

NSPS Limits For the SRU

Pollutant	Emission Limit	Reference
SO ₂	250 ppmv (dry basis) @ 0% O ₂	40 CFR 60.104(a)(2)

The resources consulted in the compilation of potential options for SO₂ control for the Ardmore refinery SRU include the following:

- EPA's New Source Review Website
- U.S. EPA's RACT/BACT/LEAR Clearinghouse (RBLC) database
- The Maximum Achievable Control Technology (MACT) floor analysis included in the preamble to the proposed 40 CFR Part 63, Subpart UUU - *NESHAP for Petroleum Refineries – Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Plants*
- Other refineries with similar process limits

Sulfur recovery (the conversion of H₂S to elemental sulfur) is usually accomplished using a modified Claus process, which consists of a thermal reactor and multi-stage catalytic reactors in series. First, one-third of the H₂S is burned with air in a thermal reactor furnace to yield SO₂. The SO₂ then reacts with H₂S in the presence of a catalyst to produce sulfur, water, and heat. Since the reaction is reversible, the reaction occurs in a series of catalytic reactors (or stages), and the vapors are cooled to condense the sulfur between each reactor driving the reaction towards completion. The Claus gas is then reheated prior to the next stage. The conversion efficiencies of an SRU range from 95% for a 2-stage to 96% for a 3-stage unit. The off-gases from the final condenser of the SRU or “tail gas” primarily consist of inert gases with less than 3% sulfur compounds (H₂S, SO₂, CS₂, and COS). The proposed SRU is a 4-Stage Claus combustion unit.

The SCOT™ TGTU proposed uses catalytic reduction (using a cobalt-molybdenum catalyst) of the tail gas sulfur compounds to H₂S followed by amine absorption to recover and recycle any H₂S present in the tail gas. The off-gases from the TGTU are usually incinerated to convert the remaining tail gas sulfur compounds to SO₂. Sulfur recovery efficiencies of catalytic reduction followed by amine recovery typically range from 92 to 97%. Therefore, the combined efficiency of the SRU and TGTU can exceed 99.7%. After incineration, the exhaust gases consist of inert gases with an SO₂ concentration of between 100 and 300 parts per million (ppm) with trace amounts of H₂S, COS, and CS₂.

Two types of control technologies are proposed for the top-down analysis for control of SO₂ emissions from the SRU Incinerator: a pre-incineration scrubbing system or a post-incinerator scrubbing system are the most feasible control technologies for the control of SO₂ emissions. For the cost analyses, the cost of the SRU, hot oil heater, and incinerator were not included.

1. Identification of Available Control Technologies
 - a. Pre-Incineration SRU Scrubbing & TGTU
 - b. Post-Incinerator Flue Gas Scrubbing without a TGTU

Wet Gas Scrubbers (WGSs)

WGSs chemically remove SO₂ emissions using an aqueous solution. Flue gas enters the scrubber where intensive gas/liquid contacting removes sulfur oxides by absorption, neutralization, or partial oxidation. Wet scrubbing is a widely used control technology because a high level of efficiency may be achieved and because the costs are low relative to comparable technologies. Pre-Incineration scrubbers use hydrogenation/reduction of the SRU tail gas and then adsorption or reduction to remove the sulfur compounds from the tail gas. Post-incineration scrubbers directly absorb the SO₂.

Dry Scrubber (with ESP or baghouse)

In a dry scrubbing system, a dry sorbent such as hydrated lime and water is injected into a venturi to remove SO₂ from the stream. Typically, lime slurry is injected into a venturi or duct to provide intimate mixing of flue gases and the sorbent. The SO₂ reacts with the sorbent in the wet phase. Inherent heat in the gas stream dries the slurry resulting in dry sorbent, which can be collected with an electrostatic precipitator (ESP) or fabric filter. The advantages of a dry scrubber include a reduction in water use and the generation of a dry waste that may be recyclable, depending on waste quality and regulatory classification and proximity of potential recyclers. One of the disadvantages of a dry scrubber is that it requires a secondary control device.

2. Eliminate Technically Infeasible Control Technologies

For the proposed control of SO₂ emissions from the incinerator, a pre-incineration front-end scrubbing system, or post-incinerator tail-end scrubbing system are the most feasible control technologies for the control of SO₂ emissions. Based on review of previous PSD permits, wet scrubbing systems are used extensively for controlling SO₂ emissions from SRUs and that type of control technology typically results in BACT. None of the SO₂ control technologies considered were eliminated as technically infeasible. However, control technologies that do not perform at an overall sulfur recovery efficiency equal to or greater than, 99.8% were eliminated.

3. Rank Remaining Control Technologies

All of the available control technologies in conjunction with the SRU result in approximately the same overall reduction of sulfur from the amine regenerator off-gases of 99.8% and a tail gas SO₂ emission reduction of 97.3%. The final emission rate proposed by the applicant (NSPS, Subpart J limitation of 250 ppmv @ 0% O₂) can be met using different scrubbing solutions and different placement of the scrubbers.

Potential SO₂ Control Technologies

Control Technology	Est. Overall Control Efficiency
SCOT Reactor w/Regenerative MDEA Scrubber	99.9%
SCOT Reactor w/Regenerative Caustic Scrubber	99.9%
SCOT Reactor w/Non-Regenerative Caustic Scrubber	99.9%

4. Evaluate Remaining Control Technologies and Document Results

Pre-Incineration Tail-Gas Amine (MDEA) Scrubbing and Regeneration Unit.

Within the proposed SRU design, based on the material balance information, approximately 9,900 lbs of sulfur will be processed by the Claus combustion unit. At the NSPS allowable of 250 ppmv @ 0% O₂ the SRU with the TGTU and ARU will emit 26.2 lbs SO₂/hr or approximately 13.1 lbs S/hr. The overall sulfur recovery efficiency at this emission rate is approximately 99.9%. Additionally, included in the proposed NSPS allowable (26.2 lbs SO₂/hr) are emissions from the sulfur-pit vacuum sweep, the liquid sulfur storage-tank, and rail car loading emissions. The proposed amine tail gas treating and regeneration unit can meet, or exceed, the control efficiencies documented in the RBLC database.

The estimated total annualized cost associated with the installation of the SCOT reactor with a MDEA TGTU and supporting ARU is approximately six million dollars. The estimated cost effectiveness of the TGTU is approximately \$1,476/ton at a recovery efficiency of 97.3% and the NSPS, Subpart J limitation of 250 ppmv. The amine based TGTU utilized in conjunction with the amine regenerator does not require the disposal of waste, utilizes less raw material (MDEA), and recovers a saleable raw material (sulfur). When the annual revenue of recovered sulfur is applied against the total annualized cost, the cost effectiveness of the system becomes approximately \$841/ton. The required energy for this system is approximately 140 MMBTU/ton SO₂ based on the proposed design.

The estimated total annualized cost associated with the installation of the SCOT reactor with a caustic scrubber TGTU is approximately five and a half million dollars. The estimated cost effectiveness of the TGTU is approximately \$1,314/ton at the same recovery efficiency of the MDEA TGTU and supporting ARU of 97.3% and the NSPS, Subpart J limitation of 250 ppmv. However, the caustic scrubber TGTU requires the disposal of waste (9,554 TPY) and utilizes more raw materials. The required energy for this system is approximately 88 MMBTU/ton SO₂.

Post-Incinerator Flue Gas Wet Scrubber w/no SCOT reactor and TGTU

The estimated total annualized cost of a post-incinerator scrubber without a SCOT reactor and TGTU is also approximately seven and a half million dollars. The estimated cost effectiveness of the post-incinerator scrubber is also approximately \$1,763/ton at a recovery efficiency of 97.3% and the NSPS, Subpart J limitation of 250 ppmv. However, the post-incinerator wet scrubber depending upon the type of wet scrubber will either require waste treatment and disposal or secondary costs associated with control or treatment of a concentrated SO₂ stream. Disposal of waste generated from the post-incinerator wet scrubber (8,633 TPY) is environmentally undesirable and secondary treatment of a concentrated gas stream will increase the estimated total annualized cost associated with post-incineration treatment. The required energy for this system is approximately 125 MMBTU/ton SO₂.

Considering the fact that both systems (pre- and post- incinerator control) operate at approximately the same efficiency and operational cost and the disadvantages of land filling solid waste, the amine-based pre-incineration scrubbing system is the preferred option. The extra energy required for the MDEA system is substantially less of an environmental impact than the resource and energies consumed land filling the wastes generated by the other systems.

Combined Pre-Incineration and Post-Incineration Scrubbing

The incremental effect of controlling the SO₂ emissions after scrubbing and incineration to a level below the NSPS, Subpart J emission level using a post-incineration scrubbing system was reviewed to determine the level of control for the SRU TGTU Incinerator. Based on a 90% control of the SO₂ emissions after incineration, the incremental cost effectiveness of this control option was calculated to be approximately \$57,071/ton.

In reviewing and researching the best available control technologies for similar processes, the information contained within RBLC was reviewed. Four of the RBLC reviews relied on reducing emissions of SO₂ based on netting and process changes to reduce the facility allowable emissions while enabling construction/modification of the respective unit. Based on the review, the industry standard for an SRU, 6 considered, would result in a minimum required overall sulfur recovery efficiency of 99.8%. The most stringent control efficiency was determined to be 99.9% overall sulfur recovery. All of the control technologies reviewed utilized tail gas scrubbers followed by incineration of the tail-gas.

There is also an economic incentive to recover and recycle the sulfur in the untreated tail gas as opposed to releasing the sulfur, in the form of H₂S, COS, S_x, and C₂S to an incineration unit. SO₂ control technologies that generate a secondary waste that requires treatment and processing reduces the economic and environmental benefit of controlling SO₂ emissions.

5. Select BACT

Based on the information provided and a minimum overall sulfur recovery efficiency of 99.9%, the proposed SCOT unit, amine-based TGTU, amine regeneration unit, and incinerator are considered BACT. The proposed amine system and incinerator is evaluated to perform at approximately a 97.3 sulfur recovery efficiency and the SRU with the TGTU has an estimated overall sulfur recovery efficiency of 99.9% at the NSPS, Subpart J allowable emissions rate. The NSPS, Subpart J allowable emissions rate is also considered the MACT floor for the recently proposed 40 CFR Part 63, Subpart UUU - *NESHAP for Petroleum Refineries – Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Plants*.

Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Emissions Limits	Proposed Monitoring
SO ₂	Hydrogenation / Reduction and scrubbing with DMEA	250 ppmdv ¹ @ 0% O ₂ 26.2 lb/hr ² 115 tons/year	SO ₂ continuous emission monitoring systems (CEMS). O ₂ monitoring to correct the concentration to 0% O ₂ .

¹ – 12-hour rolling average of contiguous 1-hour averages.

² – 2-hour average of contiguous 1-hour averages.

Hot Oil Heater

1. Identification of Available Control Technologies

The control technologies listed below were identified for controlling SO₂ emissions from the hot oil heater. The SO₂ emissions from the TGTU Incinerator from combustion of auxiliary fuel are also addressed here instead of with the other SO₂ emissions from combustion of the waste gas in the TGTU Incinerator.

- a. Pre-Combustion – Low-sulfur Fuels
- b. Post-Combustion - Flue Gas Scrubbing

Low Sulfur Fuels

Nearly all of the sulfur contained in the fuel being combusted will be converted to SO₂, therefore, SO₂ emissions are reduced by limiting the sulfur content of the fuel.

Flue Gas Scrubbing

All of the post-combustion controls for emissions of SO₂ include some sort of flue gas scrubbing using different types of scrubbing solutions or slurries. These include the lime/limestone, double alkali, Wellman-Lord, magnesium oxide, and citrate flue gas desulfurization processes. Some of these processes are regenerable and others are non-regenerable. Some require additional controls after the flue gas scrubbing such as condensers, baghouses, and waste treatment. In reviewing these controls for SO₂ emissions from the heater, an average case was used to calculate the economic impact resulting from installation of a flue gas scrubbing unit.

2. Eliminate Technically Infeasible Control Technologies

All possible controls were considered technically feasible. Post combustion control of the TGTU emissions was addressed in the SRU section. As an example for calculation of the cost associated with control of the SO₂ emissions from the heater a general case was reviewed to determine the average cost of a scrubbing system. The lime/limestone scrubbing system was used as an average case for reviewing the economic impact of installing the scrubbing unit.

3. Rank Remaining Control Technologies

Potential SO₂ Control Technologies

Control Technology	Estimated Control Efficiency
Lime/Limestone Scrubbing	95%
Fuel Specification: Low Sulfur Fuels	Base Case

4. Evaluate Remaining Control Technologies and Document Results

No energy/environmental impacts were identified to preclude any control option from review. Because flue gas scrubbing is considered to be technically feasible, add-on controls were not eliminated. The cost effectiveness for a flue gas scrubber was calculated using the average control technology based on the “EPA Air Pollution Control Cost Manual,” Sixth Edition cost estimates.

Flue Gas Scrubber				
Source	Uncontrolled Emissions (TPY)	Emissions Reduction (TPY)	Annualized Cost (\$/year)	Cost Effectiveness (\$/ton)
SBH-002	2.7	2.6	91,000	35,000

The RBLC and recently issued permits in attainment areas were reviewed for recent determinations. The reviewed determinations did not result in flue gas scrubbing as BACT. Therefore, based on the associated costs and recent determinations; flue gas scrubbing was eliminated from consideration. The RBLC database lists fuel sulfur content limits as the most prevalent form of BACT for controlling SO₂ emissions from refinery fuel gas-fired heaters and incinerators.

5. Select BACT

Based on this review, limiting the H₂S content of the refinery fuel-gas fired in the hot oil heater and the auxiliary fuel for the TGTU Incinerator (SBH-001 and SBH-002) to the NSPS, Subpart J limitation of 160 ppmv is acceptable as BACT.

Proposed BACT Controls, Emission Limits, and Monitoring

Pollutant	Selected Technology	Fuel Sulfur Content Limit	Proposed Monitoring
SO ₂	Low Sulfur Fuel NSPS, Subpart J	160 ppm _d v ¹	H ₂ S continuous monitoring system.

¹ – 3-hour rolling average of contiguous 1-hour averages.

Fugitive Equipment Leaks

There are no identified control technologies for SO₂ emissions from fugitive equipment leaks. The majority of the SO₂ emissions from fugitive equipment leaks come from flaring of H₂S emissions from pressure relief valves. Leak detection and repair (LDAR) programs are the most prevalent form of BACT for controlling fugitive VOC emissions from process equipment. All of the equipment in VOC or HAP service at this facility will either be subject to NSPS, Subpart GGG, or NESHAP, Subpart CC. Since there are no control technologies identified for control of SO₂ emissions from fugitive equipment leaks, compliance with the applicable VOC/HAP LDAR programs will act as surrogates for control of SO₂ emissions from fugitive equipment leaks. Therefore, meeting the applicable LDAR requirements for the fugitive equipment sources is acceptable as BACT.

B. Air Quality Impacts

The Valero Ardmore Refinery is located in Carter County, which is currently designated attainment or unclassified for all criteria pollutants, and there are no areas classified as non-attainment within 50 kilometers of the refinery. This modification will result in emission increases of SO₂ sufficient to trigger the Prevention of Significant Deterioration (PSD) requirements codified in 40 CFR Part 52.

Prevention of Significant Deterioration (PSD) is a construction-permitting program designed to ensure air quality does not degrade beyond the NAAQS or beyond specified incremental amounts above a prescribed baseline level. The PSD rules set forth a review procedure to determine whether a source will cause or contribute to a violation of the NAAQS or maximum increment consumption levels. If a source has the potential to emit a pollutant above the PSD significance levels, then they trigger this review process. EPA has provided modeling significance levels (MSL) for the PSD review process to determine whether a source will cause or contribute to a violation of the NAAQS or consume increment. Air quality impact analyses were conducted to determine if ambient impacts would be above the EPA defined modeling and monitoring significance levels. If impacts are above the MLS, a radius of impact (ROI) is defined for the facility for each pollutant out to the farthest receptor at or above the significance levels. If a radius of impact is established for a pollutant, then a full impact analysis is required for that pollutant. If the air quality analysis does not indicate a radius of impact, no further air quality analysis is required for the Class II area.

Valero has prepared an air quality analysis in accordance with the procedures and methodology presented, which are consistent with guidance provided by the Oklahoma Department of Environmental Quality (ODEQ) and Environmental Protection Agency (EPA). The results of this air quality analysis show that the proposed emissions authorized in this permit will not cause or contribute to an exceedance of the NAAQS or significant PSD increment consumption.

Modeling Methodology

The refined air quality modeling analyses for the Valero Ardmore Refinery employed USEPA's Industrial Source Complex (ISC3) (Version 02035) model (USEPA, 1995a). The ISC3 model is recommended as a guideline model for assessing the impact of aerodynamic downwash (40 CFR 40465-40474). The regulatory default option was selected such that USEPA guideline requirements were met.

The stack height regulations promulgated by USEPA on July 8, 1985 (50 CFR 27892), established a stack height limitation to assure that stack height increases and other plume dispersion techniques would not be used in lieu of constant emission controls. The regulations specify that Good Engineering Practice (GEP) stack height is the maximum creditable stack height which a source may use in establishing its applicable State Implementation Plan (SIP) emission limitation. For stacks uninfluenced by terrain features, the determination of a GEP stack height for a source is based on the following empirical equation:

$$H_g = H + 1.5L_b$$

where:

H_g = GEP stack height;

H = Height of the controlling structure on which the source is located, or nearby structure; and

L_b = Lesser dimension (height or width) of the controlling structure on which the source is located, or nearby structure.

Both the height and width of the structure are determined from the frontal area of the structure projected onto a plane perpendicular to the direction of the wind. The area in which a nearby structure can have a significant influence on a source is limited to five times the lesser dimension (height or width) of that structure, or within 0.5 mile (0.8 km) of the source, whichever is less. The methods for determining GEP stack height for various building configurations have been described in USEPA's technical support document (USEPA, 1985).

The heights of some of the exhaust stacks at the refinery were evaluated to determine if they are less than respective GEP stack heights, a dispersion model to account for aerodynamic plume downwash was necessary in performing the air quality impact analyses.

Since downwash is a function of projected building width and height, it is necessary to account for the changes in building projection as they relate to changes in wind direction. Once these projected dimensions are determined, they can be used as input to the ISC3 model.

In October 1993, USEPA released the Building Profile Input Program (BPIP) to determine wind direction-dependent building dimensions. The BPIP program was used to determine the wind direction-dependent building dimensions for input to the ISC3 model.

The BPIP program builds a mathematical representation of each building to determine projected building dimensions and its potential zone of influence. These calculations are performed for 36 different wind directions (at 10 degree intervals). If the BPIP program determines that a source is under the influence of several potential building wakes, the structure or combination of structures that has the greatest influence ($H + 1.5 L_b$) is selected for input to the ISC3 model. Conversely, if no building wake effects are predicted to occur for a source for a particular wind direction, or if the worst-case building dimensions for that direction yield a wake region height less than the source's physical stack height, building parameters are set equal to zero for that wind direction. For this case, wake effect algorithms are not exercised when the model is run. The building wake criteria influence zone is $5 L_b$ downwind, $2 L_b$ upwind, and $0.5 L_b$ crosswind. These criteria are based on recommendations by USEPA. The building cavity effects were then used in the modeling analysis for the refinery. For this analysis, the first step was to determine the building cavity height based on the formula:

$$h_c = H + 0.5L_b$$

where:

- h_c = GEP stack height;
- H = Height of the controlling structure on which the source is located, or nearby structure; and
- L_b = Lesser dimension (height or width) of the controlling structure on which the source is located, or nearby structure.

If the stack height was greater than or equal to the cavity height, the cavity effect would not affect the downwind maximum impacts.

The meteorological data used in the dispersion modeling analyses consisted of five years (1986, 1987, 1988, 1990, and 1991) of hourly surface observations from the Oklahoma City, Oklahoma, National Weather Service Station and coincident mixing heights from Oklahoma City (1986-1988) and Norman, Oklahoma (1990 and 1991).

Surface observations consist of hourly measurements of wind direction, wind speed, temperature, and estimates of ceiling height and cloud cover. The upper air station provides a daily morning and afternoon mixing height value as determined from the twice-daily radiosonde measurements. Based on NWS records, the anemometer height at the Oklahoma City station during this period was 6.1 meters.

Prior to use in the modeling analysis, the meteorological data sets were downloaded from the USEPA Support Center for Regulatory Air Models (SCRAM) website. This data was scanned for missing data, but no missing data was found. USEPA procedures outlined in the USEPA document, "Procedures for Substituting Values for Missing NWS Meteorological Data for Use in Regulatory Air Quality Models," were used to fill gaps of information for single missing days. For larger periods of two or more missing days, seasonal averages were used to fill in the missing periods. The USEPA developed rural and urban interpolation methods to account for the effects of the surrounding area on development of the mixing layer boundary. The rural scheme was used to determine hourly mixing heights representative of the area in the vicinity of the refinery.

The urban/rural classification is used to determine which dispersion parameter to use in the model. Determination of the applicability of urban or rural dispersion is based upon land use or population density. For the land use method the source is circumscribed by a three kilometer radius circle, and uses within that radius analyzed to determine whether heavy and light industrial, commercial, and common and compact residential, comprise greater than 50 percent of the defined area. If so, then urban dispersion coefficients should be used. The land use in the area of the proposed facility is not comprised of greater than 50 percent of the above land use types and is considered a rural area.

The refined modeling used a nested Cartesian grid. Receptors were placed no greater than 50 meters apart along the boundary. From the fence line, a 100-meter grid of receptors extended out to 1,000 meters. A 500-meter grid extended beyond this grid, out to 2.5 kilometers from the site. A 1,000-meter grid extended beyond this grid, out to 10 kilometers from the site. Beyond that, a spacing of 2.5 kilometers was used extending out to 50 kilometers from the facility. This modeling was used to define the radius of significant impact for each pollutant. All receptors were modeled with actual terrain data. The terrain data was taken from United States Geologic Survey (USGS) 7.5-minute Digital Elevation Model Files.

Summary of Modeling Emission Inventory

For each modeling analysis type (e.g., Preliminary Analysis, NAAQS or PSD Increment) varying modeling emission inventories were developed (e.g. contemporaneous increases, increases over baseline, or total emissions). However, the stack parameters for point sources in each inventory were modeled using actual stack parameters, with the exception of some pseudo-point type sources (e.g., tanks), that were modeled to represent their non-buoyant, low velocity type emissions. A discussion of the sources included in each modeling analysis is presented below.

Preliminary Analysis

Typically for PSD Preliminary Analyses, contemporaneous changes (i.e., changes within three years of the triggering event) in emissions are modeled. However, an evaluation of historic changes at the Refinery in the review, and issuance, of 98-172-C (PSD), effective January 2003, revealed that changes at the facility that occurred as early as 1982 and required permitting under PSD regulations. The contemporaneous changes of emissions modeled for Permit No. 98-172-C (PSD) included all other changes at the facility. For the purpose of this review and the AOI, only the added sources for this project were modeled.

On-Property Sources – Full Impact Analyses

Available air permitting and emissions inventory documentation was reviewed to identify on-property sources of SO₂. For the NAAQS analyses, the identified on-property sources were modeled at their proposed allowable emission rates. For the PSD Increment analyses, the identified on-property sources were modeled at their increment-consuming emission rate. The increment-consuming emission rate was estimated by subtracting the historical two-year average emission rate from the proposed allowable emission rate. The on-property source emission inventories for the Full Impact Analyses were provided in the application.

Off-Property Sources – Full Impact Analyses

Off-property sources located within a radius defined by the AOI plus 50 kilometers were included in the Full Impact PSD Increment and NAAQS Analyses that were triggered by the Preliminary Analysis. An ODEQ database retrieval, ODEQ emission inventory reports, and ODEQ permitting files were used to identify applicable sources to be included in the modeling analyses and their respective stack parameters and emission rates. Off-property sources were assumed to be increment consuming and allowable emission rates were included in the model.

Due to its proximity to the Refinery (contiguous to the south), sources at Atlas were evaluated to assess whether they were increment-consuming sources or whether they were existing emission sources prior to the minor source baseline date. Information from Atlas permit applications was used to assess construction, reconstruction, and modification dates for Atlas' emission sources. A summary of the analysis that was used to evaluate the sources included in the PSD Increment Analysis for each pollutant and a summary of the off-property modeling emission inventories for the impact analyses (PSD Increment and NAAQS) were provided in the application.

Preliminary Analysis

The first step in the PSD modeling analysis was the Preliminary Analysis (AOI analysis). In this analysis, emission increases were modeled to evaluate whether the resultant highest predicted concentrations for each pollutant averaging period combination were of regulatory significance.

These results were also used to evaluate the extent of the modeling analysis that would be required. A significant receptor file was created using either the ISCST3 "MAXIFILE" output option and/or BEE-Line's graphical (*.grf) interface for the ISCST3 model. This file contained each predicted concentration that was greater than the MSL, the receptor location, time, date and year. The results of the Preliminary Analysis were used to evaluate whether a Full Impact Analysis was required to define the resultant AOI for modeling purposes, and to evaluate whether a full analysis would be required. The results of the Preliminary Analysis are summarized on the following page.

Preliminary Analysis Results

Pollutant	Averaging Period	Max. Predicted Concentration (µg/m³)	PSD MSL (µg/m³)	AOI (km)	Monitoring Exemption Levels (µg/m³)
SO ₂	3-hour	90.3	25	2.2	N/A
	24-hour	19.8	5	2.9	13
	Annual	1.4	1	1.1	N/A

The results predicted ambient SO₂ concentrations to be greater than the MSL for all averaging periods. Since regulatory-significant concentrations were predicted for SO₂ for the applicable averaging periods greater than the modeling significance level, a full impact analysis was performed for each averaging period.

Full Impact Analysis (PSD Increment and NAAQS)

A Full Impact Analysis was performed to predict ambient concentrations for comparison to the NAAQS and PSD increment. This modeling analysis addressed emissions from the Valero Refinery’s sources and off-property sources within the radius defined by the AOI plus 50 kilometers. The highest second high impacts were evaluated for the SO₂ short-term PSD Full Impact Analyses. The highest annual concentrations were evaluated for the long-term analyses.

Air Quality Monitoring Data

The preliminary modeling conducted as part of this analysis resulted in predicted concentrations that were above the modeling significance levels for the SO₂ 3-hour, 24-hour, and annual averaging periods. Background concentration data was obtained from the ODEQ, Air Quality Division for each of the applicable averaging periods. Air Quality allowed the use of monitoring data collected from the Ponca City Area. Ponca City and Ardmore are of a similar size and have similar types of sources. The Ponca City area is actually a more heavily affected SO₂ area since the Conoco Refinery processes approximately three times the amount of crude oil and there are other sources of SO₂ emissions that impact the monitor. The 2002 monitoring data shown below should provide conservative background data for the NAAQS analysis. The refinery is located in an area that is generally free from the impact of other SO₂ point and area sources and the area impacted by the refinery is not an area of complex terrain.

Summary of Background Concentrations

Pollutant	Averaging Period	Monitored Concentration (µg/m³)
SO ₂	3-hour	120
	24-hour	76
	Annual	10

The background concentrations were added to the modeled results to demonstrate compliance with the NAAQS and increment consumption. Post-construction monitoring will not be required since the calculated impacts from all sources plus the background concentrations do not threaten the NAAQS or PSD Increments.

SO₂ NAAQS Analysis

A summary of the 3-hour, 24-hour, and annual SO₂ NAAQS modeling analyses is provided below.

SO₂ NAAQS Analysis Results

Averaging Period	NAAQS (µg/m³)	Background (µg/m³)	Max. Predicted Concentration (µg/m³)	Predicted Conc. & Background (µg/m³)
3-hour	1,300	120	587	707
24-hour	365	76	144	220
Annual	80	10	21	31

The highest predicted ambient concentration plus background was less than the NAAQS for all averaging periods. Thus, no further analysis was required.

SO₂ PSD Increment Analysis

A summary of the annual SO₂ PSD increment modeling analysis is provided below.

SO₂ Increment Analysis Results

Averaging Period	Maximum Predicted Conc. (µg/m³)	PSD Increment (µg/m³)
3-hour	143	512
24-hour	60	91
Annual	7	20

The highest predicted ambient concentrations were less than the PSD increment for all averaging periods. Thus, no further analysis was required.

F. Evaluation of Source-Related Impacts on Growth, Soils, Vegetation, & Visibility

Mobile Sources

Current EPA policy is to require an emissions analysis to include mobile sources. In this case, mobile source emissions are expected to be negligible. The number of employees needed beyond those currently employed is insignificant.

Growth Impacts

The purpose of the growth impact analysis is to quantify the possible net growth of the population of the area as a direct result of the project. This growth can be measured by the increase in residents of the area, the additional use and need of commercial and industrial facilities to assist the additional population with everyday services, and other growth, such as additional sewage treatment discharges or motor vehicle emissions.

Approximately 50 trade jobs (i.e., welders, electricians, construction workers, etc.) over a 24 month period will be needed to complete the construction of the project. It is anticipated that the majority of these jobs will be local hires, thus not requiring any additional residential or commercial capacity within the area. No full-time positions are expected. There should be no increase in community growth or the need for additional infrastructure. Therefore, it is not anticipated that the project will result in an increase in secondary emissions associated with non-project related activities or growth.

Ambient Air Quality Impact Analysis

The purpose of this aspect of impact analysis is to predict the air quality in the area of the project during construction and after commencing operation. This analysis follows the growth analysis by combining the associated growth with the emissions from the proposed project and the emissions from other permitted sources in the area to predict the estimated total ground-level concentrations of pollutants as a result of the project, including construction.

The only source of additional emissions may be from fugitive dust generated from equipment transportation or vehicles during construction. Any long-term air quality impact in the area will result from emissions increases due to operation of the facility. These impacts have been analyzed in preceding sections.

Soils and Vegetation Impact

The primary soil units in the area of the Refinery are Amber very fine sandy loam and Dale silt loam. The main crops typically grown on the soils identified within the area of interest are native grasses, and cultivated crops. No sensitive aspects of the soil and vegetation in this area have been identified. As such, the secondary NAAQS, which establish ambient concentration levels below which it is anticipated that no harmful effects to either soil or vegetation can be expected, are used as the benchmark for this analysis.

The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than 1 month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism, whereas long-term effects may be indirectly caused by secondary agents such as changes in soil pH.

SO₂ enters the plant primarily through the leaf stomata and passes into the intercellular spaces of the mesophyll, where it is absorbed on the moist cell walls and combined with water to form sulfurous acid and sulfite salts. Plant species show a considerable range of sensitivity to SO₂. This range is the result of complex interactions among microclimatic (temperature, humidity, light, etc.), edaphic, phenological, morphological, and genetic factors that influence plant response (USEPA, 1973).

The secondary NAAQS are intended to protect the public welfare from adverse effects of airborne effluents. This protection extends to agricultural soil. The modeling conducted, which demonstrated compliance with the Primary NAAQS simultaneously demonstrated compliance with the Secondary NAAQS because the Secondary NAAQS are higher or equal to the Primary NAAQS. Since the secondary NAAQS protect impact on human welfare, no significant adverse impact on soil and vegetation is anticipated.

Visibility Impairment

Visibility is affected primarily by PM and NO_x emissions. The area near the facility is primarily agricultural, consisting of pastureland. Some residences are located southeast and east of the facility. The closest airport is located approximately 3 miles north-northeast of the facility. Therefore, there are no airports, scenic vistas, or other areas that would be affected by minor reductions in visibility. The project is not expected to produce any perceptible visibility impacts in the vicinity of the plant. The project is actually expected to reduce visibility impacts of the existing facility. EPA computer software for visibility impacts analyses, intended to predict distant impacts, terminates prematurely when attempts are made to determine close-in impacts. It is concluded that there will be minimal impairment of visibility resulting from the facility's emissions. Given the limitation of 20% opacity of emissions, and a reasonable expectation that normal operation will result in 0% opacity, no local visibility impairment is anticipated.

G. Class I Area Impact Analysis

A further requirement of PSD includes the special protection of air quality and air quality related values (AQRV) at potentially affected nearby Class I areas. Assessment of the potential impact to visibility (regional haze analysis) is required if the source is located within 100 km of a Class I area. The Refinery is not within 100 km of the nearest Class I area, which is the Wichita Mountains Natural Wildlife Refuge (WMNWR). The Refinery is approximately 143 km from the WMNWR. Therefore, the Refinery was not evaluated for its impacts on the WMNWR.

SECTION VI. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-4 (New Source Performance Standards) [Applicable]
Federal regulations in 40 CFR Part 60 are incorporated by reference as they exist on July 1, 2001, except for the following: Subpart A (Sections 60.4, 60.9, 60.10, and 60.16), Subpart B, Subpart C, Subpart Ca, Subpart Cb, Subpart Cc, Subpart Cd, Subpart Ce, Subpart AAA, and Appendix G. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-5 (Registration of Air Contaminant Sources) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories have been submitted and fees paid for the past years.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the “Insignificant Activities” or “Trivial Activities” thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual EU that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

1. 5 TPY of any one criteria pollutant
2. 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for single HAP that the EPA may establish by rule
3. 0.6 TPY of any one Category A toxic substance
4. 1.2 TPY of any one Category B toxic substance
5. 6.0 TPY of any one Category C toxic substance

Emission and operating limitations have been established based on information in the permit application.

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
In the event of any release which results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. Part 70/Title V sources must report any exceedance that poses an imminent and substantial danger to public health, safety, or the environment as soon as is practicable. Under no circumstances shall notification be more than 24 hours after the exceedance.

OAC 252:100-13 (Prohibition of Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-17 (Incinerators) [Not Applicable]
This subchapter specifies design and operating requirements and emission limitations for incinerators, municipal waste combustors, and hospital, medical, and infectious waste incinerators. Thermal oxidizers, flares, and any other air pollution control devices are exempt from this subchapter. The refinery does not have any incinerators besides the control devices used at the refinery.

OAC 252:100-19 (Particulate Matter) [Applicable]

This subchapter specifies a particulate matter (PM) emission limitation of 0.6 lb/MMBTU from fuel-burning units with a rated heat input of 10 MMBTUH or less. All of the small (<10 MMBTUH) fuel-burning units are fired with refinery fuel-gas. Fuel-burning equipment with a rated heat input between 10 and 1,000 MMBTUH are limited to between 0.599 and 0.20 lb/MMBTU as defined in Appendix C. The following table lists all fuel-burning equipment greater than 10 MMBTUH affected by this permit and their associated emission limits.

EU	Type of Unit	MMBTUH	SC 19 Limit (lb/MMBTU)
SBH-002	Hot Oil Heater	20.0	0.510

AP-42 (7/98), Section 1.4, Table 1.4-2, lists the total PM emissions for natural gas to be 7.6 lb/MMft³ or about 0.0076 lb/MMBTU. The permit requires the use of refinery fuel gas to ensure compliance with Subchapter 19. Since all of the emission limits under Subchapter 19 are greater than the expected emissions from these units, having the permit require these units to only be fueled with refinery fuel gas will ensure compliance with Subchapter 19.

Fuel-burning unit is defined as “any internal combustion engine or gas turbine or any other combustion device used to convert the combustion of fuel into usable energy.” Since flares and incinerators are pollution control devices designed to destroy pollutants and are not used to convert fuel into usable energy, they do not meet the definition of fuel-burning unit and are not subject to these requirements.

This subchapter also limits emissions of PM from directly fired fuel-burning units and industrial processes based on their process weight rates. For process rates up to 60,000 lb/hr (30 TPH), the emission rate in pounds per hour (E) is not to exceed the rate calculated using the process weight rate in tons per hour (P) and the formula in appendix G ($E = 4.10 * P^{(0.67)}$). Listed in the following table are the process weight rates for the EUs affected by this permit, the estimated emissions, and the allowable emission limits.

EU	Source	Rate (TPH)	SC 19 Limit (lb/hr)	Emissions (lb/hr)
SHB-001	SRU/TGTU w/Incinerator	21.2	31.73	0.4

The SRU tail gas incinerator only combusts waste gases and refinery fuel gas as auxiliary fuel no specific requirements are needed to ensure compliance with this subchapter.

OAC 252:100-25 (Visible Emissions and Particulate Matter) [Applicable]

No discharge of greater than 20% opacity is allowed except for short-term occurrences, which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case, shall the average of any six-minute period exceed 60% opacity. When burning refinery fuel-gas in the combustion units (process heaters and boilers) there is little possibility of exceeding the opacity standards.

OAC 252:100-29 (Fugitive Dust) [Applicable]
 No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility will not cause a problem in this area, therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air impact of sulfur dioxide (SO₂) emissions from any one existing source or any one new petroleum and natural gas process source subject to OAC 252:100-31-26(a)(1). This part also limits the impact of hydrogen sulfide (H₂S) emissions from any new or existing source. Recent modeling conducted using ISCST3 was used to show the impacts of the facility on the ambient air as shown in the following tables.

Ambient Impacts of SO₂ (Preliminary Analysis)

Averaging Time	Standard µg/m³	Impact µg/m³
5-Minute*	1,300	1,072
1-hour*	1,200	652
3-hour	650	587
24-hour	130	119

* - Based on the PSD modeling preliminary analysis and adjustment factors for different averaging periods.

Ambient Impacts of H₂S (TV Application)

Averaging Time	Standard µg/m³	Impact µg/m³
24-hour	278	22

Emissions from all of the equipment have been modeled and have been shown to be in compliance with these standards.

Part 5 limits sulfur dioxide emissions from new fuel-burning equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input. This is equivalent to approximately 0.2 weight percent sulfur in the fuel gas which is equivalent to 2,000 ppm sulfur. All fuel-burning equipment constructed or modified after June 11, 1973, which combust refinery fuel gas are subject to NSPS, Subpart J, which limits the amount of H₂S in the fuel gas to 0.1 grains/DSCF or approximately 160 ppm. The refinery fuel gas has a HHV of approximately 800 BTU/SCF, which is equivalent to approximately 0.0357 lb/MMBTU. The permit will require the use of refinery fuel gas with a limit of 160 ppm.

Part 5 requires removal or oxidation of hydrogen sulfide (H₂S) from the exhaust gas of any new petroleum or natural gas process equipment. Oxidation of the H₂S must be conducted in a system that assures at least a 95% reduction of the H₂S in the exhaust gases and that is equipped with an alarm system to signal non-combustion of the exhaust gases. This does not apply to emission units that emit less than 0.3 lb/hr of H₂S. Emissions from the liquid sulfur storage tank and the regenerated amine storage tank are estimated below the exemption level. However, the liquid sulfur storage tank will be vented to the SRU incinerator. The railcar loading operations are calculated to have emissions of approximately 0.58 lb/hr/railcar based on the maximum loading rate and is subject to this requirement. For facilities with an SRU prior to release Subchapter 31 requires the SRU to meet a calculated sulfur reduction efficiency based on the SRU capacity. The new SRU will have a capacity of approximately 130 LTD. The required sulfur dioxide reduction efficiency for units with a capacity greater than 5 LTD but less than 150 LTD is calculated using the following formula: $Z = 92.34 \times (X^{0.00774})$, where X is the sulfur feed rate in LTD. Based on this formula and the capacity of the new SRU, the required sulfur reduction efficiency is 95.9%. The SRU reduction efficiency is expected to exceed 99.8%. All applicable requirements will be incorporated into the permit.

OAC 252:100-33 (Nitrogen Oxides) [Not Applicable]
NO_x emissions are limited to 0.20 lb/MMBTU from all gas-fired fuel-burning equipment constructed after February 2, 1972, with a rated heat input of 50 MMBTUH or greater. This project does not involve any fuel-burning equipment with a rated heat input of 50 MMBTUH.

OAC 252:100-35 (Carbon Monoxide) [Not Applicable to this Project]
This permit addresses none of the following affected processes: gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 1 requires all vapor-loss control devices, packing glands, and mechanical seals required by this subchapter to be properly installed, maintained, and operated.
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. Tanks subject to the equipment standards of NSPS, Subparts K, Ka, or Kb are exempt from these requirements. This permit only addresses one VOC storage tank TK-AB001 the regenerated amine storage tank, which is only subject to the recordkeeping requirements of NSPS, Subpart Kb. Since the tank does not store a VOC with a vapor pressure greater than 1.5 psia under actual storage conditions, it is exempt from this subchapter.
Part 7 requires all VOC gases from a vapor recovery blowdown system to be burned by a smokeless flare or equally effective control device unless it is inconsistent with the "Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline" or any State of Oklahoma regulatory agency. This facility flares all emissions that are not processed by a vapor recovery system.

Part 7 requires fuel-burning and refuse-burning equipment to be operated and maintained so as to minimize emissions of VOCs. Temperature and available air must be sufficient to provide essentially complete combustion. All equipment at the refinery is operated to minimize emissions of VOC.

Part 7 also requires all reciprocating pumps and compressors handling VOCs to be equipped with packing glands that are properly installed and maintained in good working order and rotating pumps and compressors handling VOCs to be equipped with mechanical seals. Equipment subject to NSPS, Subpart GGG are exempt from these requirements. The equipment affected by this permit at the refinery is subject to the requirements of NSPS, Subpart GGG.

OAC 252:100-41 (Hazardous and Toxic Air Contaminants) [Applicable]

Part 3 addresses hazardous air contaminants. NESHAP, as found in 40 CFR Part 61, are adopted by reference as they exist on July 1, 2001, with the exception of Subparts B, H, I, K, Q, R, T, W and Appendices D and E, all of which address radionuclides. In addition, General Provisions as found in 40 CFR Part 63, Subpart A, and the Maximum Achievable Control Technology (MACT) standards as found in 40 CFR Part 63, Subparts F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, CC, DD, EE, GG, HH, II, JJ, KK, LL, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, RRR, TTT, VVV, XXX, CCCC, and GGGG are hereby adopted by reference as they exist on July 1, 2001. These standards apply to both existing and new sources of HAPs. These requirements are covered in the "Federal Regulations" section.

Part 5 is a **state-only** requirement governing toxic air contaminants. New sources (constructed after March 9, 1987) emitting any category "A" pollutant above de minimis levels must perform a BACT analysis, and if necessary, install BACT. All sources are required to demonstrate that emissions of any toxic air contaminant that exceeds the de minimis level do not cause or contribute to a violation of the MAAC. There are no toxic emissions from this project that will exceed the de minimis levels.

OAC 252:100-43 (Sampling and Testing Methods) [Applicable]

All required testing must be conducted by methods approved by the Executive Director under the direction of qualified personnel. All required tests shall be made and the results calculated in accordance with test procedures described or referenced in the permit and approved by Air Quality.

OAC 252:100-45 (Monitoring of Emissions) [Applicable]

Records and reports as Air Quality shall prescribe on air contaminants or fuel shall be recorded, compiled, and submitted as specified in the permit.

The following Oklahoma Air Quality Rules are not applicable to this project:

OAC 252:100-7	Permit for Minor Facilities	not in source category
OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Existing Municipal Solid Waste Landfills	not in source category

SECTION VII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
 This facility is a PSD major source. Total potential emissions from this project exceed the SO₂ significance level of 40 TPY as shown in the “Emissions” section. The PSD requirements for this modification are addressed in the “PSD Review” section. Any future increases of emissions must be evaluated for PSD if they exceed a significance level.

NSPS, 40 CFR Part 60 [Subparts Dc, J, Kb, GGG, and QQQ are Applicable]
Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units with a heat input capacity between 10 and 100 MMBTUH and that commences construction, modification, or reconstruction after June 9, 1989. Process heaters are not affected units. “Process heater” means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst. EU SBH-002 is a hot oil heater and is considered a steam generating unit. Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. EU SBH-001 is a thermal oxidizer and is not considered a steam-generating unit. The new hot oil heater is subject to the recordkeeping requirements of this subpart.

EU	Description	MMBTUH	Const. Date
SBH-001	Hot Oil Heater	20.0	2004

Per 40 CFR 60.48(g) the owner/operator will be required to record and maintain records of the amounts of each fuel combusted during each day.

Subpart J, Petroleum Refineries. This subpart applies to the following affected facilities in petroleum refineries: FCCU catalyst regenerators, fuel gas combustion devices, and Claus sulfur recovery plants. This permit will not address any FCCU catalyst regenerators. All fuel gas combustion devices which commence construction or modification after June 11, 1973, are subject to a fuel gas H₂S limitation of 0.10 grains of H₂S/DSCF which is required to be continuously monitored and recorded. Fuel gas combusted by the affected units must be monitored and recorded and can be done at one location. Based on 1998 monitoring data, the typical sulfur content of the refinery fuel gas used at the Valero Refinery is 0.027 grains of

H₂S/DSCF. All emission limits, monitoring, and recordkeeping requirements for the refinery fuel gas combustion devices will be incorporated into the permit.

EU	Type of Unit	MMBTUH	Const. Date
SBH-001	SRU Tail Gas Incinerator	40.4	2004
SBH-002	Hot Oil Heater	20.0	2004

For Claus sulfur recovery plants with an oxidation control system or a reduction control system followed by incineration, Subpart J limits SO₂ emissions to 250 ppmvd at 0% excess air. The new SRU is subject to this emission limit, continuous emission monitoring, and the recordkeeping and reporting requirements of this subpart. All applicable requirements will be incorporated into the permit.

Subpart Kb, VOL Storage Vessels. This subpart affects storage vessels for volatile organic liquids (VOLs) which have a storage capacity greater than or equal to 10,567 gallons and which commenced construction, reconstruction, or modification after July 23, 1984. The amine storage tank is subject to the recordkeeping requirements of this subpart.

EU	Roof Type	Contents	Barrels	Const. Date
TK-AB001	Cone	Regenerated Amine	895	2004

Tanks with a capacity of less than 39,890 gallons and which store a VOL with a maximum true vapor pressure of less than 2.175 psia and tanks with a capacity equal to or greater than 39,890 gallons which store a VOL with a maximum true vapor pressure of less than 0.5 psia are required to keep records of the VOL stored and the maximum true vapor pressure of the VOL. Tank TK-AB001 has a capacity of less than 39,890 gallons. All required recordkeeping requirements will be incorporated into the permit.

Subpart VV, Equipment Leaks of VOC in the Synthetic Organic Manufacturing Industry. NSPS, Subpart GGG requires equipment in VOC service to comply with paragraphs §§ 60.482-1 through 60.482-10, 60.484, 60.485, 60.486, and 60.487 except as provided in § 60.593. All equipment in VOC service affected under this permit is subject to NSPS, Subpart GGG.

Subpart GGG, Equipment Leaks of VOC in Petroleum Refineries. This subpart affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at a process unit that commenced construction or modification after January 4, 1983, and which is located at a petroleum refinery. The permit will require all affected equipment to comply with the applicable requirements of NSPS, Subparts GGG and VV. Equipment in HAP service is only required to comply with the NESHAP, Subpart CC. The permittee has elected to comply with the alternative standard for valves §§ 483-1 and 483-2.

Subpart LLL, Onshore Natural Gas Processing: SO₂ Emissions. This subpart affects each sweetening unit and each sweetening unit followed by a sulfur recovery unit that process natural gas which commenced construction or modification after January 20, 1984. Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface. This facility only processes gases that are generated at the facility from the processing of crude oil.

Subpart QQQ, VOC Emission from Petroleum Refinery Wastewater Systems. This subpart applies to individual drain systems, oil-water separators, and aggregate facilities located in a petroleum refinery and which commenced construction, modification, or reconstruction after May 4, 1987. Drains are required to be equipped with water seal controls. Junction boxes are required to be equipped with a cover and may have an open vent pipe. Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces. Oil-water wastewater separators shall be equipped with a fixed roof, which meets the required specifications. All required recordkeeping and equipment standards will be incorporated into the permit.

NESHAP, 40 CFR Part 61

[Subpart FF is Applicable]

Subpart J, Equipment Leaks (Fugitive Emission Sources) of Benzene. This subpart affects process streams that contain more than 10% benzene by weight. The maximum benzene concentration in any product stream at this site is 5% in super unleaded gasoline, and only trace amounts are expected in the refinery fuel gas.

Subpart FF, Benzene Waste Operations. This subpart affects benzene-contaminated wastewater at petroleum refineries. Facilities with less than 1-10 metric tons of benzene from facility waste are required to conduct annual determinations of the total annual benzene quantity from facility wastes. All required monitoring, and recordkeeping requirements will be incorporated into the permit.

NESHAP, 40 CFR Part 63

[Subparts CC and UUU are Applicable]

Subpart CC, Petroleum Refineries. This subpart, promulgated on August 18, 1995, affects various process units and related emission points at petroleum refineries. The affected emission points are listed on the following page with a summary of affected EU and applicable requirements.

Miscellaneous process vents from petroleum refining process units

There are no Group 1 miscellaneous process vents affected by this permit.

Storage vessels associated with petroleum refining process units, bulk gasoline terminals, or pipeline breakout stations

Group 2 storage vessels that are part of an existing source and subject to the provisions of NSPS, Subpart Kb are only required to comply with the provisions of NSPS, Subpart Kb except as provided in § 63.640(n)(8)(i) through (vi). There are two tanks affected by this permit (TK-AB001 & TK-SB001). Both tanks included in this permit are Group 2 storage vessels. Tank TK-AB001 will be subject to the recordkeeping requirements of NSPS, Subpart Kb.

Wastewater streams and treatment operations associated with petroleum refining process units

There are no Group 1 wastewater streams affected by this permit.

Equipment leaks from petroleum refining process units, bulk gasoline terminals, or pipeline breakout stations

All equipment in organic HAP service is required to comply with the provisions of 40 CFR Part 60, Subpart VV, except as provided in § 63.648(a)(1), (a)(2), and (c) through (i). All equipment subject to NSPS, Subpart GGG and this subpart is only required to comply with this subpart. All equipment in organic HAP service will be required to comply with this subpart. All applicable requirements will be incorporated into the permit.

Gasoline loading racks or pipeline breakout stations

This permit will not address any gasoline loading racks or pipeline breakout stations.

Marine vessel loading operations

There are no marine vessel loading operations at this facility.

Sulfur recovery plant vents and fuel gas emission points are specifically exempted from this subpart. All applicable emission limits, work practices, monitoring, and recordkeeping requirements of this subpart will be incorporated into the permit.

Subpart UUU, Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. This subpart, affects the following EUs:

1. Catalytic cracking units that regenerate catalyst;
2. Catalytic reforming units that regenerate catalyst; and
3. Sulfur recovery units and the tail gas treatment unit serving it;
4. Each bypass line serving a new, existing, or reconstructed catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit.

Sulfur recovery units subject to the NSPS, Subpart J, SO₂ emission limits must comply with the NSPS Subpart J, SO₂ emission limit. Bypass lines must meet the work practice standards in Table 36 of this subpart. The SRU is subject to NSPS, Subpart J and will meet all applicable requirements of this subpart and NSPS, Subpart J.

Air Quality reserves the right to reopen this permit if any other standard becomes applicable to this project.

CAM, 40 CFR Part 64

[Not Applicable At This Time]

Compliance Assurance Monitoring (CAM), as published in the Federal Register on October 22, 1997, applies to any pollutant specific EU at a major source, that is required to obtain a Title V permit, if it meets all of the following criteria:

1. It is subject to an emission limit or standard for an applicable regulated air pollutant;
2. It uses a control device to achieve compliance with the applicable emission limit or standard; and
3. It has potential emissions, prior to the control device, of the applicable regulated air pollutant greater than major source levels.

EUs subject to an emission limit or standard for which a Part 70 permit specifies a continuous compliance determination method are exempt from the CAM for that emission limit or standard. Emissions from the SRU are above the major source levels after control. However, the SRU will use a continuous emission monitor to ensure compliance with the limitation and is exempt from the CAM.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]
This facility handles naturally occurring hydrocarbon mixtures at a refinery and the Chemical Accident Prevention Provisions are applicable to this facility. The facility was required to submit the appropriate emergency response plan prior to June 21, 1999. The facility has submitted their plan which was given EPA No. 12005 for EPA Facility No. 1000 00128177. More information on this federal program is available on the web page: www.epa.gov/ceppo.

Stratospheric Ozone Protection, 40 CFR Part 82 [Applicable]
This facility does not produce, consume, recycle, import, or export any controlled substances or controlled products as defined in this part, nor does this facility perform service on motor (fleet) vehicles that involves ozone-depleting substances. Therefore, as currently operated, this facility is not subject to these requirements. To the extent that the facility has air-conditioning units that apply, the permit requires compliance with Part 82.

SECTION VIII. TIER CLASSIFICATION, PUBLIC REVIEW, AND FEES

A. Tier Classification and Public Review

This application has been determined to be a Tier II based on the request for a construction permit for an existing Part 70 source for a physical change that is considered significant under OAC 252:100-8-7.2(b)(2).

The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land used to accomplish the permitted purpose.

The applicant published the "Notice of Filing a Tier II Application" in the *Daily Ardmoreite*, a daily newspaper, in Carter County, on March 3, 2003. The notice stated that the application was available for public review at the Ardmore Public Library located at 320 E. NW, Ardmore, Oklahoma. The applicant published the "Notice of Tier II Draft Permit" in the *Daily Ardmoreite*, a daily newspaper, in Carter County, on May 27, 2003. The notice stated that the draft permit was available for public review at the Ardmore Public Library located at 320 E. NW, Ardmore, Oklahoma, the AQD main office and the Air Quality section of the DEQ web page at <http://www.deq.state.ok.us>. This facility is located within 50 miles of the Oklahoma - Texas border. The state of Texas has been notified of the draft permit. No comments were received from the public, the state of Texas, or EPA Region VI.

B. Fees Paid

Part 70 construction permit application fee of \$1,500 for existing Part 70 sources.

SECTION IX. SUMMARY

The applicant has demonstrated the ability to comply with all applicable Air Quality rules and regulations. Ambient air quality standards are not threatened at this site. Compliance and Enforcement concur with the issuance of this permit. Issuance of the permit is recommended.

**PERMIT TO COSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS**

**Valero Energy Corporation
TPI Petroleum, Inc.
Valero Ardmore Refinery
130 Long Ton per Day (LTPD) Sulfur Recovery Unit (SRU)
200 LTPD Tail Gas treating Unit (TGTU)
200 LTPD Amine Recovery Unit (ARU)**

Permit No. 98-172-C (M-11) (PSD)

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on January 23, 2003. The Evaluation Memorandum dated August 28, 2003, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. As required by applicable state and federal regulations, the permittee is authorized to construct, and/or operate, the affected equipment in conformity with the specifications contained herein. Commencing construction, or operations, under this permit constitutes acceptance of, and consent to, the conditions contained herein:

1. Upon issuance of an operating permit, the permittee shall be authorized to operate the affected facilities noted in this permit continuously (24 hours per day, every day of the year) subject to the following condition: [OAC 252:100-8-6(a)(1)]
 - a. The SRU shall not process more than 130 tons per day (TPD) of sulfur based on a 12-month rolling average.
2. Emission limitations and standards for affected Emission Units (EU):

EUG 170 SRU Incinerator. Emission limits for the SRU Incinerator. NO_x, CO, VOC, and PM₁₀ emissions from the incinerator are based on combustion of 27.7 MMBTUH of auxiliary fuel, combustion of 552,396 SCFH of waste gas with a heat content of 23 BTU/SCF, and AP-42, Section 1.4 (7/98). SO₂ emissions are based on a flow rate of 630,000 DSCFH @ 0% O₂ and the NSPS, Subpart J, SO₂ emission limit of 250 ppmdv.

EU	Point	Description	MMBTUH
SBH-001	P-170	SRU Incinerator	40.4

NO_x		SO₂	
lb/hr	TPY	lb/hr	TPY
4.0	17.4	26.2 ²	114.7

¹ – 2-hour average of contiguous 1-hour averages.

- a. The permittee shall incorporate the following BACT for reduction of SO₂ emissions. [OAC 252:100-8-6(a)]
- i. The SRU shall be equipped with a tail gas treating unit (TGTU). The TGTU shall process the off-gases from the SRU.
- b. EU SBH-001 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
- i. § 60.104 Standards for sulfur dioxide – (a)(2)(i);
 - ii. § 60.105 Monitoring of operations – (a)(5)(i & ii) & (e)(4)(i);
 - iii. § 60.106 Test methods and procedures – (a) & (f)(1 & 3).
- c. EU SBH-001 is subject to National Emission Standards for Hazardous Air Pollutants (NESHAP), Subpart UUU and shall comply with all applicable provisions. [40 CFR Part 63, Subpart UUU]
- i. § 63.1568 What are my requirements for HAP emissions from sulfur recovery units? – (a)(1)(i), (b)(1, 2, 5, 6, & 7), & (c)(1 & 2);
 - ii. § 60.105 63.1569 What are my requirements for HAP emissions from bypass lines? – (a)(1 & 3), (b)(1-4), & (c)(1 & 2);
 - iii. § 63.1570 What are my general requirements for complying with this subpart? – (a) & (c-g);
 - iv. 63.1571 How and when do I conduct a performance test or other initial compliance demonstration? – (a) & (b)(1-5);
 - v. 63.1572 What are my monitoring installation, operation, and maintenance requirements? – (a)(1-4) & (d)(1-2);
 - vi. 63.1574 What notifications must I submit and when? – (a)(1-3), (c), (d), & (f)(1, 2(i), 2(ii), 2(viii), 2(ix), & 2(x));
 - vii. 63.1575 What reports must I submit and when? – (a-h);
 - viii. 63.1576 What records must I keep, in what form, and for how long? – (a), (b)(1, 3, 4, 5), & (d-i);
 - ix. 63.1577 What parts of the General Provisions apply to me?
- d. EU SBH-001 is subject to OAC 252:100-31-26 and shall comply with all applicable provisions. [OAC 252:100-31-26]
- i. Hydrogen sulfide from any new petroleum or natural gas process equipment shall be removed from the exhaust gas stream or it shall be oxidized to sulfur dioxide. Hydrogen sulfide emissions shall be reduced by 95% of the hydrogen sulfide in the exhaust gas. [OAC 252:100-31-26(a)(1)]
 - ii. Sulfur recovery plants operating in conjunction with any refinery process shall have the sulfur reduction efficiencies required below. [OAC 252:100-31-26(a)(2)(B)]
 - A. When the sulfur content of the acid gas stream from the refinery process is greater than 5.0 LT/D but less than or equal to 150.0 LT/D, the required sulfur dioxide emission reduction efficiency of the sulfur recovery plant shall be calculated using the following formula where Z is the minimum emission reduction efficiency required at all times and X is the sulfur feed rate expressed in LT/D of sulfur rounded to one decimal place: $Z = 92.34 (X^{0.00774})$ [OAC 252:100-31-26(a)(2)(D)]

- iii. All new thermal devices for petroleum and natural gas processing facilities regulated under OAC 252:100-31-26(a)(1) shall have installed, calibrated, maintained, and operated an alarm system that will signal noncombustion of the gas.

[OAC 252:100-31-26(c)]

EUG 171 Hot Oil Heater (SBH-002). Emission limits and standards for EU SBH-002 are listed below. Emissions from SBH-002 are based on a maximum rated capacity (HHV) of 20 MMBTUH, the respective emissions factors from AP-42, Section 1.4 (7/98), and a fuel gas H₂S concentration of 159 ppm_v.

EU	Point	Description	MMBTUH
SBH-002	P-171	Hot Oil Heater	20.0

NO_x		CO	
lb/hr	TPY	lb/hr	TPY
1.0	4.3	1.7	7.2

- a. EU SBH-002 is subject to New Source Performance Standards (NSPS), Subpart Dc and shall comply with all applicable provisions. [40 CFR Part 60, Subpart Dc]
 - i. The permittee shall record and maintain records of the amounts of each fuel combusted in EU SBH-002 during each day. [40 CFR 60.48c(g)]
- b. EU SBH-002 is subject to New Source Performance Standards (NSPS), Subpart J and shall comply with all applicable provisions. [40 CFR Part 60, Subpart J]
 - i. § 60.104 Standards for sulfur dioxide – (a)(1);
 - ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii);
 - iii. § 60.106 Test methods and procedures – (e).

EUG 172 Regenerated Amine Storage Tank (TK-AB001). Emissions from EU TK-AB001 are based on TANKS4.0, a throughput of 12,463,046 bbl/yr, and a H₂S concentration of 0.1% by weight.

EU	Point	Roof Type	Contents	Barrels
TK-AB001	P-172	Cone	Amine	895

- a. The throughput for EU TK-AB001 shall not exceed 12,463,046 bbl/yr based on a 12-month rolling total. [OAC 252:100-8-6(a)(1)]
- b. Records of throughput shall be maintained (monthly and 12-month rolling average). [OAC 252:100-8-6(a)(3)]
- c. EU TK-AB001 is subject to New Source Performance Standards (NSPS), Subpart Kb and shall comply with all applicable provisions. [40 CFR Part 60, Subpart Kb]
 - i. The owner/operator shall keep for the life of the storage vessel readily accessible records showing the dimensions of the storage vessel and an analysis showing the capacity of the storage vessel. [§ 60.116b (a) & (b)]
 - ii. The owner/operator shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period. [§ 60.116b (c)]

EUG 173 Liquid Sulfur Storage Tank (TK-SB001). Emissions from EU TK-SB001 are based on a H₂S concentration of 8,000 ppmv, a run-down rate of 12,100 lb/hr of molten sulfur (130 LTD), and the density of molten sulfur (124.8 lb/CF). These emissions are vented to the SRU incinerator and are incorporated into that limit as SO₂.

EU	Point	Roof Type	Contents	Barrels
TK-SB001	P-173	Cone	Sulfur	3,300

- a. The throughput for EU TK-SB001 shall not exceed 130 LTD based on a 12-month rolling average. [OAC 252:100-8-6(a)(1)]
- b. Records of throughput shall be maintained (monthly and 12-month rolling average). [OAC 252:100-8-6(a)(3)]

EUG 174 Molten Sulfur Railcar Loading Rack (LR-SB001). Emissions from EU LR-SB001 are based on a H₂S concentration of 8,000 ppmv, a loading rate of 100,000 lb/hr of molten sulfur, and the density of molten sulfur (124.8 lb/CF). These emissions are vented to the SRU incinerator and are incorporated into that limit as SO₂.

EU	Point	Loading Rack	Loading Arm
LR-SB001	P-171	1	1
			2
			3

- a. EU LR-SB001 is subject to OAC 252:100-31-26 and shall comply with all applicable provisions. [OAC 252:100-31-26]
 - i. Hydrogen sulfide from any new petroleum or natural gas process equipment shall be removed from the exhaust gas stream or it shall be oxidized to sulfur dioxide. Hydrogen sulfide emissions shall be reduced by 95% of the hydrogen sulfide in the exhaust gas. [OAC 252:100-31-26(a)(1)]
 - ii. All new thermal devices for petroleum and natural gas processing facilities regulated under OAC 252:100-31-26(a)(1) shall have installed, calibrated, maintained, and operated an alarm system that will signal noncombustion of the gas. [OAC 252:100-31-26(c)]

EUG 210 Cat Feed Hydrotreater Unit Fugitive VOC (Area 650). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	Point	Number Items	Type of Equipment
Area 650	F-110	4	Valves
		6	Flanges

- a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component. [40 CFR Part 63, Subpart CC]
 - i. §63.642 General Standards – (c), (d)(1), (e), & (f);
 - ii. §63.648 Equipment Leak Standards – (a), (b), (c), & (e-i);
 - iii. §63.654 Reporting and Recordkeeping Requirements – (d), & (f-h).
- b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) and which is in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
 - i. §60.592 Standards (a-e);
 - ii. §60.593 Exceptions (a-e).

EUG 220 Naptha Hydrotreater (NHT) Fugitive VOC (Area 650). Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR program.

EU	Point	Number Items	Type of Equipment
Area 400	F-107	8	Valves
		22	Flanges

- a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component. [40 CFR Part 63, Subpart CC]
 - i. §63.642 General Standards – (c), (d)(1), (e), & (f);
 - ii. §63.648 Equipment Leak Standards – (a), (b), (c), & (e-i);
 - iii. §63.654 Reporting and Recordkeeping Requirements – (d), & (f-h).
- b. Equipment determined not to be in HAP service (contacting <5% by weight HAP) and which is in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
 - i. §60.592 Standards (a-e);
 - ii. §60.593 Exceptions (a-e).

EUG 230: Amine Regenerator Unit #2 Wastewater Processing. Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR programs.

EU	Point	Number Items	Type of Equipment
WWAB-001	F-AB001	12	P-Trap
		2	Junction Boxes

- a. Equipment in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
 - i. §60.592 Standards (a-e);
 - ii. §60.593 Exceptions (a-e).

EUG 231: SCOT Unit #2 Wastewater Processing. Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR programs.

EU	Point	Number Items	Type of Equipment
WWSB-001	F-SB001	9	P-Trap
		1	Junction Box

- a. Equipment in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
 - i. §60.592 Standards (a-e);
 - ii. §60.593 Exceptions (a-e).

EUG 530: SCOT Unit #2 Fugitive Sources. Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR programs.

EU	Point	Number Items	Type of Equipment
Area 530	F-530	282	Valves
		499	Flanges
		4	Other
		6	Pumps

- a. Equipment in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
 - i. §60.592 Standards (a-e);
 - ii. §60.593 Exceptions (a-e).

EUG 560: Amine Regeneration Unit #2 Fugitive Sources. Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR programs.

EU	Point	Number Items	Type of Equipment
Area 560	F-560	314	Valves
		630	Flanges
		8	Other
		6	Pumps

- a. Equipment in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
 - i. §60.592 Standards (a-e);
 - ii. §60.593 Exceptions (a-e).

EUG 570: SRU Tail Gas Treating Unit #2 Fugitive Sources. Fugitive VOC emissions are estimated based on existing equipment items but do not have a specific limitation except to comply with the applicable LDAR programs.

EU	Point	Number Items	Type of Equipment
Area 570	F-570	252	Valves
		560	Flanges
		3	Other
		7	Pumps

- a. Equipment in VOC service (contacting >10% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]
 - i. §60.592 Standards (a-e);
 - ii. §60.593 Exceptions (a-e).

3. Certain equipment within the refinery is subject to NSPS, 40 CFR Part 60, Subpart QQQ and all affected equipment shall comply with all applicable requirements. [40 CFR 60, NSPS, Subpart QQQ]
 - a. § 60.692–1 Standards: General.
 - b. § 60.692–2 Standards: Individual drain systems.
 - c. § 60.692–3 Standards: Oil-water separators.
 - d. § 60.692–4 Standards: Aggregate facility.
 - e. § 60.692–5 Standards: Closed vent systems and control devices.
 - f. § 60.692–6 Standards: Delay of repair.
 - g. § 60.692–7 Standards: Delay of compliance.
 - h. § 60.693–1 Alternative standards for individual drain systems.
 - i. § 60.693–2 Alternative standards for oil-water separators.
 - j. § 60.695 Monitoring of operations.
 - k. § 60.696 Performance test methods and procedures and compliance provisions.
 - l. § 60.697 Recordkeeping requirements.
 - m. § 60.698 Reporting requirements.

4. The Refinery is subject to NESHAP, 40 CFR Part 61, Subpart FF and shall comply with all applicable requirements. [40 CFR 61, NESHAP, Subpart FF]
 - a. § 61.342 Standards: General.
 - b. § 61.343 Standards: Tanks.
 - c. § 61.344 Standards: Surface Impoundments.
 - d. § 61.345 Standards: Containers.
 - e. § 61.346 Standards: Individual drain systems.
 - f. § 61.347 Standards: Oil-water separators.
 - g. § 61.348 Standards: Treatment processes.
 - h. § 61.349 Standards: Closed-vent systems and control devices.
 - i. § 61.350 Standards: Delay of repair.
 - j. § 61.351 Alternative standards for tanks.
 - k. § 61.352 Alternative standards for oilwater separators.

- l. § 61.353 Alternative means of emission limitation.
 - m. § 61.354 Monitoring of operations.
 - n. § 61.355 Test methods, procedures, and compliance provisions.
 - o. § 61.356 Recordkeeping requirements.
 - p. § 61.357 Reporting requirements.
5. Until 12 consecutive months of data has been collected to determine the 12-month rolling averages applicable to the facility, the facility shall fill the missing data for the previous months with an estimated average monthly figure based on the applicable rolling average divided by 12. If there exists enough data to determine the values for the previous months, it can be used to determine the applicable 12-month rolling averages. [OAC 252:100-8-6(a)(3)]
6. The permittee shall maintain records as specified in Specific Condition 1 and 2 including but not limited to those listed below. These records shall be maintained on-site for at least five years after the date of recording and shall be provided to regulatory personnel upon request. [OAC 252:100-43]
- a. Records showing compliance with all applicable 12-month rolling averages (monthly).
 - b. Records required by NSPS, Subparts Dc, Kb, J, GGG, and QQQ and NESHAP, Subparts CC, FF, and UUU.
7. When monitoring shows an exceedance of any of the limits of Specific Condition No. 1 or 2, the owner or operator shall comply with the provisions of OAC 252:100-9 for excess emissions. [OAC 252:100-9]
8. No later than 30 days after each anniversary date of the issuance of the Part 70 operating permit for this facility, the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of the Part 70 operating permit. The following specific information for the past year is required to be included: [OAC 252:100-8-6 (c)(5)(A) & (D)]
- a. Summary of records showing compliance with all applicable 12-month rolling averages (monthly).
 - b. Summary of records required by NSPS, Subparts Dc, Kb, J, GGG, and QQQ and NESHAP, Subparts CC, FF, and UUU.

Valero Energy Corporation
TPI Petroleum, Inc.
Attn: Mr. John Shriver, P.E.
Environmental Manager
Post Office Box 188
Ardmore, OK 74302

Re: Construction Permit No. **98-172-C (M-11) (PSD)**
Valero Ardmore Refinery - 130 Long Ton per Day (LTPD) Sulfur Recovery Unit (SRU),
200 LTPD Tail Gas treating Unit (TGTU), & 200 LTPD Amine Recovery Unit (ARU)
Ardmore, Carter County

Dear Mr. Shriver:

Enclosed is the modified permit authorizing construction/modification of the referenced facility. Please note that this permit is issued subject to the certain standards and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me at (405) 702-4217.

Sincerely,

Eric L. Milligan, P.E.
Engineering Section
AIR QUALITY DIVISION

enclosures

Copy: Ardmore DEQ Office (Carter County)