Double Green Bridge
NW INNOVATION WORKS
KALAMA

380 W. Marine Drive, Kalama WA 98625

February 24, 2016

Marc Crooks
Washington Department of Ecology
Air Quality Program
300 Desmond Drive
Lacey, WA 98503

Paul Mairose
Chief Engineer
Southwest Clean Air Agency
11815 NE 99th Street #1294
Vancouver, WA 98682

Re: NW Innovation Works Kalama Manufacturing Facility

Dear Sirs:

On behalf of NW Innovation Works I am submitting the enclosed joint application for a Prevention of Significant Deterioration ("PSD") permit and an Air Discharge Permit to the Department of Ecology ("Ecology") and the Southwest Clean Air Agency ("SWCAA").

Ecology's PSD review will cover pollutants for which the project will have significant net emissions -- NOx, PM, VOC and GHGs. Per WAC 173-455-120(10), we are enclosing a check to Ecology in the amount of $15,000 to cover the PSD application fee. SWCAA's review will cover the remaining pollutants described in the application. Per SWCAA 400-109(4), we are enclosing a check in the amount of $6,500 to SWCAA to cover the application fee.

Please do not hesitate to contact me at (360) 673-7805 if you have any questions or need any additional information.

Very Truly Yours,

Kurt Humphrey
Environmental Manager

Enclosures

Prepared for:

Northwest Innovation Works, Kalama, LLC
Kalama, Washington

Prepared by:

Ramboll Environ US Corporation
Lynnwood, Washington

Date:

February 2016

Project Number:
29-36153A

PREVENTION OF SIGNIFICANT DETERIORATION AND AIR DISCHARGE PERMIT APPLICATION

KALAMA MANUFACTURING AND MARINE EXPORT FACILITY

RAMBOLL ENVIRON

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1. INTRODUCTION

Northwest Innovation Works, Kalama, LLC (NWIWK) and the Port of Kalama (Port) propose to construct and operate a methanol production facility (the Facility) on approximately 90 acres at the Port's Northport site. The Facility will be called the Kalama Manufacturing and Marine Export Facility (KMMEF), and will be located at 222 West Kalama River Road along the east bank of the Columbia River in unincorporated Cowlitz County, Washington. The location of the Facility is shown in Figure 1-1.

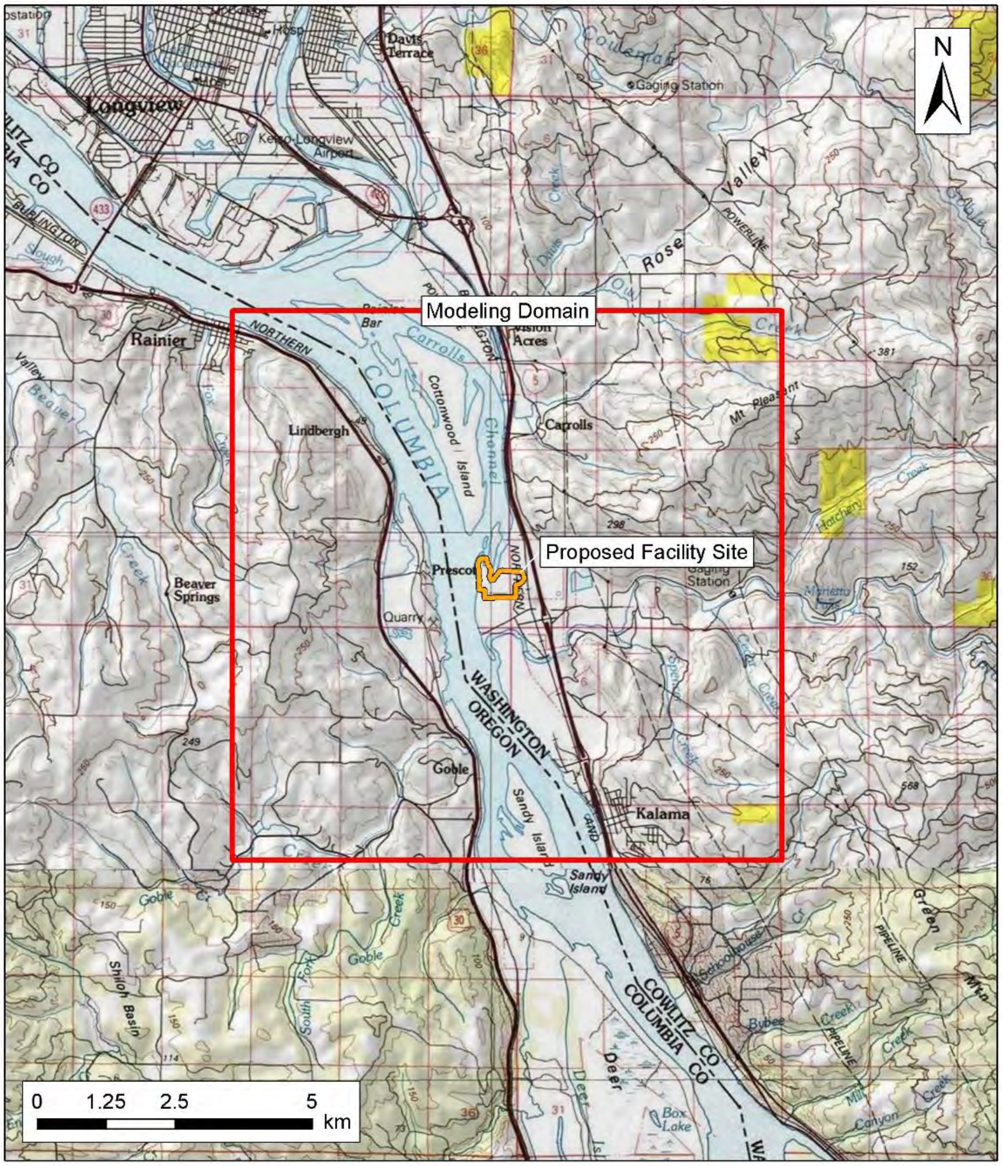

Figure 1-1: Location of Proposed Facility and Modeling Domain

The proposed methanol plant will be produce up to 10,000 metric tons of AA-grade methanol per day and, at full capacity, is expected to produce approximately 3.6 million metric tons per year (mtpy). The Facility will consist of two production lines, each with a daily production capacity of 5,000 metric tons. The methanol will be stored on site for shipment to global markets by marine vessel from a newly constructed dock.

The Facility will process natural gas from a pipeline to be constructed by Northwest Pipeline GP. Constructing this pipeline will involve installing approximately 3.1 miles of 24-inch diameter pipeline, metering facilities, and miscellaneous equipment extending from Northwest's mainline located east of the Northport site to the proposed facility. The pipeline is subject to the jurisdiction of the Federal Energy Regulatory Commission and is being permitted by Northwest Pipeline as part of a separate action.

Methanol will be manufactured at the Facility by removing impurities from natural gas, converting the purified feedstock gas into synthesis gas ("syngas") using Ultra-Low Emission (ULE) reforming technology, and converting the syngas into liquid methanol. The finished product methanol will be stored on site until it is exported using marine vessels.

The facility is within the jurisdiction of the Southwest Clean Air Agency (SWCAA). Because the proposed Facility will emit regulated air pollutants, an Air Discharge Permit (ADP) application must be filed with SWCAA, and construction cannot commence until SWCAA issues an ADP.

Based on the magnitudes of the expected air pollutant and greenhouse gas (GHG) emissions associated with the proposed Facility, some of the pollutants attributable to the project will be subject to the requirements of the state Prevention of Significant Deterioration (PSD) program. Construction of the Facility cannot commence until the Washington Department of Ecology (Ecology) issues a PSD permit.

NWIWK has retained Ramboll Environ US Corporation (Ramboll Environ) to prepare this combined PSD and ADP application on its behalf.

1.1 Organization

The key components of this application are:

- A description of the Facility and expected criteria and toxic air pollutant (TAP) emission rates attributable to the Facility;
- A discussion of potentially applicable air quality regulations;
- An analysis of compliance with ambient air quality standards and, as applicable, PSD increments;
- An analysis of ambient TAP concentration increases; and
- Completed standard SWCAA and Ecology forms (Appendix A).

1.2 Summary of Findings

Ramboll Environ conducted air dispersion modeling to demonstrate compliance with ambient air quality standards and TAP acceptable source impact levels, and prepared a Best Available Control Technology (BACT) analysis to demonstrate that new emission units associated with the project will employ BACT. In summary, these analyses indicated that:

- Predicted ambient air pollutant concentrations attributable to the proposed Facility will not cause or contribute to an exceedance of any ambient air quality standards or PSD increments,
- TAP emission increases attributable to the proposed Facility are sufficiently low to protect human health and safety from potential carcinogenic and/or other toxic effects, and
- All emission units associated with the proposed Facility will employ BACT for all criteria pollutants and TAPs.

2. PROJECT DESCRIPTION

This section provides detailed project information necessary for SWCAA's review to ensure that the Facility will be in compliance with all applicable regulations.

2.1 Project Location

The proposed project would be located at the Port's North Port site at 222 West Kalama River Road in unincorporated Cowlitz County, Washington. Cowlitz County is designated as in attainment or unclassifiable for all criteria pollutants. Existing Port facilities are located along the Columbia River between approximately river mile (RM) 72 and RM 77. The North Port site is located at approximately RM 72 along the east bank of the Columbia River. The BNSF Railway and Interstate 5 (I-5) lie immediately to the east.

The project site is bounded by the Columbia River to the west; by Tradewinds Road, an existing Air Liquide industrial facility, and the Port's industrial wastewater treatment plant to the east; by Port property primarily used for open space, recreation, and wetland mitigation to the north; and by the existing Steelscape manufacturing facility to the south.

2.2 Process Description

Methanol, also known as methyl alcohol or wood alcohol, is the simplest of all alcohols with the chemical formula CH_3OH. It is biodegradable and non-carcinogenic. Methanol can be used as a fuel, but is more commonly used as an essential ingredient in chemical and manufacturing processes for products, including paint, particle board, plastics, carpets, pharmaceuticals, laminated lumber, and windshield wiper fluid.

Making pure methanol from natural gas is an established technology: natural gas is combined with steam and heat to produce syngas, which is composed of carbon monoxide (CO), carbon dioxide (CO_2), and hydrogen (H_2). A catalyst is used to create a chemical reaction, and the resulting liquid is distilled to yield 99.9 percent pure methanol and 0.1 percent water.

Natural gas arriving at the Facility by pipeline will be treated to remove sulfur compounds, then compressed, and saturated with process water. The treated water-rich natural gas is partially reformed with steam as a primary step, and completely reformed with oxygen in a secondary step using an autothermal reformer (ATR). The combination of two reforming processes creates syngas with the optimum composition for methanol synthesis.

The Facility will use Ultra-Low Emission (ULE) reforming technology, which employs a gas-heated reformer (GHR) and an ATR to produce syngas. Rather than combusting natural gas to provide heat for the primary reforming step, the hot syngas from the secondary reforming step (i.e., the ATR) flows through the shell side of the primary reformer (i.e., the GHR), where heat in transferred to the feedstock on the tube side. After leaving the shell-side of the GHR, the syngas is passed through a series of heat exchangers that recover waste heat to provide energy for the methanol synthesis and distillation processes.

The reformed synthesis gas then enters the two converters where crude methanol is created. Not all of the synthesis gas can be converted to methanol in the first pass, so the outlet gas from the converters contains a mixture of methanol and unreacted synthesis gas.

The hot gas mixture leaving the converters flows through a series of coolers to allow methanol product to condense, and to recover and reuse waste process heat to improve energy efficiency. Condensed crude methanol is sent to the methanol distillation unit, and the non-condensed gas mixture is compressed and recycled back to the converters to enhance methanol production.

Crude methanol from the synthesis process is sent to the distillation unit where it is distilled to the required purity. Water and several other hydrocarbon by-products are synthesized at the same time as methanol. These by-products are separated from the methanol through a separation vessel and a series of three distillation columns.

The refined methanol is then directed to on-site storage tanks, the light hydrocarbon by-products are recovered and used as fuel for the boilers, and the heavy by-products (mainly water) are recycled to the reforming step for use in saturating the natural gas feedstock with process water.

ULE reforming is a proven technology, commonly used for reforming other chemicals from natural gas, and has been used at a smaller scale for the production of methanol. The proposed project will be the first large-scale application of ULE technology in the world. However, air pollutant emissions attributable to the project will be generated by commonplace industrial equipment such as boilers, process heaters, combustion turbines, and cooling towers. There will be no direct emissions from the reformers (i.e., the GHR and the ATR), the methanol synthesis and distillation process equipment, the natural gas desulfurization system, or the on-site air separation units (ASU) that will produce oxygen for the reforming process.

The proposed Facility will include the following emission units:

- 3 boilers, each with a maximum heat input capacity of approximately 530 million British thermal units per hour (MMBtu/hr) – one boiler per production line, and one held in reserve;
- 2 combustion turbines, each with a capacity to generate approximately 45 megawatts (MW), that will be operated in a 2 x 1 combined-cycle format with a steam turbine capable of generating approximately 31 MW;
- 2 process heaters, each with a maximum heat input capacity of 72 MMBtu/hr, that will be operated only during startup and shutdown of the methanol production lines;
- 1 elevated flare, with a natural gas-fired pilot, that will be used only during startup and shutdown of the methanol production lines, and, potentially, during process upsets or emergencies;
- 1 mechanical draft cooling tower with 12 cells;
- 8 final product storage tanks;
- 4 shift product storage tanks;
- 2 crude product storage tanks;
- 1 tank vent scrubber;
- 1 ship loading scrubber;
- 2 diesel-powered generators, each with a capacity of approximately 3.5 MW, for emergency use, as well as periodic use for testing and maintenance, and;
- 1 diesel-powered fire water pump, with capacity of approximately 1,600 horsepower, for emergency use, as well as periodic use for testing and maintenance.

A process flow diagram showing the relationships between the emission units and non-emitting major pieces of equipment is provided in Figure 2-1.

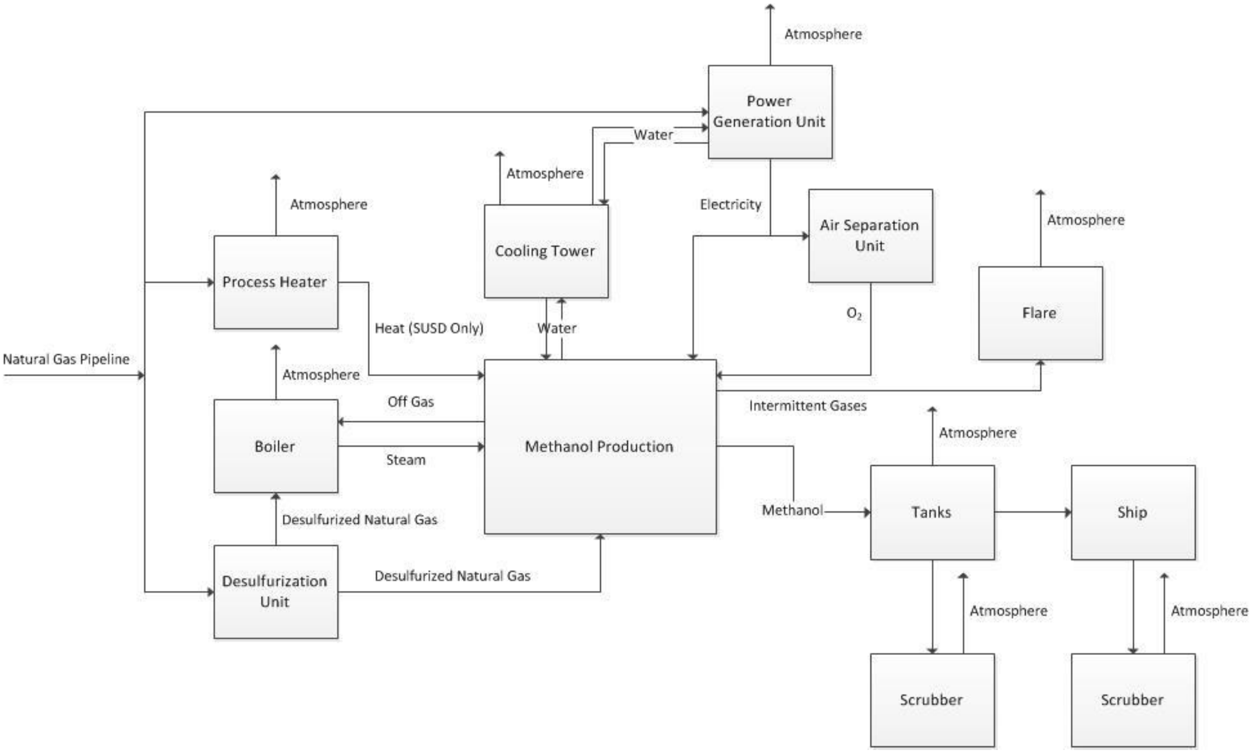

Figure 2-1: Process Flow Diagram

2.3 Process Startup and Shutdown

The methanol production lines will be designed to operate continuously. After initial startup, the only planned shutdown will be when the catalysts in the GHR and ATR have deactivated to the point where it is more economical to cease production and replace the catalysts, rather than to continue to operate at an increasingly reduced rate. Replacement of the catalysts is expected to occur every four to six years.

The production line startup process is a complicated, multi-step process, expected to take approximately 40 hours. Initially, the GHR and ATR are gradually heated by circulating nitrogen gas heated by a natural gas-fired process heater, and then heated nitrogen gas combined with steam from the boiler. When the GHR and ATR are sufficiently heated, treated (i.e., desulfurized) natural gas is gradually added to the steam and nitrogen flow, until the natural gas flow rate reaches approximately 40 percent of the rate under normal production. At that point, oxygen is introduced to the ATR, which begins the exothermic secondary reforming reaction. As the temperature of the gases exiting the ATR increase, firing of the process heater is decreased until it is no longer needed and is shut down.

Up to this point, partially-reformed gases created in the GHR and ATR following the introduction of natural gas to the process are routed to the flare for safe disposal. When the gases exiting the ATR reach a certain temperature, the reformed syngas exiting the shell side of GHR is sent to the methanol synthesis system (often referred to as "the loop") instead of the flare, and the purge gases from the synthesis loop are sent to flare. When the ATR reaches its normal operating temperature, the loop purge gases are sent to the boiler instead of the flare to replace natural gas as a fuel, and the natural gas feed to the process and the boiler load are increased until reaching full production rate.

The process line shutdown process is expected to require approximately 6 hours. Shutdown begins with reducing the natural gas feed to less than 70 percent of the normal production rate. As the natural gas feed is reduced, the boiler load is also reduced, and then shut down entirely when the natural gas feed reaches 30 percent of the normal production rate. At that point, the gases contained in the production equipment will be flared, or, if possible, the process heater will be fired at a rate that provides sufficient heat to convert as much of the reformed gas as possible to syngas, which will be sent to the synthesis loop. After the natural gas feed is halted, the partially reformed and partially synthesized gases in the system are vented to the flare for safe destruction.

2.4 Construction Phase

The proposed project would be developed in one or two phases. The construction duration would be approximately 26 to 48 months depending on whether it is built in one or two phases. Construction is expected to begin in late 2016 and be completed as early as mid-2018 and as late as mid-2020. This schedule includes workers associated with the marine terminal construction activities.

Construction of the proposed manufacturing facility and associated marine terminal would introduce construction workers and truck trips to the project site. An average of 550 workers would be on site during the construction period. During the peak construction activities, there would be an average of approximately 1,032 workers.

Construction of the proposed methanol manufacturing facility would commence with mobilization, site preparation, and civil works activities. Site preparation would consist of clearing and grubbing the site, grading, and setting up the temporary construction facilities discussed above. Civil works would follow site preparation and would involve installation of ground improvements and utilities. Utility work at project outset would include firewater, drain lines, the underground duct bank, and other underground utilities. These utilities would be prioritized along with the other civil work. Following completion of the utility work, site paving would begin.

Construction of the methanol production lines would be modularized to the maximum extent practicable, with as much of the construction activity occurring off-site as feasible. It is expected that certain components (e.g., boilers, ASUs, water treatment, substation, and motor control centers) would be assembled off-site and transported to the project site via the Columbia River. Certain components, such as the cooling towers, bulk product storage tanks, and support buildings, may be constructed on the project site. The flare would be purchased as a package and erected on site by a mechanical contractor.

2.5 Project Air Pollutant Emissions

To determine the applicability of regulations, and to predict potential air quality impacts associated with the proposed project, the types and quantities of air pollutant emission increases were identified. Pollutant emission rates were determined by the physical and operational characteristics of the proposed equipment.

This section describes how criteria pollutant and TAP emission rates associated with the proposed Facility were calculated. Potentials to emit (PTEs)[1] were calculated using representative emission factors and maximum potential activity rates. Table 2-1 presents the annual criteria pollutant PTE associated with the proposed Facility.

Table 2-1. Project Criteria Pollutant and Greenhouse Gas Annual PTE

Emission Unit	Emission Rate (tpy)						
	NO_X	CO	PM_{10}	$PM_{2.5}$	SO_2	VOC	GHG (CO_2e)
Boilers (2 + 1 redundant)	23	18	28	28	0.027	12	606,000

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[1] "Potential to emit" is defined in SWCAA 400-020(101) and WAC 173-400-030(73) as the maximum capacity (i.e., design capacity) of a "stationary source" to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the "stationary source" to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a "stationary source."

Emission Unit	Emission Rate (tpy)						
	NO_X	CO	PM_{10}	$PM_{2.5}$	SO_2	VOC	GHG (CO_2e)
Power Generation Unit	44	43	33	33	14	18	465,000
Process Heaters (2)	0.42	0.43	0.095	0.095	0.093	0.069	1,500
Flare	6.3	9.3	0.93	0.23	0.00055	17	3,500
Flare Pilot	0.10	0.45	0.015	0.0036	0.0052	0.20	171
Cooling Tower (12 cells)	--	--	2.7	0.0082	--	--	--
Methanol Tank Fugitives	--	0.0072	--	--	--	2.5	0.063
Tank Vent Scrubber	--	0.72	--	--	--	2.5	6.2
Ship Vent Scrubber	--	--	--	--	--	1.2	--
Emergency Generator Engines	0.40	0.19	0.018	0.018	0.0029	0.095	300
Emergency Fire Pump Engine	0.26	0.079	0.010	0.010	0.00054	0.010	50
Component Leaks	--	--	--	--	--	0.55	12
Total	75	72	64	61	14	54	1,076,000
PSD Significant Emission Rate	40	100	15	10	40	40	100,000

Table 2-2 presents TAP PTE associated with proposed Facility, which are compared with the Small Quantity Emission Rates (SQERs) provided in WAC 173-460.[2] Additional detail regarding how the emission rates were calculated for each emission unit type is provided in the sections that follow.

Table 2-2. Project Toxic Air Pollutant PTE

Pollutant	CAS	Emission Rate		SQER[1]		Model?
		(lb/yr)	(lb/hr)	(lb/yr)	(lb/hr)	
Acetaldehyde	75-07-0	320	0.0466	50	N/A	Yes
Acrolein	107-02-8	51.1	0.00776	175	0.02	No
Ammonia	7664-41-7	162,000	8.74	17,500	2	Yes
Arsenic	7440-38-2	2.37	0.00095	0	N/A	Yes

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[2] SWCAA regulations reference WAC 173-460, effective August 21, 1998.

		Emission Rate		SQER[1]		
Pollutant	**CAS**	**(lb/yr)**	**(lb/hr)**	**(lb/yr)**	**(lb/hr)**	**Model?**
Barium	7440-39-3	52.2	0.0209	175	0.02	Yes
Benz(a)anthracene	56-55-3	0.0240	0.0000593	TBD	TBD	No
Benzene	71-43-2	190	0.617	20	N/A	Yes
Benzo(a)anthracene	56-55-3	0.0240	0.0000593	TBD	TBD	No
Benzo(a)pyrene	50-32-8	0.0153	0.0000267	0	N/A	Yes
Benzo(b)fluoranthene	205-99-2	0.0261	0.0000991	TBD	TBD	No
Benzo(k)fluoranthene	207-08-9	0.0223	0.0000263	TBD	TBD	No
Beryllium	7440-41-7	0.142	0.000057	0	N/A	Yes
1,3-Butadiene	106-99-0	3.43	0.000478	0.5	N/A	Yes
Butane	106-97-8	24,900	9.98	43,748	5	Yes
Cadmium	7440-43-9	13.0	0.00523	0	N/A	Yes
Chromium	7440-47-3	16.6	0.00665	175	0.02	No
Chromium, Hexavalent*	18540-29-9	0.664	0.000266	0	N/A	Yes
Cobalt	7440-48-4	0.996	0.000399	175	0.02	No
Copper	7440-50-8	10.1	0.00404	175	0.02	No
Dibenz(a,h)anthracene	53-70-3	0.0157	0.0000339	TBD	TBD	No
Dibenzo(a,h)anthracene	53-70-3	0.0157	0.0000339	TBD	TBD	No
Ethylbenzene	100-41-4	256	0.0356	43,748	5	No
Formaldehyde	50-00-0	1,360	4.08	20	N/A	Yes
Hexane	110-54-3	34.8	0.101	22,750	2.6	No
Indeno(1,2,3-cd)pyrene	193-39-5	0.0231	0.0000423	TBD	TBD	No
Lead	7439-92-1	5.08	0.00226	50	A (Special)	No
Manganese	7439-96-5	4.51	0.00181	175	0.02	No
Mercury	7439-97-6	3.08	0.00124	175	0.02	No
Methanol	67-56-1	13,600	3.22	43,748	5	No
Molybdenum	7439-98-7	13.0	0.00523	1,750	0.2	No
Naphthalene	91-20-3	18.6	0.0504	22,750	2.6	No
Nickel	7440-02-0	24.9	0.00998	0.5	N/A	Yes
PAH	PAH	22.2	0.00294	0	N/A	Yes

Pollutant	CAS	Emission Rate (lb/yr)	Emission Rate (lb/hr)	SQER[1] (lb/yr)	SQER[1] (lb/hr)	Model?
Pentane	109-66-0	30,800	12.4	43,748	5	Yes
Propylene Oxide	75-56-9	232	0.0323	50	N/A	Yes
Selenium	7782-49-2	0.285	0.000114	175	0.02	No
Sulfuric Acid	7664-93-9	19,100	1.87	175	0.02	Yes
Toluene	108-88-3	1,200	0.375	43,748	5	No
Xylenes	1330-20-7	512	0.0869	43,748	5	No

1. From WAC 173-460-150, effective 8/21/1998

2.6 Boilers

Steam for the primary stage of the reforming process that produces syngas will be generated on-site by gas-fired boilers. There will be three boilers, each capable of generating a maximum of approximately 170 metric tons of steam per hour, and each with a maximum heat input of approximately 530 MMBtu/hr. When the facility is operating normally, each production line will receive steam from one boiler, and the third will be held in reserve as a redundant unit, available in case one of the other boilers becomes unavailable for some reason. Operating hours will be apportioned among the three boilers such that no one boiler is used significantly more or less often than the other two.

The light hydrocarbon by-products recovered from the methanol distillation process will be the primary fuel combusted by the boilers. The quantity of recovered by-product fuel available during normal operation is not expected to be sufficient to operate the boilers at full capacity. When the GHR and ATR catalysts are new, the recovered by-product fuel will be supplemented with treated natural gas (i.e., natural gas with sulfur removed) to satisfy the steam demand of the methanol production process. As the activity of the reformer catalysts decreases, the capacity of the methanol production process to produce methanol will decrease. Decreased methanol production will require less process steam, and, therefore, fuel use in the boilers will decrease. In response, natural gas usage will decrease until only process by-product gas will be combusted by the boilers.

Boiler startup requires approximately 4 hours, and for approximately 2 of those hours, the exhaust is insufficient to support operation of add-on controls devices (i.e., selective catalytic reduction and catalytic oxidation). As as result, NO_X, CO, and VOC emissions are increased during that period. Increased TAP emissions during startup were not considered due to lack of information. Shutdown of the boilers is nearly instantaneous, and emissions effectively cease when fuel delivery to the boiler is stopped.

Boiler criteria and greenhouse gas pollutant emission rates are summarized in Table 2-3, and toxic and hazardous air pollutant emission rates are summarized in Table 2-4.

Table 2-3. Gas-Fired Boiler Criteria Pollutant and Greenhouse Gas Emissions

Pollutant	Emission Factor (lb/MMBtu)	Emission Rate[1]					
		Hourly				Annual	
		Normal Operation[2] (lb/hr)	Production Line Startup[2] (lb/hr)	Production Line Shutdown[3] (lb/hr)	Boiler Startup[4] (lb/hr)	Continuous Normal Operation[5] (tpy)	Normal Operation w/SUSD[6] (tpy)
NO$_X$[7]	0.0049	2.60	2.60	2.21	3.90	11.4	11.5
CO[8]	0.0037	1.98	1.98	1.68	15.8	8.66	9.04
PM10/PM2.5[9]	0.0060	3.18	3.18	2.70	0.795	13.9	13.9
SO2[10]	5.9E-06	0.00313	0.00313	0.00266	0.000783	0.0137	0.0137
VOC[11]	0.0025	1.33	1.33	1.13	2.65	5.80	5.87
GHG (CO$_2$e)[12]	117	62,000	62,000	52,700	15,500	272,000	272,000

1. Emission rates for a single boiler
2. Maximum hourly emission rates during normal and production line startup operation are based on a heat input of 530 MMBtu/hr, which is the maximum continuous rating of the proposed boiler
3. Maximum hourly emission rates during production line shutdown operation are based on a heat input of 451 MMBtu/hr, which is the maximum hourly average load expected during shutdown
4. Maximum hourly emission rates during boiler startup are based on a heat input of 133 MMBtu/hr, an exhaust flow of 1,088 kscf/hr at 3% O_2, and the following exhaust concentrations: NO_X – 30 ppmv at 3% O2, CO – 200 ppmv at 3% O2, and VOC – 0.02 lb/MMBtu.
5. Continuous normal operation annual emission rates are based on a heat input of 530 MMBtu/hr and operation 8,760 hours per year
6. Annual emission rates for normal operation with 6 production line startups and shutdowns are based on a heat input of 530 MMBtu/hr during 8,262 hours of normal operation and during 480 hours of production line startup, a heat input of 451 MMBtu/hr during 18 hours of operation during production line shutdown, and a heat input of 133 MMBtu/hr and an exhaust flow of 1088 kscf/hr at 3% O_2 during 48 hours of boiler startup
7. NOx emission factor based on 4 ppmvd @ 3% O_2, achieved using low-NOx burners and SCR, and operation at 530 MMBtu/hr, which is the maximum continuous rating of the proposed boiler
8. CO emission factor based on 3 ppmvd @ 3% O_2, achieved using oxidation catalyst, and operation at 530 MMBtu/hr, which is the maximum continuous rating of the proposed boiler
9. PM_{10}/$PM_{2.5}$ emission factor based on boiler vendor recommendation, achived by combusting treated pipeline natural gas
10. SO_2 emission factor based on maximum expected sulfur content of treated natural gas
11. VOC emission factor based of boiler vendor recommendation, achieved using oxidation catalyst
12. GHG emission factors and global warming potentials from 40 CFR Part 98

Table 2-4. Gas-Fired Boiler Toxic and Hazardous Air Pollutant Emissions

			Emission Rate[1]				
			Hourly			Annual	
Pollutant	CAS	Emission Factor[2] (lb/MMBtu)	Normal Operation[3] (lb/hr)	Production Line Startup[3] (lb/hr)	Production Line Shutdown[4] (lb/hr)	Continuous Normal Operation[5] (lb/yr)	Normal Operation w/SUSD[6] (lb/yr)
Acenaphthene	83-32-9	1.80E-06	9.05E-07	9.05E-07	7.70E-07	7.93E-03	7.93E-03
Acenaphthylene	208-96-8	1.80E-06	9.05E-07	9.05E-07	7.70E-07	7.93E-03	7.93E-03
Ammonia	7664-41-7	--[7]	2.40E+00	2.40E+00	2.04E+00	2.10E+04	2.10E+04
Anthracene	120-12-7	2.40E-06	1.21E-06	1.21E-06	1.03E-06	1.06E-02	1.06E-02
Arsenic	7440-38-2	2.00E-04	1.01E-04	1.01E-04	8.55E-05	8.81E-01	8.81E-01
Barium	7440-39-3	4.40E-03	2.21E-03	2.21E-03	1.88E-03	1.94E+01	1.94E+01
Benz(a)anthracene	56-55-3	1.80E-06	9.05E-07	9.05E-07	7.70E-07	7.93E-03	7.93E-03
Benzene	71-43-2	1.70E-03	8.55E-04	8.55E-04	7.27E-04	7.49E+00	7.49E+00
Benzo(a)pyrene	50-32-8	1.20E-06	6.04E-07	6.04E-07	5.13E-07	5.29E-03	5.29E-03
Benzo(b)fluoranthene	205-99-2	1.80E-06	9.05E-07	9.05E-07	7.70E-07	7.93E-03	7.93E-03
Benzo(g,h,i)perylene	191-24-2	1.20E-06	6.04E-07	6.04E-07	5.13E-07	5.29E-03	5.29E-03
Benzo(k)fluoranthene	207-08-9	1.80E-06	9.05E-07	9.05E-07	7.70E-07	7.93E-03	7.93E-03
Beryllium	7440-41-7	1.20E-05	6.04E-06	6.04E-06	5.13E-06	5.29E-02	5.29E-02
Butane	106-97-8	2.10E+00	1.06E+00	1.06E+00	8.98E-01	9.25E+03	9.25E+03
Cadmium	7440-43-9	1.10E-03	5.53E-04	5.53E-04	4.70E-04	4.85E+00	4.85E+00
Carbon Monoxide	630-08-0	--[8]	1.98E+00	1.98E+00	1.68E+00	1.73E+04	1.73E+04

			Emission Rate[1]				
			Hourly			Annual	
Pollutant	**CAS**	**Emission Factor[2] (lb/MMBtu)**	**Normal Operation[3] (lb/hr)**	**Production Line Startup[3] (lb/hr)**	**Production Line Shutdown[4] (lb/hr)**	**Continuous Normal Operation[5] (lb/yr)**	**Normal Operation w/SUSD[6] (lb/yr)**
Chromium	7440-47-3	1.40E-03	7.04E-04	7.04E-04	5.99E-04	6.17E+00	6.17E+00
Chromium, Hexavalent	18540-29-9	5.60E-05	2.82E-05	2.82E-05	2.39E-05	2.47E-01	2.47E-01
Chrysene	218-01-9	1.80E-06	9.05E-07	9.05E-07	7.70E-07	7.93E-03	7.93E-03
Cobalt	7440-48-4	8.40E-05	4.23E-05	4.23E-05	3.59E-05	3.70E-01	3.70E-01
Copper	7440-50-8	8.50E-04	4.28E-04	4.28E-04	3.63E-04	3.75E+00	3.74E+00
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	6.04E-07	6.04E-07	5.13E-07	5.29E-03	5.29E-03
Dichlorobenzene	25321-22-6	1.20E-03	6.04E-04	6.04E-04	5.13E-04	5.29E+00	5.29E+00
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	8.05E-06	8.05E-06	6.84E-06	7.05E-02	7.05E-02
Ethane	74-84-0	3.10E+00	1.56E+00	1.56E+00	1.33E+00	1.37E+04	1.37E+04
Fluoranthene	206-44-0	3.00E-06	1.51E-06	1.51E-06	1.28E-06	1.32E-02	1.32E-02
Fluorene	86-73-7	2.80E-06	1.41E-06	1.41E-06	1.20E-06	1.23E-02	1.23E-02
Formaldehyde	50-00-0	3.60E-03	1.81E-03	1.81E-03	1.54E-03	1.59E+01	1.59E+01
Hexane	110-54-3	1.30E-03	6.54E-04	6.54E-04	5.56E-04	5.73E+00	5.73E+00
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	9.05E-07	9.05E-07	7.70E-07	7.93E-03	7.93E-03
Lead	7439-92-1	4.75E-07	2.39E-07	2.39E-07	2.03E-07	2.09E-03	2.09E-03
Manganese	7439-96-5	3.80E-04	1.91E-04	1.91E-04	1.62E-04	1.67E+00	1.67E+00
Mercury	7439-97-6	2.60E-04	1.31E-04	1.31E-04	1.11E-04	1.15E+00	1.15E+00
3-Methylchloranthrene	56-49-5	1.80E-06	9.05E-07	9.05E-07	7.70E-07	7.93E-03	7.93E-03

Pollutant	CAS	Emission Factor[2] (lb/MMBtu)	Emission Rate[1]				
			Hourly			Annual	
			Normal Operation[3] (lb/hr)	Production Line Startup[3] (lb/hr)	Production Line Shutdown[4] (lb/hr)	Continuous Normal Operation[5] (lb/yr)	Normal Operation w/SUSD[6] (lb/yr)
2-Methylnaphthalene	91-57-6	2.40E-05	1.21E-05	1.21E-05	1.03E-05	1.06E-01	1.06E-01
Molybdenum	7439-98-7	1.10E-03	5.53E-04	5.53E-04	4.70E-04	4.85E+00	4.85E+00
Naphthalene	91-20-3	3.00E-04	1.51E-04	1.51E-04	1.28E-04	1.32E+00	1.32E+00
Nickel	7440-02-0	2.10E-03	1.06E-03	1.06E-03	8.98E-04	9.25E+00	9.25E+00
Nitrogen Dioxide	10102-44-0	--[8]	2.60E+00	2.60E+00	2.21E+00	2.28E+04	2.28E+04
Polyaromatic Hydrocarbons	PAH	4.00E-04	2.01E-04	2.01E-04	1.71E-04	1.76E+00	1.76E+00
Pentane	109-66-0	2.60E+00	1.31E+00	1.31E+00	1.11E+00	1.15E+04	1.15E+04
Phenanthrene	85-01-8	1.70E-05	8.55E-06	8.55E-06	7.27E-06	7.49E-02	7.49E-02
Propane	74-98-6	1.60E+00	8.05E-01	8.05E-01	6.84E-01	7.05E+03	7.05E+03
Pyrene	129-00-0	5.00E-06	2.51E-06	2.51E-06	2.14E-06	2.20E-02	2.20E-02
Selenium	7782-49-2	2.40E-05	1.21E-05	1.21E-05	1.03E-05	1.06E-01	1.06E-01
Sulfur Dioxide	7446-09-5	--[8]	3.13E-03	3.13E-03	2.66E-03	2.74E+01	2.74E+01
Sufuric Acid	7664-93-9	--[9]	1.44E-03	1.44E-03	1.22E-03	1.26E+01	1.26E+01
Toluene	108-88-3	7.80E-03	3.92E-03	3.92E-03	3.33E-03	3.44E+01	3.44E+01
Vanadium	7440-62-2	2.30E-03	1.16E-03	1.16E-03	9.83E-04	1.01E+01	1.01E+01
Zinc	7440-66-6	2.90E-02	1.46E-02	1.46E-02	1.24E-02	1.28E+02	1.28E+02

1. Emission rates for a single boiler
2. Emission factors from AP-42 Section 1.4 (External Natural Gas Combustion), except as noted

3. Maximum hourly emission rates during normal and production line startup operation are based on a heat input of 530 MMBtu/hr, which is the maximum continuous rating of the proposed boilers
4. Maximum hourly emission rates during production line shutdown operation are based on a heat input of 451 MMBtu/hr, which is the maximum hourly average load expected during shutdown
5. Continuous normal operation annual emission rates are based on a heat input of 530 MMBtu/hr and operation 8,760 hours per year
6. Annual emission rates for normal operation with 6 production line startups and shutdowns are based on a heat input of 530 MMBtu/hr during 8,262 hours of normal operation, and during 480 hours of production line startup, and a heat input of 451 MMBtu/hr during 18 hours of operation during production line shutdown
7. Ammonia emission rates are based on a maximum ammonia slip concentration of 10 ppmvd @ 3% O_2
8. NO_2, CO, and SO_2 emissions are based on criteria pollutant emission rate calculations; 100% conversion of NO_X to NO_2 is assumed
9. Sulfuric acid emission rates are based on an assumed 30 percent conversion of SO_2 (SO_2 emission rates are not decreased to account for the converted fraction)

2.7 Power Generation Unit

The local electrical power provider, Cowlitz Public Utility District, has the capacity to provide electric power for one of the two proposed methanol production lines. Power for the second production line will be provided by an onsite power generation unit (PGU). The PGU will consist of two combined-cycle combustion turbines (CCCTs), each of which will drive a generator, and two Once-Through Steam Generators (OTSGs), which will provide steam to a steam turbine that will drive a third generator.

The CCCTs will be GE LM6000-PF+, or equivalent, and will combust pipeline natural gas exclusively. The nominal generating capacity of the CCCTs will be approximately 45 MW each, and the nominal generating capacity of the steam turbine will be approximately 31 MW, for a total generating capacity of approximately 121 MW. Under normal operating conditions, the PGU will generate approximately 100 MW. The PGU will provide power only to the facility, and be isolated from the power grid. The OTSGs will have the capability for supplemental firing (i.e., "duct firing") of the CCCT exhaust, and the CCCTs will be equipped with evaporative cooling of inlet air.

Because the methanol production lines are intended to operate as near to continuously as possible, the PGU will essentially be a baseload facility, and startups and shutdowns will be unusual occurrences. Scheduled shutdowns will occur only when the production line to which it provides power is shut down for a catalyst change, which is expected to be every 4-to-6 years. The CT units will be aero-derivative designs that are capable of quick startup and shutdown. Startup, when it does occur, will require less than an hour from initial fuel delivery to 100 percent load, and shutdown will require less than half an hour from the time fuel input rate begins to decrease from that of normal operation.

PGU criteria pollutant emission rates are summarized in Table 2-5, and toxic and hazardous air pollutant emission rates are summarized in Table 2-6.

Table 2-5. Power Generation Unit Criteria Pollutant and Greenhouse Gas Emissions

		Emission Rate[1]					
		Hourly				Annual	
Pollutant	**Emission Factor[2]**	**Normal Operation[3] (lb/hr)**	**Duct Firing[4] (lb/hr)**	**Startup[5] (lb/hr)**	**Shut-down[5] (lb/hr)**	**Cont. Normal Op.[6] (tpy)**	**Cont. DF Op.[7] (tpy)**
NO_X	2.5	5.00	5.43	9.60	3.20	22.1	22.1
CO	4.0	4.87	5.29	5.70	1.90	21.5	21.5
PM_{10}/ $PM_{2.5}$	0.0066	2.99	4.12	2.72	2.72	16.4	16.4
SO_2	0.0070 / 0.0036	3.18	4.31	2.89	2.89	7.10	7.10
VOCs	3.0	2.09	2.27	6.00	2.00	9.22	9.24
GHG (CO_2e)	117	24,900	32,900	22,900	22,900	137,000	137,000

1. Emission rates for a single combustion turbine and OTSG with duct burner
2. Emission factors for all criteria pollutants other than SO_2 are based on exhaust concentration guarantees from the equipment vendor. SO_2 emission rates are based on mass balance calculations using hourly and annual average concentrations of 2.07 and 1.05 grains sulfur per 100 cubic feet (gr/100 cf) of natural gas, respectively, as measured at the Huntingdon pumping station in British Columbia, with a 25% safety factor applied. Emission factors for NO_X, CO, and VOCs are exhaust concentrations expressed as parts per million by volume, dry at 15 percent oxygen (ppmvd@15% O_2); emission factors for PM and SO_2 are in units of lb/MMBtu. GHG emission factors and global warming potentials from 40 CFR Part 98
3. Worst-case short-term normal operation based on 100% load at design conditions – 19.14 thousand pounds of fuel per hour (kpph)
4. Worst-case short-term duct firing operation based on 100% load with duct firing at an ambient temperature of 32 °F – 20.95 kpph plus 4.9 kpph to the duct burner
5. NO_X, CO, and VOC are from startup and shutdown emission rates for a similar unit (from Table II-B-7 in Technical Support Document for Part 70 Operating Permit No. 329, issued to SWG Nevada Holidings, LLC by Clark County Dept. of Air Quality Permitting Section in May 2012); PM and SO_2 are based on 75% load at an ambient temperature of 32 °F – 17.4 kpph
6. Annual emssions for continuous normal operation assume the hourly normal operation emission rates occur 8,760 hr/yr. The NO_X, CO, and VOC emission rates include 6 startups and shutdowns, with no downtime between each shutdown and the next startup, because that represents the worst-case sceanrio for those pollutants
7. Annual emssions for continuous operation with duct firing assume the hourly operation with duct firing emission rates occur 8,760 hr/yr. The NO_X, CO, and VOC emission rates include 6 startups and shutdowns, with no downtime between each shutdown and the next startup, because that represents the worst-case sceanrio for those pollutants

Table 2-6. Power Generation Unit Toxic and Hazardous Air Pollutant Emissions

Compound	CAS #	Emission Factor		Emission Rate[1]				
				Hourly			Annual	
		Comb. Turbine[2] (lb/MMBtu)	Duct Firing[3] (lb/MMscf)	Normal Operation[4] (lb/hr)	Duct Firing[5] (lb/hr)	Startup & Shutdown[6] (lb/hr)	Cont. Normal Operation[7] (lb/yr)	Cont. DF Operation[8] (lb/yr)
Acenaphthene	83-32-9	--	1.80E-06	--	2.02E-07	--	--	1.53E-03
Acenaphthylene	208-96-8	--	1.80E-06	--	2.02E-07	--	--	1.53E-03
Acetaldehyde	75-07-0	4.00E-05	--	2.22E-02	1.98E-02	1.34E-02	1.59E+02	1.60E+02
Acrolein	107-02-8	6.40E-06	--	3.56E-03	3.18E-03	2.14E-03	2.54E+01	2.56E+01
Ammonia	7664-41-7	--[2]	--[3]	1.60E+00	1.61E+00	1.08E+00	1.29E+04	5.67E+04
Anthracene	120-12-7	--	2.40E-06	--	2.69E-07	--	--	2.04E-03
Arsenic	7440-38-2	--	2.00E-04	--	2.24E-05	--	--	1.70E-01
Barium	7440-39-3	--	4.40E-03	--	4.93E-04	--	--	3.75E+00
Benz(a)anthracene	56-55-3	--	1.80E-06	--	2.02E-07	--	--	1.53E-03
Benzene	71-43-2	1.20E-05	5.80E-03	6.67E-03	6.60E-03	4.02E-03	4.76E+01	5.29E+01
Benzo(a)pyrene	50-32-8	--	1.20E-06	--	1.35E-07	--	--	1.02E-03
Benzo(b)fluoranthene	205-99-2	--	1.80E-06	--	2.02E-07	--	--	1.53E-03
Benzo(g,h,i)perylene	191-24-2	--	1.20E-06	--	1.35E-07	--	--	1.02E-03
Benzo(k)fluoranthene	207-08-9	--	1.80E-06	--	2.02E-07	--	--	1.53E-03
Beryllium	7440-41-7	--	1.20E-05	--	1.35E-06	--	--	1.02E-02
1,3-Butadiene	106-99-0	4.30E-07	--	2.39E-04	2.13E-04	1.44E-04	1.71E+00	1.72E+00
Butane	106-97-8	--	2.10E+00	--	2.35E-01	--	--	1.79E+03

Compound	CAS #	Emission Factor		Emission Rate[1]				
				Hourly			Annual	
		Comb. Turbine[2] (lb/MMBtu)	Duct Firing[3] (lb/MMscf)	Normal Operation[4] (lb/hr)	Duct Firing[5] (lb/hr)	Startup & Shutdown[6] (lb/hr)	Cont. Normal Operation[7] (lb/yr)	Cont. DF Operation[8] (lb/yr)
Cadmium	7440-43-9	--	1.10E-03	--	1.23E-04	--	--	9.36E-01
Carbon Monoxide	630-08-0	--[2]	--[3]	5.27E+00	5.29E+00	5.70E+00	4.27E+04	1.87E+05
Chromium	7440-47-3	--	1.40E-03	--	1.57E-04	--	--	1.19E+00
Chromium, Hexavalent*	18540-29-9	--	5.60E-05	--	6.28E-06	--	--	4.77E-02
Chrysene	218-01-9	--	1.80E-06	--	2.02E-07	--	--	1.53E-03
Cobalt	7440-48-4	--	8.40E-05	--	9.42E-06	--	--	7.15E-02
Copper	7440-50-8	--	8.50E-04	--	9.53E-05	--	--	7.24E-01
Dibenzo(a,h)anthracene	53-70-3	--	1.20E-06	--	1.35E-07	--	--	1.02E-03
Dichlorobenzene	25321-22-6	--	1.20E-03	--	1.35E-04	--	--	1.02E+00
7,12-Dimethylbenz(a)anthracene	57-97-6	--	1.60E-05	--	1.79E-06	--	--	1.36E-02
Ethane	74-84-0	--	3.10E+00	--	3.47E-01	--	--	2.64E+03
Ethylbenzene	100-41-4	3.20E-05	--	1.78E-02	1.59E-02	1.07E-02	1.27E+02	1.28E+02
Fluoranthene	206-44-0	--	3.00E-06	--	3.36E-07	--	--	2.55E-03
Fluorene	86-73-7	--	2.80E-06	--	3.14E-07	--	--	2.38E-03
Formaldehyde	50-00-0	1.07E-04	1.23E-02	5.92E-02	5.42E-02	3.56E-02	4.23E+02	4.36E+02
Hexane	110-54-3	--	4.60E-03	--	5.16E-04	--	--	3.92E+00
Indeno(1,2,3-cd)pyrene	193-39-5	--	1.80E-06	--	2.02E-07	--	--	1.53E-03
Lead	7439-92-1	--	4.75E-07	--	5.32E-08	--	--	4.04E-04

Compound	CAS #	Emission Factor		Emission Rate[1]				
				Hourly			Annual	
		Comb. Turbine[2] (lb/MMBtu)	Duct Firing[3] (lb/MMscf)	Normal Operation[4] (lb/hr)	Duct Firing[5] (lb/hr)	Startup & Shutdown[6] (lb/hr)	Cont. Normal Operation[7] (lb/yr)	Cont. DF Operation[8] (lb/yr)
Manganese	7439-96-5	--	3.80E-04	--	4.26E-05	--	--	3.24E-01
Mercury	7439-97-6	--	2.60E-04	--	2.91E-05	--	--	2.21E-01
3-Methylchloranthrene	56-49-5	--	1.80E-06	--	2.02E-07	--	--	1.53E-03
2-Methylnaphthalene	91-57-6	--	2.40E-05	--	2.69E-06	--	--	2.04E-02
Molybdenum	7439-98-7	--	1.10E-03	--	1.23E-04	--	--	9.36E-01
Naphthalene	91-20-3	1.30E-06	3.00E-04	7.23E-04	6.79E-04	4.35E-04	5.16E+00	5.45E+00
Nickel	7440-02-0	--	2.10E-03	--	2.35E-04	--	--	1.79E+00
Nitrogen Dioxide	10102-44-0	--[2]	--[3]	5.41E+00	5.43E+00	9.60E+00	4.38E+04	1.92E+05
PAH	PAH	2.20E-06	4.00E-04	1.22E-03	1.14E-03	7.36E-04	8.73E+00	9.13E+00
Pentane	109-66-0	--	2.60E+00	--	2.91E-01	--	--	2.21E+03
Phenanthrene	85-01-8	--	1.70E-05	--	1.91E-06	--	--	1.45E-02
Propane	74-98-6	--	1.60E+00	--	1.79E-01	--	--	1.36E+03
Propylene Oxide	75-56-9	2.90E-05	--	1.61E-02	1.44E-02	9.70E-03	1.15E+02	1.16E+02
Pyrene	129-00-0	--	5.00E-06	--	5.60E-07	--	--	4.26E-03
Selenium	7782-49-2	--	2.40E-05	--	2.69E-06	--	--	2.04E-02
Sulfur Dioxide	7446-09-5	--[2]	--[3]	3.67E+00	4.31E+00	2.72E+00	2.79E+04	6.18E+04
Sulfuric acid	7664-93-9	--[2]	--[3]	5.62E-01	6.60E-01	4.16E-01	4.27E+03	9.47E+03
Toluene	108-88-3	1.30E-04	2.65E-02	7.23E-02	6.75E-02	4.35E-02	5.16E+02	5.42E+02

		Emission Factor		Emission Rate[1]				
				Hourly			Annual	
Compound	**CAS #**	**Comb. Turbine[2] (lb/MMBtu)**	**Duct Firing[3] (lb/MMscf)**	**Normal Operation[4] (lb/hr)**	**Duct Firing[5] (lb/hr)**	**Startup & Shutdown[6] (lb/hr)**	**Cont. Normal Operation[7] (lb/yr)**	**Cont. DF Operation[8] (lb/yr)**
Vanadium	7440-62-2	--	2.30E-03	--	2.58E-04	--	--	1.96E+00
Xylenes	1330-20-7	6.40E-05	--	3.56E-02	3.18E-02	2.14E-02	2.54E+02	2.56E+02
Zinc	7440-66-6	--	2.90E-02	--	3.25E-03	--	--	2.47E+01

1. Emission rates for a single combustion turbine and OTSG
2. Emission factors used to calcualte combustion turbine toxic and hazardous air pollutant emissions other than NO_2, CO, SO_2, sulfuric acid, and ammonia are based on emission factors from AP-42 Section 3.1, Table 3.1-3. NO_2, CO, and SO_2 emission rates are based on the criteria pollutant emission rates. Ammonia emission rates are based on an exhaust concentration guarantee of 2.0 ppmvd @ 15% O_2 from the equipment vendor. Sulfuric acid emission rates are based on an assumed 10 percent conversion of SO_2 (SO_2 emission rates are not decreased to account for the converted fraction)
3. Emission factors used to calcualte duct burner toxic and hazardous air pollutant emissions other than NO_2, CO, SO_2, sulfuric acid, and ammonia are based on emission factors from AP-42 Section 1.4, Tables 1.4-3 and 1.4-4. NO_2, CO, and SO_2 emission rates are based on the criteria pollutant emission rates. Ammonia emission rates are based on an exhaust concentration guarantee of 2.0 ppmvd @ 15% O_2 from the equipment vendor. Sulfuric acid emission rates are based on an assumed 10 percent conversion of SO_2 (SO_2 emission rates are not decreased to account for the converted fraction)
4. Worst-case short-term normal operation based on 100% load at an ambient temperature of 32 °F – 23.49 kpph
5. Worst-case short-term duct firing operation based on 100% load with duct firing at an ambient temperature of 32 °F – 20.95 kpph plus 4.9 kpph to the duct burner
6. Startup and shutdown emission rates are based on 75% load at an ambient temperature of 32 °F – 17.4 kpph
7. Annual emssions for continuous normal operation assume the hourly normal operation emission rates occur 8,760 hr/yr
8. Annual emssions for continuous operation with duct firing assume the hourly operation with duct firing emission rates occur 8,760 hr/yr

2.8 Process Heaters

Each production line will have one process heater (a.k.a. "firebox," or "GHR startup heater"), which will be used to heat the GHR and ATR until the exothermic secondary reforming process in the ATR is able to support the primary reforming process in the GHR. This heater will also be used when a production line is shut down to minimize waste by converting as much of the feedstock and intermediate materials as possible to product. The process heaters will have a maximum heat input of approximately 72 MMBtu/hr, and will combust pipeline natural gas. The process heaters will not be operated when the associated production line is operating normally.

Process heater criteria pollutant emission rates are summarized in Table 2-7, and toxic and hazardous air pollutant emission rates are summarized in Table 2-8.

Table 2-7. Process Heater Criteria Pollutant and Greenhouse Gas Emissions

Pollutant	Emission Factor[2] (lb/MMBtu)	Emission Rate[1]		
		Hourly		Annual
		Production Line Startup[3] (lb/hr)	Production Line Shutdown[4] (lb/hr)	Production Line SU & SD[5] (tpy)
NO_X	0.032	2.38	1.86	0.211
CO	0.033	2.42	1.89	0.214
PM_{10} / $PM_{2.5}$	0.0072	0.536	0.418	0.0475
SO_2	0.0070 / 0.0036	0.522	0.407	0.0463
VOC	0.0052	0.387	0.302	0.0343
GHG (CO_2e)	117	8,710	6,790	772

1. Emission rates for a single unit
2. Emission factors from AP-42 Section 1.4 (External Natural Gas Combustion), except SO_2, which is based on maximum expected sulfur content of treated natural gas, and GHGs, which are from 40 CFR Part 98, along with global warming potentials
3. Maximum hourly emission rates during production line startup operation are based on a heat input of 72 MMBtu/hr, which is the maximum firing rate during production line startup
4. Maximum hourly emission rates during production line shutdown operation are based on a heat input of 58 MMBtu/hr, which is the maximum firing rate during production line shutdown
5. Maximum annual emission rates based on 6 startups and shutdowns; assume 28 hours of firing during each startup at the maximum rate (i.e., 72 MMBtu/hr) and 2 hours of firing during each shutdown at 58 MMBtu/hr

Table 2-8. Process Heater Toxic and Hazardous Air Pollutant Emissions

Pollutant	CAS	Emission Factor[2] (lb/MMscf)	Emission Rate[1] Hourly Production Line Startup[3] (lb/hr)	Emission Rate[1] Hourly Production Line Shutdown[4] (lb/hr)	Emission Rate[1] Annual Production Line SU & SD[5] (tpy)
Acenaphthene	83-32-9	1.80E-06	1.27E-07	9.92E-08	3.05E-06
Acenaphthylene	208-96-8	1.80E-06	1.27E-07	9.92E-08	3.05E-06
Anthracene	120-12-7	2.40E-06	1.70E-07	1.32E-07	4.07E-06
Arsenic	7440-38-2	2.00E-04	1.41E-05	1.10E-05	3.39E-04
Barium	7440-39-3	4.40E-03	3.11E-04	2.42E-04	7.46E-03
Benz(a)anthracene	56-55-3	1.80E-06	1.27E-07	9.92E-08	3.05E-06
Benzene[6]	71-43-2	5.80E-03	4.10E-04	3.20E-04	9.83E-03
Benzo(a)pyrene	50-32-8	1.20E-06	8.48E-08	6.61E-08	2.03E-06
Benzo(b)fluoranthene	205-99-2	1.80E-06	1.27E-07	9.92E-08	3.05E-06
Benzo(g,h,i)perylene	191-24-2	1.20E-06	8.48E-08	6.61E-08	2.03E-06
Benzo(k)fluoranthene	207-08-9	1.80E-06	1.27E-07	9.92E-08	3.05E-06
Beryllium	7440-41-7	1.20E-05	8.48E-07	6.61E-07	2.03E-05
Butane	106-97-8	2.10E+00	1.48E-01	1.16E-01	3.56E+00
Cadmium	7440-43-9	1.10E-03	7.77E-05	6.06E-05	1.86E-03
Carbon Monoxide[7]	630-08-0	--[6]	2.42E+00	1.89E+00	5.80E+01
Chromium	7440-47-3	1.40E-03	9.89E-05	7.71E-05	2.37E-03
Chromium, Hexavalent*	18540-29-9	5.60E-05	3.96E-06	3.09E-06	9.49E-05
Chrysene	218-01-9	1.80E-06	1.27E-07	9.92E-08	3.05E-06
Cobalt	7440-48-4	8.40E-05	5.93E-06	4.63E-06	1.42E-04
Copper	7440-50-8	8.50E-04	6.00E-05	4.68E-05	1.44E-03
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	8.48E-08	6.61E-08	2.03E-06
Dichlorobenzene	25321-22-6	1.20E-03	8.48E-05	6.61E-05	2.03E-03
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	1.13E-06	8.82E-07	2.71E-05
Ethane	74-84-0	3.10E+00	2.19E-01	1.71E-01	5.25E+00
Fluoranthene	206-44-0	3.00E-06	2.12E-07	1.65E-07	5.09E-06

Pollutant	CAS	Emission Factor[2] (lb/MMscf)	Emission Rate[1]		
			Hourly		Annual
			Production Line Startup[3] (lb/hr)	Production Line Shutdown[4] (lb/hr)	Production Line SU & SD[5] (tpy)
Fluorene	86-73-7	2.80E-06	1.98E-07	1.54E-07	4.75E-06
Formaldehyde[6]	50-00-0	1.23E-02	8.69E-04	6.78E-04	2.08E-02
Hexane[6]	110-54-3	4.60E-03	3.25E-04	2.53E-04	7.80E-03
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	1.27E-07	9.92E-08	3.05E-06
Lead	7439-92-1	5.00E-04	3.53E-05	2.76E-05	8.48E-04
Manganese	7439-96-5	3.80E-04	2.68E-05	2.09E-05	6.44E-04
Mercury	7439-97-6	2.60E-04	1.84E-05	1.43E-05	4.41E-04
3-Methylchloranthrene	56-49-5	1.80E-06	1.27E-07	9.92E-08	3.05E-06
2-Methylnaphthalene	91-57-6	2.40E-05	1.70E-06	1.32E-06	4.07E-05
Molybdenum	7439-98-7	1.10E-03	7.77E-05	6.06E-05	1.86E-03
Naphthalene[6]	91-20-3	3.00E-04	2.12E-05	1.65E-05	5.09E-04
Nickel	7440-02-0	2.10E-03	1.48E-04	1.16E-04	3.56E-03
Nitrogen dioxide[7]	10102-44-0	--[6]	2.38E+00	1.86E+00	5.72E+01
Polyaromatic Hydrocarbons[6]	PAH	4.00E-04	2.83E-05	2.20E-05	6.78E-04
Pentane	109-66-0	2.60E+00	1.84E-01	1.43E-01	4.41E+00
Phenanthrene	85-01-8	1.70E-05	1.20E-06	9.37E-07	2.88E-05
Propane	74-98-6	1.60E+00	1.13E-01	8.82E-02	2.71E+00
Pyrene	129-00-0	5.00E-06	3.53E-07	2.76E-07	8.48E-06
Selenium	7782-49-2	2.40E-05	1.70E-06	1.32E-06	4.07E-05
Sufuric Acid[8]	7664-93-9	--[6]	2.40E-01	1.87E-01	5.76E+00
Sulfur dioxide[7]	7446-09-5	--[7]	5.22E-01	4.07E-01	1.25E+01
Toluene[6]	108-88-3	2.65E-02	1.87E-03	1.46E-03	4.49E-02
Vanadium	7440-62-2	2.30E-03	1.62E-04	1.27E-04	3.90E-03
Zinc	7440-66-6	2.90E-02	2.05E-03	1.60E-03	4.92E-02

1. Emission rates for a single unit
2. Emission factors from AP-42 Section 1.4 (External Natural Gas Combustion), except as noted
3. Maximum hourly emission rates during production line startup operation are based on a heat input of 72 MMBtu/hr, which is the maximum firing rate during production line startup
4. Maximum hourly emission rates during production line shutdown operation are based on a heat input of 58 MMBtu/hr, which is the maximum firing rate during production line shutdown

5. Maximum annual emission rates based on 6 startups and shutdowns; assume 28 hours of firing during each startup at the maximum rate (i.e., 72 MMBtu/hr) and 2 hours of firing during each shutdown at 58 MMBtu/hr
6. Benzene, formaldehyde, hexane, naphthalene, PAH, and toluene emissions are based on emission factors from the Ventura County Air Pollution Control District memorandum "AB 2588 Combustion Emission Factors," issued on May 17, 2001.
7. NO_2, CO, and SO_2 emissions are based on criteria pollutant calculations
8. Sulfuric acid emission rates are based on an assumed 30 percent conversion of SO_2 (SO_2 emission rates are not decreased to account for the converted fraction)

2.9 Flare and Flare Pilot

A flare system will be used for safe disposal of combustible gases during the normal startup and shutdown of the methanol production process, as well as during a process upset, or an emergency shutdown situation. Because the production lines are designed to operate continuously, planned flare operations will be limited to initial startup of the production lines, when between 48 and 60 hours of flare operation is required while the new GHR and ATR catalysts are prepared for initial use. The catalysts are expected to last between 4 and 6 years, so there would be a 2-hour shutdown, followed by another 48-to-60 hour startup, every 4 to 6 years when the catalysts are replaced.

Unscheduled startups and shutdowns, as well as upsets and emergencies, are not part of normal operations. Startups that do not follow a catalyst change are expected to require approximately 12 hours of flare operation. During an upset, the flare would be operated if production were decreased by more than 30 percent of maximum, and for as long as required to either stabilize the process and return to normal production, or to shut down the process in an orderly manner. An emergency event would involve approximately 2 hours of flaring while one or both production lines are shut down as quickly, and as safely, as possible.

While the facility is designed to operation continuously, it is understood that unplanned startups and shutdowns will occur, particularly during the first year of operations. Rather than basing flare PTE on a single catalyst replacement event involving one extended shutdown and one startup every four-to-six years, a hypothetical worst-case annual flare operation scenario was created, which would include six startups, four "normal" shutdowns, four upsets, each lasting four hours, followed by resumption of normal operation, and two emergency shutdowns.

Flare criteria pollutant emissions are summarized in Table 2-9, and toxic and hazardous air pollutant emissions are summarized in Table 2-10.

Table 2-9. Flare Criteria Pollutant and Greenhouse Gas Emissions

Pollutant	Emission Factor[1] (lb/MMBtu)	Emission Rate[2]				
		1-Hr Avg. (lb/hr)	3-Hr Avg. (lb/hr)	8-Hr Avg. (lb/hr)	24-Hr Avg. (lb/hr)	Annual Avg. (tpy)
Startup						
NO_X	0.068	173	--	--	62.2	4.53
CO	0.31	182	--	157	79.9	5.84
PM_{10}	0.010	--	--	--	9.15	0.666
$PM_{2.5}$	0.0025	--	--	--	2.29	0.166
SO_2	0.0000059	0.0151	0.0151	--	0.00541	0.000393
VOC	0.57	334	--	--	--	10.7
GHG (CO_2e)	117	68,600	--	--	--	2,210
Shutdown						
NO_X	0.068	234	--	--	25.3	1.82
CO	0.31	406	--	143	47.7	3.43
PM_{10}	0.010	--	--	--	3.72	0.268
$PM_{2.5}$	0.0025	--	--	--	0.93	0.067
SO_2	0.0000059	0.0204	0.00220	--	0.00220	0.000158
VOC	0.57	746	--	--	--	6.31
GHG (CO_2e)	117	153,100	--	--	--	1,300
Upset						
NO_X	0.068	34.5	--	--	--	--
CO	0.31	100	--	--	--	--
PM_{10}	0.010	5.07	--	--	--	--
$PM_{2.5}$	0.0025	1.27	--	--	--	--
SO_2	0.0000059	0.00300	--	--	--	--
VOC	0.57	184	--	--	--	--
GHG (CO_2e)	117	59,300	--	--	--	--
Emergency						
NO_X	0.068	418	--	--	--	--
CO	0.31	28.0	--	--	--	--
PM_{10}	0.010	61.5	--	--	--	--
$PM_{2.5}$	0.0025	15.4	--	--	--	--
SO_2	0.0000059	0.0363	--	--	--	--
VOC	0.57	51.5	--	--	--	--
GHG	117	719,000	--	--	--	--

(CO_2e)						

1. Emission factors for NO_X, CO, and VOC are from AP-42 Section 13.5 (Industrial Flares), Tables 13.5-1 and 13.5-2. SO_2 emission factor is based on the maximum expected sulfur content of treated natural gas. PM_{10} emission factor is based on an emission factor that has been used in the past for flares at petroleum refineries; use of this factor is conservative, given that the proposed flare will combust lighter hydrocarbons and fewer carbon-containing compounds than a flare at a refinery. $PM_{2.5}$ emission factor is assumed to be 25% of the PM_{10} emission factor. GHG emission factors and global warming potentials from 40 CFR Part 98
2. Short-term emission rates are worst-case hourly rates, averaged over the applicable period. Annual emission rates assume 6 startups, 4 shutdowns, 4 upsets followed by normal operation, and 2 emergency shutdowns all occur within a 12-month period.

Table 2-10. Flare Toxic and Hazardous Air Pollutant Emissions

			Emission Rate						
			Startup		Shutdown				
Pollutant	CAS #	Emission Factor[1] (lb/MMscf)	(lb/hr)	(lb/day)	(lb/hr)	(lb/day)	Total SU+SD (lb/yr)	Upset (lb/hr)	Emerg. (lb/hr)
Acenaphthene	83-32-9	1.80E-06	4.50E-06	1.61E-06	6.08E-06	6.56E-07	6.82E-04	8.66E-07	1.05E-05
Acenaphthylene	208-96-8	1.80E-06	4.50E-06	1.61E-06	6.08E-06	6.56E-07	6.82E-04	8.66E-07	1.05E-05
Anthracene	120-12-7	2.40E-06	6.00E-06	2.15E-06	8.11E-06	8.75E-07	9.09E-04	1.15E-06	1.40E-05
Arsenic	7440-38-2	2.00E-04	5.00E-04	1.79E-04	6.76E-04	7.29E-05	7.57E-02	9.62E-05	1.17E-03
Barium	7440-39-3	4.40E-03	1.10E-02	3.95E-03	1.49E-02	1.60E-03	1.67E+00	2.12E-03	2.57E-02
Benz(a)anthracene	56-55-3	1.80E-06	4.50E-06	1.61E-06	6.08E-06	6.56E-07	6.82E-04	8.66E-07	1.05E-05
Benzene	71-43-2	1.59E-01	3.97E-01	1.43E-01	5.37E-01	5.80E-02	6.02E+01	7.65E-02	9.28E-01
Benzo(a)pyrene	50-32-8	1.20E-06	3.00E-06	1.08E-06	4.06E-06	4.37E-07	4.54E-04	5.77E-07	7.00E-06
Benzo(b)fluoranthene	205-99-2	1.80E-06	4.50E-06	1.61E-06	6.08E-06	6.56E-07	6.82E-04	8.66E-07	1.05E-05
Benzo(g,h,i)perylene	191-24-2	1.20E-06	3.00E-06	1.08E-06	4.06E-06	4.37E-07	4.54E-04	5.77E-07	7.00E-06
Benzo(k)fluoranthene	207-08-9	1.80E-06	4.50E-06	1.61E-06	6.08E-06	6.56E-07	6.82E-04	8.66E-07	1.05E-05
Beryllium	7440-41-7	1.20E-05	3.00E-05	1.08E-05	4.06E-05	4.37E-06	4.54E-03	5.77E-06	7.00E-05
Butane	106-97-8	2.10E+00	5.25E+00	1.88E+00	7.10E+00	7.65E-01	7.95E+02	1.01E+00	1.23E+01
Cadmium	7440-43-9	1.10E-03	2.75E-03	9.87E-04	3.72E-03	4.01E-04	4.16E-01	5.29E-04	6.42E-03
Carbon Monoxide	630-08-0	--	1.82E+02	1.92E+03	4.06E+02	1.14E+03	1.85E+04	1.00E+02	2.80E+01
Chromium	7440-47-3	1.40E-03	3.50E-03	1.26E-03	4.73E-03	5.10E-04	5.30E-01	6.73E-04	8.17E-03
Chromium, Hexavalent*	18540-29-9	5.60E-05	1.40E-04	5.02E-05	1.89E-04	2.04E-05	2.12E-02	2.69E-05	3.27E-04
Chrysene	218-01-9	1.80E-06	4.50E-06	1.61E-06	6.08E-06	6.56E-07	6.82E-04	8.66E-07	1.05E-05

Pollutant	CAS #	Emission Factor[1] (lb/MMscf)	Emission Rate						
			Startup		Shutdown		Total SU+SD (lb/yr)	Upset (lb/hr)	Emerg. (lb/hr)
			(lb/hr)	(lb/day)	(lb/hr)	(lb/day)			
Cobalt	7440-48-4	8.40E-05	2.10E-04	7.53E-05	2.84E-04	3.06E-05	3.18E-02	4.04E-05	4.90E-04
Copper	7440-50-8	8.50E-04	2.12E-03	7.62E-04	2.87E-03	3.10E-04	3.22E-01	4.09E-04	4.96E-03
Dibenzo(a,h) anthracene	53-70-3	1.20E-06	3.00E-06	1.08E-06	4.06E-06	4.37E-07	4.54E-04	5.77E-07	7.00E-06
Dichlorobenzene	25321-22-6	1.20E-03	3.00E-03	1.08E-03	4.06E-03	4.37E-04	4.54E-01	5.77E-04	7.00E-03
7,12-Dimethylbenz(a) anthracene	57-97-6	1.60E-05	4.00E-05	1.44E-05	5.41E-05	5.83E-06	6.06E-03	7.69E-06	9.34E-05
Ethane	74-84-0	3.10E+00	7.75E+00	2.78E+00	1.05E+01	1.13E+00	1.17E+03	1.49E+00	1.81E+01
Fluoranthene	206-44-0	3.00E-06	7.50E-06	2.69E-06	1.01E-05	1.09E-06	1.14E-03	1.44E-06	1.75E-05
Fluorene	86-73-7	2.80E-06	7.00E-06	2.51E-06	9.46E-06	1.02E-06	1.06E-03	1.35E-06	1.63E-05
Formaldehyde	50-00-0	1.17E+00	2.92E+00	1.05E+00	3.95E+00	4.26E-01	4.43E+02	5.62E-01	6.82E+00
Hexane	110-54-3	2.90E-02	7.25E-02	2.60E-02	9.80E-02	1.06E-02	1.10E+01	1.39E-02	1.69E-01
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	4.50E-06	1.61E-06	6.08E-06	6.56E-07	6.82E-04	8.66E-07	1.05E-05
Lead	7439-92-1	5.00E-04	1.25E-03	4.48E-04	1.69E-03	1.82E-04	1.89E-01	2.40E-04	2.92E-03
Manganese	7439-96-5	3.80E-04	9.50E-04	3.41E-04	1.28E-03	1.39E-04	1.44E-01	1.83E-04	2.22E-03
Mercury	7439-97-6	2.60E-04	6.50E-04	2.33E-04	8.79E-04	9.48E-05	9.84E-02	1.25E-04	1.52E-03
3-Methylchlor anthrene	56-49-5	1.80E-06	4.50E-06	1.61E-06	6.08E-06	6.56E-07	6.82E-04	8.66E-07	1.05E-05
2-Methylnaphthalene	91-57-6	2.40E-05	6.00E-05	2.15E-05	8.11E-05	8.75E-06	9.09E-03	1.15E-05	1.40E-04
Molybdenum	7439-98-7	1.10E-03	2.75E-03	9.87E-04	3.72E-03	4.01E-04	4.16E-01	5.29E-04	6.42E-03
Naphthalene	91-20-3	1.10E-02	2.75E-02	9.87E-03	3.72E-02	4.01E-03	4.16E+00	5.29E-03	6.42E-02

Pollutant	CAS #	Emission Factor[1] (lb/MMscf)	Emission Rate						
			Startup		Shutdown		Total SU+SD (lb/yr)	Upset (lb/hr)	Emerg. (lb/hr)
			(lb/hr)	(lb/day)	(lb/hr)	(lb/day)			
Nickel	7440-02-0	2.10E-03	5.25E-03	1.88E-03	7.10E-03	7.65E-04	7.95E-01	1.01E-03	1.23E-02
Nitrogen Dioxide	10102-44-0	--	1.73E+02	1.49E+03	2.34E+02	6.07E+02	1.27E+04	3.45E+01	4.18E+02
PAH	PAH	1.40E-02	3.50E-02	1.26E-02	4.73E-02	5.10E-03	5.30E+00	6.73E-03	8.17E-02
Pentane	109-66-0	2.60E+00	6.50E+00	2.33E+00	8.79E+00	9.48E-01	9.84E+02	1.25E+00	1.52E+01
Phenanthrene	85-01-8	1.70E-05	4.25E-05	1.52E-05	5.74E-05	6.20E-06	6.44E-03	8.18E-06	9.92E-05
Propane	74-98-6	1.60E+00	4.00E+00	1.44E+00	5.41E+00	5.83E-01	6.06E+02	7.69E-01	9.34E+00
Pyrene	129-00-0	5.00E-06	1.25E-05	4.48E-06	1.69E-05	1.82E-06	1.89E-03	2.40E-06	2.92E-05
Selenium	7782-49-2	2.40E-05	6.00E-05	2.15E-05	8.11E-05	8.75E-06	9.09E-03	1.15E-05	1.40E-04
Sufuric Acid	7664-93-9	--	5.10E-01	4.39E+00	6.89E-01	1.78E+00	5.09E+01	1.01E-01	1.23E+00
Sulfur Dioxide	7446-09-5	--	1.51E-02	1.30E-01	2.04E-02	5.27E-02	1.82E+00	3.00E-03	3.63E-02
Toluene	108-88-3	5.80E-02	1.45E-01	5.20E-02	1.96E-01	2.11E-02	2.20E+01	2.79E-02	3.38E-01
Vanadium	7440-62-2	2.30E-03	5.75E-03	2.06E-03	7.77E-03	8.38E-04	8.71E-01	1.11E-03	1.34E-02
Zinc	7440-66-6	2.90E-02	7.25E-02	2.60E-02	9.80E-02	1.06E-02	1.10E+01	1.39E-02	1.69E-01

1. Emission factors are from AP-42 Section 1.4 (Natural Gas Combustion), Tables 1.4-2, 1.4-3, and 1.4-4, except for NO_X and CO, which are from AP-42 Section 13.5 (Industrial Flares), Tables 13.5-1 and 13.5-2, SO_2, which is based on the maximum expected sulfur content of treated natural gas, and benzene, formaldehyde, hexane, naphthalene, PAH, and toluene, which are from the Ventura County Air Pollution Control District memorandum "AB 2588 Combustion Emission Factors," issued on May 17, 2001.
2. Short-term emission rates are worst-case hourly rates, averaged over the applicable period. Annual emission rates assume 6 startups, 4 shutdowns, 4 upsets followed by normal operation, and 2 emergency shutdowns all occur within a 12-month period.

The flare will be equipped with a small pilot, which will combust pipeline natural gas, and operate at all times. Flare pilot criteria pollutant emission rates are summarized in Table 2-11, and toxic and hazardous air pollutant emission rates are summarized in Table 2-12.

Table 2-11. Flare Pilot Criteria Pollutant and Greenhouse Gas Emissions

Pollutant	Emission Factor[1] (lb/MMBtu)	Emission Rate[2]	
		Hourly (lb/hr)	Annual (tpy)
NO_X	0.068	0.0226	0.0992
CO	0.31	0.103	0.452
PM_{10}	0.01	0.00333	0.0146
$PM_{2.5}$	0.0025	0.000832	0.00365
SO_2	0.0070 / 0.0036	0.00234	0.00519
VOC	0.14	0.0466	0.204
GHG (CO_2e)	117	39.0	171

1. Emission factors for NO_X, CO, and VOC are from AP-42 Section 13.5 (Industrial Flares), Tables 13.5-1 and 13.5-2. SO_2 emission factor is based on the maximum expected sulfur content of treated natural gas. PM_{10} emission factor is based on an emission factor that has been used in the past for flares at petroleum refineries; use of this factor is conservative, given that the proposed flare will combust lighter hydrocarbons and fewer carbon-containing compounds than a flare at a refinery. $PM_{2.5}$ emission factor is assumed to be 25% of the PM_{10} emission factor. GHG emission factors and global warming potentials from 40 CFR Part 98
2. Hourly emission rates are based on a heat input rate of 0.333 MMBtu/hr. Annual emission rates are based on the hourly emissions rate and 8,760 hr/yr of operation.

Table 2-12. Flare Pilot Toxic and Hazardous Air Pollutant Emissions

Pollutant	CAS #	Emission Factor[1] (lb/MMscf)	Emission Rate[2]	
			Hourly (lb/hr)	Annual (lb/yr)
Acenaphthene	83-32-9	1.80E-06	5.69E-10	4.98E-06
Acenaphthylene	208-96-8	1.80E-06	5.69E-10	4.98E-06
Anthracene	120-12-7	2.40E-06	7.58E-10	6.64E-06
Arsenic	7440-38-2	2.00E-04	6.32E-08	5.54E-04
Barium	7440-39-3	4.40E-03	1.39E-06	1.22E-02
Benz(a)anthracene	56-55-3	1.80E-06	5.69E-10	4.98E-06
Benzene	71-43-2	1.59E-01	5.02E-05	4.40E-01

Benzo(a)pyrene	50-32-8	1.20E-06	3.79E-10	3.32E-06
Benzo(b)fluoranthene	205-99-2	1.80E-06	5.69E-10	4.98E-06
Benzo(g,h,i)perylene	191-24-2	1.20E-06	3.79E-10	3.32E-06
Benzo(k)fluoranthene	207-08-9	1.80E-06	5.69E-10	4.98E-06
Beryllium	7440-41-7	1.20E-05	3.79E-09	3.32E-05
Butane	106-97-8	2.10E+00	6.64E-04	5.81E+00
Cadmium	7440-43-9	1.10E-03	3.48E-07	3.04E-03
Carbon Monoxide	630-08-0	--[1]	1.03E-01	9.04E+02
Chromium	7440-47-3	1.40E-03	4.42E-07	3.88E-03
Chromium, Hexavalent*	18540-29-9	5.60E-05	1.77E-08	1.55E-04
Chrysene	218-01-9	1.80E-06	5.69E-10	4.98E-06
Cobalt	7440-48-4	8.40E-05	2.65E-08	2.33E-04
Copper	7440-50-8	8.50E-04	2.69E-07	2.35E-03
Dibenzo(a,h)anthracene	53-70-3	1.20E-06	3.79E-10	3.32E-06
Dichlorobenzene	25321-22-6	1.20E-03	3.79E-07	3.32E-03
7,12-Dimethylbenz(a)anthracene	57-97-6	1.60E-05	5.06E-09	4.43E-05
Ethane	74-84-0	3.10E+00	9.80E-04	8.58E+00
Fluoranthene	206-44-0	3.00E-06	9.48E-10	8.30E-06
Fluorene	86-73-7	2.80E-06	8.85E-10	7.75E-06
Formaldehyde	50-00-0	1.17E+00	3.69E-04	3.24E+00
Hexane	110-54-3	2.90E-02	9.16E-06	8.03E-02
Indeno(1,2,3-cd)pyrene	193-39-5	1.80E-06	5.69E-10	4.98E-06
Lead	7439-92-1	5.00E-04	1.58E-07	1.38E-03
Manganese	7439-96-5	3.80E-04	1.20E-07	1.05E-03
Mercury	7439-97-6	2.60E-04	8.22E-08	7.20E-04
3-Methylchloranthrene	56-49-5	1.80E-06	5.69E-10	4.98E-06
2-Methylnaphthalene	91-57-6	2.40E-05	7.58E-09	6.64E-05
Molybdenum	7439-98-7	1.10E-03	3.48E-07	3.04E-03
Naphthalene	91-20-3	1.10E-02	3.48E-06	3.04E-02

Nickel	7440-02-0	2.10E-03	6.64E-07	5.81E-03
Nitrogen dioxide	10102-44-0	--[1]	2.26E-02	1.98E+02
PAH	PAH	1.40E-02	4.42E-06	3.88E-02
Pentane	109-66-0	2.60E+00	8.22E-04	7.20E+00
Phenanthrene	85-01-8	1.70E-05	5.37E-09	4.71E-05
Propane	74-98-6	1.60E+00	5.06E-04	4.43E+00
Pyrene	129-00-0	5.00E-06	1.58E-09	1.38E-05
Selenium	7782-49-2	2.40E-05	7.58E-09	6.64E-05
Sufuric Acid	7664-93-9	--[1]	6.66E-05	3.50E-01
Sulfur dioxide	7446-09-5	--[1]	2.34E-03	1.04E+01
Toluene	108-88-3	5.80E-02	1.83E-05	1.61E-01
Vanadium	7440-62-2	2.30E-03	7.27E-07	6.37E-03
Zinc	7440-66-6	2.90E-02	9.16E-06	8.03E-02

1. Emission factors are from AP-42 Section 1.4 (Natural Gas Combustion), Tables 1.4-2, 1.4-3, and 1.4-4, except for NO_X and CO, which are from AP-42 Section 13.5 (Industrial Flares), Tables 13.5-1 and 13.5-2, SO_2, which is based on the maximum expected sulfur content of treated natural gas, and sulfuric acid, which is based on an assumed 30 percent conversion of SO_2 (SO_2 emission rates are not decreased to account for the converted fraction).
2. Hourly emission rates are based on a heat input rate of 0.333 MMBtu/hr. Annual emission rates are based on the hourly emissions rate and 8,760 hr/yr of operation

2.10 Cooling Tower

To facilitate the dissipation of waste heat generated by the methanol production process and to condense steam from the PGU so that water can be recycled, a 12-cell, mechanical-draft, counter-current flow cooling tower will be installed and operated at the facility. Cooling towers release water droplets that contain naturally-occurring dissolved solids from the water supply, which are considered particulate matter. To be conservative, all PM is assumed to be $PM_{2.5}$. Emission rate calculations are summarized in Table 2-13.

Table 2-13. Cooling Tower Criteria Pollutant Emissions

Pollutant	Emission Rate[1]	
	Hourly (lb/hr)	Annual[2] (tpy)
PM[3]	0.806	3.53
PM_{10}[4]	0.619	2.71
$PM_{2.5}$[4]	0.00187	0.00818

1 Emission rates for all 12 cells of the cooling tower combined

2. Based on continuous operation (8,760 hr/yr)

3. Total PM emissions based on: total water circulation rate of 260,400 gal/min, maximum expected total dissolved solids (TDS) in makeup water of 156 parts per million by weight (ppmw); maximum expected TDS in circulating cooling water at 8 cycles = 8 x 156 = 1,248 ppmw; density of water 8.270 lb/gal; and mist eliminators limit drift to 0.0005% of circulating water. (260,400 gal/min) * (60 min/hr) * (8.27 lb H_2O/gal) * (0.000005 lb drift/lb H_2O) * (1,248 lb PM/MMlb drift) * (1 MMlb drift/1E+06 lb drift) = 0.806 lb/hr

4. PM_{10} estimated to be 76.7% of total PM, and $PM_{2.5}$ estimated to be 0.232% of total PM, based on Reisman-Frisbie methodology

2.11 Methanol Storage Tanks

Storage tanks will be used to store methanol on site. All storage tanks will be of a vertical, cylindrical design, and will be erected in the field. There will be 2 crude (or "rework") tanks, 4 shift tanks, and 8 bulk product storage tanks. The crude tanks will hold raw methanol created during the production process, and will be approximately 82 feet in diameter and 58 feet in height; each will hold up to 2,275,000 gallons. Shift tanks will hold refined methanol for testing prior to discharge to the storage tanks. Shift tanks will be approximately 60 feet in diameter and 50 feet in height, and each will hold approximately 1,000,000 gallons.

After the methanol in the shift tanks is analyzed, and verified to be of sufficient purity, it will be pumped to one of 8 bulk product storage tanks to await loading onto vessels. The bulk product storage tanks will be approximately 82 feet in height and 143 feet in diameter, each with a maximum storage capacity of 9,400,000 gallons.

All methanol tanks will have a fixed external roof, and the shift and bulk product storage tanks will also have an internal floating roof. The crude methanol will potentially contain dissolved gases, and if these gases are flashed off and separated from the liquid phase under a floating roof, the roof could become unstable, creating a safety hazard. All three types of methanol tanks would be capped with inert nitrogen gas (a "nitrogen blanket") to keep the oxygen level in the individual tanks to a level below that required for combustion.

EPA's TANKS 4.0.9d program was used to calculate fugitive emissions from the methanol storage tanks. The TANKS 4.0.9d program uses working volume and number of turnovers to establish a total throughput for estimating fugitive emissions. Methanol storage tank emissions calculated by TANKS are summarized in Table 2-14, and the input data and results from TANKS are provided in Appendix B.

Table 2-14. Methanol Storage Tank Fugitive Emissions

Tank Type	Number of Tanks	Emission Rate[1]			
		Carbon Monoxide		Methanol	
		Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)
Crude	2	0.000827	0.00362	0.280	1.23
Shift	4	--	--	0.00306	0.0134
Product	8	--	--	0.000434	0.00190

1.Emission rates are for each tank of a given type. Based on vendor guarantees, closed ventilation system will capture 99% of potential fugitive emissions calculated by TANKS 4.0.9d

2.12 Ship Loading and Tank Vent Scrubbers

All on-site methanol storage tanks will be equipped with closed ventilation systems, and the exhausts will be combined and routed to a wet scrubber. Captured emissions from the shift and product tanks will be comprised entirely of methanol, as that is all those tanks will contain. The crude tanks will contain methanol with some dissolved CO. Because methanol readily dissolves in water, the wet scrubber will use only water to capture the emitted methanol. According to the scrubber vendor, the ventilation system will capture 99 percent of potential fugitive emissions, and the scrubber will remove 99 percent of the captured methanol, for an overall fugitive methanol control efficiency of 98 percent. All of the dissolved CO is assumed to pass through the scrubber and be emitted to the atmosphere.

When the tanks on the ships that will be used to transport the methanol from the facility are loaded, the displaced vapors will be captured by a similar, but smaller in scale, capture and control system. Because the ships used to transport the methanol will be dedicated, the displaced vapors will be entirely comprised of methanol. As with the tank vent system, the ship loading control system will capture 99 percent of the displaced vapors, and the wet scrubber will use water to remove 99 percent of the methanol, for an overall fugitive methanol control efficiency of 98 percent.

Emissions from the tank vent and ship loading scrubbers are summarized in Table 2-15.

Table 2-15. Tank Vent and Ship Loading Scrubber Emissions

Scrubber	Emission Rate[1]			
	Carbon Monoxide		Methanol	
	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)
Tank[1]	0.164	0.717	0.571	2.50
Ship Loading[2]	--	--	1.94	1.21

1. Crude, shift, and product methanol storage tank losses were calculated using the TANKS 4.0.9d program, and 99 percent of losses were assumed to be captured by the closed ventilation system and sent to the scrubber. The scrubber was assumed to remove 99 percent of methanol from the captured vapors. Captured carbon monoxide was assumed to be unaffected by scrubber.
2. Maximum annual methanol production was estimated to be 3,649,416 mt/yr, based on a maximum single production line hourly production rate of 208.3 mt/hr, and continuous production (i.e., 8,760 hr/yr). Loading emission rate was calculated using a modified version of Equation 1 from AP-42 Section 5.2 (Transportation and Marketing of Petroleum Liquids). Based on information from the vendor, ship loading scrubber is expected to capture and remove 99% of fugitive methanol emissions generated by ship loading operations.

2.13 Diesel Engines Powering Emergency Equipment

Two diesel-fueled back-up generators will be available to assist with an orderly shutdown of the Facility in the unusual situation that electrical power is not available from the grid. Additionally, a diesel-fueled engine powering a firewater pump will be available to provide pressurized water for fire protection to the Facility in the unusual situation that a fire coincides with a power outage. The engines will meet Tier 4 Final emission standards for non-emergnecy engines, which means the engines will comply with the emission standards prescribed by 40 CFR Part 60 Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines).

Planned operation of the engines powering the emergency generators will be limited to approximately 52 hours per year, and approximately 56 hours for the engines powering the emergency firewater pump. It is assumed that no more than one engine will be operated at a given time for maintenance and testing purposes. Hourly and annual criteria pollutant emission rates are summarized in Tables 2-16 and 2-17, and TAP emission rates are summarized in Tables 2-18 and 2-19.

Table 2-16. Emergency Generator Engine Criteria Pollutant and Greenhouse Gas Emissions

	Emission Factors[1]		Emission Rate[2]	
Pollutant	**(g/hp-hr)**	**(lb/hp-hr)**	**(lb/hr)**	**(tpy)**
NO_X	0.75	0.0017	7.65	0.199
CO	0.36	0.00079	3.67	0.0955
SO_2	0.0055	0.000012	0.0562	0.00146
PM_{10}	0.034	0.000075	0.347	0.00902
$PM_{2.5}$	0.034	0.000075	0.347	0.00902
VOC	0.18	0.00040	1.84	0.0477
GHG (CO_2e)	74.21	163.6	5,784	150.4

1. NO_X, PM_{10}, $PM_{2.5}$, and VOC emission factors are Tier 4 Final emission standards for non-emergency engines. Because the Tier 4 standards, as codified in 40 CFR 1039.101 Table 1, are based on a weighted average of emissions rates at varying loads the standards themselves do not represent the maximum potential emissions rate for an engine. However, 40 CFR 1039.101(e) provides Not-to-Exceed multipliers that are applied to the Tier 4 standards to establish maximum emission limits that engines may not exceed in operation. CO Emission factor is from a representative generator set (Caterpillar 4,000 ekW 5,000 kVA Standby), based on 100% load. SO_2 emission factor is based on the formula in AP-42 Section 3.4, Table 3.4-1 and a fuel sulfur content of 0.0015% by weight (8.09e-3 × %S). GHG emission factors (in kg/MMBtu and lb/MMBtu) and global warming potentials from 40 CFR Part 98
2. Emission rates reflect a single 4,628-horsepower unit. Annual emissions are based on 52 hours of operation per year.

Table 2-17. Emergency Firewater Pump Engine Criteria Pollutant and Greenhouse Gas Emissions

	Emission Factors[1]		Emission Rate[2]	
Pollutant	**(g/hp-hr)**	**(lb/hp-hr)**	**Hourly (lb/hr)**	**Annual (tpy)**
NO_X	2.6	0.0057	9.17	0.257
CO	0.8	0.00176	2.822	0.0790
SO_2	0.0055	0.000012	0.0194	0.000544
PM_{10}	0.1	0.000220	0.3527	0.00988
$PM_{2.5}$	0.1	0.000220	0.3527	0.00988
VOC	0.1	0.000220	0.3527	0.00988
GHG (CO_2e)	74.21	163.6	1,772	163.6

1. Emission factors are from a representative engine (Clarke model JW6H-UFADF0 @ 2100 rpm), based on 100% load, except SO_2. SO_2 emission factor is based on the formula in AP-42 Section 3.4, Table 3.4-1 and a fuel sulfur content of 0.0015% by weight (8.09e-3 × %S). GHG emission factors (in kg/MMBtu and lb/MMBtu) and global warming potentials from 40 CFR Part 98

2. Emission rates reflect a single 1,600-horsepower unit. Annual emissions are based on 56 hours of operation per year.

Table 2-18. Emergency Generator Engine Toxic and Hazardous Air Pollutant Emissions

Pollutant	CAS	Emission Factor[1] (lb/MMBtu)	Emission Rate[2]	
			Hourly (lb/hr)	Annual (lb/yr)
Acenaphthene	83-32-9	4.68E-06	0.000165	0.00860
Acenaphthylene	208-96-8	9.23E-06	0.000326	0.0170
Acetaldehyde	75-07-0	0.0000252	0.000891	0.0463
Acrolein	107-02-8	7.88E-06	0.000279	0.0145
Anthracene	120-12-7	1.23E-06	4.35E-05	0.00226
Benzene	71-43-2	0.000776	0.0274	1.43
Benzo(a)anthracene	56-55-3	6.22E-07	2.20E-05	0.00114
Benzo(a)pyrene	50-32-8	2.57E-07	9.09E-06	0.000472
Benzo(b)fluoranthene	205-99-2	1.11E-06	3.92E-05	0.00204
Benzo(g,h,i)perylene	191-24-2	5.56E-07	1.97E-05	0.00102
Benzo(k)fluoranthene	207-08-9	2.18E-07	7.71E-06	0.000401
Carbon monoxide	630-08-0	--	3.67	191
Chrysene	218-01-9	1.53E-06	5.41E-05	0.00281
Dibenz(a,h)anthracene	53-70-3	3.46E-07	1.22E-05	0.000636
Diesel Engine Exhaust PM	DEP	--	0.408	21.2
Fluoranthene	206-44-0	4.03E-06	0.000142	0.00741
Fluorene	86-73-7	0.0000128	0.000453	0.0235
Formaldehyde	50-00-0	0.0000789	0.00279	0.145
Indeno(1,2,3-cd)pyrene	193-39-5	4.14E-07	1.46E-05	0.000761
Naphthalene	91-20-3	0.00014	0.00495	0.257
Nitrogen dioxide	10102-44-0	--	5.10	265
Phenanthrene	85-01-8	0.0000408	0.00144	0.0750
Propylene	115-07-1	0.00279	0.0986	5.13
Pyrene	129-00-0	3.71E-06	0.000131	0.00682

Pollutant	CAS	Emission Factor[1]	Emission Rate[2]	
Sulfur dioxide	7446-09-5	--	0.0562	2.92
Sulfuric Acid	7664-93-9	--	0.0258	1.34
Toluene	108-88-3	0.000281	0.00993	0.517
Xylenes	1330-20-7	0.000193	0.00682	0.355

1. Emission factors are from AP-42 Section 3.4, Tables 3.4-3 and 3.4-4, except NO_X, CO, SO_2, and sulfuric acid. NO_X, CO, and SO_2 emissions are the same as the critiera pollutant emissions; sulfuric acid emission rates are based on an assumed 30 percent conversion of SO_2 (SO_2 emission rates are not decreased to account for the converted fraction)
2. Emission rates reflect a single unit that consumes diesel fuel at a rate of 275 gallons per hour. Diesel fuel was assumed to have a density of 7.001 pounds per gallon, and a higher heating value of 18,390 Btu per gallon. Annual emissions are based on 52 hours of operation per year.

Table 2-19. Emergency Firewater Pump Engine Toxic and Hazardous Air Pollutant Emissions

Pollutant	CAS	Emission Factor[1] (lb/MMBtu)	Emission Rate[2]	
			Hourly (lb/hr)	Annual (lb/yr)
Acenaphthene	83-32-9	4.68E-06	5.07E-05	0.00284
Acenaphthylene	208-96-8	9.23E-06	9.99E-05	0.00560
Acetaldehyde	75-07-0	0.0000252	0.000273	0.0153
Acrolein	107-02-8	7.88E-06	8.53E-05	0.00478
Anthracene	120-12-7	1.23E-06	1.33E-05	0.000746
Benzene	71-43-2	0.000776	0.00840	0.471
Benzo(a)anthracene	56-55-3	6.22E-07	6.73E-06	0.000377
Benzo(a)pyrene	50-32-8	2.57E-07	2.78E-06	0.000156
Benzo(b)fluoranthene	205-99-2	1.11E-06	1.20E-05	0.000673
Benzo(g,h,i)perylene	191-24-2	5.56E-07	6.02E-06	0.000337
Benzo(k)fluoranthene	207-08-9	2.18E-07	2.36E-06	0.000132
Carbon monoxide	630-08-0	--	2.82	158
Chrysene	218-01-9	1.53E-06	1.66E-05	0.000928
Dibenz(a,h)anthracene	53-70-3	3.46E-07	3.75E-06	0.000210
Diesel Engine Exhaust PM	DEP	--	0.353	19.8
Fluoranthene	206-44-0	4.03E-06	4.36E-05	0.00244

Pollutant	CAS	Emission Factor[1] (lb/MMBtu)	Emission Rate[2] Hourly (lb/hr)	Emission Rate[2] Annual (lb/yr)
Fluorene	86-73-7	0.0000128	0.000139	0.00776
Formaldehyde	50-00-0	0.0000789	0.000854	0.0478
Indeno(1,2,3-cd)pyrene	193-39-5	4.14E-07	4.48E-06	0.000251
Naphthalene	91-20-3	0.00014	0.00152	0.0849
Nitrogen dioxide	10102-44-0	--	9.17	514
Phenanthrene	85-01-8	0.0000408	0.000442	0.0247
Propylene	115-07-1	0.00279	0.0302	1.69
Pyrene	129-00-0	3.71E-06	4.02E-05	0.00225
Sulfur dioxide	7446-09-5	--	0.0194	1.09
Sulfuric Acid	7664-93-9	--	0.00892	0.499
Toluene	108-88-3	0.000281	0.00304	0.170
Xylenes	1330-20-7	0.000193	0.00209	0.117

1. Emission factors are from AP-42 Section 3.4, Tables 3.4-3 and 3.4-4, except NO_X, CO, SO_2, and sulfuric acid. NO_X, CO, and SO_2 emissions are the same as the criteria pollutant emissions; sulfuric acid emission rates are based on an assumed 30 percent conversion of SO_2 (SO_2 emission rates are not decreased to account for the converted fraction)
2. Emission rates reflect a single unit that consumes diesel fuel at a rate of 84.1 gallons per hour. Diesel fuel was assumed to have a density of 7.001 pounds per gallon, and a higher heating value of 18,390 Btu per gallon. Annual emissions are based on 56 hours of operation per year.

2.14 Ammonia Storage Tanks

The boilers and the PGU will all employ a Selective Catalytic Reduction (SCR) system to reduce NO_X emissions. A 25 percent by weight solution of aqueous ammonia will be used as the reagent in all of the SCR systems. Three tanks, each with a capacity of approximately 9,000 gallons, will be used to store the aqueous ammonia on site. The tanks will all be pre-built units of a vertical, cylindrical design, with fixed roofs. As with the methanol storage tanks, EPA’s TANKS 4.0.9d program was used to calculate maximum potential fugitive emissions from the tanks. Ammonia storage tank emissions are summarized in Table 2-20 and the input data and results from TANKS are provided in Appendix B.

Table 2-20. Ammonia Storage Tank Emissions

Tank Type	Number	Emission Rate[1] Ammonia Hourly (lb/hr)	 Annual (lb/yr)
Ammonia	3	0.105	919

1. Emissions for a single tank, estimated using TANKS 4.0.9d

2.15 Component Leaks

VOC emissions associated with minute vapor leakage from valve seals, pump seals, pressure relief valves, flanges, and similar equipment were calculated using anticipated component counts and USEPA fugitive emissions factors. Fugitive emission factors were obtained from Protocol for Equipment Leak Estimates, USEPA 453-R95-017, November 1995. Fugitive VOC emissions associated with leaks from gaseous and liquid streams are presented in Table 2-21.

Table 2-21. Component Leak Fugitive Emissions

Pollutant	CAS	Emission Rate[1] Hourly (lb/hr)	 Annual (lb/yr)
Carbon Monoxide	630-08-0	0.00875	76.6
VOCs[2]	--	0.126	1,101
Butane	106-97-8	0.000145	1.27
Ethane	74-84-0	0.00273	23.9
Methane	74-82-8	0.104	913
Methanol	67-56-1	0.125	1,095
Propane	74-98-6	0.000556	4.87
Carbon Dioxide	124-38-9	0.0274	240
GHG (CO_2e)[3]	--	2.63	23,070

1. Annual emissions are hourly emissions multiplied by 8,760 hr/yr
2. VOC emission rate is the sum of the butane, methanol, and propane emission rates
3. GHG emission rate is the sum of the CO_2 and methane emission rates, converted to CO_2e using the global warming potential factors from 40 CFR Part 98.

3. REGULATORY REVIEW

This section identifies and discusses federal, state, and local air quality regulations and guidelines that potentially apply to the Project.

3.1 Permitting Programs

3.1.1 Prevention of Significant Deterioration Permits

Ecology administers the state PSD air quality permit process that applies to major sources. Because synthesis of methanol from natural gas is considered a chemical process (SIC code 28), the PSD permit path is triggered if emissions of a non-GHG PSD pollutant exceed 100 tons per year (tpy).

On June 23, 2014, the U.S. Supreme Court determined that USEPA did not have the authority to require PSD permitting of new sources when only the GHG emissions exceeded the permitting threshold established by the "Tailoring Rule."[3] However, because Ecology adopted the federal PSD program by reference into state regulations as it existed on August 13, 2012, removal of the tailored GHG permitting thresholds from the federal PSD program on August 19, 2015[4] had no effect on the state PSD program. As a result, new sources in Washington are subject to review under the state PSD program, even when only the GHG emissions exceed 100,000 tpy.

As discussed in Section 2 of this permit application, the Facility will emit GHGs at a rate exceeding 100,000 tpy, and is therefore required to submit an application for a state-only PSD permit to Ecology. Because NO_X, PM_{10}, $PM_{2.5}$, and VOCs will be emitted in quantities greater than the PSD Significant Emission Rates (SERs; see Table 2-1), those pollutants are also subject to PSD review. Criteria pollutants that will be emitted at rates less than the SERs (i.e., CO and SO_2; see Table 2-1), as well as TAPs, are appropriately reviewed through the minor source (i.e., ADP) path, as discussed below.

3.1.2 Air Discharge Permits

SWCAA 400-109 requires an ADP application be filed and approved prior to the construction of an air contaminant source or emission unit. To obtain an ADP, the

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[3] 75 Federal Register 31514

[4] 80 Federal Register 50199

applicant must demonstrate that BACT has been employed to control criteria pollutants and TAPs (i.e., "tBACT"), that ambient air quality standards are protected, and that new sources of toxic air pollutants do not generate ambient concentrations that exceed applicable Acceptable Source Impact Levels (ASILs). In addition, SWCAA must confirm that the project will meet all relevant NSPS and NESHAPs requirements. This permit application is intended to fulfill the requirements for an ADP.

3.1.3 State Environmental Protection Act

Before Ecology and SWCAA can issue permits, the project must undergo review pursuant to the State Environmental Protection Act (SEPA). The Port of Kalama and Cowlitz County are serving as co-lead agencies for the SEPA environmental review. A Draft Environmental Impact Statement (DEIS) is currently being prepared for release in 2016.

3.1.4 Air Operating Permits

Title V of the federal Clean Air Act requires facilities with the potential to emit more than 100 tons of a regulated criteria pollutant, 10 tons of a single HAP, or 25 tons of all HAP combined on an annual basis to obtain a Title V Air Operating Permit (AOP). As indicated in Section 2 of this permit application, facility-wide potential emissions will be less than these Title V thresholds.[5] Consequently, the Project will not be subject to Title V AOP requirements.

3.2 Emission Standards

3.2.1 New Source Performance Standards

New Source Performance Standards (NSPS) are nationally uniform standards applied to specific categories of stationary sources that are constructed, modified, or reconstructed after the standard was proposed. NSPS are found in Title 40, Part 60 of the Code of Federal Regulations (CFR). NSPS represent the minimum level of control that is required on a new or modified source. The following NSPS regulations potentially apply to the Project, and applicability will be discussed in the following sections.

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[5] Similar to the federal PSD program, the Tailoring Rule provided an emission rate threshold to bring facilities into the Title V program based solely on GHG emissions. On Feburary 3, 2016, Ecology revised WAC 173-401 to clarify that GHG emissions alone do not trigger the requirement for an AOP.

- Subpart A – General Provisions (40 CFR Part 60.1-60.19)
- Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60.40b-60.49b)
- Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60.40c-60.48c)
- Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (40 CFR Part 60.110b-117b)
- Subpart VVa - Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (40 CFR Part 60.480a-60.489a)
- Subpart NNN—Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations (40 CFR Parts 60.660 – 60.668)
- Subpart RRR—Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes (40 CFR Parts 60.700 – 60.708)
- Subpart IIII – Standards of Performance for Compression Ignition Combustion Engines (40 CFR Parts 60.4200 – 60.4219)
- Subpart KKKK - Standards of Performance for Stationary Combustion Turbines (40 CFR Parts 60.4200 – 60.4219)

Subpart A – General Provisions

Elements of Subpart A apply to each affected facility under any NSPS rule, as specified in each NSPS source category standard. Subpart A contains general requirements for notifications, monitoring, performance testing, reporting, recordkeeping, and operation and maintenance.

Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Subpart Db of the NSPS applies to steam generating units that commence construction, modification, or reconstruction after June 19, 1984, and have a maximum design heat input capacity of greater than 100 MMBtu/hr. The three boilers will be constructed after June 19, 1984 and will each have a maximum design heat input capacity of 530 MMBtu/hr per boiler, and are therefore subject to the subpart.

Subpart Db establishes particulate matter limits for boilers that burn coal, oil, wood, or solid waste, but Project boilers will combust only gaseous fuels. Therefore, the new boilers are subject only to the Subpart Db NOx emission limitation of 0.10 lb/MMBtu (40 CFR 60.44b(a)(1)). The boilers will be equipped with low NO_X burners (LNBs) and selective catalytic reduction (SCR) units expected to achieve 0.0049 lb NOx/MMBtu. NWIWK will comply with all applicable testing, monitoring, recordkeeping and reporting requirements.

Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Subpart Dc applies to steam generating units that commence construction, modification, or reconstruction after June 9, 1989, and have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. The process heaters have a maximum design heat input capacity of 72 MMBtu/hr per heater and would therefore be potentially subject to the subpart. However, the process heaters are defined in 40 CFR 60.41c as 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." As discussed in Section 2 of this application, the primary purpose of the process heaters is to provide heat to the reforming units during startup, where water-rich natural gas is converted into syngas, until the syngas from the secondary reforming step (i.e., the ATR) is hot enough to provide heat to the primary reformer (i.e., the GHR). Process heaters are excluded from the definition of steam generating unit under Subpart Dc (40 CFR 60.41c). Consequently, Subpart Dc does not apply to the process heaters.

Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

Subpart Kb applies to any storage vessels with a capacity greater than or equal to 75 m^3 (19,813 gal) that stores volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984, except those storage vessels that meet specified applicability exceptions. Subpart Kb does not apply to storage vessels with a capacity greater than or equal to 151 m^3 (39,900 gal) storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

The three ammonia tanks will store 25 percent Aqueous Ammonia, which is not a volatile organic liquid, therefore, Subpart Kb does not apply to the ammonia tanks.

The two crude methanol tanks, four shift tanks and eight bulk product storage tanks meet the applicability criteria of Subpart Kb as they have a capacity greater than 39,900 gallons each and will store VOL material with a maximum true vapour pressure greater than 3.5 kPa. NWIWK will comply with the subpart by installing a closed vent system and scrubber (Tank Scrubber) that meets the following specifications of 40 CFR 60.112b(a)(3):

- The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, Subpart VV, §60.485(b); and
- The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater.

Owners and operators of affected sources that are equipped with a closed vent system and control device are exempt from the performance testing requirements of §60.8. NWIWK will submit an initial notification that includes an operating plan and must operate the system in accordance to the plan.

Subpart VVa - Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

Subpart VVa of the NSPS applies to affected facilities in the synthetic organic chemicals manufacturing industry that commence construction, modification, or reconstruction after November 7, 2006 and have a maximum design capacity of greater than 1,102 tpy of a chemical listed in §60.489. Methanol is a listed chemical and the facility’s design capacity is greater than the exemption threshold, therefore the facility is subject to the subpart.

Subpart VVa applies to all equipment that is in VOC service, which means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight.

In accordance with §60.480a(e)(2), owners and operators may choose to comply with the provisions of 40 CFR part 63, Subpart H, to satisfy the requirements Subpart VVa. As discussed in the BACT analysis, included as Appendix C, a comparison of fugitive component emissions regulations compiled by the Louisiana Department of Environmental Quality (LDEQ) found that the requirements of 40 CFR 63 Subpart H are the most stringent. NWIWK will comply with part 63 Subpart H in order to meet the requirements of part 60 Subpart VVa.

However, the requirements to test and demonstrate that equipment is in VOC service and light liquid service still apply (§60.485a(d), (e), and (f)) and NWIWK must keep records of the design capacity of the facility and all analyses of whether equipment is in VOC service (§60.486a(i) and (j)). Also, owners or operators who choose to comply with 40 CFR part 63, Subpart H must also comply with the General Requirements of Subpart A for that equipment (§§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16).

Subpart NNN—Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations

Subpart NNN applies to affected facilities that commence construction, modification, or reconstruction on distillation units that produce any of the chemicals listed in 40 CFR 60.667 as a product, co-product, by-product, or intermediate. The distillation unit will produce refined methanol, which is listed as a chemical affected by Subpart NNN. Accordingly, NSPS Subpart NNN will apply to the distillation unit and NWIWK will comply with the applicable NSPS requirements.

NSPS Subpart NNN requires that emissions from atmospheric vents from distillation columns be routed to a control device or the flame zone of a boiler or heater. NWIWK proposes to direct the light hydrocarbon by-products from the distillation unit to be used as fuel for the boilers to comply with 40 CFR 60.662(a). In accordance with 40 CFR 60.663(c)-(d), NWIWK will install, calibrate, maintain and operate according to the manufacturer's specifications a vent stream flow meter and temperature monitoring device. NWIWK must also monitor and record the periods of operation of the boiler. Initial performance testing is not required for boilers with a design input capacity greater than 150 MMBtu/hr. NWIWK will comply with all applicable recordkeeping and reporting requirements.

Subpart RRR—Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes

Subpart RRR applies to affected facilities that commence construction, modification, or reconstruction on reactor process units that produce any of the chemicals listed in 40 CFR 60.707 as a product, co-product, by-product, or intermediate. Following the two reformers, the synthesis gas then enters the two converters where crude methanol is created, which is listed as a chemical affected by Subpart RRR.

Subpart RRR establishes standards for "vent streams" which the subpart defines as "any gas stream discharged directly from a reactor process to the atmosphere or indirectly to the atmosphere after diversion through other process equipment. The vent stream excludes relief valve discharges and equipment leaks." [40 CFR 60.701]

The vent stream from the two converters does not discharge to the atmosphere but flows through a series of coolers to allow methanol product to condense, and to recover and reuse waste process heat to improve energy efficiency. Condensed crude methanol is sent to the methanol distillation unit, and the non-condensed gas mixture is compressed and recycled back to the converters to enhance methanol production.

Finally, in accordance with 40 CFR 60.700(c)(5), if the vent stream from an affected facility is routed to a distillation unit subject to Subpart NNN and has no other releases to the air except for a pressure relief valve, the facility is exempt from all provisions of this subpart except for §60.705(r), which requires NWIWK to submit a process design description, that must be retained for the life of the process. NWIWK will submit a process design description along with the notification of the actual date of initial startup, postmarked within 15 days after such date. No other records or reports would be required unless process changes are made.

Subpart IIII– Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

This subpart is applicable to manufacturers, owners, and operators of certain stationary compression ignition (CI) internal combustion engines (ICE). NWIWK proposes to install two 4,628 horsepower (hp) diesel-fueled reciprocating emergency generator engines (one per line) to assist with an orderly shutdown of the Facility in the unusual situation that electrical power is not available from the grid. Additionally, a 1,600 hp diesel-fueled engine powering a firewater pump will be available to provide pressurized water for fire protection to the Facility in the unusual situation that a fire coincides with a power outage.

NWIWK proposes to permit these engines as Subpart IIII "emergency" engines, but to equip them with the emission controls required to meet Tier 4 Final standards. In order to be considered emergency engines per Subpart IIII, the engines must operate in accordance to the following requirements as specified in § 60.4211(f):

- There is no time limit on the use of emergency stationary ICE in emergency situations.
- Maintenance checks and readiness testing is limited to 100 hours per year unless the permittee has approval or records indicating that Federal, State, or local standards require maintenance and testing beyond 100 hours per year.

There are several other provisions that allow for additional use of the emergency engines but NWIWK proposes to use their RICE only for readiness testing and during power outages and emergencies.

Pursuant to §§ 60.4205(b), 60.4202(b)(2), and 60.4211(c), the two emergency generator engines must be certified to the applicable emission standards in Table 1 of 40 CFR 89.112, below:

Rated Power (kW)	**Tier**	**Model Year**	**Emission standards**		
			g/kW-hr		
			NMHC+NOX	**CO**	**PM**
kW > 560	Tier 2	2006	6.4	3.5	0.2

Pursuant to §§ 60.4205(c), and Table 4 to Subpart IIII, the firewater pump emergency engine must be certified to the following emission limits.

Rated Power (kW)	**Model Year**	**Emission standards**		
		g/kW-hr		
		NMHC+NO$_X$	**CO**	**PM**
kW > 560	2008+	6.4	3.5	0.2

Additionally, NWIWK must use diesel fuel that meets the following requirements:

1. Sulfur content – 15 ppm maximum
2. Cetane index or aromatic content, as follows:
    i. A minimum Cetane index of 40; or
    ii. A maximum aromatic content of 35 volume percent.

NWIWK will comply with the subpart by installing certified engines that meet the emissions standards listed above, and by using ultra-low sulfur diesel (ULSD) as fuel for the engines. The engines must be installed with a non-resettable hour meter and a backpressure monitor that notifies the operator when the high backpressure limit of the engine is approached. NWIWK will operate and maintain the engines according to the manufacturer's emission-related written instructions, and will keep records of the engine certification, hours of emergency and non-emergency operation, and any corrective action taken after the backpressure monitor has notified the operator that the high backpressure limit of the engine was approached. No performance testing, notification, or reporting is required for these units by Subpart IIII.

Subpart KKKK, Standards of Performance for Stationary Combustion Turbines

Subpart KKKK establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that combust more than 10 MMBtu/hr and commenced construction, modification or reconstruction after February 18, 2005. The combustion turbines proposed for the Facility meet these criteria, and will therefore be subject to the requirements of Subpart KKKK. Subpart KKKK limits NO_X exhaust concentration to 15 ppm, which is significantly higher than the proposed NO_X exhaust concentration (2.5 ppmvd at 15 percent O_2). Subpart KKKK limits SO_2 emissions to 0.90 lb/MWe-hr, or 4.5 lb/hr for the proposed combustion turbines at maximum operating conditions; estimated SO_2 emissions are 3.13 pounds per hour per combustion turbine.

3.2.2 National Emission Standards for Hazardous Air Pollutants / Maximum Achievable Control Technology Standards

Under the provisions of Section 112 of the 1990 Clean Air Act Amendments, EPA was required to regulate emissions of a total of 189 hazardous air pollutants (HAPs) from stationary sources.[6] EPA does this by specific industry categories to tailor the controls to the major sources of emissions and the HAPs of concern from that industry. The rules promulgated under Section 112 generally specify the Maximum Achievable Control Technology (MACT) that must be applied for a given industry category. Consequently, these rules are often called MACT standards.

MACT standards can require facility owners/operators to meet emission limits, install emission control technologies, monitor emissions and/or operating parameters, and use specified work practices. In addition, the standards typically include recordkeeping and reporting provisions. MACT standards are codified in 40 CFR Parts 61 and 63.

There are two types of HAP sources, "major" sources of HAP emissions and "area" sources of HAP emissions. Major sources are facilities that have a potential to emit more than 10 tons of a single HAP, or 25 tons of all HAPs combined. Area sources are facilities that are not a major source. The Facility is an area source of HAP because, as shown in Table 3-1, facility-wide emissions of all HAP are below major source thresholds.

Table 3-1. Facility-Wide Hazardous Air Pollutant Emissions

Pollutant	CAS #	Emission Rate (tpy)
Acetaldehyde	75-07-0	0.160
Acrolein	107-02-8	0.0256
Arsenic	7440-38-2	0.00119
Benzene	71-43-2	0.0654
Beryllium	7440-41-7	7.12E-05
1,3-Butadiene	106-99-0	0.00172
Cadmium	7440-43-9	0.00652
Chromium	7440-47-3	0.00830
Cobalt	7440-48-4	0.000498
Ethylbenzene	100-41-4	0.128

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[6] EPA has removed three HAPs from the list: caprolactum, ethylene glycol monobutyl ether, and methyl ethyl ketone (MEK).

Pollutant	CAS #	Emission Rate (tpy)
Formaldehyde	50-00-0	0.474
Hexane	110-54-3	0.353
Lead	7439-92-1	0.00230
Manganese	7439-96-5	0.00225
Mercury	7439-97-6	0.00154
Methanol	67-56-1	6.78
Naphthalene	91-20-3	0.00734
Nickel	7440-02-0	0.0125
Propylene Oxide	75-56-9	0.116
Selenium	7782-49-2	0.000142
Toluene	108-88-3	0.590
Xylenes	1330-20-7	0.256
Total		8.99
Maximum		6.78

The following subparts potentially apply to the Project:

- 40 CFR Part 61 Subpart FF – National Emission Standard for Benzene Waste Operations (40 CFR Part 61.140-61.157)
- 40 CFR Part 63 Subpart A – General Provisions (40 CFR Part 63.1-63.16)
- 40 CFR Part 63 Subpart H — National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks (40 CFR Part 63.160-63.183)
- 40 CFR Part 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (40 CFR Part 63.6580-63.6675)
- 40 CFR Part 63 Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources (40 CFR Part 63.11193-63.11237)

Subpart FF – National Emission Standard for Benzene Waste Operations

The provisions of this subpart apply to owners and operators of chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries;

and to owners and operators of hazardous waste treatment, storage, and disposal facilities that treat, store or dispose of hazardous waste generated by such facilities. A chemical manufacturing plant means "any facility engaged in the production of chemicals by chemical, thermal, physical, or biological processes for use as a product, co-product, by-product, or intermediate including but not limited to industrial organic chemicals, organic pesticide products, pharmaceutical preparations, paint and allied products, fertilizers, and agricultural chemicals." The purpose of this subpart is to minimize benzene emissions from the waste operations that may exist at these facilities. For each of the previously listed facilities, the following waste[7] is exempt from the requirements of this subpart:

- Waste in the form of gases or vapors that is emitted from process fluids; and
- Waste that is contained in a segregated stormwater sewer system.

A key concept under this subpart is the total annual benzene (TAB) quantity from a facility's waste. The TAB quantity of a facility's waste is the primary determinative factor for which requirements of the subpart apply to the facility. The TAB quantity for a facility is the sum of the annual benzene quantity for each waste stream at the facility (except for wastes generated by remediation conducted by the facility) that has a flow-weighted annual average water content greater than 10 percent or that is mixed with water, or other wastes, at any time and the mixture has an annual average water content greater than 10 percent.

KMMEF meets the definition of a chemical manufacturing plant. Based on process knowledge, it is expected that the total annual benzene (TAB) quantity from facility waste will be less than 1 megagrams per year (Mg/yr). NWIWK will determine the TAB quantity in accordance with 40 CFR 61.355(a)(1), (a)(2), and (a)(5). A facility with a TAB quantity less than 1 Mg/yr is required to maintain documentation of the quantity of benzene in the waste. If the TAB quantity is greater than 1 Mg/yr, but less than 10 Mg/yr, the Facility would be subject to reporting and recordkeeping requirements. Facilities with TAB quantities greater than 10 Mg/yr are required to control each benzene waste stream.

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[7] *Waste* – means any material resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, thermally, or biologically treated prior to being discarded, recycled, or discharged.

40 CFR Part 63 Subpart A – General Provisions

The provisions of Subpart A apply to each affected facility under any Part 63 NESHAP rule. Subpart A contains general requirements for notifications, monitoring, performance testing, reporting, recordkeeping, and operation and maintenance. These general requirements will apply to the proposed Project as referenced in the applicable NESHAP Subparts.

40 CFR Part 63 Subpart H - National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks

Subparts F, G, and H form the hazardous organic NESHAP, also known as HON MACT, that apply to major sources of HAP. KMMEF is an area source of HAP, therefore, the facility is not subject to these subparts. However, as discussed above, NWIWK will comply with Part 63 Subpart H in order to meet the requirements of part 60 Subpart VVa. An affected source is a piece of equipment that is in VOC service, meaning it contains or contacts a process fluid that is at least 10 percent VOC by weight.

Subpart H applies to pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or line, valves, connectors (except for those that are welded), surge control vessels, bottoms receivers, instrumentation systems, and control devices or closed vent systems required by this subpart that intend to operate in organic HAP service for 300 hours or more during the calendar year.

NWIWK will operate pumps, compressors, pressure relief devices, valves, and connectors subject to requirements of Subpart G. For each type of equipment, the subpart establishes definitions of what measurement value constitutes a leak (in parts per million and greater), monitoring frequency, defined periods during which repairs must be made, post repair inspection requirements, notification, recordkeeping and reporting requirements. The specifics of these requirements are summarized in a comparison of fugitive component emissions regulations compiled by the Louisiana Department of Environmental Quality (LDEQ), included in the BACT analysis provided in Appendix C. NWIWK will comply with each applicable requirement of Subpart H.

40 CFR Part 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

This subpart contains emission standards for stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions.

Two diesel-fueled back-up generators will be available to assist with an orderly shutdown of the Facility in the unusual situation that electrical power is not available from the grid. Additionally, a diesel-fueled engine powering a firewater pump will be available to provide pressurized water for fire protection to the Facility in the unusual situation that a fire coincides with a power outage. These diesel-fueled engines are considered new RICE located at an area source under this regulation because the engines will be constructed after June 12, 2006.

Pursuant to § 63.6590(c)(1) of this subpart, new and reconstructed emergency RICE located at an area source of HAP emissions must comply with 40 CFR part 60, Subpart IIII, and no further requirements apply for such engines under 40 CFR part 63. As discussed above, the proposed diesel-fueled engines are subject to the requirements of 40 CFR part 60, Subpart IIII. Therefore, the engines will comply with 40 CFR part 60 Subpart IIII, and they will not be subject to any further requirements under this Subpart.

Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

Subpart JJJJJJ applies to industrial, commercial, or institutional boilers located at area sources of HAPs. A boiler is defined as "an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam or hot water...Waste heat boilers, process heaters, and autoclaves are excluded from the definition of *Boiler.*" New boilers are those that commenced construction or reconstruction of the affected source after June 4, 2010.

The three boilers will burn only gaseous fuel, natural gas and the light hydrocarbon by-products recovered from the methanol distillation process. As provided in 40 CFR 63.11195(e), gas-fired boilers are not subject to the rule and the boilers are not affected sources subject to applicable requirements of this regulation.

As stated above, Subpart JJJJJJ specifically excludes process heaters and waste heat boilers from the definition of boiler and the requirements of the subpart do not apply to these emissions units. The two process heaters proposed for each production line meet the definition of process heater under the subpart because their "primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. Process heaters include units that heat water/water mixtures for pool heating, sidewalk heating, cooling tower water heating, power washing, or oil heating." Therefore, the process heaters are not subject to Subpart JJJJJJ.

3.2.3 General Air Pollution Control Regulations

The Southwest Clean Air Agency has established air quality regulations that apply to the project site. Section 040 of SWCAA's General Regulations for Air Pollution Sources establishes general emission standards that apply to all emission units in its jurisdiction. Paraphrasing this section, it 1) limits opacity from all emission units to 20% (with some exceptions) and SO2 exhaust concentrations to 1000 ppm at 7% oxygen; 2) prohibits particulate matter fallout that affects adjacent properties; and 3) requires reasonable precautions to prevent odors and the release of fugitive emissions that affect neighboring properties.

SWCAA Section 050 limits particulate matter emissions greater than 0.1 grain/dscf from combustion units, incineration units, and from general process units.

As part of the ADP application reviews, SWCAA will review NWIWK's proposed emission control technologies to ensure that BACT is being applied to minimize criteria and toxic air pollutants. The BACT analysis identifies pollutant-specific alternatives for emission control; the determination of which control constitutes BACT is made on a case-by-case basis and considers the economic, energy and environmental costs. The requirement for emission sources to achieve BACT virtually always results in emission rates lower than the general state and local agency emission requirements noted in the preceing paragraphs. The BACT analysis can be found in Appendix C.

3.3 Chemical Accident Prevention Provisions

Section 112r of the Clean Air Act Amendments of 1990 requires EPA to publish regulations and guidance for chemical accident prevention at facilities using substances that pose risk of harm from accidental releases. These regulations require companies of all sizes that use certain listed regulated flammable and toxic substances to develop a Risk Management Program. The RMP information helps local fire, police, and emergency response personnel (who must prepare for and respond to chemical accidents).

40 CFR Part 68 sets the requirements for owners and operators of stationary sources concerning the prevention of accidental releases of regulated substances. A stationary source that has on-site more than a threshold quantity of a regulated substance, listed in 40 CFR 68.130 must develop a RMP.

The use of SCR to control NOx emissions from the combustion turbines at the Facility will require the storage and use of aqueous ammonia, one of the substances addressed in 40CFR Part 68. NWIWK proposes to install three tanks to store 25 percent aqueous ammonia; each would have a capacity of 9,000 gallons. Table 1 of 40 CFR 68.130 indicates a threshold of 20,000 pounds of aqueous ammonia with a concentration exceeding 20 percent. Because the facility would store more than 20,000 pounds of aqueous ammonia, 40 CFR Part 68 will require preparation of a RMP addressing a potential spill of aqueous ammonia. The completed RMP must be submitted before 20,000 lb of aqueous ammonia is on site.

4. CLASS II DISPERSION MODELING ANALYSIS

An air permit cannot be issued by Ecology or SWCAA to a proposed new source without a demonstration that the emissions attributable to the project will not cause or contribute to a violation of any ambient air quality standard, or, in the case of a major source subject to PSD review, cause a PSD increment to be exceeded. A dispersion modeling analysis is typically used to predict potential impacts of the proposed project on air quality in the area surrounding the Facility to assess compliance with the National Ambient Air Quality Standards (NAAQS), the Washington Ambient Air Quality Standards (WAAQS),[8] applicable PSD increments, and, for TAPs, the ASILs. This chapter presents the near field (i.e., Class II) ambient impact analysis; Chapter 5 addresses the regional (Class I) impact analysis.

4.1 Model Selection

Ramboll Environ reviewed regulatory modeling techniques to select an appropriate air quality model to simulate dispersion of air pollutants emitted by the proposed project for a near-field air quality impact analysis. The selection of regulatory modeling tools is influenced by situations where exhaust plumes have the potential to interact with onsite structures (i.e., “building downwash”) or impact complex terrain. There are several onsite structures with the potential to interact with exhaust plumes, and there is terrain in the east and southwest portions of the modeling domain with elevations in excess of the exhaust heights of proposed emission units. As a result, the dispersion model selected for the analysis will be required to consider both complex terrain and building downwash effects to allow for the possibility of emissions from stacks shorter than dictated by Good Engineering Practice (GEP).

EPA’s “Guideline of Air Quality Models” in 40 CFR 51 Appendix W (“the Guideline”) recommends the use of AERMOD in this situation. AERMOD was specifically designed to estimate impacts of air pollutants in areas containing both simple and complex terrain. AERMOD also includes the PRIME downwash algorithms to estimate effects of surrounding buildings on the dispersion of plumes. Ramboll

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[8] The WAAQS are identical to the NAAQS, except Washington has 24-hour and annual average SO_2 standards, which do not have federal equivalents.

Environ used the latest version of AERMOD (Version 15181) for the dispersion modeling analysis.

4.2 Modeling Procedures

Ramboll Environ applied AERMOD to model criteria pollutant and TAP emission rates using the regulatory defaults in addition to the options and data discussed below. One exception to the use of current regulatory defaults is the use of the option to adjust the surface friction velocity (U*) for low wind or stable conditions. While this is currently considered a non-default option, USEPA has indicated that this option will be incorporated into the regulatory version of AERMOD (i.e., be a default option). An archive of modeling files is provided for review.

4.3 Averaging Periods

Criteria pollutant and TAP concentrations predicted by AERMOD were averaged over short-term (1-, 3-, 8-, and 24-hour) and annual averaging periods as required by the applicable ambient criteria for each modeled pollutant.

4.4 Chemical Transformations

Based on EPA guidance, 1-hour average NO_2 concentrations were assumed to be 80 percent of the NO_X concentrations calculated by the model.[9] Annual average NO_2 concentrations were assumed to be 75 percent of the NO_X concentrations calculated by the model, based on guidance in Section 6.2.3 of the Guidelines.

4.5 Elevation Data and Receptor Network

Terrain elevations for receptors were prepared using 1/3th arc-second elevation data from the National Elevation Dataset (NED), which is a product of the United States Geological Survey (USGS). The NED is a seamless elevation dataset covering the continental United States, Alaska, and Hawaii. The elevation dataset for the modeling demonstration was downloaded from the internet.[10] These data have a horizontal spatial resolution of approximately 10 meters (m).

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[9] "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard" memorandum issued on March 1, 2011 by Tyler Fox, Leader of the Air Quality Modeling Group at EPA's Office of Air Quality Planning and Standards

[10] (http://seamless.usgs.gov)

For the dispersion model analyses, receptors were spaced 500 meters apart covering the 10 kilometer (km) square simulation domain (shown in Figure 1-1), with a 5-km-by-5-km nested receptor grid with 200-m receptor spacing, a 3-km-by-3-km nested receptor grid with 50-m receptor spacing, and a 1.8-km-by-1.8-km nested receptor grid with 25-m receptor spacing. All receptor grids were centered on the location of the proposed project. Receptors were also located at 10-m intervals along ambient air boundary of the post-project facility. The final receptor locations are shown in Figure 4-1. The base elevation and hill height scale for each of the 8,210 receptors were determined using the EPA's terrain processor AERMAP (Version 11103), which generates the receptor output files that are read by AERMOD. All receptor locations are in Universal Transverse Mercator (UTM) coordinates using the spatial reference of NAD 83, Zone 10.

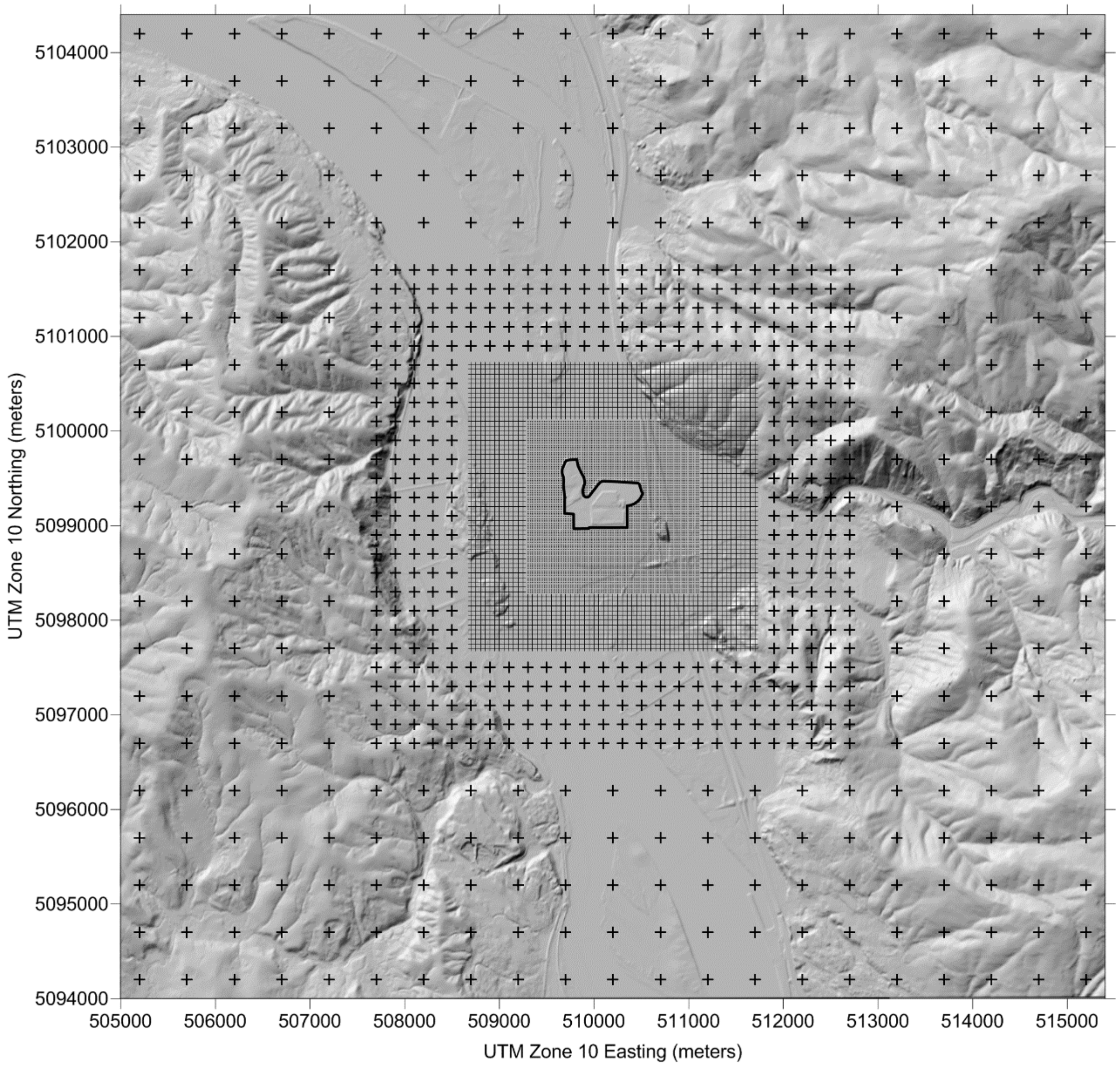

Figure 4-1: Modeling Receptor Locations and Varying Receptor Grid

4.6 Meteorological Data

A meteorological database was constructed using the AERMET meteorological data preprocessor (version 15181) and available surface and upper air data. A survey was conducted of available meteorological data to identify representative data for use in the simulations. Ramboll Environ identified two possible surface meteorological datasets from the National Weather Service (NWS) that could be used in the dispersion modeling analysis: meteorological data collected at Southwest Washington Regional Airport in Kelso, Washington, approximately 9 kilometers (km) north-northwest of the proposed facility, or data collected at Portland International Airport, which is approximately 55 km to the south-southeast. In addition, TRC Consultants, Inc. operated a meteorological station from 1994 to 2001 for Noveon Chemical (now Emerald Kalama Chemical), which is located about 3 km south-southeast of the proposed facility.

A 1995-calendar-year meteorological data set based on surface observations from Noveon Chemical was approved by Ecology for use in dispersion modeling analyses for projects previously proposed at the same site. The station is located within the same portion of the Columbia River valley as the proposed facility, and collected data specifically for PSD permit applications. The sensors and audit procedures employed meet USEPA requirements for meteorological data to be used in support of PSD permit applications. The Noveon station includes parameters required by the latest regulatory dispersion model (AERMOD), including sigma theta, which is used to estimate lateral dispersion. For the current analysis, Ramboll Environ was able to obtain all data collected by the station; in addition to 1995, the data recovery rate was sufficient during calendar years 1997 and 2000 to add those years to the meteorological database.

Figure 4-2 presents a wind rose constructed from the Noveon meteorological database. As shown, the winds are bimodal, following the general north-south orientation of this portion of the Columbia River Valley. The average wind velocity was 2.7 meters per second (m/s), and periods of calm wind are rare, occurring for less than 1 percent of the observations. Light winds tend to come up the valley from the north, while the highest wind velocities are from the south and southwest. The winds in the Noveon dataset are quite different from those observed at low-level stations such as those located at Kelso or Portland airports, and reflect the influence of the local topography.

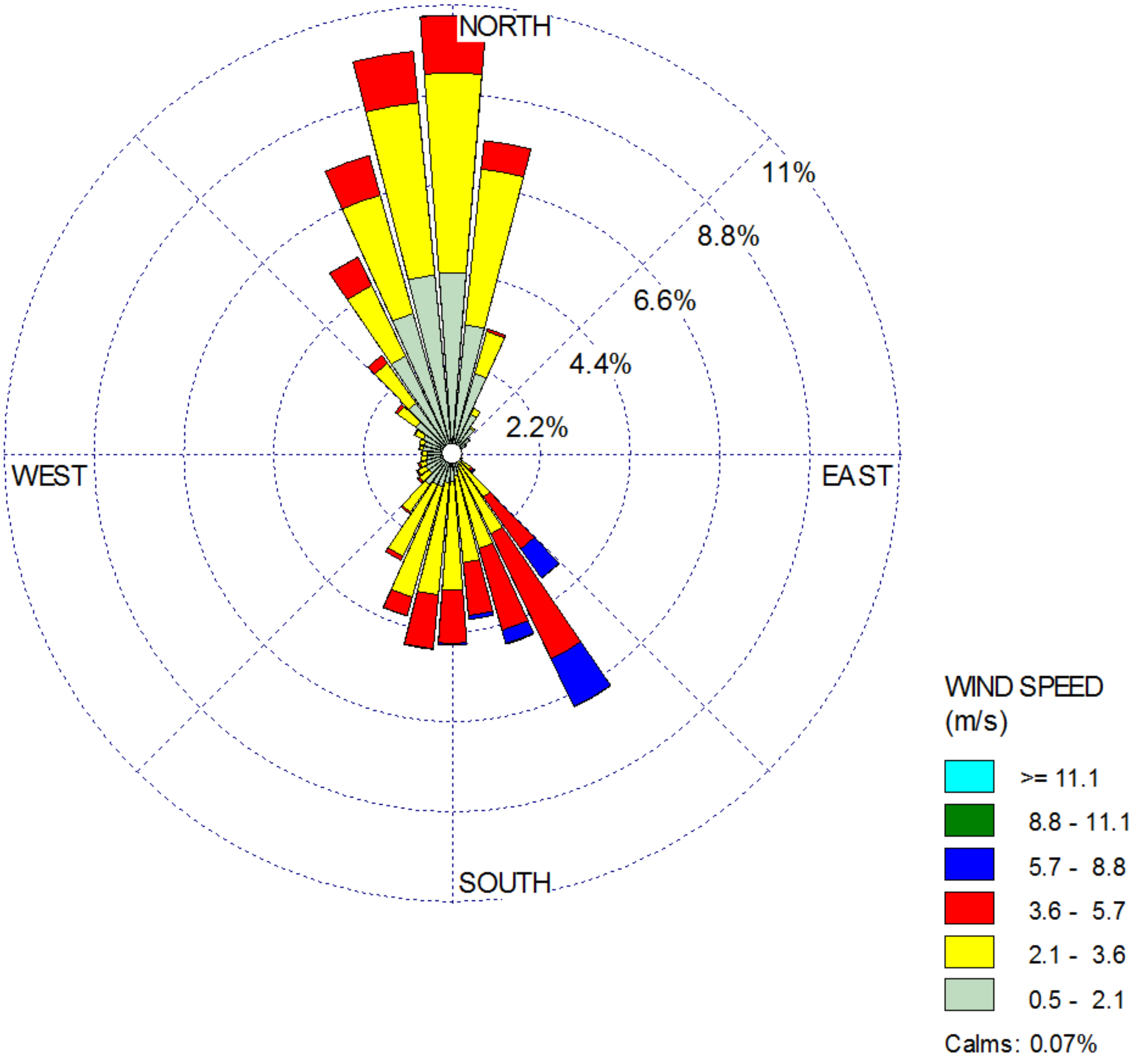

Figure 4-2: Wind Speed and Wind Direction Data for Calendar Years 1995, 1997 & 2000

Additional meteorological variables and geophysical parameters are required for the dispersion modeling analysis to estimate the surface energy fluxes and construct boundary layer profiles. Surface characteristics including the surface roughness length, albedo, and Bowen ratio were determined for the area surrounding the Noveon meteorological station using the AERMET surface characteristic preprocessor, AERSURFACE (version 13016), and the USGS 1992 National Land

Cover (NLCD92) land use data set.[11] The NLCD92 data set used in the analysis has a 30 m mesh size and 21 land use categories. Seasonal surface parameters were determined using AERSURFACE according to the EPA's guidance.[12]

Seasonal albedo and Bowen ratio values were based on averaging over a 10-km-by-10-km region centered on the location of the Noveon meteorological station. An unweighted arithmetic average was used for calculating seasonal albedo; and an unweighted geometric average was used for calculating seasonal Bowen ratio. Seasonal surface roughness values were calculated for twelve 30-degree sectors within 1 km of the Noveon meteorological station. An inverse-distance weighted geometric average was used to calculate seasonal surface roughness length values for each of the 12 sectors.

The AERSURFACE input file requires the user to provide additional location and climatological information regarding the primary meteorological station (in this case, the Noveon station). The following information was used to process seasonal surface parameters for the meteorological station:

- Seasonal temporal resolution
- No continuous winter snow cover, given the low frequency of snow cover events near the Facility.
- Site location not at an airport – the Noveon dataset is not at located an airport or similar area with land-use that would qualify for use of the "airport" surface roughness adjustment algorithm used within AERSURFACE.
- Average surface moisture characteristics over the 3-year period of the meteorological database.

Table 4-1 presents the seasonal albedo, Bowen ratio, and surface roughness length values calculated by AERSURFACE for the area surrounding the Noveon meteorological station.

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[11] The USGS NLCD92 data set is described and can be accessed at http://landcover.usgs.gov/natllandcover.php.
[12] The AERMOD Implementation Guide (EPA, 2009) and the AERSURFACE User's Guide (EPA-454/B-08-001, January 2008).

Table 4-1. Seasonal Surface Parameters

Season	Sector	Albedo	Bowen Ratio	Surface Roughness (m)	Season	Sector	Albedo	Bowen Ratio	Surface Roughness (m)
Winter	1	0.15	0.7	0.386	Summer	1	0.15	0.3	0.478
	2	0.15	0.7	0.335		2	0.15	0.3	0.43
	3	0.15	0.7	0.413		3	0.15	0.3	0.625
	4	0.15	0.7	0.38		4	0.15	0.3	0.525
	5	0.15	0.7	0.237		5	0.15	0.3	0.346
	6	0.15	0.7	0.017		6	0.15	0.3	0.026
	7	0.15	0.7	0.005		7	0.15	0.3	0.005
	8	0.15	0.7	0.005		8	0.15	0.3	0.006
	9	0.15	0.7	0.004		9	0.15	0.3	0.004
	10	0.15	0.7	0.007		10	0.15	0.3	0.01
	11	0.15	0.7	0.22		11	0.15	0.3	0.278
	12	0.15	0.7	0.456		12	0.15	0.3	0.557
Spring	1	0.14	0.54	0.438	Fall	1	0.15	0.7	0.478
	2	0.14	0.54	0.381		2	0.15	0.7	0.43
	3	0.14	0.54	0.511		3	0.15	0.7	0.625
	4	0.14	0.54	0.439		4	0.15	0.7	0.525
	5	0.14	0.54	0.255		5	0.15	0.7	0.346
	6	0.14	0.54	0.019		6	0.15	0.7	0.026
	7	0.14	0.54	0.005		7	0.15	0.7	0.005
	8	0.14	0.54	0.005		8	0.15	0.7	0.006
	9	0.14	0.54	0.004		9	0.15	0.7	0.004
	10	0.14	0.54	0.008		10	0.15	0.7	0.01
	11	0.14	0.54	0.246		11	0.15	0.7	0.278
	12	0.14	0.54	0.495		12	0.15	0.7	0.557

4.7 Emission Unit Release Parameters

Figure 4-3 shows the proposed layout of the Facility, superimposed on a recent aerial photograph of the area. Locations of proposed new emission units are indicated, as well as significant structures that could potentially influence emissions. Tables 4-2 and 4-3, respectively, provide summaries of the release parameters used to represent emission from point and volume sources at the proposed facility.

Table 4-2. Point Source Release Parameters

Emission Unit	**Number of Units**	**Release Height (ft / m)**	**Exhaust Temp. (°F / K)**	**Exit Velocity (ft/s / m/s)**	**Inside Diameter (ft / m)**	**Model ID**
Process Heater (annual average)	2	50 / 15.2	570 / 572	43.8 / 13.4	3.21 / 0.978	FIREBOX
Process Heater (Process Startup)	2	50 / 15.2	570 / 572	56.2 / 17.1	3.21 / 0.978	FIREBOXSU
Process Heater (Process Shutdown)	2	50 / 15.2	570 / 572	43.8 / 13.4	3.21 / 0.978	FIREBOXSD
Boiler	2/3	50 / 15.2	300 / 422	49.1 / 15	8.17 / 2.49	BOIL
Boiler (Process Startup)	2	50 / 15.2	300 / 422	49.1 / 15	8.17 / 2.49	BOILSU
Boiler (Process Shutdown)	2	50 / 15.2	300 / 422	41.7 / 12.7	8.17 / 2.49	BOILSD
Boiler (Boiler & Process SU & SD)	3	50 / 15.2	300 / 422	41.7 / 12.7	8.17 / 2.49	BLRSUSD
Boiler (Boiler Startup)	1	50 / 15.2	250 / 394	9.17 / 2.80	8.17 / 2.49	BNPSU
Flare Pilot	1	75 / 22.9	1830 / 1270	228 / 69.5	0.167 / 0.0508	FLRPILOT
Flare (Upset)	1	136 / 41.4	1830 / 1270	65.6 / 20	16.7 / 5.1	FLAREUPS
Flare (Emergency)	1	275 / 84	1830 / 1270	65.6 / 20	58.3 / 17.8	FLAREEM
Flare (Process Startup - 1 hr avg)	1	207 / 63	1830 / 1270	65.6 / 20	37.5 / 11.4	FLARESU
Flare (Process Startup - 3 hr avg)	1	207 / 63	1830 / 1270	65.6 / 20	37.5 / 11.4	FLARESU
Flare (Process Startup - 8 hr avg)	1	196 / 59.8	1830 / 1270	65.6 / 20	34.5 / 10.5	FLARESU
Flare (Process Startup - 24 hr avg)	1	156 / 47.4	1830 / 1270	65.6 / 20	22.5 / 6.85	FLARESU
Flare (Process	1	227 / 69.2	1830 / 1270	65.6 / 20	43.6 / 13.3	FLARESD

Emission Unit	Number of Units	Release Height (ft / m)	Exhaust Temp. (°F / K)	Exit Velocity (ft/s / m/s)	Inside Diameter (ft / m)	Model ID
Shutdown - 1 hr avg)						
Flare (Process Shutdown - 3 hr avg)	1	204 / 62	1830 / 1270	65.6 / 20	36.6 / 11.2	FLARESD
Flare (Process Shutdown - 8 hr avg)	1	164 / 49.9	1830 / 1270	65.6 / 20	24.8 / 7.56	FLARESD
Flare (Process Shutdown - 24 hr avg)	1	127 / 38.8	1830 / 1270	65.6 / 20	14.3 / 4.37	FLARESD
Flare (annual average)	1	154 / 46.8	1830 / 1270	65.6 / 20	21.9 / 6.67	WCFLSUSD
CCCT (short-term)	2	95 / 29	201 / 367	31.6 / 9.62	12.6 / 3.85	CT
CCCT (annual average)	2	95 / 29	197 / 365	32.5 / 9.9	12.6 / 3.85	CT
CCCT (Process Startup)	2	95 / 29	190 / 361	28.7 / 8.76	12.6 / 3.85	CTSU
CCCT (Process Shutdown)	2	95 / 29	190 / 361	28.7 / 8.76	12.6 / 3.85	CTSD
CCCT w/Duct Firing (short-term)	2	95 / 29	169 / 349	36.6 / 11.2	12.6 / 3.85	CTDF
CCCT w/Duct Firing (annual average)	2	95 / 29	197 / 365	32.5 / 9.9	12.6 / 3.85	CTDF
Cooling Tower Cell	12	38.5 / 11.7	87 / 304	24.2 / 7.37	35.6 / 10.9	COOLT
Emergency Generator Engine	2	26.6 / 8.1	885 / 747	163 / 49.8	2 / 0.61	EGEN
Fire Water Pump Engine	1	36.1 / 11	748 / 671	120 / 36.6	1.17 / 0.356	FIREPMP
Ship Loading Scrubber	1	35 / 10.7	120 / 322	50 / 15.2	3 / 0.914	SHPSCRUB
Tank Scrubber	1	30 / 9.14	120 / 322	50 / 15.2	3 / 0.914	TNKSCRUB

Table 4-3. Volume Source Release Parameters

Volume Source	Number of Sources	Release Height (ft / m)	Sigma Y (ft / m)	Sigma Z (ft / m)	Model ID
Crude Tank (Top)	2	69.8 / 21.3	19.1 / 5.81	24.6 / 7.5	CTNKTOP

Volume Source	Number of Sources	Release Height (ft / m)	Sigma Y (ft / m)	Sigma Z (ft / m)	Model ID
Crude Tank (Bottom)	2	0 / 0	19.1 / 5.81	57.4 / 17.5	CTNKBOT
Shift Tank (Top)	4	58.1 / 17.7	13.7 / 4.18	17.7 / 5.39	STNKTOP
Shift Tank (Bottom)	4	0 / 0	13.7 / 4.18	41.3 / 12.6	STNKBOT
Product Tank (Top)	8	103 / 31.5	33.2 / 10.1	42.8 / 13.1	PTNKTOP
Product Tank (Bottom)	8	0 / 0	33.2 / 10.1	99.9 / 30.5	PTNKBOT
Ammonia Tank (Top)	3	17 / 5.18	2.33 / 0.709	3 / 0.914	ATNKTOP
Ammonia Tank (Bottom)	3	0 / 0	2.33 / 0.709	7 / 2.13	ATNKBOT
Component Leaks	60	6.56 / 2	63.9 / 19.5	3.05 / 0.93	LEAKS

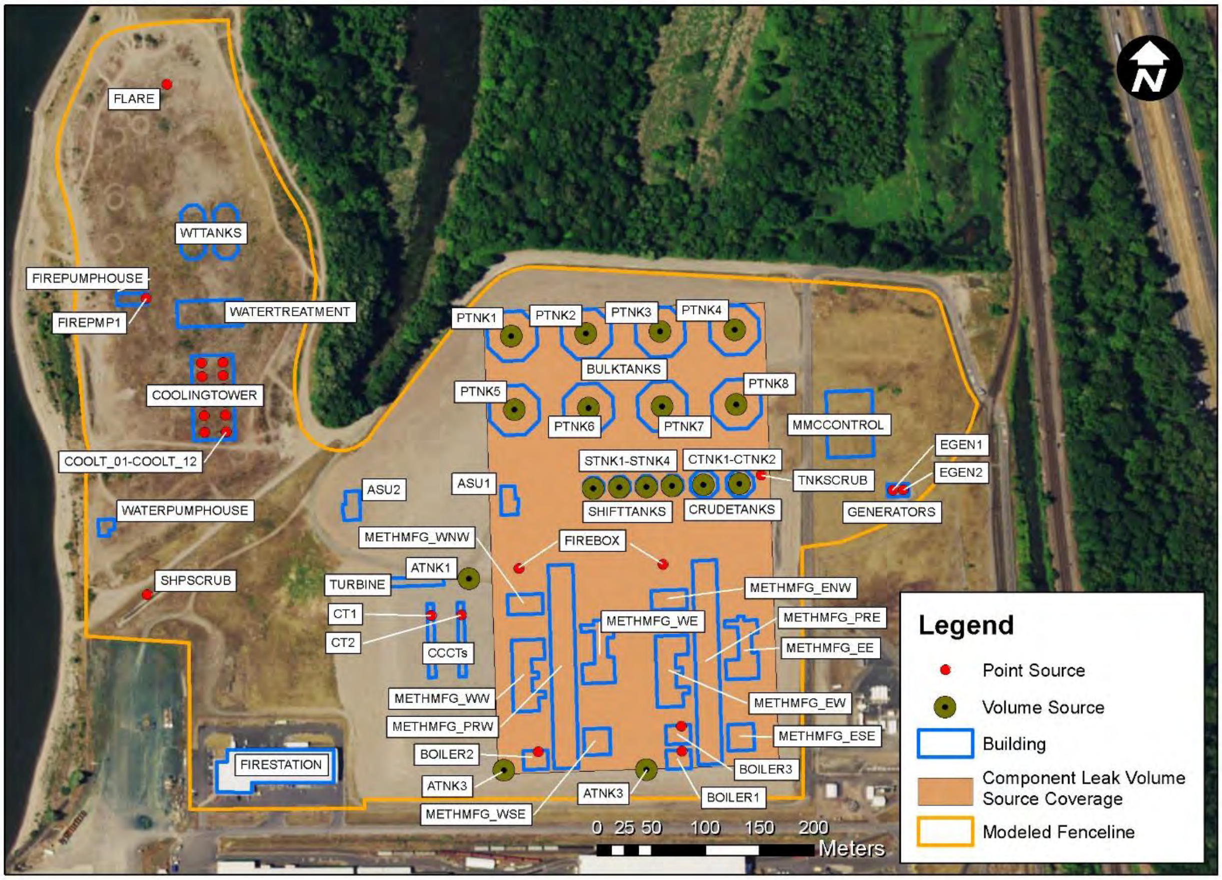

Figure 4-3: Locations of Structures and Emission Units

In addition to the release parameters discussed above, the dimensions and configuration of significant on-site structures were provided to AERMOD to assess potential downwash effects. Wind direction-specific building profiles were prepared for the modeling using EPA's Building Profile Input Program including the PRIME algorithm (BPIP PRIME). The site layout and heights of significant on-site proposed structures, as shown in Figure 4-3 and Table 4-4, were used to prepare data for BPIP PRIME, which calculates the necessary input data for AERMOD.

Table 4-4. Structure Heights

Description	BPIP ID	Height (ft / m)
Air Separation Units	ASU1 - 2	42.7 / 13.0
Boilers	BOILER1 - 3	40.0 / 12.2
Control Building	MMCCONTROL	59.1 / 18.0
Cooling Tower	COOLINGTOWERS	38.4 / 11.7
Crude Methanol Tanks	CRUDETANK_E & W	63.3 / 19.3
Emergency Generators	GENERATORS	11.3 / 3.44
Fire Pump House	FIREPUMPHOUSE	21.0 / 6.40
Fire Station	FIRESTATION	33.8 / 10.3
Methanol Manufacturing - East	METHMFG_EE & WE	76.3 / 23.3
Methanol Manufacturing - Northwest	METHMFG_ENW & WNW	81.7 / 24.9
Methanol Manufacturing - Primary	METHMFG_PRE & W	71.5 / 21.8
Methanol Manufacturing - Southeast	METHMFG_ESE & WSE	157 / 48.0
Methanol Manufacturing - West	METHMFG_EW & WW	99.8 / 30.4
PGU CCCTs	CCCT_E & W	30.0 / 9.14
PGU Turbine	TURBINE	20.2 / 6.17
Product Storage Tanks	BULKTANK1 - 8	112 / 34.2
Shift Tanks	SHIFTTANK1 - 4	56.1 / 17.1
Water Pump House	WATERPUMPHOUSE	23.0 / 7.00
Water Treatment	WATERTREATMENT	27.8 / 8.47
Water Treatment Tanks	WTTANK_NE, NW, SE & SW	46.9 / 14.3

4.8 Scenarios

The proposed Facility is designed to operate as continuously as possible to maximize both production rate and efficiency. Short-term and annual modeling scenarios were developed that reflect normal operations. While unscheduled startups and shutdowns, emergency equipment maintenance and testing, upsets, and emergencies are not normal operating conditions for the facility, modeling scenarios were developed for those occurrences to demonstrate that, even during those unusual events, the Facility will be in compliance with ambient standards.

In all scenarios, PTE was assumed for each emission unit, unless the basis for the scenario involved a particular emission unit being started up, shut down, or operated in some mode other than full load. Emission units were conservatively assumed to be operating at full capacity, when, in reality, the scenario under consideration would dictate that certain emission units be operated at partial load, or shut down entirely. Table 4-5 outlines the scenarios that were developed, and a matrix showing which emission units were assumed to be operating for each scenario is presented in Appendix D.

Table 4-5. Modeled Scenarios

Scenario No.	Scenario Description	Averaging Period
0	Production Lines 1 & 2 and PGU operating normally	Short-term
1	Production Lines 1 & 2 and PGU operating normally[1]	Annual
2	Startup Production Line 1 while Production Line 2 and PGU operate normally	Short-term
3	Shut down Production Line 1 while Production Line 2 and PGU operate normally	Short-term
4	Startup Production Line 2 while Production Line 1 and PGU operate normally	Short-term
5	Shut Down Production Line 2 while Production Line 1 and PGU operate normally	Short-term
6	Production Lines 1 & 2 operate normally, except for 6 startups and shutdowns of each Production Line, and PGU operates normally[1]	Annual
7	Production Lines 1 & 2 and PGU operate normally while Emergency Generator 1 is tested	Short-term
8	Production Lines 1 & 2 and PGU operate normally while Emergency Generator 2 is tested	Short-term
9	Production Lines 1 & 2 and PGU operate normally while Emergency Firewater Pump is tested	Short-term
10	Production Lines 1 & 2 experience an upset that requires flaring[2]	Short-term
11	Production Lines 1 & 2 require emergency shutdown[2]	Short-

Scenario No.	Scenario Description	Averaging Period
		term
12	Production Lines 1 & 2 operate normally while Combustion Turbine 1 of the PGU is started up and Combustion Turbine 2 operates normally[3]	Short-term
13	Production Lines 1 & 2 operate normally while Combustion Turbine 2 of the PGU is started up and Combustion Turbine 1 operates normally[3]	Short-term
14	Production Lines 1 & 2 and PGU operating normally with Duct Firing	Short-term
15	Production Lines 1 & 2 and PGU operating normally with Duct Firing[1]	Annual
16	Production Lines 1 & 2 and PGU operating normally, and Reserve Boiler is started up	Short-term

1. PGU NO_X and CO annual average emission rates include 6 startups and shutdowns. For other pollutants, continuous operation is the worst-case emission rate scenario
2. To be conservative, these scenarios include, in addition to the emissions from the flare, emissions from all emission units associated with normal operations (e.g., boilers, PGU, cooling tower, etc.); in reality, emission units would be operated at an appropriate reduced capacity for an upset, and shutdown entirely in the case of an emergency
3. Startup emissions are greater than shutdown emissions with similar stack parameters, and therefore represent worst-case conditions; shutdown emissions were not modeled.

4.9 Analysis Results

To evaluate the potential ambient air pollutant concentrations attributable to the proposed Facility, the criteria pollutant emission rates in Section 2 were evaluated using AERMOD to assess compliance with ambient standards and, where applicable, PSD increments. Analogous modeling was conducted for TAPs emitted at rates that exceed the SQERs (see Table 2-2) to assess compliance with the ASILs. No modeling demonstration is required for TAPs with emissions that do not exceed the applicable SQER.

Ramboll Environ evaluated each of the scenarios outlined in Table 4-5. Table 4-6 identifies maximum cumulative concentrations attributable to typical operation of the Facility (i.e., the highest predicted value, expressed in the format of the ambient standard, at any of the 8,210 locations evaluated by the model). Table 4-7 identifies the maximum cumulative concentrations considering all possible operating scenarios. Both Tables 4-6 and 4-7 provide a comparison to the significant impact levels (SILs) in SWCAA 400-113 and WAC 173-400-113. If all predicted ambient concentrations for a given pollutant and averaging period are less than the applicable SIL, that pollutant is assumed to not have the potential to cause or contribute to a violation of the corresponding ambient standard. Ambient standard and PSD increment compliance demonstrations are required for pollutants with predicted ambient concentrations that exceed the applicable SIL.

Table 4-6. Normal Operation Project Only Design Concentrations

Pollutant	Averaging Period	Project Design Concentration[1] (µg/m³)	SIL[2] (µg/m³)	Compliance Demonstration Required?
NO_2	1-Hour	21	7.5	Yes
	Annual	1.0	1	Yes
CO	1-Hour	58	2,000	No
	8-Hour	13	500	No
SO_2	1-Hour	10	7.8	Yes
	3-Hour	13	25	No
	24-Hour	1.9	5	No
	Annual	0.12	1	No
PM_{10}	24-Hour	10	5	Yes
$PM_{2.5}$	24-Hour	4.0	1.2	Yes
	Annual	1.2	0.3	Yes

1. Design concentrations for comparison to the SILs are the maximum concentration predicted by the model for the applicable averaging period, except as follows: the maximum 3-year average of the daily maximum 1-hour average NO_2 concentrations at each receptor (based on guidance in the "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard" memorandum issued on March 1, 2011 by Tyler Fox, Leader of the Air Quality Modeling Group of EPA's Office of Air Quality Planning and Standards (OAQPS)), the maximum 3-year average of the maximum 24-hour average $PM_{2.5}$ concentrations at each receptor, the maximum 3-year average of the maximum annual average $PM_{2.5}$ concentrations at each receptor (based on guidance in the "Modeling Procedures for Demonstrating Compliance with the $PM_{2.5}$ NAAQS" memorandum issued on March 23, 2010 by Stephen Page, Director of OAQPS), and the maximum 3-year average of the daily maximum 1-hour average SO_2 concentrations at each receptor (based on guidance in the March 1, 2011 memorandum issued by Tyler Fox).
2. SIL = significant impact level, from SWCAA 400-113 and WAC 173-400-113, except 1-hour average NO_2 and SO_2, which are interim standards provided by EPA guidance memoranda (Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program, Stephen D. Page, Director of the Office of Air Quality Planning and Standards, June 29, 2010, and Guidance Concerning the Implementation of the 1-hour SO_2 NAAQS for the Prevention of Significant Deterioration Program, Stephen D. Page, Director of the Office of Air Quality Planning and Standards, Aug 23, 2010).

Table 4-7. Project-Only Design Concentrations

Pollutant	Averaging Period	Project Design Concentration[1] (µg/m³)	SIL[2] (µg/m³)	Compliance Demonstration Required?	Maximum Operating Scenario

Pollutant	Averaging Period	Project Design Concentration[1] (µg/m³)	SIL[2] (µg/m³)	Compliance Demonstration Required?	Maximum Operating Scenario
NO_2	1-Hour	111	7.5	Yes	3
	Annual	1.0	1	Yes	1
CO	1-Hour	874	2,000	No	5
	8-Hour	306	500	No	2
SO_2	1-Hour	11.2	7.8	Yes	14
	3-Hour	15	25	No	14
	24-Hour	2.7	5	No	2
	Annual	0.13	1	No	6
PM_{10}	24-Hour	13	5	Yes	9
$PM_{2.5}$	24-Hour	5.4	1.2	Yes	2
	Annual	1.2	0.3	Yes	15

1. Design concentrations for comparison to the SILs are the maximum concentration predicted by the model for the applicable averaging period, except as follows: the maximum 3-year average of the daily maximum 1-hour average NO_2 concentrations at each receptor (based on guidance in the "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard" memorandum issued on March 1, 2011 by Tyler Fox, Leader of the Air Quality Modeling Group of EPA's Office of Air Quality Planning and Standards (OAQPS)), the maximum 3-year average of the maximum 24-hour average $PM_{2.5}$ concentrations at each receptor, the maximum 3-year average of the maximum annual average $PM_{2.5}$ concentrations at each receptor (based on guidance in the "Modeling Procedures for Demonstrating Compliance with the $PM_{2.5}$ NAAQS" memorandum issued on March 23, 2010 by Stephen Page, Director of OAQPS), and the maximum 3-year average of the daily maximum 1-hour average SO_2 concentrations at each receptor (based on guidance in the March 1, 2011 memorandum issued by Tyler Fox).
2. SIL = significant impact level, from SWCAA 400-113 and WAC 173-400-113, except 1-hour average NO_2 and SO_2, which are interim standards provided by EPA guidance memoranda (Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program, Stephen D. Page, Director of the Office of Air Quality Planning and Standards, June 29, 2010, and Guidance Concerning the Implementation of the 1-hour SO_2 NAAQS for the Prevention of Significant Deterioration Program, Stephen D. Page, Director of the Office of Air Quality Planning and Standards, Aug 23, 2010).

Similar to Table 4-7, maximum model-predicted ambient concentrations for TAPs with emission rates expected to exceed the SQERs are presented in Table 4-8 and compared to the applicable ASILs. A maximum predicted TAP concentration that is less than the ASIL indicates that emissions of that TAP do not cause adverse human health effects. As shown in Table 4-8, predicted ambient concentrations attributable to the Facility are less than the ASILs in all cases.

Table 4-8. Ambient TAP Impact Compliance Demonstration

Averaging Period	Toxic Pollutant	Maximum Concentration (μg/m^3)	ASIL[1] (μg/m^3)	% of ASIL	Maximum Operating Scenario
24-Hour	Ammonia	28	100	28%	0
	Barium	0.0057	1.7	0.3%	14
	Butane	2.7	6,300	0.04%	14
	Methanol	14	870	1.6%	0
	Pentane	3.4	6,000	0.06%	14
	Sulfuric Acid	0.70	3.3	21%	2
Annual	1,3-Butadiene	2.0E-05	0.0036	0.6%	15
	Acetaldehyde	0.0014	0.45	0.3%	15
	Arsenic	4.0E-05	0.00023	17%	1
	Benzene	0.00061	0.12	0.5%	6
	Benzo(a)pyrene	2.2E-07	0.00048	0.05%	15
	Beryllium	2.2E-06	0.00042	0.5%	15
	Cadmium	0.00020	0.00056	36%	1
	Chromium, Hexavalent	1.0E-05	0.000083	12%	1
	Formaldehyde	0.0042	0.077	5.4%	6
	Nickel	0.00038	0.0021	18%	1
	PAH	0.00010	0.00048	21%	1
	Propylene Oxide	0.0010	0.27	0.4%	1

1. From WAC 173-460-150, effective 8/21/1998

4.10 Ambient Standard and PSD Increment Compliance Demonstrations

A compliance demonstration is required for each criteria pollutant that exceeds the applicable SIL. As indicated in Table 4-7, such demonstrations are required for 1-hour average NO_2 and SO_2, 24-hour average PM_{10} and $PM_{2.5}$, and annual average NO_2 and $PM_{2.5}$ emissions.

To demonstrate compliance with the ambient standards, design concentrations attributable to the Facility, design concentrations attributable to significant nearby industrial facilities, and a representative background concentration are combined and compared to the standard. To demonstrate compliance with the PSD increment, the highest second-high model-predicted concentrations attributable to the Facility and the highest second-high model-predicted concentrations attributable to increment-consuming emissions from significant nearby industrial facilities are combined at each receptor and compared to the PSD increment.

Because the Facility's SO_2 PTE is less than the PSD SER (see Table 2-1), SO_2 emissions are not subject to PSD review. Typically, when a pollutant that is not subject to PSD review is predicted to exceed the applicable SIL, compliance with the ambient standard is assessed by combining the model-predicted design concentration attributable to the Facility with a representative background concentration; nearby significant industrial sources are not included. Because SO_2 is not subject to PSD review, the PSD increments do not apply, and no compliance assessement is required.

The results of the compliance demonstrations for 1-hour average NO_2 and SO_2, 24-hour average PM_{10} and $PM_{2.5}$, and annual average NO_2 and $PM_{2.5}$ emissions are presented in Tables 4-9 and 4-10. The methodology used to create the nearby industrial source inventory, and to screen the inventory for significant facilities is described in Appendix E. Cumulative concentrations are based on the sum of the model predicted concentrations attributable to Facility emissions, model-predicted concentrations attributable to significant nearby industrial sources, and representative background concentration for each pollutant and averaging period.[13]

Table 4-9. Ambient Standard Compliance Demonstration Results

Pollutant	Averaging Period	Cumulative Design Conc.[1] (µg/m³)	Back-ground Conc.[2] (µg/m³)	Total Conc.[3] (µg/m³)	Ambient Standard[4] (µg/m³)	Complies with Ambient Standard?	Maximum Operating Scenario
NO_2	1-Hour	111	62	173	188	Yes	3
	Annual	1.0	10	11.0	100	Yes	1
SO_2[5]	1-Hour	11.2	21	32.2	196	Yes	14
PM_{10}	24-Hour	13	27	40	150	Yes	9

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[13] Representative background concentrations for 1-hour average NO_2 and SO_2, 24-hour average $PM_{2.5}$ and PM_{10}, and annual average NO_2 and $PM_{2.5}$ were obtained using an online tool, available at the Northwest International Air Quality Environmental Science and Technology (NW-AIRQUEST) Consortium website (http://www.lar.wsu.edu/nw-airquest/lookup.html) which interpolates modeled and monitored concentrations to obtain pollutant concentration estimates at a given location.

Pollutant	Averaging Period	Cumulative Design Conc.[1] (µg/m³)	Back-ground Conc.[2] (µg/m³)	Total Conc.[3] ($\mu g/m^3$)	Ambient Standard[4] ($\mu g/m^3$)	Complies with Ambient Standard?	Maximum Operating Scenario
$PM_{2.5}$	24-Hour	5.4	18	23.4	35	Yes	2
	Annual	1.2	5.7	6.9	12	Yes	15

1. Design concentrations for comparison to ambient standards are the highest second high predicted by the model for those based on a short term (i.e., 24-hour or less) averaging period, or the maximum concentration for those based on an annual averaging period, except as follows: the maximum 3-year average of the 98th percentile of the daily maximum 1-hour average NO_2 concentrations at each receptor (based on guidance in the "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard" memorandum issued on March 1, 2011 by Tyler Fox, Leader of the Air Quality Modeling Group of EPA's Office of Air Quality Planning and Standards (OAQPS)), the maximum 3-year average of the maximum 98th percentile 24-hour average $PM_{2.5}$ concentrations at each receptor, the maximum 3-year average of the maximum annual average $PM_{2.5}$ concentrations at each receptor (based on guidance in the "Modeling Procedures for Demonstrating Compliance with the $PM_{2.5}$ NAAQS" memorandum issued on March 23, 2010 by Stephen Page, Director of OAQPS), and the maximum 3-year average of the 99th percentile of the daily maximum 1-hour average SO_2 concentrations at each receptor (based on guidance in the March 1, 2011 memorandum issued by Tyler Fox).
2. Representative background concentrations for 1-hour average NO_2 and SO_2, 24-hour average $PM_{2.5}$ and PM_{10}, and annual average NO_2 and $PM_{2.5}$ were obtained using an online tool, available at the Northwest International Air Quality Environmental Science and Technology (NW-AIRQUEST) Consortium website (http://www.lar.wsu.edu/nw-airquest/lookup.html) which interpolates modeled and monitored concentrations to obtain pollutant concentration estimates at a given location.
3. Total concentration is the sum of the cumulative design concentration and the background concentration.
4. Ambient standards from WAC 173-476.
5. Because facility-wide SO_2 PTE is less than the PSD major source threshold, the cumulative design concentration for SO_2 reflects facility-wide emissions, but does not include contributions from nearby industrial sources.

Table 4-10. PSD Increment Compliance Demonstration Results

Pollutant	Averaging Period	Cumulative Design Conc.[1] (µg/m³)	PSD Increment ($\mu g/m^3$)	Complies with Increment?	Maximum Operating Scenario
NO_2	Annual	1.0	25	Yes	1
PM_{10}	24-Hour	13.2	30	Yes	9
	Annual	1.2	17	Yes	15
$PM_{2.5}$	24-Hour	8.7	9	Yes	5
	Annual	1.2	4	Yes	15

1. Design concentrations for comparison to ambient standards are the highest second high concentration predicted by the model for those based on a short term (i.e., 24-hour or less) averaging period, or the maximum concentration for those based on an annual averaging period

4.11 Conclusions

The AERMOD modeling methodology described above predicted that emissions attributable to the proposed project will not cause or contribute to an exceedance of any ambient standards. Compliance with the ambient impact requirement was demonstrated for all TAPs, which indicates that the increase in TAP emissions from the proposed Facility are sufficiently low to protect human health and safety from potential carcinogenic and/or other toxic effects.

5. CLASS I DISPERSION MODELING ANALYSIS

As stated in Chapter 4, new industrial sources must demonstrate that the proposed allowable emissions associated with the Facility will not cause or contribute to violation of any ambient air quality standard or increment. For major sources subject to PSD review, this requirement extends to Class I areas, which include National Parks and Wilderness Areas. In addition, PSD regulations require an analysis of potential impacts to air quality related values (AQRVs) of concern (i.e., visibility, soil, flora, fauna, and aquatic resources) in Class I areas within 100 km (62.1 miles) of the Facility site from pollutants emitted by the project that are subject to PSD review. In some cases, the Federal Land Managers (FLMs; e.g., National Park Service, U.S. Forest Service) have requested that the radius used to determine which Class I areas are included in the AQRV impact assessment be extended to 300 km (186 miles). Figure 5-1 displays the location of the proposed Facility site relative to nearby Class I areas.

In November 2010, the Federal Land Managers' Air Quality Related Values Work Group (FLAG) issued a revision of the Phase I report that provides guidance and recommendations for how AQRV analyses should be conducted. That report describes screening criteria that could potentially exempt a source from conducting any further AQRV impact analysis based on annual emission rates and distance from a Class I area.

The status of a proposed new source or modification with respect to these screening criteria is determined by a calculated factor, often referred to as "Q over D" (Q/D). Q/D is calculated by dividing the total combined project emission increases of NO_X, SO_2, PM_{10}, and sulfuric acid (H_2SO_4), in tons per year (the "Q" in Q/D), by the distance from the site of the proposed project to each Class I area, in kilometers (the "D" in Q/D). The FLMs consider a project located greater than 50 km from any Class I area to have a negligible impacts with respect to Class I AQRVs if the Q/D factor is 10 or less.[14] As shown in Figure 5-1, there are no Class I areas within 50 km of the proposed Facility site.

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[14] U.S. Forest Service, National Park Service, and U.S. Fish and Wildlife Service, 2010, Federal Land Managers' Air Quality Related Values Work Group (FLAG): Phase I Report - Revised (2010), Natural

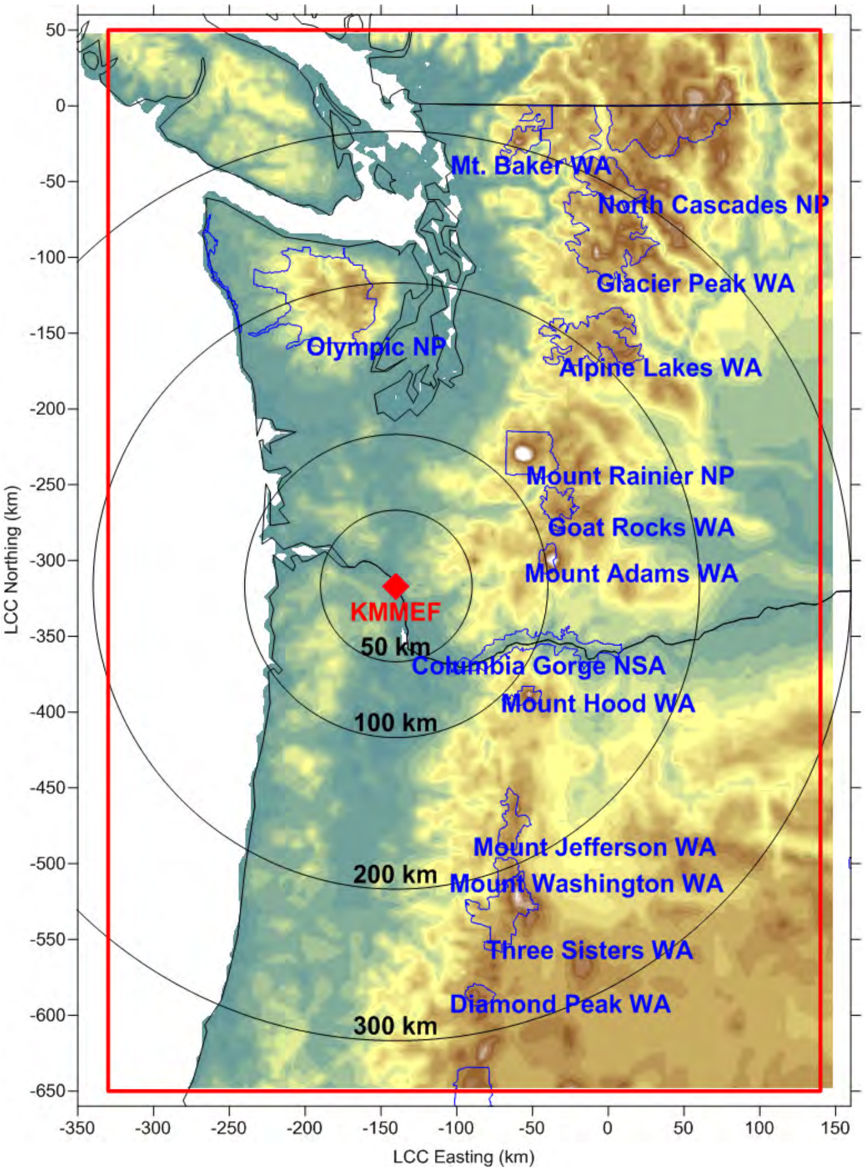

Figure 5-1: Class I Area Locations and Distances from Facility[15]

A Q/D screening analysis was developed for the proposed project using the facility's expected potential future emissions (Potential to Emit – or "PTE"). As prescribed by the screening methodology, the maximum facility-wide 24-hour average hourly emission rates for each pollutant of interest (NO_X, SO_2, PM_{10}, and H_2SO_4) were

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Resource Report NPS/ NRPC/NRR - 2010/232, National Park Service, Denver, Colorado, pages 18-19

[15] Mt. Baker Wilderness Area and Columbia River Gorge National Scenic Area are not Class I areas, but FLMs typically request that they be included in Class I analyses.

converted from pounds per hour to tons per year by multiplying by 8,760 hr/yr and dividing by 2,000 lb/ton, and summed. For each pollutant, 2 PTEs were calculated: one assuming continuous operation throughout the year, and one assuming 6 startups and shutdowns per year with no downtime between each shutdown and the next startup. The maximum of the 2 PTEs was used to calculate Q/D for each Class I area regardless of whether the worst-case scenario for a given pollutant conflicts with that of another.

Table 5-1 summarizes the results of the Q/D analysis: the maximum Q/D factor for a Class I area is 1.8 for the Mt. Adams Wilderness Area. Although not a Class I area, the CRGNSA was included in the analyses; the maximum Q/D is 2.7. As shown in Table 5-1, all of the calculated Q/D values are less than 10.

Table 5-1. Results of Q/D Analysis

Class I Area / Area of Interest	Distance (km)	Q/D[1]
Alpine Lakes Wilderness Area	176	0.9
Glacier Peak Wilderness Area	240	0.7
Goat Rocks Wilderness Area	108	1.5
Mt. Adams Wilderness Area	95	1.8
Mt. Hood Wilderness Area	102	1.6
Mt. Jefferson Wilderness Area	153	1.1
Mt. Rainier National Park	103	1.6
Mt. Washington Wilderness Area	192	0.9
Olympic National Park	160	1.0
Three Sisters Wilderness Area	206	0.8
Columbia River Gorge National Scenic Area	62	2.7

1. Q is annual emissions in tons per year of NO_X, PM, SO_2, and H2SO4, extrapolated from maximum hourly emission rates and assuming 8,760 hours of operation per year. D is the distance to the Class I area. The value shown is Q divided by D.

The AQRV screening method outlined above does not have any bearing on the PSD program requirement to assess compliance with ambient standards and Class I increments for pollutants that increase by more than the PSD SERs. As shown in Table 2-1, the expected NO_X, PM_{10}, and $PM_{2.5}$ emission rate increases are expected to exceed the PSD SERs. (The maximum annual VOC emission rate also exceeds the PSD SER, but ambient standards and PSD increments have not been established for VOCs.)

5.1 Dispersion Model Selection

The choice of dispersion model for the Class I analysis was determined by the FLMs decision as to whether a modeling analysis is warranted to assess potential impacts to AQRVs in Class I areas. In cases where the FLMs determine that an AQRV analysis is required, the CALPUFF modeling system is typically used to quantify AQRV impacts to nearby Class I areas, as well as to assess compliance with ambient standards and PSD increments. If the FLMs determine that an AQRV analysis is not warranted, AERMOD can be used with a screening methodology to assess compliance with ambient standards and PSD Increments in nearby Class I areas.

Based on a Q/D analysis similar to the one outlined above that was presented in a modeling protocol provided to the FLMs in October 2015, the FLMs determined that an AQRV analysis was not needed. As a result, AERMOD was used with a screening methodology to assess compliance with ambient standards and PSD increments in nearby Class I areas.

5.2 Class I Screening Modeling Methodology

Employing AERMOD to assess compliance with ambient standards and PSD increments in Class I areas involves using the same modeling procedures used to predict concentrations in Class II areas that are described in Section 4, with the exception of the receptor locations. For the Class I area screening analysis, four sets of receptors were included in the modeling simulations, each set arranged in 2-degree increments, 50 km from the Facility. Each set of receptors was assigned a uniform elevation based on:

- the maximum elevation found in the FLM-provided receptors for all Class I areas within 200 km of the proposed facility (4,227 m);
- the minimum elevation found in the FLM-provided receptors for all Class I areas within 200 km of the proposed facility (29 m);
- the calculated plume height of the gas-fired boilers at the Facility, assuming Pasquill/Gifford stability class "F" and a wind speed of 2.5 m/s (84 m); and
- the calculated plume height of the PGU at the Facility, assuming Pasquill/Gifford stability class "F" and a wind speed of 2.5 m/s (91 m).

The location of the receptors corresponds with the 50 km ring shown in Figure 5-1.

5.3 Class I Screening Analysis Results

The evaluate the potential ambient air pollutant concentrations in nearby Class I areas attributable to the Facility, the criteria pollutant emission rates presented in Section 2 were evaluated using AERMOD to assess compliance with ambient standards and PSD increments. Each of the scenarios outlined in Table 4-6 were evaluated. Table 5-2 presents the maximum model-predicted concentration and the Class I SILs recommended by USEPA.[16] As with the SILs established for Class II areas,[17] model-predicted concentrations less than those thresholds are presumed to not have the potential to cause or contribute to exceedance of the associated ambient standard or PSD Increment.

Table 5-2. Class I Screening Analysis Concentrations

Pollutant	Averaging Period	Design Concentration[1] ($\mu g/m^3$)	USEPA Recommended SIL[2] ($\mu g/m^3$)	Exceeds Recommended SIL?
NO_2	Annual	0.0200	0.1	No
PM_{10}	24-Hour	0.243	0.3	No
	Annual	0.0262	0.2	No
$PM_{2.5}$	24-Hour	0.104	0.07	Yes
	Annual	0.0190	0.06	No
SO_2[3]	3-Hour	0.703	1	No
	24-Hour	0.0983	0.2	No
	Annual	0.00347	0.1	No

1. Maximum modeled concentrations for NO_2, PM_{10}, and SO_2; highest of the 3-year averages of the maximum modeled concentrations predicted each year at each receptor for $PM_{2.5}$
2. The NO_2, PM_{10}, and SO_2 SILs for Class I areas are from 61 Federal Register 38250; the $PM_{2.5}$ SILs for Class I areas are from 75 Federal Register 64864.
3. Facility-wide annual SO_2 emission rate will be less

The maximum predicted annual average NO_2, PM_{10}, and $PM_{2.5}$ and 24-hour PM_{10} concentrations are all less than the applicable SIL. Because the 24-hour $PM_{2.5}$

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[16] NO_2, PM_{10}, and SO_2 – 61 FR 38250; $PM_{2.5}$ – 75 FR 64864

[17] All areas of the U.S. that are not designated Class I are Class II areas. There is a provision for Class III areas, but none have been designated.

design concentration exceeds the SIL, a more refined analysis was required to assess compliance with the ambient standards and PSD increment associated with 24-hour $PM_{2.5}$.

5.4 Class I Refined Modeling Methodology

The CALPUFF modeling system is currently the EPA's preferred model for long-range transport assessments, and for evaluating potential impacts to Class I Areas. Features of the CALPUFF modeling system include the ability to consider: secondary aerosol formation; gaseous and particle deposition; wet and dry deposition processes; complex three-dimensional wind regimes; and the effects of humidity on regional visibility. Ramboll Environ used CALMET and CALPUFF Version 5.8.4, both released on July 31, 2013, which are the current "official" EPA versions of CALMET and CALPUFF. Post-processing of the modeling results was performed using CALPOST version 6.221.

The modeling procedures followed Federal Land Managers' Air Quality Related Workgroup (FLAG) and Interagency Workgroup on Air Quality Modeling (IWAQM) recommendations – in particular, the FLAG guidance document issued in 2000 and revised in October 2010,[18] and the IWAQM guidance document issued in 1998. A clarification memo issued by Tyler Fox on August 31, 2009[19] prescribes specific CALMET/CALPUFF settings to be used when the model is used for permitting.

5.4.1 Model Setup and Application

Although the CALPUFF modeling system is equipped with a host of modeling options, Ramboll Environ used the procedures and defaults recommended by the FLAG Phase I Report and the EPA-FLM CALMET Clarification Memo. Three years were modeled (2003, 2004, 2005) using 4 km resolution output from the MM5 meteorological model. The PM_{10} and $PM_{2.5}$ emission rates and stack parameters provided to AERMOD were used in CALPUFF to represent the emission units. Building downwash is considered optional by Ecology, and was not included in the analysis.

$PM_{2.5}$ concentrations were predicted within each Class I areas at discrete receptors obtained from the NPS using the CALPUFF dispersion model. For the Columbia

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[18] The FLAG 2000 and 2010 documents can be found at http://www.nature.nps.gov/air/Permits/flag/

[19] http://www.epa.gov/ttn/scram/CALMET%20CLARIFICATION.pdf

Gorge National Scenic Area (CRGNSA) and Mt Baker Wilderness Area, which are not Class I areas, and do not have NPS-developed receptors, 1-km grids were created within each area, and receptor elevations were calculated from the CALMET terrain data.

Land use and terrain data were prepared from the USGS 1:250,000 scale data sets available on the internet resulting in 4-km spacing fields. The same terrain grid was used to develop the CALMET wind fields and internally by CALPUFF was also used to obtain receptor and source base elevations.

The modeling domain, shown in red in Figure 5-1, fully includes each of the Class I areas within 300 km of the Facility, and extends 50 km beyond the far edge of each Class I area, with the exception of the North Cascades National Park, only part of which is within 300 km of the Facility. The CALMET mesh size is 4 km and the coordinates were chosen to coincide with the MM5 4-km grid points.

5.4.2 Meteorological Data

Ramboll Environ obtained meteorological data from the University of Washington's numerical simulations of Pacific Northwest weather with the Penn State and National Center of Atmospheric Research Mesoscale Model (MM5).[20] The AQRV analysis used three years of hourly 4-km horizontal mesh size MM5 output data from January 2003 to December 2005. For the current analysis the 4-km mesh size simulations were used in order to better resolve the flow in the complex terrain.

CALMET (Version 5.8.4), the meteorological pre-processor component of the CALPUFF system, was used to combine the MM5 simulation data, surface observations, terrain elevations, and land use data into the format required by the dispersion modeling component CALPUFF. In addition to specifying the three-dimensional wind field, CALMET also estimates the boundary layer parameters used to characterize diffusion and deposition by the dispersion model.

The techniques used to construct the meteorological database follow the recent August 31, 2009 clarification memo from Tyler Fox of the USEPA and the FLMs. Major features of the CALMET application and input data preparation are as follows:

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[20] http://www.atmos.washington.edu/mm5rt/mm5info.html

The model domain is shown in Figure 1. The horizontal mesh size is 4 km and the domain covers an area of 470 km by 700 km. There are 10 vertical levels, ranging geometrically from the surface to 4,000 m. A Lambert Conformal Conic coordinate system was used with an origin of 49°N, 121°W and standard latitudes of 30°N and 60°N (chosen to match the MM5 dataset).

- Land use and terrain data were prepared using the standard CALPUFF processing tools and the USGS GTOPO30 elevation data sets available on the USGS website. Figure 5-1 shows the 4-km mesh size terrain used in the simulations.
- Surface weather observations were obtained from the National Climatic Data Center dataset ds3505 for stations in and around the domain. Figure 5-2 shows the surface weather observation stations in and around the modeling domain.
- Two upper air stations were used for twice-daily soundings. Data from Quillayute, Washing-ton (UIL) and Salem, Oregon (SLE) were obtained from the National Oceanic and Atmospheric Administration (NOAA) radiosonde database and processed with the CALMET utility READ62. The upper-air stations are also shown in Figure 5-2.
- Hourly precipitation data was obtained from the National Climatic Data Center's TD 3240 (COOP) dataset. Figure 5-3 shows the locations of the precipitation data set. This data was pro-cessed with the CALMET utility PMERGE.
- MM5 winds based on a 4-km grid spacing for January 2003 through December 2005 were used to initialize the three-dimensional wind field predictions. The MM5 data was processed with the CALMM5 utility for use by CALMET.

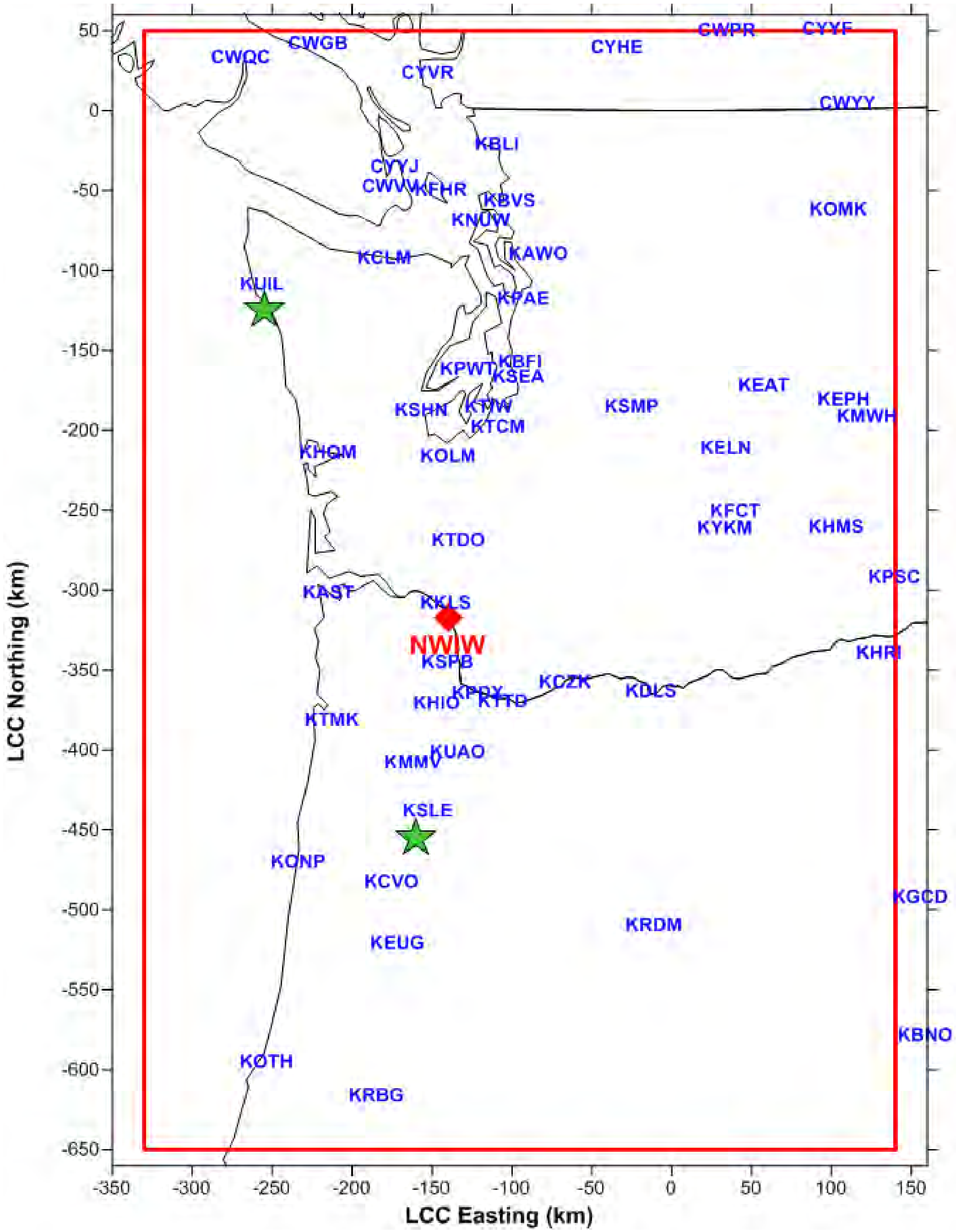

Figure 5-2. Surface Met Sites (blue) and Upper Air Sites (green stars)

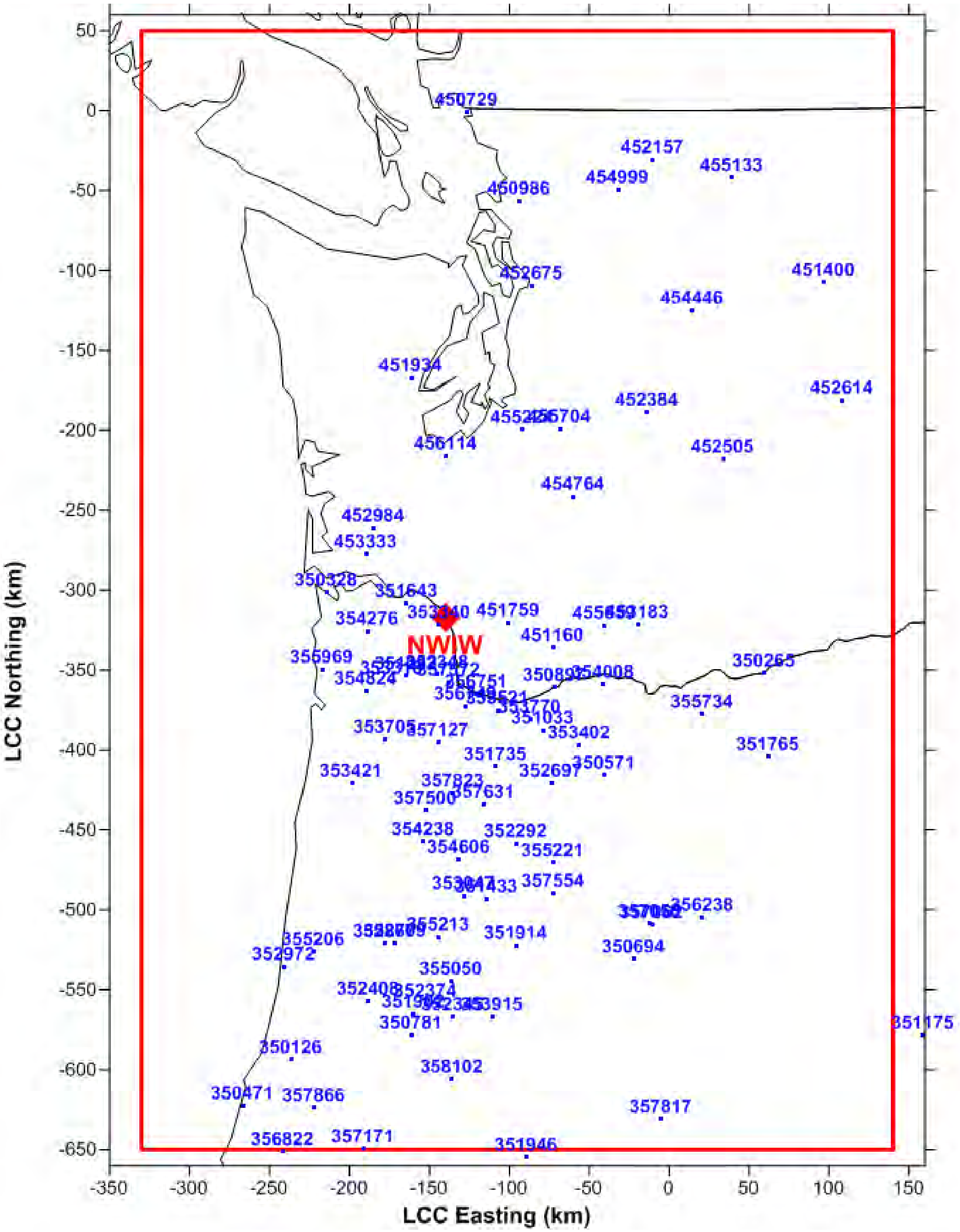

Figure 3. COOP Precipitation Sites

5.4.3 Class I Refined Analysis Results

The CALPUFF utility POSTUTIL was used to manipulate the large CALPUFF output files and calculate a number of the parameters needed to assess AQRVs in the areas of interest. Following the application of POSTUTIL, the CALPOST post-processor was used to summarize the modeling results and obtain maximum predicted concentrations of $PM_{2.5}$ in Class I areas and in the CGRNSA. The CALPUFF modeling system was used to predict concentrations of $PM_{2.5}$ in regional Class I areas. Table 5-3 summarizes the predicted maximum concentrations and compares them to the Class I SILs. Table 5-3 indicates predicted concentrations are all less than the applicable SILs.

Table 4. Predicted Class I Area Criteria Pollutant Concentrations

Class I Area of Interest	Maximum Predicted Concentration (μg/m^3)	
	$PM_{2.5}$	
	24-Hour Average	Annual Average
Alpine Lakes Wilderness	0.0014	0.0004
Mount Baker Wilderness	0.0013	0.0002
Columbia Gorge National Scenic Area	0.0050	0.0030
Diamond Peak Wilderness	0.0011	0.0002
Glacier Peak Wilderness	0.0034	0.0002
Goat Rocks Wilderness	0.0036	0.0007
Mount Adams Wilderness	0.0022	0.0010
Mount Hood Wilderness	0.0026	0.0013
Mount Jefferson Wilderness	0.0021	0.0007
Mount Rainier National Park	0.0030	0.0009
Mount Washington Wilderness	0.0017	0.0005
N Cascades National Park	0.0012	0.0002
Olympic National Park	0.0027	0.0004
Three Sisters Wilderness	0.0016	0.0004
Class I Maximum Concentration	0.0050	0.0030
Class I SIL	0.07	0.06

APPENDIX A: FORMS

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
PO Box 47600 • Olympia, WA 98504-7600 • 360-407-6000
711 for Washington Relay Service • Persons with a speech disability can call 877-833-6341

July 1, 2011

NOTICE

The Air Quality Program has revised our permit fees beginning July 1, 2011. Bear with us as we fine-tune this new system. We want to give you a heads up on one point. Ecology set the initial fee rate at an amount that would cover the simplest type of permit. The amount of time required to review a permit application and issue a permit varies based on the complexity of the project. Therefore, it is possible that your initial fee will not cover the cost of processing your request. If that happens, we will send you a bill to cover our expenses.

We encourage you to work closely with your permit writer so that the permitting process, timeline, and costs are clear. These changes are our first step toward meeting the legislative mandate of shifting the cost of permitting from the state General Fund to the recipients of the permits. If you have any questions, please call the contact listed below.

Ecology Permitting Authority	**Contact**
Ecology Central Regional Office – Air Quality Program Chelan, Douglas, Kittitas, Klickitat, or Okanogan County	Lynnette Haller (509) 457-7126
Ecology Eastern Regional Office – Air Quality Program Adams, Asotin, Columbia, Ferry, Franklin, Garfield, Grant, Lincoln, Pend Oreille, Stevens,	Greg Flibbert (509) 329-3452 greg.flibbert@ecy.wa.gov
Ecology Northwest Regional Office – Air Quality Program San Juan County	Nick Roach (425) 649-7082
Ecology Industrial Section – W2Resources Program For actions taken at	Garin Schrieve (360) 407-6916
Ecology Nuclear Waste Program	Ron Skinnarland (509) 372-7924

Application for Prevention of Significant Deterioration

INSTRUCTIONS

Use this form for all projects in Washington that are subject to the Prevention of Significant Deterioration (PSD) Program. If you want Ecology to determine whether your project is subject to the PSD Program, submit a Request for a PSD Program Applicability Determination form (ECY 070-413).

Fill out the front and back of this form. Attach a check for the initial fee and mail the form and your application to:

Department of Ecology
Cashiering Unit
P.O. Box 47611
Olympia, WA 98504-7611

For Fiscal Office Use Only:
001-NSR-216-0299-000404

Check the box to indicate what you are submitting for review.

New project	**Initial Fee**
☒ New project application. The initial fee covers 158 hours of review.	$15,000
☐ New PSD permit application that is limited to greenhouse gases. The initial fee covers 79 hours of review.	$7,500
Revise an existing PSD permit	
☐ Administrative permit revision. The initial fee covers 20 hours of review.	$1,900
☐ All other permit revisions. The initial fee covers 79 hours of review.	$7,500
☐ Major modification. The initial fee covers 158 hours of review.	$15,000
Other actions	
☐ Permit extension. This is a flat fee.	$500
☐ Plant-wide applicability emission limit: establish limit. The initial fee covers 158 hours of review. [See note]	$15,000
☐ Plant-wide applicability emission limit: all other requests. Other requests may include increasing a limit; renewing a limit; or processing an expired limit. The initial fee covers 79 hours of review. [See note]	$7,500
Note. An additional fee does not apply when a request to establish a plant-wide applicability limit is part of an application covered by the new project, all other permit revisions, or major modification fees on this form.	

For more information	
Air Quality Program Science and Engineering Section Ecology Headquarters Office	Marc Crooks, P.E. Phone: (360) 407-6803 E-mail: marc.crooks@ecy.wa.gov

If you need this document in a format for the visually impaired, call the Air Quality Program at 360-407-6800. Persons with hearing loss can call 711 for Washington Relay Service. Persons with a speech disability can call 877-833-6341.

Application for Prevention of Significant Deterioration

Read each statement, then check the box next to it to acknowledge what you have read.

☒	The initial fee you submit may not cover the cost of processing your application. Ecology will track the number of hours spent on your project. If the number of hours exceeds the number of hours included in your initial fee, Ecology will send you a bill for that extra time.
☒	Ecology will bill you $95 per hour for each hour worked beyond the initial hours.
☒	You must pay the bill before we will issue your permit or finalize an action or decision.

Applicant Information

The applicant is the business requesting services from Ecology and is responsible for paying the costs Ecology incurs.

Name of business: Northwest Innovation Works, Kalama, LLC

Physical location of project (city): Kalama, Washington

Name of project: Kalama Manufacturing and Marine Export Facility

Project Manager Information

Ecology will send this person all official correspondence.

Name, Title: Kurt Humphrey, Environmental Manager

Mailing address: 380 W. Marine Drive

City, State, Zip: Kalama, Washington 98625

Phone, Fax, E-mail: 360-673-7805, kurth@nw-iw.com

Project Billing Contact Information

Ecology will send the Project Manager the bills if there are any.

☐ If the Project Billing Contact is different from the Project Manager, check this box and provide the required information.

Name, Title____________________

Mailing address ____________________

City, State, Zip____________________

Phone, Fax, E-mail____________________

Project Consultant Information

☒ If you hired a consultant to prepare the application (or materials), check this box and provide the required information.

Consultant Name, Title: Eric Albright, Senior Manager

Organization: Ramboll Environ US Corporation

Mailing address: 19020 33rd Ave W, Suite 310

City, State, Zip: Lynnwood, Washington 98036

Phone, Fax, E-mail: 425-412-1804, 425-412-1840, ealbright@ramboll.com

Responsible Official Signature Block

I certify, based on information and belief formed after reasonable inquiry, the statements and information in this application are true, accurate, and complete.

Printed Name, Title: Murray V. Godley III, President

Signature, Date: X 2-24-16

THE RED THERMO SECURED *"SP"* LOGO IN THE LOWER CORNER OF THIS CHECK MUST FADE TEMPORARILY WHEN WARMED BY TOUCH OR FRICTION. SEE BACK FOR ADDITIONAL FEATURES.

PAN-PACIFIC ENERGY CORP.
13215 SE MILL PLAIN BLVD. STE C8331
VANCOUVER, WA 98684

1068

DATE 1-28-16

11-24/1210

PAY TO THE ORDER OF Washington Department of Ecology

$ 15,000.00

Fifteen Thousand and 00/100 DOLLARS

WELLS FARGO
Wells Fargo Bank, N.A.

MEMO NWIW PSD AIR Permit Application

⑈1068⑈ ⑆121000248⑆ 4128655289⑈

THERMO SECURED

JB - 2115520

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Southwest Clean Air Agency
INSTRUCTIONS FOR PERMIT APPLICATION

Use this sheet as a checklist to determine when your application is substantially complete.

☞ Each PERMIT APPLICATION for the construction, installation, or establishment of a new air contaminant source, or modification of existing air pollution source or control equipment or permit needs to be accompanied by the following information to be considered complete:

Included	N/A	
☒	☐	Process flow sheets and equipment layout diagrams.
☐	☐	Process and control equipment manufacturer, model number, size, serial number, date of manufacture (for each piece of control equipment). See permit application.
☒	☐	Quantify average and maximum hourly throughput values, average yearly totals, and maximum concentrations for each pollutant.
☒	☐	Applicant's calculation of the kinds and amounts of emissions for each emission point, materials handling operation or fugitive category (both controlled and uncontrolled).
☒	☐	Plot plan including identification of proposed emission points to the atmosphere, distance to property boundaries, height of buildings, and stack height above ground level.
☒	☐	Identification of raw materials and/or product specifications (physical and chemical properties) and typical ranges of operating conditions as related to each emission point (toxic air contaminants require a separate summary); Material Safety Data Sheets (MSDSs) should be included in the PERMIT APPLICATION for all compounds used.
☒	☐	Identification of the methods/equipment proposed for prevention/control of emissions to the atmosphere.
☒	☐	Information sufficient to demonstrate the ability of the emission controls proposed as being consistent with those provided in the applicable regulations (BACT/NSPS/RACT/NESHAPS/LAER analysis) – see attached worksheet for typical layout of BACT analysis information.
☐	☒	The kinds and amounts of emission offset credits proposed for assignment when operations are within a maintenance boundary (see SWCAA 400-120 and 400-130).
☒	☐	Estimates of the proposed project ambient impact under average and least favorable conditions where pertinent to PSD (WAC 173-400-171) or Toxic Air Pollutants (WAC 173-460) requirements.
☐	☒	Additional information, evidence, or documentation as required by the Board of Directors, or the Control Officer, to show that the proposed project will meet federal, state, and local air pollution control regulations.
☐	☒	For applications that include equipment that has previously been approved, authorized or registered, a lapse is considered to have occurred if the registration fees are delinquent for more than one calendar year or the source has not operated within five years prior to the receipt of any required PERMIT APPLICATION (SWCAA 400-030(56) and SWCAA 400-110).
☐	☒	Applications that include previously approved or authorized equipment require that additional information regarding previous owners or approvals be provided so that SWCAA records can be updated. Equipment registered and/or approved for a given company cannot be authorized without a legal name change, purchase of company or equipment, or a legal contract or subcontract to do business with or for the approved source. Responsibility for operation of authorized equipment rests with the registered source.
☐	☐	All applications need to be accompanied with a completed SEPA checklist or SEPA determination. See permit application document.

☞ The application transmittal shall conform to SWCAA review requirements wherever possible as detailed in SWCAA General Regulations for Air Pollution Sources (SWCAA 400).

☞ Each drawing, document, or other form of transmittal considered by the applicant to be proprietary and confidential must be suitably identified as confidential in red ink, and signed and dated by the applicant or its agent. Be aware that SWCAA follows the requirements in SWCAA 400-270 and 40 CFR 2 for determination of confidentiality. SWCAA may not process company sensitive information as confidential.

☞ Air Discharge Permits (to construct, modify, or install) are issued for specific equipment or processes described in the application. Changes to the processes or control equipment are not allowed without new source review (Permit Application and Permit) if these changes result in an emission of a different type or an increase in emissions (SWCAA 400-110). Process equipment changes that result in decreased emissions require notification to SWCAA.

☞ The SIC code is identified as the four digit major group classification in the 1987 Standard Industrial Code Classification Manual or refer to the SWCAA website at http://www.swcleanair.org/forms.html for a listing of SIC codes and NAICS Codes.

☞ Mail or deliver in person the completed application package to:

Southwest Clean Air Agency
11815 NE 99th Street, Suite 1294
Vancouver, WA 98682-2322

☞ **Application and engineering review fees must accompany the application for the application to be considered complete. Make checks payable to "Southwest Clean Air Agency" or "SWCAA."**

☞ **The PERMIT APPLICATION package submitted must be complete. All applications are screened for completeness before processing. Applicants submitting incomplete application packages will be notified of their incomplete status and may result in a delay in processing the application.**

Southwest Clean Air Agency

A permit application review fee is required with the submittal of each permit application. There is a base fee composed of an application fee and an engineering review fee from Table A, which is based on the primary emission unit or activity of the proposed new, modified or altered "stationary source." Permit application review fees based on emissions are determined using the proposed emissions (after controls) as supported by test data or emission factors and review fees based on equipment capacity or size are to utilize the design capacities of affected equipment.

If the staff time required to review a permit application exceeds the number of review hours associated specified in Table A, B, or C, the applicant will be invoiced for each additional work hours at a rate of $70.00/hr as provided in SWCAA 400-109(3).

FEE CALCULATION

APPLICATION FEE	**Required**	$ 500.00	If expedited, enter $1,000.00
ENGINEERING REVIEW FEE	**Required**	+ $ 6,000.00	Enter the fee for the *primary* equipment/activity from **Table A** or if you want an expedited review, enter double the fee from **Table A**
	TOTAL FEE	$ 6,500.00	← **Submit this amount with application**

Additional Fees
After you have submitted your application and the fee above, **contact SWCAA concerning any additional applicable fees.** You will be invoiced for any additional fees prior to the issuance of your final permit.

- Legal Notice Fee. This fee is $70.00 plus the actual publication cost of the legal notice;
- Additional Review Time Fee. If the review time needed to process your application exceeds the time listed in **Table A**, you will be charged $70.00/hr for each additional hour of review;
- Additional Engineering Review Fee. Specific projects or activities listed in **Table B** are subject to a fee; and
- Major NSR Review Fee. Specific projects or activities are subject to the fee listed **in Table C**.

TABLE A
Engineering Review Fees

	Equipment/Activity	**Fee and Review Hours**
i.	Fuel burning equipment (Million Btu/hr heat input at design capacity):	
	0.4 or more but less than 5	$ 600.00 for **8** hrs of review time
	5 or more but less than 10	$ 700.00 for **10** hrs of review time
	10 or more but less than 30	$ 850.00 for **12** hrs of review time
	30 or more but less than 50	$ 1,000.00 for **14** hrs of review time
	50 or more but less than 100	$ 1,200.00 for **17** hrs of review time
	100 or more but less than 250	$ 2,500.00 for **35** hrs of review time
	250 or more but less than 500	$ 4,000.00 for **57** hrs of review time
	500 or more	$ 6,000.00 for **85** hrs of review time
	Change in fuel type	One half of the applicable fee listed above

TABLE A
Engineering Review Fees (continued)

	Equipment/Activity	Fee and Review Hours
ii.	Discharge from control equipment or from uncontrolled process equipment in actual cubic feet per minute (acfm):	
	Less than 50	$ 600.00 for **8** hrs of review time
	50 or more but less than 5,000	$ 700.00 for **10** hrs of review time
	5,000 or more but less than 20,000	$ 800.00 for **11** hrs of review time
	20,000 or more but less than 50,000	$ 900.00 for **12** hrs of review time
	50,000 or more but less than 100,000	$ 950.00 for **13** hrs of review time
	100,000 or more but less than 250,000	$ 1,000.00 for **14** hrs of review time
	250,000 or more but less than 500,000	$ 2,000.00 for **28** hrs of review time
	500,000 or more	$ 4,000.00 for **57** hrs of review time
iii.	Refuse burning equipment and incinerators (Tons/day capacity):	
	Less than 0.5	$ 700.00 for **10** hrs of review time
	0.5 or more but less than 5	$ 800.00 for **11** hrs of review time
	5 or more but less than 12	$ 1,000.00 for **14** hrs of review time
	12 or more but less than 50	$ 3,000.00 for **42** hrs of review time
	50 or more	$ 6,000.00 for **85** hrs of review time
iv.	Storage tanks, reservoirs, or containers, other than gasoline or diesel fuel dispensing facilities (Gallons-total capacity):	
	250 or more but less than 10,000	$ 600.00 for **8** hrs of review time
	10,000 or more but less than 40,000	$ 1,000.00 for **14** hrs of review time
	40,000 or more but less than 100,000	$ 1,500.00 for **21** hrs of review time
	100,000 or more	$ 2,000.00 for **28** hrs of review time
v.	Gasoline dispensing facilities:	
	Stage I	$ 600.00 for **8** hrs of review time
	Stage II	$ 700.00 for **10** hrs of review time
	Stages I & II, combined	$ 800.00 for **11** hrs of review time
	Toxics review for gasoline facility	$ 1,500.00 for **21** hrs of review time
	Stage II removal	**$ 600.00 for 8 hrs of review time**
vi.	Other not classified in sections i, ii, iii, iv, or v above	$ 200.00 per ton of emissions
vii.	Toxic air contaminants	$ 200.00 per ton of emissions
viii.	Complex stationary source or modification:	$ 6,000.00 for **85** hrs of review time
ix.	Synthetic minor application (including, but not limited to Title V and HAP):	$ 2,500.00 for **35** hrs of review time

TABLE A
Engineering Review Fees (continued)

	Equipment/Activity	Fee and Review Hours
x.	Particulate matter and fugitive emissions from rock crushing, material transfer and ship loading (Emissions - tons per year):	
	Less than or equal to 10	$ 600.00 for **8** hrs of review time
	More than 10 but less than or equal to 50	$ 1,000.00 for **14** hrs of review time
	More than 50 but less than or equal to 100	$ 1,500.00 for **21** hrs of review time
	More than 100 but less than 250	$ 2,500.00 for **35** hrs of review time
	250 or greater	$ 6,000.00 for **85** hrs of review time
xi.	Minor modifications to existing permit conditions:	$ 600.00 for **8** hrs of review time
xii.	Dry cleaner:	$ 600.00 for **8** hrs of review time
xiii.	Internal Combustion Engines (Aggregate horsepower rating):	
	Less than 500	$ 700.00 for **10** hrs of review time
	500 or more but less than 2,000	$ 1,000.00 for **14** hrs of review time
	2,000 or more but less than 5,000	$ 1,500.00 for **21** hrs of review time
	5,000 or more but less than 10,000	$ 3,000.00 for **42** hrs of review time
	10,000 or more	$ 6,000.00 for **85** hrs of review time
xiv.	Crematory/small incinerators/small flares:	$ 700.00 for **10** hrs of review time
xv.	Gluing/flow coating operations without active ventilation:	$ 800.00 for **11** hrs of review time
xvi.	Soil/groundwater remediation:	$ 800.00 for **11** hrs of review time
xvii.	Composting Facilities (Average material throughput – tons per day):	
	Less than 50	$ 600.00 for **8** hrs of review time
	50 or more but less than 100	$ 1,000.00 for **14** hrs of review time
	100 or more but less than 200	$ 1,500.00 for **21** hrs of review time
	200 or more but less than 500	$ 3,000.00 for **42** hrs of review time
	500 or more	$ 6,000.00 for **85** hrs of review time
xviii.	Coffee roasters:	$ 700.00 for **10** hrs of review time
xix.	Municipal wastewater treatment plants (Annual average design capacity – Million Gallons per Day)	
	More than 1 but less than 5	$ 800.00 for **11** hrs of review time
	5 or more but less than 10	$ 1,500.00 for **21** hrs of review time
	10 or more	$ 2,500.00 for **35** hrs of review time

TABLE B
Additional Fees

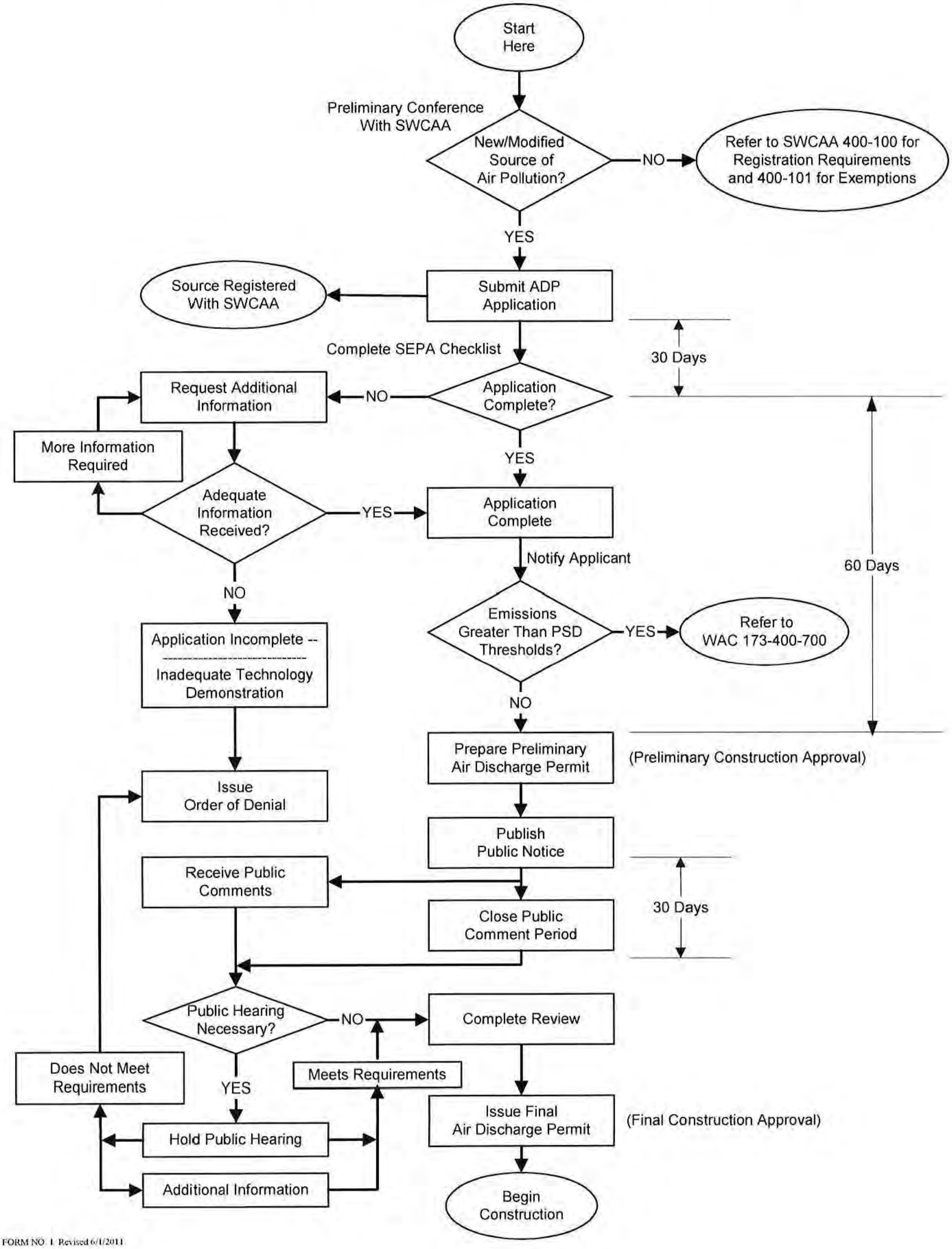
	Equipment/Activity	**Fee and Hours**
xx.	Emission offset analysis or bubble:	$ 700.00 for **10** hrs of review time
xxi.	Emission reduction credit (ERC) application (Deposit or withdrawal):	$ 700.00 for **10** hrs of review time
xxii.	State environmental policy act (SEPA) – lead agency:	
	Minor	$ 1,000.00 for **14** hrs of review time
	Major	$ 2,500.00 for **35** hrs of review time
xxiii.	Environmental impact statement (EIS) review:	
	Minor	$ 800.00 for **11** hrs of review time
	Major	$ 2,000.00 for **28** hrs of review time
xxiv.	RACT, BACT, MACT, BART, or LAER determination:	$ 70.00/hr for review time
xxv.	Variance request:	$ 800.00 for **11** hrs of review time
xxvi.	Review of ambient impact analysis:	$ 70.00/hr for review time
xxvii.	Review of Ecology agreed orders and consent orders pursuant to RCW 70.105D.090(1):	$ 70.00/hr for review time

TABLE C
Major NSR Fees

	Equipment/Activity	**Fee and Hours**
xxviii.	Plantwide applicability limitations:	$ 10,000.00 for **142** hrs of review time

Southwest Clean Air Agency

AIR DISCHARGE PERMIT APPLICATION FLOW CHART



Southwest Clean Air Agency

11815 NE 99th Street, Suite 1294, Vancouver, WA 98682-2322 Voice: (360) 574-3058 Fax: (360) 576-0925 Page 1 of 3

PERMIT APPLICATION

TOTAL ENCLOSED FEE: $ 6,500 (to be submitted with application, no fee required for change of location or change of registered owner)

If you want this permit application to be expedited, have you **doubled the fee**? ☐ YES ☒ NO

COMPANY INFORMATION

NAME OF APPLICANT	STREET	CITY	STATE	ZIP	PHONE	FAX
Northwest Innovation Works, Kalama, LLC	380 W. Marine Drive	Kalama	WA	98625	360-673-7805	

LEGAL NAME OF BUSINESS FOR WHICH APPLICATION APPLIES	PHONE	FAX
Northwest Innovation Works, Kalama, LLC	360-673-7805	

STREET	PO BOX	CITY	COUNTY	STATE	ZIP
380 W. Marine Drive		Kalama	Cowlitz	WA	98625

TYPE OF ORGANIZATION

☐ CORPORATION ☐ LIMITED PARTNERSHIP ☐ GOVERNMENT ENTITY

☐ INDIVIDUAL (Sole Proprietorship) ☐ GENERAL PARTNERSHIP ☒ OTHER Washington Limited Liability Corporation

ARE ALL FACILITIES, UNDER THE SAME OWNERSHIP IN WASHINGTON, IN COMPLIANCE WITH FEDERAL, STATE, AND LOCAL AIR POLLUTION REGULATIONS? ☒ YES ☐ NO

ARE YOU THE OWNER OF THE EQUIPMENT UNDER THIS APPLICATION? ☒ YES ☐ NO

OWNER IDENTIFICATION NUMBER

IF NO, ENTER LEGAL NAME OF OWNER: ____________

☐ S.S. NUMBER ___-__-____

☐ UBI No. 603366498

FACILITY INFORMATION

FACILITY NAME	EQUIPMENT ADDRESS / LOCATION Street	City	County	State	Zip
Northwest Innovation Works, Kalama, LLC	222 Tradewinds Rd.	Kalama	Cowlitz	WA	98625

MAILING ADDRESS Street 380 W. Marine Drive City Kalama State WA Zip 98625

FACILITY OPERATING SCHEDULE hrs/day 24 days/wk 7 wks/yr 52

CONTACT PERSON AND TITLE	PHONE	EMAIL
Kurt Humphrey, Environmental Manager	360-673-7805	kurth@nw-iw.com

NAICS Code (refer to instructions)
325199 (All other basic organic chemical manufacturing)

IS THERE A SCHOOL OR DAYCARE WITHIN 1000 FT OF THIS FACILITY? ☐ YES ☒ NO

CONTROL EQUIPMENT INFORMATION

EQUIPMENT DESCRIPTION
Methanol Production Facility

APPLICATION FOR:

☒ New Construction or Installation ☐ Modification or Alteration of Equipment ☐ Change of Location

☐ Change of Approval Condition (Title V Opt-Out) ☐ Change of Registered Owner ☐ Other ____________

☐ Existing Equipment Operating Without Approval ☐ Existing Equipment With Expired or Lapsed Approval or Registration

Has a Notice of Violation been Issued? ☐ Yes ☒ No If Yes, Number: ____________

ESTIMATED COST:
For Total Modification / New Facility: $1.8 Billion For Air Pollution Control Equipment: $60 million

ESTIMATED INSTALLATION START DATE: 12/16 **ESTIMATED COMPLETION DATE:** 12/19

DO YOU CLAIM CONFIDENTIALITY OF INFORMATION? ☐ YES ☐ NO (Each page with confidential information must be clearly marked in red ink)

I do hereby certify that the information contained in this PERMIT APPLICATION is, to the best of my knowledge, accurate and complete.

Signature: ____________ Name: Murray V. Godley III Title: President Date: 2-24-16

AGENCY USE ONLY

SWCAA ID #: ____________ Expedited Application: ☐ YES ☐ NO

Application Fee: $500 or $1,000 Date: ________ Application #: ________

Review/Add'l Fees: $ ________ Date: ________ SIC/NAICS #: ________

AGENCY USE ONLY

Date Stamp

SWCAA FORM NO 1 Revised 6/1/2011

Southwest Clean Air Agency

11815 NE 99th Street, Suite 1294, Vancouver, WA 98682-2322 Voice: (360) 574-3058 Fax (360) 576-0925

PERMIT APPLICATION / NEW SOURCE REVIEW

BACT IMPACT ANALYSIS WORKSHEET

Facility Name: Kalama Manufacturing and Marine Export Facility **Date:** ____________

CONTROL ALTERNATIVE	EMISSIONS [lbs/hr] & [tons/yr]	EMISSIONS REDUCTION ① [tons/yr]	INSTALLED CAPITAL COST ② [$]	TOTAL ANNUALIZED COST ③⑦ [$]	AVERAGE COST EFFECTIVENESS OVER BASELINE ④ [$/ton]	INCREMENTAL COST EFFECTIVENESS ⑤ [$/ton]	ENERGY INCREASE OVER BASELINE ⑥ [MMBtu/yr]	TOXICS IMPACT [Yes/No]	ADVERSE ENVIRONMENTAL IMPACT [Yes/No]
1) See permit application document for details									
2)									
3)									
4)									
5) Uncontrolled Baseline (worst case - no controls)									

① Emissions reduction over baseline control level.
② Installed capital cost relative to baseline.
③ Total annualized cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation) is used to express capital costs in present-day annual costs.
④ Average cost effectiveness over baseline is equal to total annualized cost for the control option divided by the emissions reductions resulting from the uncontrolled baseline.
⑤ The optional incremental cost effectiveness criterion is the same as the average cost effectiveness criteria except that the control alternative is considered relative to the next most stringent alternative rather than the baseline control alternative.
⑥ Energy impacts are the difference in total project energy requirements with the control alternative uncontrolled baseline expressed in equivalent millions of Btus per year.
⑦ Assumptions made on catalyst life may have a substantial affect upon cost effectiveness.

Notes:

The number of alternatives to be evaluated will vary depending on application.
Values for each variable should be provided as they are applicable. Use N/A if not applicable.
Emission rates are the expected or predicted emission rates.
Calculations should provide for a range of alternatives.
Emissions reduction should use estimated efficiency if actual efficiency is unknown - should so state.
Attach worksheets as necessary to substantiate above values.

Southwest Clean Air Agency

11815 NE 99th Street, Suite 1294, Vancouver, WA 98682-2322 Voice: (360) 574-3058 Fax (360) 576-0925

ESTIMATION CODE	
Process Knowledge	0
Source Test	1
Material Balance	2
EPA Factor	3
Guess	4
Non-EPA Factor	5
Other ____________	6

PERMIT APPLICATION / NEW SOURCE REVIEW

EMISSION ESTIMATE SUMMARY WORKSHEET

FACILITY NAME: Kalama Manufacturing and Marine Export Facility

DATE: ____________

EMISSION POINT NUMBER①: ________

EMISSION POINT NAME: See permit application document for details

POLLUTANT: (circle)	UNCONTROLLED EMISSIONS lbs/yr or tons/yr	CONTROLLED EMISSIONS lbs/yr or tons/yr	MAX HOURLY CONCENTRATION $\mu g/m^3$ or grains	HOURLY/MONTHLY EMISSIONS lbs or tons	YEARLY EMISSIONS lbs/yr or tons/yr	ESTIMATION CODE	TOXIC② Y / N
Particulate Matter (PM):							
PM$_{10}$:							
Sulfur Dioxide (SO_2):							
Nitrogen Oxides (NO_x):							
Volatile Organic Compounds (VOC):							
Carbon Monoxide (CO):							
Other:							

① Emission Point Number should be consistent with the annual Air Emission Inventory Data Sheets. If this application represents a new emission point, write "new."

② VOC toxics should be summarized on the VOC Emission Summary Worksheet. All other toxics should be explained below.

EXPLANATION / NOTES: ____________

PAN-PACIFIC ENERGY CORP.
13215 SE MILL PLAIN BLVD. STE C8331
VANCOUVER, WA 98684

1047

DATE Feb. 2nd

11-24/1210

PAY TO THE ORDER OF Southwest Clean air Agency

$ 6500/

six thousand five hundred DOLLARS

WELLS FARGO
Wells Fargo Bank, N.A.

MEMO Air permitting Application

⑈1047⑈ ⑆121000248⑆ 4128655289⑈

APPENDIX B: TANK EMISSION MODELING

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	TK-04001
City:	Kalama
State:	WA
Company:	NWIW
Type of Tank:	Vertical Fixed Roof Tank
Description:	Crude Methanol Tank

Tank Dimensions

Shell Height (ft):	57.50
Diameter (ft):	82.00
Liquid Height (ft) :	57.50
Avg. Liquid Height (ft):	28.75
Volume (gallons):	2,291,283.23
Turnovers:	720.00
Net Throughput(gal/yr):	1,649,723,923.62
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Cone
Height (ft)	0.00
Slope (ft/ft) (Cone Roof)	0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Portland, Oregon (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

TK-04001 - Vertical Fixed Roof Tank
Kalama, WA

		Daily Liquid Surf. Temperature (deg F)			Liquid Bulk Temp	Vapor Pressure (psia)			Vapor Mol.	Liquid Mass	Vapor Mass	Mol.	Basis for Vapor Pressure
Mixture/Component	Month	Avg.	Min.	Max.	(deg F)	Avg.	Min.	Max.	Weight.	Fract.	Fract.	Weight	Calculations
Raw Methanol	All	55.06	50.48	59.64	53.57	1.2314	0.9004	1.5893	32.0634			28.58	
Ethyl alcohol						0.5542	0.4712	0.6497	46.0700	0.0010	0.0003	46.07	Option 2: A=8.321, B=1718.21, C=237.52
Heptane (-n)						0.5267	0.4574	0.6049	100.2000	0.0018	0.0005	100.20	Option 3: A=37358, B=8.2585
Methyl alcohol						1.2322	1.0615	1.4258	32.0400	1.1200	0.7345	32.04	Option 2: A=7.897, B=1474.08, C=229.13
Unidentified Components						1.2314	0.6929	0.6936	32.0763	-0.1228	0.2647	18.84	

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

TK-04001 - Vertical Fixed Roof Tank
Kalama, WA

Annual Emission Calcaulations	
Standing Losses (lb):	11,423.0384
Vapor Space Volume (cu ft):	156,340.1147
Vapor Density (lb/cu ft):	0.0071
Vapor Space Expansion Factor:	0.0821
Vented Vapor Saturation Factor:	0.3411
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	156,340.1147
Tank Diameter (ft):	82.0000
Vapor Space Outage (ft):	29.6042
Tank Shell Height (ft):	57.5000
Average Liquid Height (ft):	28.7500
Roof Outage (ft):	0.8542
Roof Outage (Cone Roof)	
Roof Outage (ft):	0.8542
Roof Height (ft):	0.0000
Roof Slope (ft/ft):	0.0625
Shell Radius (ft):	41.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0071
Vapor Molecular Weight (lb/lb-mole):	32.0634
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.2314
Daily Avg. Liquid Surface Temp. (deg. R):	514.7306
Daily Average Ambient Temp. (deg. F):	53.5542
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	513.2442
Tank Paint Solar Absorptance (Shell):	0.1700
Tank Paint Solar Absorptance (Roof):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	1,113.3533
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0821
Daily Vapor Temperature Range (deg. R):	18.3136
Daily Vapor Pressure Range (psia):	0.6889
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.2314
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.9004
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	1.5893
Daily Avg. Liquid Surface Temp. (deg R):	514.7306
Daily Min. Liquid Surface Temp. (deg R):	510.1522
Daily Max. Liquid Surface Temp. (deg R):	519.3090
Daily Ambient Temp. Range (deg. R):	18.0750
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.3411
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	1.2314
Vapor Space Outage (ft):	29.6042

Working Losses (lb):	323,094.7796
Vapor Molecular Weight (lb/lb-mole):	32.0634
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.2314
Annual Net Throughput (gal/yr.):	1,649,723,923.6200
Annual Turnovers:	720.0000
Turnover Factor:	0.2083
Maximum Liquid Volume (gal):	2,291,283.2273
Maximum Liquid Height (ft):	57.5000
Tank Diameter (ft):	82.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	334,517.8180

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

TK-04001 - Vertical Fixed Roof Tank
Kalama, WA

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Raw Methanol	323,094.78	11,423.04	334,517.82
Methyl alcohol	237,313.12	8,390.22	245,703.34
Ethyl alcohol	96.93	3.43	100.36
Heptane (-n)	161.55	5.71	167.26
Unidentified Components	85,523.19	3,023.68	88,546.87

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	TK-04002A,B
City:	Kalama
State:	WA
Company:	NWIW
Type of Tank:	Internal Floating Roof Tank
Description:	Product Shift Methanol Tank

Tank Dimensions

Diameter (ft):	59.00
Volume (gallons):	959,900.00
Turnovers:	720.00
Self Supp. Roof? (y/n):	Y
No. of Columns:	0.00
Eff. Col. Diam. (ft):	0.00

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Rim-Seal System

Primary Seal:	Mechanical Shoe
Secondary Seal	Rim-mounted

Deck Characteristics

Deck Fitting Category:	Detail
Deck Type:	Welded

Deck Fitting/Status	Quantity
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	1
Automatic Gauge Float Well/Bolted Cover, Gasketed	1
Roof Leg (3-in. Diameter)/Adjustable, Pontoon Area, Gasketed	9
Roof Leg (3-in. Diameter)/Adjustable, Center Area, Gasketed	7
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Slotted Guide-Pole/Sample Well/Gask. Sliding Cover, w. Float	1
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Rim Vent (6-in. Diameter)/Weighted Mech. Actuation, Gask.	1

Meterological Data used in Emissions Calculations: Portland, Oregon (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

TK-04002A,B - Internal Floating Roof Tank
Kalama, WA

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Methyl alcohol	All	55.06	50.48	59.64	53.57	1.2322	N/A	N/A	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

TK-04002A,B - Internal Floating Roof Tank
Kalama, WA

Annual Emission Calcaulations	
Rim Seal Losses (lb):	24.7377
Seal Factor A (lb-mole/ft-yr):	0.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.4000
Value of Vapor Pressure Function:	0.0218
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.2322
Tank Diameter (ft):	59.0000
Vapor Molecular Weight (lb/lb-mole):	32.0400
Product Factor:	1.0000
Withdrawal Losses (lb):	2,615.6141
Number of Columns:	0.0000
Effective Column Diameter (ft):	0.0000
Annual Net Throughput (gal/yr.):	691,128,000.0000
Shell Clingage Factor (bbl/1000 sqft):	0.0015
Average Organic Liquid Density (lb/gal):	6.6300
Tank Diameter (ft):	59.0000
Deck Fitting Losses (lb):	40.6634
Value of Vapor Pressure Function:	0.0218
Vapor Molecular Weight (lb/lb-mole):	32.0400
Product Factor:	1.0000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	58.1900
Deck Seam Losses (lb):	0.0000
Deck Seam Length (ft):	0.0000
Deck Seam Loss per Unit Length Factor (lb-mole/ft-yr):	0.0000
Deck Seam Length Factor(ft/sqft):	0.0000
Tank Diameter (ft):	59.0000
Vapor Molecular Weight (lb/lb-mole):	32.0400
Product Factor:	1.0000
Total Losses (lb):	2,681.0152

		Roof Fitting Loss Factors			
Roof Fitting/Status	Quantity	KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	1	1.60	0.00	0.00	1.1181
Automatic Gauge Float Well/Bolted Cover, Gasketed	1	2.80	0.00	0.00	1.9567
Roof Leg (3-in. Diameter)/Adjustable, Pontoon Area, Gasketed	9	1.30	0.08	0.65	8.1760
Roof Leg (3-in. Diameter)/Adjustable, Center Area, Gasketed	7	0.53	0.11	0.13	2.5926
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	1	6.20	1.20	0.94	4.3326
Slotted Guide-Pole/Sample Well/Gask. Sliding Cover, w. Float	1	31.00	36.00	2.00	21.6629
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1	0.47	0.02	0.97	0.3284
Rim Vent (6-in. Diameter)/Weighted Mech. Actuation, Gask.	1	0.71	0.10	1.00	0.4962

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

TK-04002A,B - Internal Floating Roof Tank
Kalama, WA

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Methyl alcohol	24.74	2,615.61	40.66	0.00	2,681.02

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	TK-11001A,B,C,D
City:	Kalama
State:	WA
Company:	NWIW
Type of Tank:	Internal Floating Roof Tank
Description:	Product Shift Methanol Tank

Tank Dimensions

Diameter (ft):	142.75
Volume (gallons):	9,356,000.00
Turnovers:	18.00
Self Supp. Roof? (y/n):	Y
No. of Columns:	0.00
Eff. Col. Diam. (ft):	0.00

Paint Characteristics

Internal Shell Condition:	Light Rust
Shell Color/Shade:	White/White
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Rim-Seal System

Primary Seal:	Mechanical Shoe
Secondary Seal	Rim-mounted

Deck Characteristics

Deck Fitting Category:	Detail
Deck Type:	Welded

Deck Fitting/Status	Quantity
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	1
Automatic Gauge Float Well/Bolted Cover, Gasketed	1
Roof Leg (3-in. Diameter)/Adjustable, Pontoon Area, Gasketed	15
Roof Leg (3-in. Diameter)/Adjustable, Center Area, Gasketed	35
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Slotted Guide-Pole/Sample Well/Gask. Sliding Cover, w. Float	1
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1
Rim Vent (6-in. Diameter)/Weighted Mech. Actuation, Gask.	1

Meterological Data used in Emissions Calculations: Portland, Oregon (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

TK-11001A,B,C,D - Internal Floating Roof Tank
Kalama, WA

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Methyl alcohol	All	55.06	50.48	59.64	53.57	1.2322	N/A	N/A	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

TK-11001A,B,C,D - Internal Floating Roof Tank
Kalama, WA

Annual Emission Calcaulations	
Rim Seal Losses (lb):	59.8526
Seal Factor A (lb-mole/ft-yr):	0.6000
Seal Factor B (lb-mole/ft-yr (mph)^n):	0.4000
Value of Vapor Pressure Function:	0.0218
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.2322
Tank Diameter (ft):	142.7500
Vapor Molecular Weight (lb/lb-mole):	32.0400
Product Factor:	1.0000
Withdrawal Losses (lb):	263.4231
Number of Columns:	0.0000
Effective Column Diameter (ft):	0.0000
Annual Net Throughput (gal/yr.):	168,408,000.0000
Shell Clingage Factor (bbl/1000 sqft):	0.0015
Average Organic Liquid Density (lb/gal):	6.6300
Tank Diameter (ft):	142.7500
Deck Fitting Losses (lb):	56.4844
Value of Vapor Pressure Function:	0.0218
Vapor Molecular Weight (lb/lb-mole):	32.0400
Product Factor:	1.0000
Tot. Roof Fitting Loss Fact.(lb-mole/yr):	80.8300
Deck Seam Losses (lb):	0.0000
Deck Seam Length (ft):	0.0000
Deck Seam Loss per Unit Length Factor (lb-mole/ft-yr):	0.0000
Deck Seam Length Factor(ft/sqft):	0.0000
Tank Diameter (ft):	142.7500
Vapor Molecular Weight (lb/lb-mole):	32.0400
Product Factor:	1.0000
Total Losses (lb):	379.7601

		Roof Fitting Loss Factors			
Roof Fitting/Status	Quantity	KFa(lb-mole/yr)	KFb(lb-mole/(yr mph^n))	m	Losses(lb)
Access Hatch (24-in. Diam.)/Bolted Cover, Gasketed	1	1.60	0.00	0.00	1.1181
Automatic Gauge Float Well/Bolted Cover, Gasketed	1	2.80	0.00	0.00	1.9567
Roof Leg (3-in. Diameter)/Adjustable, Pontoon Area, Gasketed	15	1.30	0.08	0.65	13.6267
Roof Leg (3-in. Diameter)/Adjustable, Center Area, Gasketed	35	0.53	0.11	0.13	12.9628
Vacuum Breaker (10-in. Diam.)/Weighted Mech. Actuation, Gask.	1	6.20	1.20	0.94	4.3326
Slotted Guide-Pole/Sample Well/Gask. Sliding Cover, w. Float	1	31.00	36.00	2.00	21.6629
Gauge-Hatch/Sample Well (8-in. Diam.)/Weighted Mech. Actuation, Gask.	1	0.47	0.02	0.97	0.3284
Rim Vent (6-in. Diameter)/Weighted Mech. Actuation, Gask.	1	0.71	0.10	1.00	0.4962

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

TK-11001A,B,C,D - Internal Floating Roof Tank
Kalama, WA

	Losses(lbs)				
Components	Rim Seal Loss	Withdrawl Loss	Deck Fitting Loss	Deck Seam Loss	Total Emissions
Methyl alcohol	59.85	263.42	56.48	0.00	379.76

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Ammonia Tank
City:	Kalama
State:	Washington
Company:	NWIW
Type of Tank:	Horizontal Tank
Description:	Tank to provide 25% aqueous ammonia to SCR systems for controlling NOx emissions from the reformer heaters and boilers at KMMEF.

Tank Dimensions

Shell Length (ft):	30.00
Diameter (ft):	7.50
Volume (gallons):	9,000.00
Turnovers:	162.00
Net Throughput(gal/yr):	1,458,028.00
Is Tank Heated (y/n):	N
Is Tank Underground (y/n):	N

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Portland, Oregon (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Ammonia Tank - Horizontal Tank
Kalama, Washington

		Daily Liquid Surf. Temperature (deg F)			Liquid Bulk Temp	Vapor Pressure (psia)			Vapor Mol.	Liquid Mass	Vapor Mass		
Mixture/Component	Month	Avg.	Min.	Max.	(deg F)	Avg.	Min.	Max.	Weight.	Fract.	Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Aqueous Ammonia 25%	All	55.06	50.48	59.64	53.57	5.4585	4.8175	6.0995	35.0500			35.05	

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

Ammonia Tank - Horizontal Tank
Kalama, Washington

Annual Emission Calcaulations	
Standing Losses (lb):	855.5980
Vapor Space Volume (cu ft):	844.1780
Vapor Density (lb/cu ft):	0.0346
Vapor Space Expansion Factor:	0.1671
Vented Vapor Saturation Factor:	0.4796
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	844.1780
Tank Diameter (ft):	7.5000
Effective Diameter (ft):	16.9300
Vapor Space Outage (ft):	3.7500
Tank Shell Length (ft):	30.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0346
Vapor Molecular Weight (lb/lb-mole):	35.0500
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	5.4585
Daily Avg. Liquid Surface Temp. (deg. R):	514.7306
Daily Average Ambient Temp. (deg. F):	53.5542
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	513.2442
Tank Paint Solar Absorptance (Shell):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	1,113.3533
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.1671
Daily Vapor Temperature Range (deg. R):	18.3136
Daily Vapor Pressure Range (psia):	1.2819
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	5.4585
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	4.8175
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	6.0995
Daily Avg. Liquid Surface Temp. (deg R):	514.7306
Daily Min. Liquid Surface Temp. (deg R):	510.1522
Daily Max. Liquid Surface Temp. (deg R):	519.3090
Daily Ambient Temp. Range (deg. R):	18.0750
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.4796
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	5.4585
Vapor Space Outage (ft):	3.7500
Working Losses (lb):	2,336.8567
Vapor Molecular Weight (lb/lb-mole):	35.0500
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	5.4585
Annual Net Throughput (gal/yr.):	1,458,028.0000
Annual Turnovers:	162.0031
Turnover Factor:	0.3518

Tank Diameter (ft):	7.5000
Working Loss Product Factor:	1.0000
Total Losses (lb):	3,192.4547

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

Ammonia Tank - Horizontal Tank
Kalama, Washington

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Aqueous Ammonia 25%	2,336.86	855.60	3,192.45

APPENDIX C: BEST AVAILABLE CONTROL TECHNOLOGY ANALYSES

Prepared for:

Northwest Innovation Works LLC
Kalama, Washington

Prepared by:

Ramboll Environ US Corporation
Lynnwood, Washington

February 2016

Project Number:
29-36153A

BEST AVAILABLE CONTROL TECHNOLOGY

KALAMA MANUFACTURING AND MARINE EXPORT FACILITY

RAMBOLL ENVIRON

CONTENTS

LIST OF TABLES

ATTACHMENTS

1. INTRODUCTION

Northwest Innovation Works, Kalama LLC (NWIWK) and the Port of Kalama (Port) propose to construct and operate a methanol manufacturing and marine export facility (the Facility) on approximately 90 acres at the Port's Northport site, in Cowlitz County near Kalama, Washington. The Facility will be called the Kalama Manufacturing and Marine Export Facility (KMMEF). At full capacity, the facility will produce approximately 10,000 metric tons (mt) of AA-grade methanol per day and approximately 3.6 million mt per year.

Because Cowlitz County is within the jurisdiction of the Southwest Clean Air Agency (SWCAA), the proposed Facility must comply with regulations adopted by that agency, as applicable. As a new source of air pollutants, the proposed Facility must file an application for an Air Discharge Permit (ADP) with SWCAA. Construction of the Facility cannot commence until SWCAA[1] issues an ADP. Because the area in which the Facility will be located is in attainment of all applicable ambient air quality standards, or unclassifiable, to obtain these permits, the proposed Facility must comply with the requirements for new sources in attainment or unclassifiable areas in SWCAA 400-113.

Among the requirements for new sources in attainment or unclassifiable areas is the requirement that the proposed new source employ Best Available Control Technology (BACT) for all pollutants. NWIW has retained Ramboll Environ US Corporation (Ramboll Environ) to prepare this BACT analysis in support of the ADP permit application developed for KMMEF.

1.1 Project Description

Methanol will be manufactured at the Facility using a methane reforming process that converts natural gas and water to a synthesis gas, or "syngas," comprised primarily of hydrogen (H_2), carbon monoxide (CO), and carbon dioxide (CO_2). The technology used to create the syngas is a two-step process. In the first step, saturated, de-sulfurized natural gas and steam are combined and passed through catalyst-filled tubes, where an endothermic reaction converts some of the feedstock to syngas. The partially reformed gas is then sent to an auto-thermal reformer (ATR), where oxygen is added and passed over another catalyst to create more

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[1] SWCAA Regulation 400-110(2)(a)

syngas in an exothermic reaction. The hot, fully-reformed syngas is sent to the gas-heated reformer (GHR), which heats the catalyst-filled tubes where the initial, endothermic, syngas reforming reaction took place. The syngas is synthesized and distilled to produce nearly pure methanol, which is stored on site until it is transferred to marine vessels for export.

The Facility will have two methanol production lines, each with the capacity to produce approximately 5,000 mt per day. The production lines are designed to operate on a nearly continuous basis; the only planned shutdown is when the catalysts used to create syngas are deactivated to the point where they must be replaced, which is expected to occur every four or five years. Inevitably, there will be other shutdowns, but the frequency and duration will be kept to a minimum to maximize production.

Equipment with the potential to emit air contaminants (and are required to employ BACT) are:

- Three gas-fired package boilers, each with a maximum nominal heat input capacity of 530 MMBtu/hr;
- Two natural gas-fired process heaters, each with a maximum nominal heat input capacity of 82 MMBtu/hr;
- One power generation unit that will consist of two natural gas-fired combined-cycle combustion turbines (CCCTs), two once-through steam generators (OTSGs) with supplemental firing capability, and one steam turbine;
- One cooling tower with 12 cells;
- One flare with a natural gas-fired pilot;
- Two crude methanol storage tanks (internal floating roof);
- Four shift methanol storage tanks (internal floating roof);
- Eight product methanol storage tanks (fixed roof);
- One marine vessel methanol loading operation;
- Two nominal 3.5 megawatt-capacity diesel-fueled emergency generators;
- One nominal 1,600 horsepower-capacity diesel-fueled emergency fire water pump; and

- Piping, valves, connectors, pumps, compressors, and other components to move natural gas, methanol, and intermediates throughout the facility.

1.2 BACT Review Process

BACT, as it applies to regulated pollutants not subject to major new source review, is defined in WAC 173-400-030 as:

"…an emission limitation based on the maximum degree of reduction for each air pollutant subject to regulation under chapter 70.94 RCW emitted from or which results from any new or modified stationary source, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. "

An almost identical definition of BACT, as applied to sources located in attainment areas and subject to major new source review, appears in 40 CFR 52.21 (the PSD regulations, adopted by reference in WAC 463-78-005).

In a December 1, 1987 memorandum from the U.S. Environmental Protection Agency (USEPA) Assistant Administrator for Air and Radiation, the agency provided guidance on the "top-down" methodology for determining BACT. The "top-down" process involves the identification of all applicable control technologies according to control effectiveness. Evaluation begins with the "top," or most stringent, control alternative. If the most stringent option is shown to be technically or economically infeasible, or if environmental impacts are severe enough to preclude its use, then it is eliminated from consideration and then the next most stringent control technology is similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by technical or economic considerations, energy impacts, or environmental impacts. The top control alternative that is not eliminated in this process becomes the proposed BACT basis.

This top-down BACT analysis process can be considered to contain five basic steps:

- Step 1: Identify all available emission reduction alternatives with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;

- Step 2: Eliminate all technically infeasible alternatives;
- Step 3: Rank remaining alternatives by effectiveness;
- Step 4: Evaluate the economic, energy, and environmental impacts starting with the most effective alternative; and
- Step 5: Select BACT, which will be the most effective practical alternative not rejected in the previous steps.

Formal use of these steps is not always necessary. However, USEPA, Ecology, and SWCAA have consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which USEPA 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 technologies: i.e., those that 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” contained in the record of the permit decisions.

Additionally, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate no less stringent than the applicable New Source Performance Standard (NSPS) emission rate, if any NSPS standard for that pollutant is applicable to the source.

This BACT analysis was conducted in a manner consistent with this stepwise approach. Control options for potential reductions in criteria pollution emissions were identified for each emission unit. These options were identified by researching the EPA database known as the RACT/BACT/LAER Clearinghouse (RBLC), drawing upon previous environmental permitting experience for similar units, a review of available regulatory agency[2] BACT guidelines, and surveying available literature. Available controls that are judged to be technically feasible are further evaluated based on an analysis of economic, environmental, and energy impacts.

Assessing the technical feasibility of emission control alternatives is discussed in EPA's draft "New Source Review Workshop Manual." Using terminology from this manual, if a control technology has been "demonstrated" successfully for the type

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[2] Including the Texas Commission on Environmental Quality (TCEQ), the Bay Area Air Quality Management District (BAAQMD), the South Coast Air Quality Management District (SCAQMD), and the Massachusetts Department of Environmental Protection (MassDEP)

of emission unit under review, then it would normally be considered technically feasible. For an undemonstrated technology, “availability” and “applicability” determine technical feasibility. An available technology is one that is commercially available; meaning that it has advanced through the following steps:

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

Suitability for consideration as a BACT measure involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission unit), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission unit may not be applicable to a similar unit, depending on differences in the gas streams’ physical and chemical characteristics.

2. GAS-FIRED BOILERS

Each of the two production lines at the facility will employ a boiler (with a third unit held in reserve) to generate steam for the methane reforming process that converts natural gas and water to the syngas ultimately used to produce methanol. The boilers will combust natural gas and process off-gases to generate the heat needed to produce steam.

Pollutant emissions from the boilers include oxides of nitrogen (NO_X), particulate matter (PM), including PM less than 10 microns (PM_{10}) and PM less than 2.5 microns ($PM_{2.5}$), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOCs), and toxic air pollutants (TAPs).

2.1 Identify Commercially-Available Emission Reduction Alternatives

Review of the federal RBLC database, recent BACT determinations, and other emission reduction information indicates that the following emission reduction alternatives are available for reducing pollutants emitted by gas-fired boilers:

- Good Combustion Practices (GCPs),
- Oxidation Temperature Minimization (OTM),
- Low-NO_X Burners (LNBs),
- Selective Non-Catalytic Reduction (SNCR),
- Selective Catalytic Reduction (SCR),
- Non-Selective Catalytic Reduction (NSCR),
- Oxidation Catalysts,
- EMx,
- Low-Sulfur Fuels,
- Cyclone Separator,
- Electrostatic Precipitator (ESP),
- Fabric Filter,
- Wet Collector, and
- Flue Gas Desulfurization (FGD).

2.1.1 Combustion Controls

Techniques that seek to influence the combustion process and, thereby, prevent the formation of a given pollutant, are referred to as “combustion controls.”

2.1.1.1 Good Combustion Practices

GCPs include combustor design elements and operational strategies intended to control the amount and distribution of excess air in the combustion zone to ensure that enough oxygen is present for complete combustion.

2.1.1.2 Oxidation Temperature Minimization

Techniques intended to reduce NO_X emissions by reducing oxidation temperatures in the combustion zone include flue gas recirculation (FGR), staged combustion, overfire air injection (OFA), and water/steam injection. All of these practices seek to limit the creation of NO_X by limiting peak combustion temperatures and/or controlling the mixture of oxygen and fuel. FGR employs both mechanisms, because introducing cooled flue gas into the combustion zone reduces the temperature of the combustion zone by absorbing heat, and the relatively oxygen-poor flue gas also reduces the oxygen content in the combustion zone. Staged combustion and OFA injection are similar techniques that both restrict the amount of oxygen available at the start of the combustion process by providing too little combustion air, and then introducing additional air later. By limiting the availability of oxygen to the fuel, combustion temperatures and NO_X creation are both reduced. Water or steam injected into the combustion zone absorbs heat, which reduces the flame temperature, and, therefore, NO_X creation. Because CO and VOC emissions are minimized by high temperatures and oxygen/fuel interaction, these techniques tend to increase CO and VOC emissions.

2.1.1.3 Low-NO_X Burners

LNBs are similar to the oxidation temperature minimization techniques described above, but the staged combustion of fuel that controls NO_X formation is accomplished through burner design rather than manipulating combustion in the furnace. The design controls both the stoichiometry and temperature of combustion by tuning the fuel and air locally within each individual burner’s flame envelope. Burner design includes features that regulate the aerodynamic distribution and mixing of the fuel and air. A lean, pre-mixed burner design mixes the fuel and air prior to combustion. This results in a homogeneous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_X emissions. A lean fuel-to-air ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower the combustion temperature, which in turn lowers thermal NO_X formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment. LNBs that feature an FGR system integrated into the burner design, which further minimizes flame temperatures and oxygen availability, are often referred to as ultra-low NO_X burners (ULNBs).

2.1.1.4 Low-Sulfur Fuel

This technique seeks to limit the quantity of sulfur introduced to the combustion system. Unlike the formation of NO_X, which can be mitigated through combustion controls, the potential for SO_2 emissions is entirely dependent upon the quantity of sulfur present in the fuel. Sulfur compounds in fuel readily oxidize at combustion temperatures to form SO_2 (as well as some SO_3). Minimizing the sulfur content of the fuel combusted, either by selecting a fuel that naturally contains little sulfur, or one that has been processed to remove sulfur, is a popular method for reducing SO_2 emissions. In addition, sulfur in fuel has been shown to contribute to fine particulate emissions. Therefore, controlling or minimizing the sulfur content of the fuel will also minimize PM emissions.

2.1.2 Add-On Controls

Control alternatives that involve adding equipment designed to remove or transform a given pollutant after it has been created are referred to as “add-on controls.”

2.1.2.1 Selective Non-Catalytic Reduction

In the SNCR process, ammonia is mixed with the exhaust from the combustion device and the NO_X in the exhaust reacts with the introduced ammonia to form nitrogen (N_2) and water (H_2O). The reagent, which can be anhydrous ammonia (NH_3), aqueous ammonia, or urea dissolved in water, is typically injected at the exit of the furnace to mix with the hot flue gases. The success of this process in reducing NO_X emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas. This must occur within a zone of the exhaust stream where the flue gas temperature is within a range, typically from 1,600°F to 2,200°F. In order to achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 second. The consequences of operating outside the optimum temperature range are severe. Within the temperature range, the reagent will be converted to NO_X. At temperatures less than that range, the reagent will not react with the NO_X

and significant quantities of will NH_3 discharge from the stack (known as "ammonia slip").

2.1.2.2 Selective Catalytic Reduction

The SCR process is similar to SNCR, in that a reagent (usually NH_3) reacts with NO_X to form N_2 and H_2O, but a catalyst matrix is used to allow the reduction reaction to take place at reduced temperatures compared to SNCR (i.e., 600 to 700ºF for SCR, as opposed to 1,600 to 2,200ºF for SNCR).

2.1.2.3 Non-Selective Catalytic Reduction

NSCR uses a catalyst to reduce NO_X, CO, and hydrocarbons (HCs) to N_2, CO_2, and H_2O. Because the CO and HCs will more readily react with O_2 than NO_X, there must be little O_2 in the exhaust (between 0.5 and 4 percent, depending upon the system). Excess oxygen is removed by the catalyst or, in some designs, an afterburner, which necessitates injecting additional hydrocarbons (i.e., natural gas) to act as the reducing agent.

2.1.2.4 Oxidation Catalysts

Catalytic oxidation does not rely on the introduction of additional chemical reagents to promote the desired reactions. The activation energy required for the oxidation reaction between O_2, CO, and VOCs to proceed is reduced in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. The catalyst oxidizes CO to CO_2, and VOCs to CO_2 and H_2O, but it also can promote other, less desirable, oxidation reactions such as NH_3 to NO_X and SO_2 to SO_3. Consequently, the presence of an oxidation catalyst can cause emissions of other pollutants to increase, and therefore its design needs to be carefully considered.

2.1.2.5 EMx

The EMx (formerly SCONOx) system is an add-on control device that reduces emissions of multiple pollutants. EMx control technology is provided by Emerachem, LLC (formerly Goal Line Environmental Technologies). EMx utilizes a single catalyst for the reduction of CO, VOC and NO_X, which are converted to CO_2, H_2O and N_2. The system does not use NH_3, and operates most effectively at temperatures ranging from 300°F to 700°F. Operation of EMx requires natural gas, water, steam, electricity and ambient air, and no special reagent chemicals or processes are necessary. Steam is used periodically to regenerate the catalyst bed and is an integral part of the process.

2.1.2.6 Cyclone Separator

A cyclone separator, also called simply a “cyclone,” employs centrifugal force generated by spinning a gas stream in a cylindrical chamber. Because cyclone operating costs and collection efficiency of fine PM are low, they are often used to remove larger particulate matter before the exhaust reaches the primary control device (e.g., ESP, fabric filter).

2.1.2.7 Electrostatic Precipitator

ESPs remove PM from an exhaust stream by imposing an electrical charge on the particles and then attracting them to an oppositely charged plate. The dust collected on the charged plates is periodically removed by vibrating or rapping of the plates.

2.1.2.8 Fabric Filter

Also referred to as “baghouses,” fabric filters use various types of materials (generally fabrics) to trap PM while the gas passes through the voids in the material. The dust that becomes caked on the fabric bags is removed periodically by shaking, by blowing jets of air, or by using sonic horns.

2.1.2.9 Wet Collector

Wet collectors use a liquid, typically water, to capture PM or to increase the size of aerosol to facilitate capture in another control device. Configurations include spray chambers (with or without impingement baffles), wet cyclones, and venturi scrubbers. They tend to complicate disposal of the collected PM by introducing liquids that create sludge, though, in some cases, a sludge is easier to handle than dry dust.

2.1.2.10 Flue Gas Desulfurization

The FGD or SO_2 scrubbing process typically uses a calcium- or sodium-based alkaline reagent. The reagent is injected in the flue gas in a spray tower or directly into the exhaust duct. The SO_2 is absorbed, neutralized and/or oxidized by the alkaline reagent into a solid compound, either calcium or sodium sulfate. The solid is removed from the waste gas stream using downstream equipment.

FGDs are classified as “once-through” or “regenerable”, based on how the solids generated by the process are handled. Once-through systems either dispose of the spent sorbent as a waste or utilize it as a byproduct. Regenerable systems recycle the sorbent back into the system. Regenerable process systems typically have higher costs than once-through systems; however, regenerable processes might be chosen if space or disposal options are limited and markets for the byproduct (i.e., gypsum) are available.

2.2 Eliminate Technically Infeasible Alternatives

In this section, the technical feasibility of each of the emission reduction alternatives identified in the previous section is considered. In the following sections, alternatives determined to be technically feasible, as well as combinations of feasible alternatives, will be ranked and evaluated for each pollutant for which BACT is required.

2.2.1 Good Combustion Practices

GCPs are a technically feasible method of controlling CO, VOC, and, to some extent, PM emissions from the proposed boilers, and are considered a baseline emission reduction technique.

2.2.2 Oxidation Temperature Minimization

Oxidation temperature minimization (OTM) techniques are considered technically feasible alternatives for reducing NO_X emissions from the boilers.

2.2.3 Low-NO_X Burners

LNBs and ULNBs are commonly employed to reduce NO_X emissions from gas-fired boilers, and are considered technically feasible.

2.2.4 Low-Sulfur Fuels

Natural gas, the feedstock used to produce methanol, will be available at the facility and is considered a low sulfur fuel. The boilers will combust natural gas and process off-gases that will have been through a desulfurization process; as a result, the sulfur content of the fuel combusted by the boilers will even less by volume than that of pipeline natural gas. Use of low-sulfur fuels to reduce SO_2 emissions is considered technically feasible.

2.2.5 Selective Non-Catalytic Reduction

As noted above, SNCR requires flue gas temperatures in the range of 1,600 to 2,200 F, which is common in industrial boilers. SNCR is considered technically feasible for reducing NO_X emissions from the proposed boilers.

2.2.6 Selective Catalytic Reduction

SCR is commonly employed to reduce NO_X emissions from most gaseous combustion operations, and is considered technically feasible for the proposed boilers.

2.2.7 Non-Selective Catalytic Reduction

Exhaust from the proposed boilers will not be the low-oxygen, fuel-rich exhaust stream that an NSCR system requires. In addition, there is no evidence that such a system has ever been employed to reduce emissions from an external gaseous combustion device. At one time, the technology was used to reduce process (not combustion) NO_X emissions from adipic and nitric acid plants, but it has fallen out of favor for economic reasons. NSCR is currently used in some cases to reduce NO_X emissions from reciprocating internal combustion engines, which can run under stoichiometric or fuel-rich conditions. NSCR is not technically feasible for the proposed boilers.

2.2.8 Oxidation Catalysts

Catalytic oxidation is technically feasible for reducing CO and VOC emissions from the proposed boilers.

2.2.9 EMx

There are currently several EMx units in commercial installations worldwide, although all are applied to small combustion turbines. The original application of EMx was at the Federal Plant in Vernon, California, owned by Sunlaw Cogeneration. This installation was on a GE LM2500, an approximately 34 megawatt (MW) combined-cycle system, and has been in operation since December 1996. The system has undergone many changes over the years.

The second commissioning of an EMx system was at the Genetics Institute in Massachusetts on a 5 MW Solar Turbine Taurus 50 Model. This facility has reported problems with meeting permitted NO_X levels of 2.5 parts per million (ppm), and subsequently received a permit modification extending the EMx demonstration period. Three other units were installed in recent years: two on 13 MW Solar Titan combustion turbines at the University of California, San Diego, and one on an 8 MW Allison combustion turbine at Los Angeles International Airport.

EMx was considered at some larger applications including a 250 MW unit at the La Paloma plant near Bakersfield and a 510 MW plant in Otay Mesa. However, the La Paloma and Otay Mesa projects have installed SCR systems instead.

The EMx technology has not been demonstrated for a large gas-fired boiler. The technical and capacity differences between the proposed boilers and the few emission units to which EMx has been demonstrated in practice result in a determination that EMx is technically infeasible for reducing emissions from the proposed boilers, and is removed from consideration as BACT.

2.2.10 Cyclone Separator

Combustion processes produce PM as unburned solid carbon (soot), unburned vapors or gases that subsequently condense, and the unburnable portion of the fuel (ash). Because gaseous fuels contain little or no ash, and a burner operated with GCPs combusting gaseous fuels typically does not generate much soot, the majority of the PM resulting from combusting gaseous fuel is condensed unburnt fuel or combustion products. Source tests conducted on gas-fired external combustion devices indicate that the filterable portion of particulate, which is the portion a cyclone would be capable of capturing, comprises a quarter or less of the total. Furthermore, filterable particulate from gaseous combustion is typically less than one micron in size,[3] and cyclones are not efficient at capturing particles of that size. A cyclone separator would be ineffective at controlling PM generated by the proposed boilers, and is therefore considered technically infeasible and is removed from consideration as BACT.

2.2.11 Electrostatic Precipitator

In an ESP, an electric field is used to impart a charge on particles suspended in the flue gas. The charged particles migrate to charged plates where they are collected. The low particulate concentration produced by gaseous fuel combustion would not allow significant charge buildup on the particles, resulting in poor migration to the

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[3] US EPA AP-42 Section 1.4 – Emission Factors for Natural Gas Combustion (http://www.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf)

collecting plates. Therefore, ESPs are considered technically infeasible and removed from consideration as BACT controlling PM emitted by the proposed boilers.

2.2.12 Fabric Filter

In a fabric filter, or baghouse, flue gas is passed through a tightly woven or felted fabric, causing PM present in the gas to be collected on the fabric and previously collected particulate (called the “filter cake”) by sieving and other mechanisms. Most of the particle collection is performed by the filter cake. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group.

Source tests conducted on gas-fired external combustion units indicate that the filterable portion of particulate comprises a quarter or less of the total. The condensable portion, the majority of the PM present in the flue gas, will not be collected by a fabric filter. Also, due to the low particulate concentration, the filter cake will be slow to form (assuming one forms at all), resulting in poor collection efficiency.

To capture the volatile compounds that will become condensable PM, the gas stream would need to be cooled before reaching the baghouse. However, cooling would result in condensation of acids, which would cause the filter media and baghouse structure to corrode. Low collection efficiency, additional costs associated with cooling the flue gas, and small particle size combine to make implementation of a baghouse to control PM generated by the proposed boilers technically infeasible, and this technology is removed from consideration as BACT.

2.2.13 Wet Collector

Wet collection depends on the inertia of particles suspended in flue gas to impact, and be collected by, a scrubbing liquid. However, the fine particles generated by gaseous fuel combustion (less than one micron in size) have little inertia, so the particles tend to follow the gas stream rather than impacting and being collected by the scrubbing liquid. Therefore, wet scrubbers are not a suitable control technology for application to the proposed boilers, and are eliminated from consideration as BACT based on technical infeasibility.

2.2.14 Flue Gas Desulfurization

There are no instances of FGD, or any other add-on control technology, having been used to reduce SO_2 in exhaust from any gas-fired combustion unit. While this technology has been proven effective at removing SO_2 from large coal-fired boiler exhaust, it has never been demonstrated on gas-fired boilers such as those proposed. As a result, this technology is considered technically infeasible, and is removed from consideration as BACT.

2.3 NO_X BACT

Several of the alternatives identified in the previous section are commercially available combustion and post-combustion techniques which are capable of reducing NO_X emissions from a gas-fired boiler. These controls include GCPs, SNCR, OTM, LNBs, and SCR.

2.3.1 Ranking of Remaining Alternatives

In top-down order of decreasing stringency, the feasible NO_X reduction techniques are listed with the approximate emission factor achieved by each alternative or combination of alternatives:[4]

- LNBs with OTM, SCR, and GCPs – 4 ppm (equivalent to ~0.005 lb/MMBtu)
- LNBs with OTM and GCPs – 0.037 lb/MMBtu (equivalent to ~30 ppm)
- LNBs with GCPs – 0.05 lb/MMBtu (equivalent to ~40 ppm)
- Conventional Burners with SNCR and GCPs – 0.05 lb/MMBtu (equivalent to ~40 ppm)
- Conventional Burners with GCPs – 0.1 lb/MMBtu (equivalent to ~80 ppm)

2.3.2 Consideration of Energy, Environmental and Cost Factors

The boilers proposed for the project will achieve the most stringent emission level (4 ppm), and, therefore, energy, environmental, or cost were not considered.

2.3.3 Proposed BACT Limits and Control Option

An exhaust concentration of 4 ppm (approximately 0.005 lb/MMBtu) is proposed as BACT for NO_X emissions from the proposed gas-fired boilers, achieved using LNBs, OTM, SCR, and GCPs.

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[4] Reduction strategies that rely on combustion zone temperature reduction (i.e., oxidation temperature minimization and low-NOX burners) are not compatible with SNCR, so those combinations are not considered.

2.4 CO and VOC BACT

The only post-combustion control available for reducing emissions of CO and VOCs emitted by the proposed boilers is an oxidation catalyst module. Based on the RBLC review presented in Attachment A, the range of BACT CO emission limits for recently permitted natural gas-fired boilers (since 2005) is from 0.037 lb/MMBtu to 0.08 lb/MMBtu, and the range for VOCs is 0.0044 lb/MMBtu to 0.0054 lb/MMBtu. BACT for CO and VOCs on most units in the RBLC is GCP.

2.4.1 Ranking of Remaining Alternatives

The identified control technologies, GCP and oxidation catalyst, are considered technically feasible for gaseous fuel fired boilers. In top-down order of decreasing stringency, the feasible CO and VOC controls are listed with the approximate level of control that could be achieved:

- For CO:
    - Oxidation Catalyst and GCP – 5 ppm (equivalent to ~0.0037 lb/MMBtu)
    - GCP – 50 ppm (equivalent to ~0.037 lb/MMBtu)
- For VOCs:
    - Oxidation Catalyst and GCP – 6 ppm (equivalent to ~0.0025 lb/MMBtu)
    - GCP – 12 ppm (equivalent to ~0.005 lb/MMBtu)

2.4.2 Consideration of Energy, Environmental and Cost Factors

The only non-baseline emission reduction alternative is the use of an oxidation catalyst to reduce emissions of both CO and VOCs. Using equations from the 6th Edition of the EPA Air Pollution Control Cost Manual, an oxidation catalyst would have an annual cost of approximately $627,000, and would eliminate approximately 83.4 tons of combined CO and VOC emissions per year, for a cost effectiveness of approximately $7,500 per ton. A review of the RBLC indicates that this cost-effectiveness is excessive for control of CO and VOCs, and is removed from consideration as BACT. However, NWIWK will employ oxidation catalysts to reduce CO emissions from the boiler, despite this alternative not being considered BACT. Detailed cost effectiveness calculations are provided in Attachment B.

2.4.3 Proposed BACT Limits and Control Option

Exhaust concentrations of 5 ppm (0.0037 lb/MMBtu) and 6 ppm (0.0025 lb/MMBtu) are proposed as BACT for CO and VOCs, respectively, to be achieved by employing oxidation catalysts and GCPs.

2.5 PM and SO_2 BACT

This BACT analysis assumes that all PM emissions from the proposed boilers are $PM_{2.5}$, and that the PM, PM_{10}, and $PM_{2.5}$ emission rates are all equivalent. Any reference to PM emissions in this BACT analysis represents all definitions of particulate matter emissions: PM, PM_{10}, and $PM_{2.5}$.

2.5.1 Ranking of Remaining Alternatives

For these pollutants, the commercially-available control measures that are identified in the most-stringent BACT determinations are use of low-sulfur, pipeline natural gas, and GCP. Based on review of the RBLC database, a summary of which is presented in Attachment A, add-on controls were not implemented to achieve BACT limits for these pollutants. The ranges of BACT emission limits for these pollutants are:

- SO_2 – 0.0006 lb/MMBtu to 0.082 lb/MMBtu
- PM – 0.0044 lb/MMBtu to 0.0075 lb/MMBtu

The two most-stringent available technologies are to be adopted for the proposed boilers, so further evaluation is unnecessary.

2.5.2 Proposed BACT Limits and Control Option

The use of pipeline natural gas and GCPs are proposed as BACT for PM and SO_2 emissions from the gas-fired boiler. Boiler vendor information indicates that the hourly average PM emission factor will be 0.0075 lb/MMBtu, and mass balance calculations based on the sulfur content of the expected source of natural gas indicates that the daily average SO_2 emission factor will be approximately 0.0070 lb/MMBtu. However, NWIWK does not propose that these emission factors be used as numeric permit limits. Instead, BACT should be considered the use of pipeline natural gas and GCPs.

The boiler will combust primarily process offgas that results from a natural gas feedstock that has been desulfurized to a maximum of 30 parts per billion (ppb) to protect the process catalysts from poisoning. As a result, SO_2 and PM emissions attributable to the proposed boilers are expected to be less than would be achieved by applying BACT. However, NWIWK does not propose that combusting desulfurized natural gas or desulfurized process offgas is BACT for gas-fired boilers.

2.6 BACT During Startup and Shutdown

During startup and shutdown, NO_X, CO, and VOC concentrations in the exhaust have the potential to exceed those experienced under normal operation for brief periods. This is a characteristic of all combustion devices because optimum combustion conditions are not achieved immediately after startup or shutdown commences. During startup and shutdown it is not technologically feasible to meet NO_X, CO, or VOC BACT limits that are specified on the basis of normal boiler operation. NWIWK proposes that, during startup and shutdown periods, BACT for NO_X, CO, and VOCs is to limit the frequency and duration of startups, shutdowns, and periods of upset through the implementation of best practices and training.

3. PROCESS HEATERS

As described in Section 1.1, the heat created in the ATR during the second step of the reforming process is used to heat the first step of the reforming process in the GHR, which provides the partially-reformed gases that react exothermically in the ATR. With the addition of natural gas, steam, and oxygen, this arrangement is essentially self-sustaining, but an external heat source is required to initiate the process. Each methanol production line will have a dedicated process heater to provide the heat needed during startup.

Because new catalysts must be de-oxygenated with nitrogen, the duration of the initial startup is expected to between 76 and 88 hours. Of that, the process heater will operate between 25 and 90 percent load for approximately 64 to 76 hours. These long-duration starts with fresh catalyst are expected to occur once every 4 to 5 years, depending on the life of the catalysts. With an already de-oxygenated catalyst, approximately 40 hours are required to start a production line, with the process heater operating between 25 and 90 percent load for approximately 28 of the 40 hours.

It is likely that the process heater will also be used during an orderly shutdown to maximize the quantity of methanol produced and minimize the quantity of intermediate gases that must be sent to the flare. In a hypothetical worst-case year, which would include one initial startup lasting 80 hours and six “normal” startups and shutdowns, the process heater would operate approximately 260 hours (just less than 11 days).

3.1 Identify Commercially-Available Emission Reduction Alternatives

Emission reduction alternatives available for reducing pollutants emitted by the natural gas-fired process heater are identical to those listed in the Section 2.1 as potentially available for the gas-fired boilers.

3.2 Eliminate Technically Infeasible Alternatives

The technical feasibility determinations for each of the emission reduction alternatives are the same as those presented in Section 2.2 for the gas-fired boilers.

3.3 NO_X BACT

Several of the alternatives identified in the previous section are commercially available combustion and post-combustion techniques which are capable of reducing NO_X emissions from a natural gas-fired process heater. These controls include GCPs, OTM, and LNBs.

3.3.1 Ranking of Remaining Alternatives

In top-down order of decreasing stringency, the feasible NO_X reduction techniques are listed with the approximate emission factor achieved by each alternative or combination of alternatives:[5]

- LNBs with OTM, SCR, and GCPs – 0.005 lb/MMBtu (equivalent to ~5 ppm)
- LNBs with OTM and GCPs – 0.010 lb/MMBtu (equivalent to ~9 ppm)
- LNBs with GCPs – 0.016 lb/MMBtu (equivalent to ~15 ppm)
- Conventional Burners with OTM and GCPs – 0.032 lb/MMBtu (equivalent to ~30 ppm)
- Conventional Burners with SNCR – 0.045 lb/MMBtu (equivalent to ~42 ppm)
- Conventional Burners with GCPs – 0.091 lb/MMBtu (equivalent to ~85 ppm)

3.3.2 Consideration of Energy, Environmental and Cost Factors

The addition of LNBs and/or OTM techniques would have minimal energy and environmental factors. Annualized cost analyses were developed for the five non-baseline alternatives to evaluate the cost effectiveness of each:

- SNCR is expected to cost in excess of approximately $227,000 per ton of NO_X reduced,
- Flue gas recirculation (FGR), an OTM technique, is expected to cost approximately $7,500 per ton,
- Using LNBs instead of baseline burners is expected to cost approximately $66,000 per ton,
- Employing both FGR and LNBs is expected to cost just less than $66,000 per ton, and

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[5] Reduction strategies that rely on combustion zone temperature reduction (i.e., oxidation temperature minimization and low-NO_X burners) are not compatible with SNCR, so those combinations are not considered.

- SCR, combined with FGR and LNBs is expected to cost more than \$183,000 per ton

Detailed cost effectiveness calculations are provided in Attachment B.

3.3.3 Proposed BACT Limits and Control Option

An exhaust concentration of 30 ppm (approximately 0.032 lb/MMBtu) is proposed as BACT for NO_X emissions from the proposed process heaters, achieved using OTM (specifically, FGR) and GCPs.

3.4 CO and VOC BACT

Based on the RBLC review presented in Attachment C, the range of BACT CO emission limits for recently permitted natural gas-fired boilers (since 2005) is from 0.037 lb/MMBtu to 0.08 lb/MMBtu, and the range for VOCs is 0.0044 lb/MMBtu to 0.0054 lb/MMBtu. BACT for CO and VOCs on most units in the RBLC is GCP.

3.4.1 Ranking of Remaining Alternatives

Only GCPs are considered technically feasible for the process startup heaters. Because there is a single alternative, no ranking of alternatives is possible.

3.4.2 Consideration of Energy, Environmental and Cost Factors

The process startup heaters will employ the most stringent emission reduction technique for CO and VOCs, and, therefore, energy, environmental, or cost were not considered.

3.4.3 Proposed BACT Limits and Control Option

Exhaust concentrations of 5 ppm (0.00325 lb/MMBtu) and 14 ppm (0.0052 lb/MMBtu) are proposed as BACT for CO and VOCs, respectively, to be achieved by employing GCPs.

3.5 PM and SO_2 BACT

This BACT analysis assumes that all PM emissions from the proposed boilers are $PM_{2.5}$, and that the PM, PM_{10}, and $PM_{2.5}$ emission rates are all equivalent. Any reference to PM emissions in this BACT analysis represents all definitions of particulate matter emissions: PM, PM_{10}, and $PM_{2.5}$.

3.5.1 Ranking of Remaining Alternatives

For these pollutants, the commercially-available control measures that are identified in the most-stringent BACT determinations are use of low-sulfur, pipeline natural gas, and GCP. Based on review of the RBLC database, a summary of which is presented in Attachment A, add-on controls were not implemented to achieve BACT limits for these pollutants. The ranges of BACT emission limits for these pollutants are:

- SO_2 – 0.0006 lb/MMBtu to 0.082 lb/MMBtu
- PM – 0.0044 lb/MMBtu to 0.0075 lb/MMBtu

The two most-stringent available technologies are to be adopted for the proposed boilers, so further evaluation is unnecessary.

3.5.2 Proposed BACT Limits and Control Option

The use of pipeline natural gas and GCPs are proposed as BACT for PM and SO_2 emissions from the gas-fired heater. Process heater vendor information indicates that the hourly average PM emission factor will be 0.0075 lb/MMBtu, and mass balance calculations based on the sulfur content of the expected source of natural gas indicates that the daily average SO_2 emission factor will be approximately 0.00725 lb/MMBtu. However, NWIWK does not propose that these emission factors be used as numeric permit limits. Instead, BACT should be considered the use of pipeline natural gas and GCPs.

3.6 BACT During Startup and Shutdown

The process heaters will be used only when the methanol production lines are being started up or shut down. The process heaters will be operated according to the specifications of the methanol production line designer with the primary goals of minimizing startup or shutdown time while preserving the effectiveness of the production equipment. However, it should be noted that the desire is for the Facility to be operated as near to continuously as possible, and only be shut down and restarted every four or five years when the catalysts are replaced.

4. POWER GENERATION UNIT

A PGU will be used to generate electricity that will be used to power one of the two proposed methanol production lines. The proposed PGU will consist of two natural gas-fired combined-cycle combustion turbines (CCCTs), each of which will be a combustion turbine paired with a power generator and a once-through steam generator (OTSG) that will include supplemental heating (i.e., a “duct burner”). The CCCTs will be GE LM6000-PF+, or equivalent. Steam from the two OTSGs will be sent to a single steam turbine that will turn a third power generator. The combustion turbines, as well as the duct burners, will be fueled exclusively by pipeline quality natural gas. Pollutant emissions from the PGU will include NO_X, PM, CO, SO_2, and VOCs.

4.1 Identify Commercially-Available Emission Reduction Alternatives

Review of the federal RBLC database and selected state permit information indicates that several emission reduction technologies have been identified in BACT determinations natural gas-fired combined cycle (NGCC) projects. Because the LM6000-PF+ units are “aero-derivative” combustion turbines (i.e., those adapted from aircraft engine designs), only projects with aero-derivative engines were considered. Projects that included heavy-duty industrial combustion turbines designed specifically to be power generation units were not considered.

The RBLC database survey results indicate that available BACT options for the pollutants emitted from the power generation unit include:

- Good Combustion Practices,
- Oxidation Temperature Minimization,
- Low-NO_X Burners,
- Selective Non-Catalytic Reduction,
- Selective Catalytic Reduction,
- Oxidation Catalysts,
- EMx,
- XONON,
- Low-sulfur fuels, and
- Flue Gas Desulfurization.

4.2 Eliminate Technically Infeasible Alternatives

4.2.1 Good Combustion Practices

GCPs include operational and combustor design elements to control the amount and distribution of excess air in the combustion zone to ensure that enough oxygen is present for complete combustion. GCPs are a technically feasible method of controlling CO and VOC emissions from CCCTs, and are considered a baseline control technology. Such control practices applied to the proposed CCCTs can achieve CO emission levels of 15 ppm during steady state, full load operation. At lower loads (50-70 percent), the combustion efficiency drops off notably, and CO emissions would be higher.

4.2.2 Low-NO_X Burners

Low-NO_X Burners (LNBs) burners use staged combustion to limit NO_X formation in CCCTs. This is accomplished by designing the burners to control both the stoichiometry and temperature of combustion by tuning the fuel and air locally within each individual burner's flame envelope. Burner designs include features that regulate the distribution and mixing of fuel and air, with are mixed prior to combustion. This results in a homogeneous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and increase NO_X emissions. A lean fuel-to-air ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower the combustion temperature, which in turn lowers thermal NO_X formation. A pilot flame is used to maintain combustion stability in the fuel-lean environment. LNBs are a technically feasible alternative for reducing NO_X emissions from CCCTs, and are considered a baseline control technology.

4.2.3 SNCR

Selective Non-Catalytic Reduction (SNCR) is a post-combustion NOX control technology in which a reagent (anhydrous NH_3 or urea) is injected into the exhaust gases to react chemically with NO_X, forming elemental nitrogen and water without the use of a catalyst. The success of this process in reducing NO_X emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas. This must occur within a zone of the exhaust stream where the flue gas temperature is within a narrow range, typically from 1,700°F to 2,000°F. In order to achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 second. The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to NO_X. Below the lower end of the temperature range, the reagent will not react with the NO_X and the NH_3 discharge from the stack (known as "ammonia slip") will be very high.

This technology is occasionally used in heaters or boilers upstream of any HRSG or heat recovery unit. SNCR has never been used in combustion turbine applications to control NO_X, primarily because there are no flue gas locations within the combustion turbine or upstream of the HRSG with the requisite temperature and residence time characteristics to facilitate the SNCR flue gas reactions. Because of the incompatibility of the exhaust temperature with the SNCR operating regime, this technology is considered to be technically infeasible and is removed from further consideration as BACT.

4.2.4 SCR

Selective Catalytic Reduction (SCR) is a technology that achieves post-combustion reduction of NO_X from flue gas within a catalytic reactor. The SCR process involves the injection of ammonia (NH_3) into the exhaust gas stream upstream of a specialized catalyst module, promoting conversion of NO_X to molecular nitrogen. The hardware of an SCR system is composed of an ammonia storage tank, an injection grid (system of nozzles that spray NH_3 into the exhaust gas ductwork), a structured, fixed-bed catalyst module, and electronic controls. SCR systems are commonly employed to reduce NO_X emissions from CCCTs.

In the SCR process, NH_3, usually diluted with air or steam, is injected through a grid system into the exhaust gas upstream of the catalyst bed. On the catalyst surface, the NH_3 reacts with NOX to form molecular nitrogen and water. The basic reactions are:

$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$

$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$

A fixed-bed catalytic reactor is typically used for SCR systems. The function of the catalyst is to lower the activation energy required for NO_X decomposition to occur. In a natural gas-fired turbine, NO_X removal of 90 percent or higher is theoretically achievable at optimum conditions. Key SCR performance issues focus on flue gas characteristics (temperature and composition), catalyst design, and ammonia distribution. Compounds such as sulfur and certain metals, if present in the exhaust gas stream, can “poison” the catalyst, impacting catalyst activity, inhibiting conversion efficiency, and reducing the useful life of the catalyst.

4.2.5 Oxidation Catalysts

Catalytic oxidation is a post-combustion technology, which does not rely on the introduction of additional chemical reagents to promote the desired reactions. The oxidation of CO to CO_2 utilizes excess air present in the combustion turbine exhaust, and the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. The catalyst oxidizes CO to CO_2, and VOCs to CO_2 and H_2O, but also can promote other oxidation reactions such as NH_3 to NO_X and SO_2 to SO_3. Consequently, the presence of a CO catalyst can cause emissions of other pollutants to increase, and therefore its design needs to be carefully considered.

Oxidation catalyst systems typically operate at temperatures between 750 to 1,100°F (400 to 600°C), and greater temperatures within that range generally result in more effective oxidation reactions. Typical CO to CO_2 conversion efficiencies from a CO oxidation catalyst are 80 to 90 percent, and typical VOC conversion efficiencies are 40 to 50 percent. This technology has been required CO and VOC control equipment in a significant number of permits for CCCT projects, and is considered technically feasible for application to a CCCT.

4.2.6 XONON

XONON is a technology developed by Catalytica Combustion Systems to lower the temperatures in conventional combustion turbine combustors, and, therefore, reduce NO_X formation. However, XONON has been demonstrated only on smaller combustion turbines (i.e., 1.5 MW), and has not yet been scaled up for use on larger combustion turbines such as the GE LM6000-PF+, or equivalent. As a result, XONON is not considered technically feasible for use on the proposed CCCTs, and is eliminated from further consideration as BACT.

4.2.7 EMx

The EMx (formerly SCONOx) system is an add-on control device that reduces emissions of multiple pollutants. EMx control technology is provided by Emerachem, LLC (formerly Goal Line Environmental Technologies). EMx utilizes a single catalyst for the reduction of CO, VOC and NO_X, which are converted to CO_2, H2O and N_2. The system does not use NH3 and operates most effectively at temperatures ranging from 300°F to 700°F. Operation of EMx requires natural gas, water, steam, electricity and ambient air, and no special reagent chemicals or processes are necessary. Steam is used periodically to regenerate the catalyst bed and is an integral part of the process.

There are currently several EMx units in commercial installations worldwide, although all are applied to emission units that are much smaller than those proposed for the KEC. The original application of EMx was at the Federal Plant in Vernon, California owned by Sunlaw Cogeneration. This installation was on a GE LM2500, an approximately 34 MW combined cycle system, which has had an operating EMx system since December 1996. That system has undergone many changes over the years. The second commissioning of an EMx system was at the Genetics Institute in Massachusetts on a 5 MW Solar Turbine Taurus 50 Model. This facility has reported problems with meeting permitted NOx levels of 2.5 ppm, and subsequently received a permit modification extending the EMx demonstration period. Three other units were installed in recent years, two on 13 MW Solar Titan combustion turbines at the University of California, San Diego, and one on an 8 MW Allison combustion turbine at Los Angeles International airport.

There is no current working experience of EMx on large combustion turbine units such as those proposed for the KEC. EMx was considered at some larger applications including a 250 MW unit at the La Paloma plant near Bakersfield, and a 510 MW plant in Otay Mesa. However, the La Paloma and Otay Mesa projects were given the alternative to install SCR and now plan to do so. In evaluating technical feasibility for large CCCT power stations, additional concerns were identified, which include the following:

- EMx uses a series of dampers to re-route air streams to regenerate the catalyst. The proposed NGCC units are significantly larger than the much smaller facilities where EMx has been used. This would require a significant redesign of the damper system, which raises feasibility concerns regarding reliable mechanical operation of the larger and more numerous dampers that would be required for application to the proposed combustion turbines.

- The EMx catalyst is very susceptible to poisoning by sulfur compounds. Because pipeline natural gas contains some sulfur, a separate catalyst system or filter may be required to absorb SO_2 before it could contact the catalyst bed. However, operation of such an SO_2 absorption system on a combustion turbine is not proven, and, upon regeneration, the process would create an H_2S stream requiring treatment.

- EMx would not be expected to achieve lower guaranteed NO_X levels than SCR, and, for reasons described above, it has greater feasibility concerns than SCR for application on large CCCTs.

Although application of an EMx system to a large-scale CCCT has not be demonstrated in practice, it must be considered technically feasible for such an application. However, the high capital and operating costs of the EMx system make it not cost effective when compared to an SCR system capable of achieving similar emission rates. This cost-effectiveness determination was proposed for both the Cherry Point Cogeneration Project Electric Generating Facility and the Sumas Energy 2 Generation Facility and accepted by the Washington Energy Site Evaluation Council (EFSEC) and the Washington State Department of Ecology (Ecology). Because the economics associated with applying an EMx system to the NWIWK project are substantially the same as those presented for the Cherry Point and Sumas Energy 2 projects, the cost-effectiveness analysis in not repeated here. EMx is not a cost effective control technology, despite its alleged ability to control multiple pollutants.

4.3 NO_X BACT

NO_X is primarily formed in combustion processes in two ways: 1) the reaction of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_X), and 2) the oxidation of nitrogen contained in the fuel (fuel NO_X). Natural gas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is expected that essentially all NO_X emissions from the power generation unit will originate as thermal NO_X.

A natural gas-fired combustion turbine is an inherently low-emitting process. The remainder of this analysis considers the use of this lower-emitting process in conjunction with add-on controls that eliminate emissions after they are produced by fuel combustion in the turbine and the HRSG.

The rate of formation of thermal NO_X in an NGCC combustion turbine is a function of residence time, oxygen radicals, and peak flame temperature. Front-end NO_X control techniques, such as low-NO_X burners, are aimed at controlling one or more of these variables during combustion. Post-combustion controls (e.g., SCR) seek to convert NO_X formed during combustion to nitrogen and water using a reductant injected into the exhaust. These technologies are considered to be commercially available pollution prevention techniques.

4.3.1 Ranking of Remaining Alternatives

Among the control technologies considered in the previous subsection, only the use of low-NO_X combustors and installation of an SCR system were considered both technically feasible and cost-effective to reduce NO_X emissions from the CCCT, and LNBs are considered the baseline NO_X control technology.

4.3.2 Consideration of Energy, Environmental and Cost Factors

The next step in a BACT analysis is to conduct an analysis of the energy, environmental and economic impacts associated with each feasible control technology. Based on the evaluation in the previous step, the only technically feasible and commercially proven technology suitable for establishment of BACT limits is an SCR system. The most notable environmental impact associated with this NO_X control technology is NH_3 emissions associated with use of NH_3 as the reagent chemical. The unreacted portion of the NH_3 passes through the catalyst and is emitted from the stack. These emissions are referred to as “ammonia slip,” and their magnitude depends on the catalyst activity and the degree of NO_X control desired.

Economic and energy impacts associated with application of an SCR system are a decrease in the net power output of the units due to the increased pressure drop across the catalyst bed, the ongoing ammonia procurement and storage requirements, and increased maintenance costs associated with the accumulation of ammonia salts on the HRSG and the eventual de-activation of the catalyst. Because SCR has long been considered BACT for large CCCT units, the environmental, economic, and energy impacts have generally been deemed acceptable by USEPA and other permitting agencies.

4.3.3 Proposed BACT Limits and Control Option

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. NWIWK proposes that the use of LNBs and installation of an SCR system to reduce NO_X exhaust gas concentration to 2.5 ppmvd NO_X at 15 percent O_2 (3-hour average) be considered BACT for the CCCT units. Similar units have been permitted with slightly more stringent NO_X limits (i.e., 2.0 ppmvd at 15 percent O_2), but those units are not expected to provide power on a continuous basis, meaning catalyst replacements are less frequent and easier to accommodate without compromising planned availability.

4.4 CO and VOC BACT

CO is a product of incomplete combustion. CO is minimized by providing adequate fuel residence time and high temperature in the combustion zone to maximize combustion. These control factors, however, can also tend to result in increased emissions of NO_X. Conversely, a lower NO_X emission rate achieved through flame temperature control (by diluent injection or dry lean pre-mix) may result in higher levels of CO emissions. Thus, a compromise must be established, whereby the flame temperature reduction is set to achieve the lowest NO_X emission rate possible while keeping CO emissions to an acceptable level.

CO emissions from combustion turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Possible post-combustion control involves the use of catalytic oxidation, while front-end control involves controlling the combustion process to suppress CO formation.

VOCs are a product of incomplete combustion of the natural gas fuel. VOC emissions are minimized by providing adequate fuel residence time and high temperature in the combustion zone to maximize combustion. Technologies identified for reducing VOC emissions from CCCTs are oxidation catalysts and GCPs. A survey of the RBLC database indicated that good combustion control and burning clean fuel are the VOC control technologies most often determined to be BACT.

4.4.1 Ranking of Remaining Alternatives

GCPs and oxidation catalysts are technically feasible for the proposed CCCTs. GCPs are the baseline control technology, and oxidation catalyst systems provide additional emission control. In practice, GCPs are always used, and an oxidation catalyst system would be used in addition to, not in place of, GCPs.

4.4.2 Consideration of Energy, Environmental and Cost Factors

The energy, environmental, and cost considerations were discussed in the section that eliminated the infeasible control technologies (Section 4.2). The two identified control alternatives will both be proposed as BACT so further analysis of the energy, environmental, and economic factors was not conducted.

4.4.3 Proposed BACT Limits and Control Option

The use of GCPs in conjunction with an oxidation catalyst system is proposed to be BACT for control of CO and VOCs from the CCCTs. NWIWK proposes a CO BACT-based limit for the power generation units of 4 ppmvd at 15 percent O_2 on a 3-hour average during non-startup operation. NWIWK further proposes a VOC BACT-based limit for the CCCTs of 3 ppmvd at 15 percent O_2 on a 3-hour average during non-startup operation. Similar units have been permitted with slightly more stringent CO and VOC limits (i.e., 2.0 and 1. 0 ppmvd at 15 percent O_2, respectively), but those units are not expected to provide power on a continuous basis, meaning catalyst replacements are less frequent and easier to accommodate without compromising planned availability.

4.5 PM BACT

Particulate matter (PM) emissions from natural gas-fired combustion sources consist of inert contaminants in natural gas, sulfates from fuel sulfur, dust drawn in from the ambient air that passes through the combustion turbine inlet air filter and particles of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low PM emissions.

The EPA has indicated that PM control devices are not typically installed on combustion turbines and that the cost of installing such control devices is prohibitive. When the NSPS for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA acknowledged, "Particulate emissions from stationary gas turbines are minimal." Similarly, the revised Subpart GG NSPS (2004) did not impose a particulate emission standard. Therefore, performance standards for PM control of stationary gas turbines have not been proposed or promulgated at a federal level.

Post combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial combustion turbines burning gaseous fuels. Therefore, the use of ESPs and baghouses is considered technically infeasible.

In the absence of add-on controls, the most effective control method demonstrated for gas-fired combustion turbines is the use of low ash fuel, such as natural gas. Use of GCPs and the firing of fuels with negligible or zero ash content (such as natural gas) is the predominant control method listed.

The use of pipeline natural gas and good combustion control is proposed as BACT for PM/PM_{10}/$PM_{2.5}$ control in the proposed NWIWK power generating units. These operational controls will limit combined filterable and condensable PM_{10} emissions to 6.0 pounds per hour (lb/hr) combined during normal operation, based on an emission factor of 0.0066 lb/MMBtu, though NWIWK does not propose these as permit limits.

4.6 SO_2 BACT

4.6.1 Identify Control Technologies

SO_2 emissions from any combustion process are largely defined by the sulfur content of the fuel being combusted and the rate of the fuel usage. The combustion of natural gas in an NGCC combustion turbine creates primarily SO_2 and small amounts of sulfite (SO_3) by the oxidation of the fuel sulfur. The SO_3 can react with the moisture in the exhaust to form sulfuric acid mist, or H_2SO_4. Emissions of these sulfur species can be controlled by limiting the sulfur content of the fuel (pre-combustion control) or by scrubbing the SO_2 from the exhaust gas (post-combustion control). Potentially available control technologies include:

- Use of low-sulfur fuel - Pre-Combustion Process Controls
- Flue Gas Desulfurization (FGD) - Post-Combustion Controls

<u>Use of Low-Sulfur Fuel</u>

Natural gas contains sulfur as hydrogen sulfide (H_2S), carbonyl sulfide (COS), dimethyl sulfide (DMS), and various mercaptans, but at extremely low concentrations. Natural gas is generally considered a low-sulfur fuel, and on-site treatment to remove additional sulfur, while technically feasible, would not be cost-effective.

Flue Gas Desulfurization

Typical FGD processes operate by contacting the exhaust gas downstream of the combustion zone with an alkaline slurry or solution that absorbs and subsequently reacts with the acidic SO_2. FGD technologies may be wet, semi-dry, or dry based on the state of the reagent as it is injected or pumped into the absorber vessel. Also, the reagent may be regenerable (where it is treated and reused) or non-regenerable (all waste streams are de-watered and either discarded or sold). Wet, calcium-based processes, which use lime (CaO) or limestone ($CaCO_3$) as the alkaline reagent, are the most common FGD systems in PC unit applications. After the exhaust gas has been scrubbed, it is passed through a mist eliminator and exhausted to the atmosphere through a stack

FGD systems are commonly employed in conventional pulverized coal plants, where the concentration of oxidized sulfur species in the exhaust is relatively high. If properly designed and operated, FGD technology can reliably achieve more than 95 percent sulfur removal.

4.6.2 Evaluate Technical Feasibility

The use of an FGD system to control SO_2 emissions from an NGCC combustion turbine is technically feasible in theory, but infeasible in practice. The pressure drop introduced by the FGD system could not be overcome by the combustion turbine without the addition of an induced draft fan, which would cause problems with the air/fuel mixture in the combustion turbine combustor. As a result, FGD technology is considered technically infeasible for controlling SO_2 emissions from an NGCC combustion turbine.

4.6.3 Select Control Technology

The applicant proposes that BACT for control of SO_2 emissions from the proposed NGCC combustion turbine be defined as the use of pipeline natural gas, which is considered a low-sulfur fuel.

4.7 BACT During Startup and Shutdown

During startup and shutdown, NO_X, CO, and VOC concentrations in the exhaust have the potential to exceed those experienced under normal operation for brief periods. This is a characteristic of all combustion devices because optimum combustion conditions are not achieved immediately after startup or shutdown commences. During startup and shutdown it is not technologically feasible to meet NO_X, CO, or VOC BACT limits that are specified on the basis of normal power generation unit operation. NWIWK proposes that, during startup and shutdown periods, BACT for NO_X, CO, and VOCs is to limit the frequency and duration of startups, shutdowns, and periods of upset through the implementation of best practices and training.

5. COOLING TOWER

The methanol production lines, as well as the steam turbine associated with the PGU, will generate excess heat that cannot be effectively used. The Facility will employ a cooling system that will consist of a circulating water system that will utilize a 12-cell mechanical draft cooling tower. Wet (evaporative) cooling towers emit aqueous aerosol "drift" particles that evaporate to leave crystallized solid particles attributable to dissolved solids in the local water supply, which are considered PM emissions.

5.1 Identify Commercially-Available Emission Reduction Alternatives

Review of the federal RBLC database for large cooling towers indicates high efficiency drift eliminators and limits on total dissolved solids (TDS) concentration in the circulating water are BACT for cooling towers. The efficiency of drift eliminator designs is characterized by the percentage of the circulating water flow rate that is lost to drift. The drift eliminators to be used on the proposed cooling tower will be designed such that the drift rate is less than a specified percentage of the circulating water. Typical geometries for the drift eliminators include chevron blade, honeycomb, or wave form patterns, which attempt to optimize droplet impingement with minimal pressure drop.

Table 5-1 summarizes recent BACT determinations for utility-scale mechanical draft cooling towers. The commercially available techniques listed to limit drift PM releases from utility-scale cooling towers include:

- Use of Dry Cooling (no water circulation) Heat Exchanger Units
- High-Efficiency Drift Eliminators, as low as 0.0005 percent of circulating flow
- Limitations on TDS concentrations in the circulating water
- Combinations of Drift Eliminator efficiency rating and TDS limit
- Installation of Drift Eliminators (no efficiency specified)

The use of high-efficiency drift eliminating media to de-entrain aerosol droplets from the air flow exiting the wetted-media tower is commercially proven technique to reduce PM emissions. Compared to "conventional" drift eliminators, advanced drift eliminators reduce the PM emission rate by more than 90 percent.

In addition to the use of high efficiency drift eliminators, management of the tower water balance to control the concentration of dissolved solids in the cooling water can also reduce particulate emissions. Dissolved solids accumulate in the cooling water due to increasing concentration of dissolved solids in the make-up water as the circulating water evaporates, and, secondarily, the addition of anti-corrosion, anti-biocide additives. However, to maintain reliable operation of the tower without the environmental impact of frequent acid wash cleanings, the water balance must be considered. The proposed cooling tower design will be based on 8 cooling water cycles (i.e., the concentration of dissolved solids in the circulating water will be, on average, 8 times that of the introduced make-up water), and a total dissolved solids (TDS) concentration of 156 ppmw in the makeup water, which translates to a cooling water TDS concentration of 1,248 ppmw.

Lastly, the substitution of a dry cooling tower is a commercially available option that has been adopted by utility-scale combined cycle plants in arid climates, usually because of concerns other than air emissions. This option involves use of a very large, finned-tube water-to-air heat exchanger through which one or more large fans force a stream of ambient dry air to remove heat from the circulating water in the tube-side of the exchanger.

5.2 Eliminate Technically Infeasible Alternatives

Dry cooling towers are usually a means to reduce the water consumption rather than as BACT for PM emissions. A substantial capital cost penalty accompanies adoption of this technology, in addition to the process changes (e.g., operating pressures) necessary to condense water at the ambient dry bulb temperature, rather than at ambient wet bulb temperature.

Because of the process design changes involved in the use of a dry cooling tower, that option is considered technically infeasible, and is removed from consideration.

5.3 Ranking of Available Control Measures

High-efficiency drift eliminators can be implemented at different levels of stringency. Development of increasingly effective de-entrainment structures now allows a cooling tower to be specified to achieve drift release no higher than 0.0005 percent of the circulating water rate. This is the most stringent BACT option.

There are no significant costs or environmental factors which favor implementation of a less-stringent drift eliminator option.

In “top down” order from most to less stringent, the potentially available candidate control techniques are:

- Combinations of high-efficiency drift eliminators and TDS limit
- High-Efficiency drift eliminators to control drift to as low as 0.0005 percent of circulating flow
- Limitations on TDS concentrations in the circulating water
- Installation of Drift Eliminators (no efficiency specified)

5.4 Consideration of Energy, Environmental and Cost Factors

Development of increasingly effective de-entrainment structures has resulted in equipment vendors claims that a cooling tower may be specified to achieve drift release no higher than 0.0005 percent of the circulating water rate. This is the most stringent BACT for cooling towers in current permits, but confirming this drift rate is difficult or impossible to achieve in a real-world setting.

Even incremental improvement in drift control involves substantial changes in the tower design. First, the velocity of the draft air that is drawn through the tower media must be reduced compared to “conventional” specifications. This is necessary to use drift eliminator media with smaller passages (to improve droplet capture) without encountering unacceptably high pressure drop. Since reducing the air velocity also reduces the heat transfer coefficient of the tower, it is likely that a proportional increase in the overall size of the media will be needed. For example, a 6-cell tower may need to be expanded to 14 cells in order to accommodate higher drift eliminator efficiency for the same heat rejection duty. These changes will also result in an energy penalty in the form of larger and higher powered fans to accommodate the improved droplet capture. More importantly, there is a substantial increase in both tower operating costs and capital costs that deliver relatively few tons of PM abatement.

Adopting a TDS limit for the circulating water is usually viewed as a measure that benefits air quality by reducing the dissolved salts that can be precipitated from drift aerosols. To reduce TDS the facility must introduce a higher volume flow of make-up water to the tower. This has the potential environmental disadvantage of increasing the overall plant water requirements.

5.5 Proposed BACT Limits and Control Options

Based on the information from the RBLC database survey, and the energy and cost factors described above, the proposed BACT option for the proposed cooling towers is use of drift eliminators designed to achieve a maximum drift of 0.0005 percent of the circulating water in combination with a TDS limit of 1,250 ppmw. This represents the most stringent of the identified emission limits and control techniques.

6. FLARE

The facility will utilize a flare to control emissions from process startups, shutdowns, maintenance turnarounds, and malfunctions. In the event of a plant upset or during a power failure, the flare will process any hydrocarbon vapor released from the pressure relief mechanisms. The hydrocarbons controlled by the flare will consist primarily of methanol as well as a small amounts of other hydrocarbons. These vapors are conditioned, as needed, with natural gas to ensure a safe concentration in excess of the upper flammable limit. The flare will be equipped with a small pilot, which will combust pipeline natural gas, and operate at all times. Pollutant emissions from the flare are expected to include NO_X, PM (including PM_{10} and $PM_{2.5}$), CO, SO_2, VOCs, and TAPs.

6.1 Identify Commercially-Available Emission Reduction Alternatives

A broad review of permitted flares, vapor combustion units (VCUs), and thermal oxidizers (TOs), included in the federal RBLC database indicates that emission reduction alternatives are limited to:

- Good combustion practices
- Proper design and operation
- Use of gaseous fuels and/or pipeline natural gas

Pollutant emissions from the flare fall into two categories: 1) vapors, typically VOCs that escape the flare without being destroyed as intended; and 2) combustion products of the destroyed vapors and any supplemental fuel used to ensure sufficient flame temperature. Proper design and operation of the flare are intended to minimize the quantity of vapors that escape destruction. Good combustion practices, and the use of clean, gaseous fuel, are intended to minimize the production of criteria pollutant emissions.

In most cases, the VOC stream that a given VCU, TO, or flare controls is of variable composition and concentration. For this facility, while the composition is less variable than for other sources (such as a refinery), the concentration of the VOC stream is still highly variable. As a result, the associated burner must be designed to handle a wide range of combustion conditions, and cannot be optimized. In contrast, gas-fired burners associated with boilers or process heaters can be designed to minimize specific pollutants, such as NO_X or CO. While NO_X emissions vary among VCU, TO, and flare combustor designs, none can utilize a true "Low-NO_X burner" design similar to a boiler or process heater.

NO_X emissions associated with VCU, TO, and flare designs are typically in the range of 20 to 40 ppmvd. BACT for current Low-NO_X burner designs associated with small (i.e., less than 100 MMBtu/hr) natural gas-fired boilers is typically in the range of 9 to 11 ppmvd. When a VCU, TO, or flare manufacturer or vendor says their product incorporates a "Low-NO_X burner," the burner in question does not incorporate the same technology as a burner intended for use in a boiler, and will not achieve the same NO_X emission rate. For purposes of this BACT analysis, minimizing NO_X emissions while maintaining an acceptable destruction efficiency is considered part of "good combustion practices, and "Low-NO_X burner" is not considered an available technology for the proposed flare.

6.2 Eliminate Technically Infeasible Alternatives

Because no pollutant-specific emission reduction alternatives were identified, all pollutants will be considered together in this and the following sections.

The emission reduction alternatives identified in the previous sections are all considered technically feasible for flares.

6.3 Ranking of Available Control Measures

Good combustion practices, proper design and operation, and use of pipeline natural gas as a pilot and assist gas, are all considered baseline controls for flares; therefore, it is not possible to rank the remaining alternatives.

6.4 Consideration of Energy, Environmental and Cost Factors

Because the facility proposes to use the most effective alternatives, no evaluation of energy, environmental, or cost was conducted.

6.5 Proposed BACT Limits and Control Options

The facility proposes that BACT for reducing criteria pollutant and TAP emissions from the proposed flare is achieved by implementing good combustion practices, proper design and operation, and use of pipeline natural gas as an assist gas and for pilot flames.

7. METHANOL STORAGE TANKS

There will be four types of storage tanks at the Facility: crude methanol tanks, shift methanol tanks, product methanol tanks, and ammonia tanks. The number, designs, dimensions, and capacities of the tanks are summarized in Table 7-7. All are vertical cylindrical tanks. BACT for ammonia tanks is discussed in Section 9 of this appendix.

Table 7-1: Methanol Tanks

Tank	Quantity	Tank Design	Height (ft)	Diameter (ft)	Volume (gal)
Crude Methanol	2	Fixed Roof	58	82	2,275,000
Shift Methanol	4	Internal Floating Roof	50	60	1,000,000
Product Storage	8	Internal Floating Roof	82	143	9,400,000

Fugitive emissions from the tanks are expected to occur due to working and breathing losses. Working losses are primarily due to the loading and unloading of the tank during which the hydrocarbon vapor located in the headspace is displaced due to changes in the level of material in the tanks. Breathing loss emissions occur from the cyclical diurnal temperature changes. The diurnal heating and cooling cycle allows for vapor displacement due to the expansion and contraction of the headspace because the equilibrium pressure of the vapor and liquid phases (vapor pressure) is a function of temperature. Pollutant emissions from the tanks are expected to include VOCs and methanol.

7.1 Identify Commercially-Available Emission Reduction Alternatives

A review of the RBLC database contains several BACT determinations for the control of VOC emission from storage tanks at Synthetic Organic Chemical Manufacturing/ Hazardous Organic NESHAP facilities (SOCMI/HON). The typical VOC control practice for the storage tanks consists of design measures to minimize the hydrocarbon vapor space displacement. Emission reduction strategies identified in RBLC database review include

- Fixed roof with a closed vent system and vapor capture system sent to a thermal oxidizer
- Fixed roof with a closed vent system and vapor capture system sent to a scrubber
- Internal floating roof with dual seals and vapor capture system sent to a thermal oxidizer
- Internal floating roof with dual seals and vapor capture system sent to a scrubber
- External floating roof with dual rim seals

7.1.1 Internal Floating Roof Tank with Appropriate Seal Design

Fixed roof tanks are a common storage tank design which consists of a cone or dome shaped roof that is permanently attached to the cylindrical shell. A breather valve (or pressure vacuum valve) is commonly installed on fixed roof tanks and allows the tank to operate at a slight internal pressure or vacuum.

7.1.2 Internal Floating Roof Tank with Appropriate Seal Design

An internal floating roof tank has a roof structure that floats on the surface of the liquid where it exerts pressure on the vapor phase and decreases the volume of vapor available to emit. Appropriate seal design minimizes the amount of vapor that can exit as rim losses. Internal floating roof tanks also have a fixed roof atop the storage tank to protect the floating roof and to further limit the vapor displacement to the atmosphere.

7.1.3 External Floating Roof Tank with Appropriate Seal Design

An external floating roof tank is very similar to an internal floating roof tank but there is no fixed roof atop the storage tank.

7.1.4 Vapor Capture with a Thermal Oxidizer

Fixed roof and internal floating roof tanks can be equipped with a vapor capture system. Once captured, the vapors can be vented to thermal oxidizer that combusts the VOC-containing vapor stream with a control efficiency greater than 98%. Thermal oxidizers can be used to control emissions of any VOC-containing stream, including storage tanks. During the destruction of the VOCs, other combustion emissions are created and must be considered in assessing the feasibility of the control technology as well as in the emission inventory for the facility.

7.1.5 Vapor Capture with a Water Scrubbing

Another control option for the captured vapors is to be passed through a water scrubber. Methanol is soluble in water and water scrubbers can achieve a control efficiency of greater than 98% while controlling any methanol-containing stream. The water-methanol effluent can be recycled back into the process, reducing waste and increasing yield.

7.2 Eliminate Technically Infeasible Alternatives

The technical feasibility of the control options will depend on the tank characteristics and the material stored. Floating roof tanks are technically feasible for the shift and product storage tanks but not for the crude methanol tanks. Crude methanol is off-spec material that contains some non-reacted gases. The crude methanol is sent through a Letdown Vessel where dissolved gases are flashed off and separated from the liquid phase before the methanol stream is stored in the crude methanol tanks. However, the Letdown Vessel is not 100% efficient at removing the gases and the release of any remaining gases under a floating roof could cause the roof to become unstable. This represents a safety risk and floating roof tanks are not considered technically feasible for crude methanol storage.

Internal floating roof tanks are generally considered to be of superior control with less maintenance than external floating roof tanks. Methanol product quality can also be compromised because the external floating roof is exposed to the environment. Therefore, external floating roof tanks are not a viable option for methanol storage tanks and are not considered technically feasible.

All other control options are considered technically feasible and are evaluated further.

7.3 Ranking of Available Control Measures

In top-down order of decreasing stringency, the feasible VOC emission reduction techniques are listed with the approximate control efficiencies:

- Internal floating roofs, vapor capture and thermal oxidizer (98%+)
- Internal floating roofs, vapor capture and water scrubber (98%+)
- Fixed roof tanks, vapor capture and thermal oxidizer (98%)
- Fixed roof tanks, vapor capture and water scrubber (98%)
- Internal floating roof tanks (>95%)

7.4 Consideration of Energy, Environmental and Cost Factors

Internal floating roof tanks will be used for all tanks where it is technically feasible to do so (the only tanks it is not feasible are the crude methanol tanks, see Section 7.2 above). The only consideration is how the VOC vapors from the tanks are captured and controlled. Based on the vendor quotations received for the proposed project, there is not a significant difference in the control efficiencies of a thermal oxidizer versus a water scrubber. There are two main disadvantages of using a thermal oxidizer. It will produce combustion emissions, including criteria pollutants NO_X, CO, PM_{10}, $PM_{2.5}$, SO_2, and VOCs as well as TAPs due to the destruction of the VOC vapors as well as the combustion of natural gas for the pilot light. Further, the methanol that is captured is destroyed by the thermal oxidizer and can’t be recovered and reintroduced back into the process.

The advantages of using a water scrubber are that the unit would not generate any products of combustion while controlling the VOC vapors and the recovered methanol can be recycled back into the production process. Based on these reasons, the thermal oxidizer has been rejected as BACT for the methanol storage tanks.

7.5 Proposed BACT Limits and Control Options

The use of fixed roof tanks for crude methanol storage and internal floating roof tanks for shift product and final product storage with all tanks being controlled by a water scrubber are proposed as BACT for the methanol storage tanks. The vapor control system will capture 99% of the VOC emissions and the water scrubbers will reduce VOC emissions by at least 99% for an overall control efficiency of 98% for the methanol storage tanks.

8. MARINE VESSEL LOADING

Product loading onto marine vessels will produce VOC emissions due to volatilization of the methanol into the available vapor space in the vessels.

8.1 Identify Commercially-Available Emission Reduction Alternatives

A review of the RBLC database identified several BACT determinations for the control of VOC emission from vessel loading operations:

- Closed vent system and vapor capture system sent to a thermal oxidizer
- Closed vent system and vapor capture system sent to a scrubber

8.1.1 Vapor Capture with Thermal Oxidation

Marine vessels can be equipped with a vapor capture system. Once captured, the vapors can be vented to thermal oxidizer that combusts the VOC-containing vapor stream with a control efficiency greater than 98%. Thermal oxidizers can be used to control emissions of any VOC-containing stream. During the destruction of the VOCs, combustion emissions are created and must be considered in assessing the overall effectiveness of the control technology.

8.1.2 Vapor Capture with Water Scrubbing

Another control option for the captured vapors is a water scrubber. Methanol is soluble in water and water scrubbers can achieve a control efficiency of greater than 98 percent while controlling a methanol-containing stream. The water-methanol effluent can be recycled back into the process, reducing waste and increasing yield.

8.2 Eliminate Technically Infeasible Alternatives

8.2.1 Vapor Capture with Thermal Oxidation

Thermal oxidation is technically feasible for marine vessel loading.

8.2.2 Vapor Capture with a Water Scrubbing

Water scrubbing is technically feasible for marine vessel loading.

8.3 Ranking of Available Control Alternatives

Based on vendor quotations, both control technologies identified as potential BACT for marine vessel loading are able to reduce VOC emissions by 98 percent or greater.

8.4 Consideration of Energy, Environmental and Cost Factors

There are two drawbacks to using a thermal oxidizer. First, it will produce combustion emissions, including criteria pollutants NO_X, CO, PM_{10}, $PM_{2.5}$, SO_2, and VOCs as well as TAPs due to the destruction of the VOC vapors as well as the combustion of natural gas for the pilot light. Second, the methanol that is captured is destroyed by the thermal oxidizer and can't be recovered and reintroduced back into the process.

In contrast, using a water scrubber would not generate any products of combustion while controlling the VOC vapors and the recovered methanol can be recycled back into the production process. .

8.5 Proposed BACT Limits and Control Options

The use of a closed vent system with vapor capture and a water scrubber are proposed as BACT for marine vessel loading. The vapor control system will capture 99 percent of the VOC emissions and the water scrubbers will reduce VOC emissions by at least 99 percent for an overall control efficiency of 98 percent for the marine loading operations.

9. AQUEOUS AMMONIA TANKS

The boilers and the PGU will employ SCR to reduce NO_X emissions. A 25 percent by weight solution of aqueous ammonia will be used as the reagent in all of the SCR systems. Three tanks, each with a capacity of approximately 9,000 gallons, will be used to store the aqueous ammonia on site. The tanks will all be pre-built units of a vertical, cylindrical design, with fixed roofs.

Fugitive emissions are expected to occur due to working and breathing losses. Working losses are primarily due to the loading and unloading of the tank during which the ammonia vapor located in the headspace is displaced due to changes in the level of material in the tanks. Breathing loss emissions occur from the cyclical diurnal temperature changes. The diurnal heating and cooling cycle allows for vapor displacement due to the expansion and contraction of the headspace because the equilibrium pressure of the vapor and liquid phases (vapor pressure) is a function of temperature. Ammonia is considered a TAP but not a HAP.

9.1 Identify Commercially-Available Emission Reduction Alternatives

A review of the RBLC database and agency BACT guidelines identified very few BACT determinations for the control of ammonia emissions from aqueous ammonia storage tanks. RBLC searches for “aqueous ammonia” and “ammonia tank” produced no results and the only results for “ammonia storage” were for ammonia storage tank flares at fertilizer and ammonia producing facilities; these most likely addressed anhydrous not aqueous storage tanks. The few controls identified in other permit applications include:

- Locate tanks in adequately sized secondary containment area;
- System/equipment to minimize emissions in the event of a potential spill;

9.2 Proposed BACT Limits and Control Options

NWIWK proposes to use all of the identified BACT options for the aqueous ammonia storage tanks. The tanks will be equipped with secondary containment sized to accommodate the entire volume of one tank and sufficient freeboard for precipitation. The tanks will be located outdoors within an impermeable containment area, surrounded by a wall. The floor of the containment area will be covered with plastic balls designed to float on the liquid surface in the event of a spill, thereby reducing the exposed surface area, and minimizing potential emissions.

10. ENGINES POWERING EMERGENCY EQUIPMENT

NWIWK proposes to install 2 diesel-fueled generator sets (one per line), rated at approximately 3.5 MW each, to assist with an orderly shutdown of the Facility in the unusual situation that electrical power is not available from the grid. Additionally, a diesel-fueled engine rated at approximately 1,600 hp will be available to power a firewater pump, which will provide pressurized water for fire protection to the Facility in the unusual situation that a fire coincides with a power outage.

NWIWK proposes to operate these engines as Subpart IIII “emergency” engines (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines). In order to be considered emergency engines per Subpart IIII, the engines must operate in accordance to the following requirement as specified at 40 CFR § 60.4211(f):

- There is no time limit on the use of emergency stationary internal combustion engine (ICE) in emergency situations.
- Maintenance checks and readiness testing is limited to 100 hours per year unless the permittee has approval or records indicating that Federal, State, or local standards require maintenance and testing beyond 100 hours per year.

There are several other provisions that allow for additional use of the emergency engines but NWIWK proposes to use their RICE only for readiness testing and during power outages and emergencies. Planned operation for routine testing, maintenance, and inspection purposes of the engines powering the emergency generators will be limited to 52 hours per year and to 56 hours for the engine powering the emergency firewater pump.

Additionally, NWIWK must use diesel fuel that meets the following requirements:

1. Sulfur content – 15 ppm maximum
2. Cetane index or aromatic content, as follows:
    i. A minimum Cetane index of 40; or
    ii. A maximum aromatic content of 35 volume percent.

10.1 NO_X BACT

10.1.1 Identification and Technical Feasibility of Available Control Alternatives

There are a limited number of technically-feasible NO_X control technologies that are commercially available for internal combustion engines. Two general types of control options have emerged as technically feasible: combustion process modifications, and post-combustion controls.

Combustion Process Modifications

This option is incorporated in the engine design. Typical design features include electronic fuel/air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean-burn fuel mix. Currently available new engines that must meet Subpart IIII emission standards for emergency engines include these features as standard equipment; accordingly this measure is deemed the baseline case for purposes of the BACT analysis.

Selective Catalytic Reduction (SCR)

In this technology, nitrogen oxides are reduced to gaseous nitrogen by reaction with ammonia in the presence of a supported precious metal catalyst. The SCR system includes a catalyst module in the engine exhaust stream. Just upstream of the catalyst, a reagent liquid (typically ammonia or urea solution) is injected directly into the exhaust stream.

Non-Selective Catalytic Reduction (NSCR)

Similar to automobile catalytic converters, this method employs noble metal catalysts to oxidize nitrogen oxides to molecular nitrogen. It operates in regimes with less than four percent oxygen in the exhaust, which corresponds to fuel-rich operation. The method is not feasible with lean-burn internal combustion engines such as those to be operated at the Facility.

10.1.2 Ranking of Available Control Alternatives

The use of SCR offers the highest potential level of control for the proposed diesel-fired emergency engines. Up to 90 percent reduction in NO_X mass emission at all load levels is claimed for typical internal combustion engines.

The option offering the next highest control level is combustion process modifications, as would be implemented as standard equipment (i.e. no additional cost) in the selected engines. Advanced combustion design allows the engines to operate at rated horsepower, while burning an optimized fuel mix. This feature includes ignition timing retard to reduce cylinder temperatures for lean mixtures. The controls are also designed to optimize the air/fuel ratio and ignition timing in response to actual operating conditions.

10.1.3 Consideration of Energy, Environmental, and Cost Factors

There are several distinguishing factors between the two technically-feasible options with regard to energy and environmental impacts. One drawback associated with SCR systems is the environmental risk of handling and using ammonia reagent solutions. Most SCR catalyst modules can operate well without excess reagent. However, this requires particular attention to the controlled injection of the reagent in response to changes in load, temperature, and other parameters. Further, it should be assumed that ammonia emissions will occur under some or all operating conditions. This represents an additional air pollutant that is not emitted when SCR is not used for these engines. Also, the handling and storage of substantial volumes of the required ammonia or urea reagent solutions can pose an additional safety risk to facility personnel, and the risk of environmental harm in the event of an accidental release.

The SCR catalyst requires periodic cleaning due to fouling of the surfaces due to the presence of trace contaminants, such as sulfur compounds, particulate, and organic species. This requirement generates a secondary waste stream of contaminated cleaning solutions that must be disposed as hazardous waste.

When SCR or any add-on emission control technology is used, the presence of the catalyst module adds an increment of pressure drop to the exhaust train. To avoid a substantial drop-off in engine performance, the SCR modules must be designed to minimize the increase in back pressure. However, the energy requirements of auxiliary equipment and even minor back-pressure increases reduce the net energy efficiency of the unit.

In contrast, the implementation of combustion process controls does not require an add-on system with increased energy use by auxiliary equipment, or the use of catalyst and ammonia materials. There is some additional complexity in the engine controls for this option. Proper engine tuning and fuel/air ratio is needed across the full load range to achieve reduced emissions while avoiding a reduction in engine efficiency. The automatic fuel/air ratio controller helps accomplish this objective.

Because combustion process controls is a standard feature of the currently available new engines, the emissions reported by vendors for this package are taken as the base case in this BACT analysis. Although SCR would improve emission control, it is not cost effective for engines that are operated minimally for testing and maintenance. Based on the cost effectiveness analysis presented in Attachment B, SCR is not cost effective for the emergency generators; because the firewater pump is a smaller unit, it was assumed that the cost-effectiveness would be no better and a unit-specific analysis is not provided.

10.1.4 Proposed BACT Limits and Control Options for NO_X

NWIWK proposes that BACT is combustion process control, achieved by the use of engines that meet applicable Subpart IIII Tier 2 emission standards. Pursuant to § 60.4205(b), 60.4202(b)(2), and 60.4211(c), the two emergency generator engines must be certified to the applicable emission standards in Table 1 of 40 CFR 89.112, below:

Rated Power (kW)	Tier	Model Year	Emission standards g/kW-hr		
			$NMHC+NO_X$	CO	PM
kW > 560	Tier 2	2006	6.4	3.5	0.2

Pursuant to §§ 60.4205(c), and Table 4 to Subpart IIII, the firewater pump emergency engine must be certified to the following emission limits (Tier 2).

Rated Power (kW)	Model Year	Emission standards g/kW-hr		
		$NMHC+NO_X$	CO	PM
kW > 560	2008+	6.4	3.5	0.2

Annual emissions would be limited by restricting non-emergency hours of operation.

Although not cost-effective, NWIWK is voluntarily proposing to purchase generators that include diesel engines supplied with exhaust after-treatment that are compliant with Tier 4 emission standards. The firewater pump engine will not include the Tier 4 exhaust after-treatment.

10.2 CO and VOCs BACT

10.2.1 Identification and Technical Feasibility of Available Control Alternatives

Commercially available controls for CO and VOC emissions from ICEs are:

Combustion Process Modifications

This option is implemented in the design of the internal combustion engine. Typical design features include an electronic fuel/air ratio control and ignition retard, turbocharging, intercoolers, and lean-burn fuel mix. Currently available engines include these features as standard equipment, so these measures are used as the base case for the BACT cost-effectiveness analysis.

Catalytic Oxidation

This control technology employs a module containing an oxidation catalyst that is located in the exhaust path of the engine. In the catalyst module, CO and VOCs diffuse through the surfaces of a ceramic honeycomb structure coated with noble metal catalyst particles. Oxidation reactions on the catalyst surface form carbon dioxide and water.

10.2.2 Consideration of Economic Factors

Analogous to the SCR discussion, given the low number of routine operating hours per year, the cost for catalytic oxidation for CO and VOC control will be prohibitive.

10.2.3 Proposed BACT Limits and Controls for CO and VOCs

NWIWK proposes that BACT for the emergency generators and the firewater pump emergency engine is the combustion process controls supplied by the manufacturer as standard equipment that enable the emergency engines to meet the applicable Tier 2 emission standards in Subpart IIII. Annual emissions would be limited by restricting non-emergency hours of operation.

10.3 SO_2 and PM BACT

The emergency engines (generators and firewater pump engine) proposed for the project will combust ULSD, which is considered a low-sulfur fuel. Given the low emission rates expected as a result of using ULSD, there are no available technologies beyond good combustion controls that are considered to provide feasible or cost effective emission control. Use of engines certified by manufacturers to meet Subpart IIII Tier 2 emission standards, use of ULSD, and limitations on non-emergency operation will minimize emissions of SO_2 and PM, and NWIWK proposes these as BACT measures for these pollutants. Annual emissions would be limited by restricting non-emergency hours of operation.

NWIWK is voluntarily proposing to purchase generators that include diesel engines supplied with exhaust after-treatment that are compliant with Tier 4 emission standards. The firewater pump engine will not include the Tier 4 exhaust after-treatment.

11. COMPONENT LOSSES

The proposed project will include piping, valves, connectors, pumps, compressors, and other components to transfer and methanol, natural gas, syngas, and other hydrocarbons. All components are subject to some level of leakage, and fugitive VOC and TAP emissions are expected to occur when components are in service.

11.1 Identify Commercially-Available Emission Reduction Alternatives

A broad review of permitted operations included in the federal RBLC database and other permitted sources indicates that fugitive emissions from leaking components are reduced through a combination of proper equipment selection and a leak detection and repair (LDAR) program. Identified alternatives include:

- Use of leakless components technology
- Implementation of an LDAR program
- Audio/visual/olfactory (AVO) monitoring
- Proper equipment selection

LDAR programs involve periodic monitoring of components with a hydrocarbon analyzer, identification of components that leak above the leak definition levels specified in the equipment leak standard, and subsequent repair of the leaking components. LDAR programs are frequently defined by regulations; those deemed to represent BACT for other facilities permitted in the past ten years that were found in the RBLC include:

- 40 CFR 63 Subpart H (National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks)
- 40 CFR 63 Subpart CC (National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries)
- 40 CFR 63 Subpart UU (National Emission Standards for Equipment Leaks—Control Level 2 Standards)
- 40 CFR 60 Subpart VVa (Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006)
- 40 CFR 60 Subpart GGGa (Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006)

- 40 CFR 61 Subpart V (National Emission Standard for Equipment Leaks (Fugitive Emission Sources))
- Louisiana Refinery MACT (Louisiana Administrative Code §2121, §2122, and Chapter 51)
- TCEQ LDAR Programs

The RBLC findings are summarized in Table 11-1.

Table 11-1 Summary of BACT Determinations for Component Losses from the RBLC

Facility	State	Date Permitted	BACT Determination
Ticona Polymers – Bishop	Texas	11/12/2015	TCEQ 28VHP LDAR program
Golden Pass Products	Texas	9/11/2015	LDAR program
Motiva – Port Arthur	Texas	7/31/2015	Enhanced LDAR program with quarterly monitoring, and 500 ppmv leak definition
Nuevo Midstream – Ramsey Gas Plant	Texas	11/18/2014	40 CFR Part 60, Subpart OOOO LDAR program, AVO monitoring
Corpus Christi Liquefaction	Texas	9/12/2014	Leakless components where possible, TCEQ 28VHP LDAR program
Formosa Plastics – Point Comfort	Texas	8/8/2014	TCEQ 28VHP LDAR program, AVO monitoring
C3 Petrochemicals	Texas	6/12/2014	TCEQ 28VHP LDAR program
Dominion Cove Point LNG	Maryland	6/9/2014	LDAR program, AVO monitoring
Natgasoline	Texas	5/16/2014	TCEQ 28VHP LDAR program
Occidental Chemical Corp.	Texas	5/16/2014	TCEQ 28MID LDAR program
Dow Chemical Eythylene	Texas	3/27/2014	TCEQ 28VHP LDAR program
DCP Midstream	Texas	1/13/2014	Leakless components where possible, TCEQ 28LAER LDAR program
Celanese – Clear Lake	Texas	9/16/2013	TCEQ 28LAER LDAR program
KM Liquids – Galena Park	Texas	6/12/2013	TCEQ 28LAER LDAR program
Phillips 66 – Alliance	Louisiana	7/25/2012	LA Refinery MACT LDAR program
Sabine Pass LNG	Louisiana	12/6/2011	LDAR program
BASF Fina Petrochemicals	Texas	5/17/2011	TCEQ 28LAER LDAR Program

Facility	State	Date Permitted	BACT Determination
Valero Refining - St. Charles Refinery	Louisiana	11/17/2009	LA Refinery MACT, 40 CFR 63 Subpart H, 40 CFR 61 Subpart V
Sunoco Toledo Refinery	Ohio	2/23/2009	40 CFR 63 Subpart CC, 40 CFR 60 Subparts VV & GGG
ConocoPhillips Wood River Refinery	Illinois	8/5/2008	40 CFR 63 Subpart H
Marathon Petroleum Garyville Refinery	Louisiana	12/27/2006	40 CFR 63 Subpart CC, 40 CFR 60 Subpart GGG, LA Refinery MACT LDAR program

11.2 Eliminate Technically Infeasible Alternatives

Because leakless technology components cannot be repaired without a unit shutdown, they are typically used only in situations where highly toxic or otherwise hazardous materials are present. Because the VOCs that will be present in the proposed components are not considered highly toxic or hazardous materials, it is not necessary to employ components that require a full unit shutdown for maintenance or repair. Therefore leakless technology components are considered technically infeasible.

AVO programs are applicable for inorganic/odorous and low vapor pressure compounds such as chlorine, ammonia, hydrogen sulfide, hydrogen fluoride, and hydrogen cyanide, or when natural gas is used onsite with an odorant. Because the components at the Facility will not contain apprceciable amounts of any of these comoupnds, an AVO program is considered technically infeasible.

Proper equipment selection and implementing an LDAR program based on any of the regulations identified in the previous section are considered technically feasible for reducing fugitive VOC and TAP emissions from component leaks.

11.3 Ranking of Available Control Measures

There are many LDAR programs available, some codified in regulations (e.g., NSPS, NESHAP, etc.), some developed by state agencies for consent decrees, and others developed by industry groups. Some of the non-regulatory alternatives include:

- LDAR programs
- Proper equipment selection

The effectiveness of these alternative programs have not been quantified, but none are thought to be any more effective than a regulatory LDAR program which includes implementation of EPA Method 21 (Determination of Volatile Organic Compound Leaks). All of the regulations identified in the previous section that require implementation of a formal LDAR program include Method 21.

A comparison of fugitive component emissions regulations compiled by the Louisiana Department of Environmental Quality (LDEQ) is provided in Attachment D. Taken as a whole, the requirements of 40 CFR 63 Subpart H are the most stringent. Implementation of an LDAR program and proper equipment selection are considered baseline alternatives, so there is no ranking.

11.4 Consideration of Energy, Environmental and Cost Factors

Because NWIWK proposes to use the most effective alternatives, no evaluation of energy, environmental, or cost was conducted.

11.5 Proposed BACT Limits and Control Options

NWIWK proposes that implementation of an LDAR program that meets the requirements of 40 CFR 63 Subpart H represents BACT for VOC and TAP component leaks at the proposed facility. NWIWK believes that emission rate limits are not appropriate for a fugitive source, and, therefore, does not propose any such limits as BACT. It should be noted that the proposed facility is not subject to the requirements of Subpart H as a result of the regulatory applicability criteria, but would meet the requirements of the rule, as appropriate, because it represents the most stringent implementation of an LDAR program.

12. TOXIC AIR POLLUTANT BACT (TBACT)

Toxic air pollutant (TAP) compounds are, in general, either volatiles (VOCs) or particles (PM). The proposed BACT for VOC and PM are also proposed to be tBACT for VOC and PM TAPs, respectively. tBACT for TAPs that sulfur (e.g., sulfuric acid) is proposed to be the same as that proposed for SO_2. For nitrogen-containing compounds (e.g., nitric oxide), tBACT is proposed to be the same as that proposed for NO_X.

ATTACHMENT A: RBLC SEARCH RESULTS

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
IA-0109	7/28/2015	City of Ames	Story County, IA	Boiler	476 MMBtu/hr	CO - 0.2 lb/MMBtu	GCP	BACT-PSD
IA-0109	7/28/2015	City of Ames	Story County, IA	Boiler	775 MMBtu/hr	CO - 0.2 lb/MMBtu	GCP	BACT-PSD
TX-0704	12/2/2014	M&G Resins USA, LLC	Nueces County, TX	Boiler	450 MMBtu/hr	NOx - 0.01 lb/MMBtu CO - 50 PPMVD @ 3%	GCP, SCR	BACT-PSD
TX-0704	12/2/2014	M&G Resins USA, LLC	Nueces County, TX	Boiler	250 MMBtu/hr	NOx - 0.01 lb/MMBtu CO - 50 PPMVD @ 3% O2	GCP, SCR	BACT-PSD
IL-0114	9/5/2014	Chronus Chemicals, LLC	Douglas County, IL	Boiler	864 MMBtu/hr	NOx - 0.012 lb/MMBtu CO - 0.02 lb/MMBtu	GCP, LNB	BACT-PSD
ND-0032	6/20/2014	CHS, Inc.	Stutsman County, ND	Boiler	280 MMBtu/hr	NOx - 0.018 lb/MMBtu CO - 0.06 lb/MMBtu	GCP, LNB	BACT-PSD
AL-0271	6/11/2014	Georgia Pacific LLC	Escambia County, AL	Boiler	425 MMBtu/hr	NOx - 0.02 lb/MMBtu	LNB, FGR	BACT-PSD
OK-0162	5/29/2014	Koch Nitrogen Co., LLC	Garfield County, LLC	Boiler	450 MMBtu/hr	CO - 0.037 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD

TX-0707	12/20/2013	Rohm and Haas Texas, Inc.	Harris County, TX	Boiler	515 MMBtu/hr	NOx - 0.01 lb/MMBtu CO - 50 PPMVD @ 3% O3	GCP, SCR	BACT-PSD
WY-0074	11/18/2013	Solvay Chemicals	Sweetwater County, WY	Boiler	254 MMBtu/hr	NOx - 0.011 lb/MMBtu CO - 0.037 lb/MMBtu PM - 0.007 lb/MMBtu	GCP, LNB	BACT-PSD
NE-0054	9/12/2013	Cargill, Inc.	Washington County, Inc.	Boiler	300 MMBtu/hr	NOx - 0.04 lb/MMBtu CO - 0.08 lb/MMBtu	GCP, LNB	BACT-PSD
TX-0698	9/5/2013	Air Liquide Large Industries U.S., L.P.	Harris County, TX	Boiler	550 MMBtu/hr	NOx - 0.01 lb/MMBtu CO - 50 PPMVD @ 3% O2	GCP, SCR	BACT-PSD
FL-0344	8/27/2013	New Hope Power Company	Palm Beach County, FL	Boiler	589 MMBtu/hr	NOx - 0.035 lb/MMBtu CO - 0.08 lb/MMBtu PM - 2 grains per 100 SCF	Overfire Air, GCP, LNB, Fuel Monitoring for Sulfur Content	BACT-PSD
IA-0106	7/12/2013	CF Industries Nitrogen, LLC	Woodbury County, IA	Boiler	456 MMBtu/hr	CO - 0.0013 lb/MMBtu PM - 0.0024 lb/MMBtu	GCP, Oxidation Catalyst	BACT-PSD
VA-0320	12/6/2012	Celanese Acetate, LLC	Giles County, VA	Boiler	400 MMBtu/hr	CO - 50 PPMVD @ 3% O3	GCP	BACT-PSD
IA-0105	10/26/2012	Iowa Fertilizer Company	Lee County, IA	Auxiliary Boiler	472.4 MMBtu/hr	NOx - 0.0125 lb/MMBtu CO - 0.0013 lb/MMBtu PM - 0.0024 lb/MMBtu	GCP, LNB	BACT-PSD

IN-0166	6/27/2012	Indiana Gasification, LLC	Spencer County, IN	Boiler	408 MMBtu/hr	NOx - 0.0125 lb/MMBtu CO - 0.036 lb/MMBtu SO2 - 0.0006 lb/MMBtu	GCP, LNB, Natural Gas	BACT-PSD
LA-0254	8/16/2011	Entergy Louisiana, LLC	Power County, LA	Auxiliary Boiler	338 MMBtu/hr	CO - 0.25 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
CT-0156	4/6/2010	NRG Energy	Montville, CT	Boiler	995 MMBtu/hr	NOx - 0.06 lb/MMBtu CO - 0.084 lb/MMBtu PM - 0.0076 lb/MMBtu	Dry ESP, SCR, Oxidation Catalyst	BACT-PSD
LA-0238	7/10/2009	ConocoPhillips Company	Plaquemines County, LA	Boiler	831.3 MMBtu/hr	CO - 0.456 lb/MMBtu SO2 - 1.55 lb/MMBtu	Cortometric High Intensity Combustion Units	BACT-PSD
LA-0233	1/30/2009	Citgo Petroleum Company	Calcasieu County, LA	Boiler	337.6 MMBtu/hr	CO - 0.122 lb/MMBtu	GCP	BACT-PSD
AR-0094	11/5/2008	Southwest Electric Power Company	Fulton County, AR	Auxiliary Boiler	555 MMBtu/hr	NOx - 0.11 lb/MMBtu CO - 0.036 lb/MMBtu SO2 - 0.0006 lb/MMBtu	LNB	BACT-PSD
ND-0025	12/20/2007	Tharaldson Ethanol Plant 1, LLC	Cass County, ND	Boiler	480 MMBtu/hr	NOx - 0.033 lb/MMBtu CO - 0.09 lb/MMBtu	LNB	BACT-PSD
IA-0088	6/29/2007	Archer Daniels Midland	Linn County, IA	Boiler	292.5 MMBtu/hr	NOx - 0.02 lb/MMBtu CO - 0.072 lb/MMBtu PM - 0.005 lb/MMBtu SO2 - 0.0006 lb/MMBtu	GCP, LNB, Natural Gas Fuel Only	BACT-PSD

WI-0244	6/19/2007	Appleton Coated	Outagamie County, WI	Boiler	285 MMBtu/hr	NOx - 0.09 lb/MMBtu CO - 0.12 lb/MMBtu SO2 - 0.365 lb/MMBtu	GCP, LNB, FGR, Natural Gas	BACT-PSD
TX-0511	2/3/2006	BASF Fina Petrochemicals	Jefferson County, TX	Boiler	425.4 MMBtu/hr	NOx - 0.02 lb/MMBtu CO - 0.07 lb/MMBtu SO2 - 0.028 lb/MMBtu		BACT-PSD
LA-0177	9/8/2005	Amerada Hess Corp	Vermillion County, LA	Boiler	363 MMBtu/hr	NOx - 0.04 lb/MMBtu	LNB	BACT-PSD
WA-0324	6/16/2005	Phillips 66	Whatcom County, WA	Boiler		NOx - 127 PPM @ 15% O2 CO - 100 PPM @ 15% O2	GCP, SNCR	BACT-PSD
WA-0301	4/20/2005	British Petroleum	Whatcom County, WA	Boiler	363 MMBtu/hr	NOx - 0.028 lb/MMBtu CO - 0.05 lb/MMBtu	GCP, LNB, FGR	BACT-PSD
AZ-0046	4/14/2005	Arizona Clean Fuels Yuma LLC	Yuma County, AZ	Boiler	419 MMBtu/hr	NOx - 0.0125 lb/MMBtu CO - 0.016 lb/MMBtu	LNB	BACT-PSD

RBLC ID	Permit Issuance Date	Company	Location	Description	Maximum Production Rate	Pollutant	Limit	Control	Basis
TX-0763	9/4/2015	PHILLIPS 66 COMPANY	HUTCHINSON, TX	Boiler	560 MMBtu/hr	NOx	0.015 lb/MMBtu	SCR	BACT-PSD
TX-0763	9/4/2015	PHILLIPS 66 COMPANY	HUTCHINSON, TX	Boiler	462 MMBtu/hr	NOx	0.040 lb/MMBtu		BACT-PSD
TX-0763	9/4/2015	PHILLIPS 66 COMPANY	HUTCHINSON, TX	Boiler	365 MMBtu/hr	NOx	0.015 lb/MMBtu	SCR	BACT-PSD
TX-0763	9/4/2015	PHILLIPS 66 COMPANY	HUTCHINSON, TX	Boiler	560 MMBtu/hr	PM	0.007 lb/MMBtu		BACT-PSD
TX-0763	9/4/2015	PHILLIPS 66 COMPANY	HUTCHINSON, TX	Boiler	462 MMBtu/hr	PM	0.007 lb/MMBtu		BACT-PSD
TX-0763	9/4/2015	PHILLIPS 66 COMPANY	HUTCHINSON, TX	Boiler	462 MMBtu/hr	PM	0.007 lb/MMBtu		BACT-PSD
TX-0763	9/4/2015	PHILLIPS 66	HUTCHINSO	Boiler	365 MMBtu/hr	PM	0.007 lb/MMBtu		BACT-PSD
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT, MD	Auxiliary Boiler	435 MMBtu/hr	NOx	0.010 lb/MMBtu	SCR, LNB, Process Fuel	LAER
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT, MD	Auxiliary Boiler	435 MMBtu/hr	CO	0.009 lb/MMBtu	GCP, Oxidation	BACT-PSD
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT, MD	Auxiliary Boiler	435 MMBtu/hr	PM	0.005 lb/MMBtu	Process Fuel Gas, GCP	BACT-PSD
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT, MD	Auxiliary Boiler	435 MMBtu/hr	PM	0.014 lb/MMBtu	Process Fuel Gas, GCP	BACT-PSD
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT, MD	Auxiliary Boiler	435 MMBtu/hr	PM	0.014 lb/MMBtu	Process Fuel Gas, GCP	BACT-PSD
DE-0020	2/26/2010	VALERO ENERGY CORP	NEW CASTLE, DE	Boiler	618 MMBtu/hr	NOx	0.015 lb/MMBtu	SCR, FGR	BACT-PSD

DE-0020	2/26/2010	VALERO ENERGY CORP	NEW CASTLE, DE	Boiler	618 MMBtu/hr	NOx	0.015 lb/MMBtu	SCR, FGR	BACT-PSD
TX-0597	12/11/2009	CONOCOPHILLIPS COMPANY	HUTCHINSON, TX	Boiler	462 MMBtu/hr	NOx	0.115 lb/MMBtu		BACT-PSD
TX-0597	12/11/2009	CONOCOPHILLIPS COMPANY	HUTCHINSON, TX	Boiler	365 MMBtu/hr	NOx	0.010 lb/MMBtu	SCR	BACT-PSD
TX-0597	12/11/2009	CONOCOPHILLIPS COMPANY	HUTCHINSON, TX	Boiler	462 MMBtu/hr	PM	0.007 lb/MMBtu	GCP	BACT-PSD
TX-0597	12/11/2009	CONOCOPHILLIPS COMPANY	HUTCHINSON, TX	Boiler	365 MMBtu/hr	PM	0.007 lb/MMBtu		BACT-PSD
LA-0213	11/17/2009	VALERO REFINING - NEW ORLEANS, LLC	ST. CHARLES, LA	Boiler	715 MMBtu/hr	CO	0.080 lb/MMBtu	40 CFR 60 NNN and RRR	BACT-PSD
LA-0213	11/17/2009	VALERO REFINING - NEW ORLEANS, LLC	ST. CHARLES, LA	Boiler	354 MMBtu/hr	NOx	0.131 lb/MMBtu	Fuel, LNB	BACT-PSD
LA-0213	11/17/2009	VALERO REFINING - NEW ORLEANS, LLC	ST. CHARLES, LA	Boiler	715 MMBtu/hr	NOx	0.040 lb/MMBtu	LNB, FGR	BACT-PSD
LA-0213	11/17/2009	VALERO REFINING - NEW ORLEANS, LLC	ST. CHARLES, LA	Boiler	354 MMBtu/hr	CO	0.082 lb/MMBtu	GCP	BACT-PSD
LA-0213	11/17/2009	VALERO REFINING - NEW ORLEANS, LLC	ST. CHARLES, LA	Boiler	525 MMBtu/hr	CO	0.080 lb/MMBtu	GCP	BACT-PSD
LA-0213	11/17/2009	VALERO REFINING - NEW ORLEANS, LLC	ST. CHARLES, LA	Boiler	354 MMBtu/hr	SO2	0.027 lb/MMBtu	Natural Gas	BACT-PSD
LA-0213	11/17/2009	VALERO REFINING - NEW ORLEANS, LLC	ST. CHARLES, LA	Boiler	354 MMBtu/hr	PM	0.007 lb/MMBtu	Clean Fuels	BACT-PSD
OH-0308	2/23/2009	SUNOCO, INC.	LUCAS, OH	Boiler	374 MMBtu/hr	NOx	0.036 lb/MMBtu	LNB, FGR	N/A

OH-0308	2/23/2009	SUNOCO, INC.	LUCAS, OH	Boiler	374 MMBtu/hr	CO	0.075 lb/MMBtu		BACT-PSD
OH-0308	2/23/2009	SUNOCO, INC.	LUCAS, OH	Boiler	374 MMBtu/hr	SO2	0.027 lb/MMBtu		BACT-PSD
OH-0308	2/23/2009	SUNOCO, INC.	LUCAS, OH	Boiler	374 MMBtu/hr	PM	0.007 lb/MMBtu		BACT-PSD
WA-0343	11/17/2007	BP WEST COAST PRODUCTS LLC	WHATCOM, WA	Boiler	363 MMBtu/hr	CO	0.037 lb/MMBtu	GCP	BACT-PSD
WA-0343	11/17/2007	BP WEST COAST PRODUCTS LLC	WHATCOM, WA	Boiler	363 MMBtu/hr	SO2	0.037 lb/MMBtu	Natural Gas	BACT-PSD
WA-0343	11/17/2007	BP WEST COAST PRODUCTS LLC	WHATCOM, WA	Boiler	363 MMBtu/hr	PM	0.009 lb/MMBtu	Refinery Fuel Gas/Natural Gas	BACT-PSD
LA-0211	12/27/2006	MARATHON PETROLEUM CO LLC	ST. JOHN THE BAPTIST, LA	Boiler	526 MMBtu/hr	NOx	0.400 lb/MMBtu	LNB, FGR	BACT-PSD
LA-0211	12/27/2006	MARATHON PETROLEUM CO LLC	ST. JOHN THE BAPTIST, LA	Boiler	526 MMBtu/hr	CO	0.040 lb/MMBtu	GCP	BACT-PSD
LA-0211	12/27/2006	MARATHON PETROLEUM CO LLC	ST. JOHN THE BAPTIST, LA	Boiler	526 MMBtu/hr	PM	0.008 lb/MMBtu	GCP	BACT-PSD
TX-0490	12/20/2006	CONOCOPHILLIPS	HUTCHINSON, TX	Boiler	598 MMBtu/hr	NOx	0.020 lb/MMBtu	LNB, FGR	BACT-PSD
TX-0490	12/20/2006	CONOCOPHILLIPS	HUTCHINSON, TX	Boiler	598 MMBtu/hr	CO	0.167 lb/MMBtu	GCP	BACT-PSD

RBLC ID	Permit Issuance Date	Company	Location	Decription	Throughput	Pollutant	Limit	Controls	Basis
AK-0083	1/6/2015	Agrium U.S. Inc.		Startup Heater	101 MMBtu/hr	PM	0.007 lb/MMBtu	Limited Use (200 hr/yr)	BACT-PSD
AK-0083	1/6/2015	Agrium U.S. Inc.		Startup Heater	101 MMBtu/hr	PM	0.007 lb/MMBtu		BACT-PSD
AK-0083	1/6/2015	Agrium U.S. Inc.		Startup Heater	101 MMBtu/hr	PM	0.007 lb/MMBtu	Limited Use (200 hr/yr)	BACT-PSD
AK-0083	1/6/2015	Agrium U.S. Inc.		Startup Heater	101 MMBtu/hr	VOC	0.005 lb/MMBtu	Limited Use (200 hr/yr)	BACT-PSD
AK-0083	1/6/2015	Agrium U.S. Inc.		Startup Heater	101 MMBtu/hr	CO	0.082 lb/MMBtu	Limited Use (200 hr/yr)	BACT-PSD
AK-0083	1/6/2015	Agrium U.S. Inc.		Startup Heater	101 MMBtu/hr	NOx	0.098 lb/MMBtu	Limited Use (200 hr/yr)	BACT-PSD
IA-0105	10/26/2012	Iowa Fertilizer Company	Lee County, IA	Startup Heater	110.1 MMBtu/hr	PM	0.002 lb/MMBtu	GCP	BACT-PSD
IA-0105	10/26/2012	Iowa Fertilizer Company	Lee County, IA	Startup Heater	110.1 MMBtu/hr	PM	0.002 lb/MMBtu	GCP	BACT-PSD
IA-0105	10/26/2012	Iowa Fertilizer Company	Lee County, IA	Startup Heater	110.1 MMBtu/hr	PM	0.002 lb/MMBtu	GCP	BACT-PSD
IA-0105	10/26/2012	Iowa Fertilizer Company	Lee County, IA	Startup Heater	110.1 MMBtu/hr	VOC	0.001 lb/MMBtu	GCP	BACT-PSD

IA-0105	10/26/2012	Iowa Fertilizer Company	Lee County, IA	Startup Heater	110.1 MMBtu/hr	CO	0.019 lb/MMBtu	GCP	BACT-PSD
IA-0105	10/26/2012	Iowa Fertilizer Company	Lee County, IA	Startup Heater	110.1 MMBtu/hr	NOx	0.119 lb/MMBtu	GCP	BACT-PSD
IA-0106	7/12/2013	CF Industries Nitrogen, LLC	Woodbury County, IA	Startup Heater	58.8 MMBtu/hr	PM	0.002 lb/MMBtu	GCP	BACT-PSD
IA-0106	7/12/2013	CF Industries Nitrogen, LLC	Woodbury County, IA	Startup Heater	58.8 MMBtu/hr	PM	0.002 lb/MMBtu	GCP	BACT-PSD
IA-0106	7/12/2013	CF Industries Nitrogen, LLC	Woodbury County, IA	Startup Heater	58.8 MMBtu/hr	PM	0.002 lb/MMBtu	GCP	BACT-PSD
IA-0106	7/12/2013	CF Industries Nitrogen, LLC	Woodbury County, IA	Startup Heater	58.8 MMBtu/hr	VOC	0.001 lb/MMBtu	GCP	BACT-PSD
IA-0106	7/12/2013	CF Industries Nitrogen, LLC	Woodbury County, IA	Startup Heater	58.8 MMBtu/hr	CO	0.019 lb/MMBtu	GCP	BACT-PSD
IL-0114	9/5/2014	Cronus Chemicals, Llc	Douglas County, IL	Startup Heater	104 MMBtu/hr	PM	0.008 lb/MMBtu	GCP	BACT-PSD
IL-0114	9/5/2014	Cronus Chemicals, LLC	Douglas County, IL	Startup Heater	104 MMBtu/hr	PM	0.008 lb/MMBtu	GCP	BACT-PSD

IL-0114	9/5/2014	Cronus Chemicals, LLC	Douglas County, IL	Startup Heater	104 MMBtu/hr	VOC	0.005 lb/MMBtu	GCP	BACT-PSD
IL-0114	9/5/2014	Cronus Chemicals, LLC	Douglas County, IL	Startup Heater	104 MMBtu/hr	CO	0.037 lb/MMBtu	GCP	BACT-PSD
IL-0114	9/5/2014	Cronus Chemicals, LLC	Douglas County, IL	Startup Heater	104 MMBtu/hr	NOx	0.080 lb/MMBtu	GCP	BACT-PSD
IL-0114	9/5/2014	Cronus Chemicals, LLC	Douglas County, IL	Startup Heater	104 MMBtu/hr	PM	0.002 lb/MMBtu	GCP	BACT-PSD
IN-0173	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Startup Heater	92.5 MMBtu/hr	PM	0.007 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
IN-0173	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Startup Heater	92.5 MMBtu/hr	PM	0.007 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
IN-0173	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Startup Heater	92.5 MMBtu/hr	VOC	0.005 lb/MMBtu	GCP	BACT-PSD
IN-0173	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Startup Heater	92.5 MMBtu/hr	CO	0.037 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
IN-0173	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Startup Heater	92.5 MMBtu/hr	NOx	0.180 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
IN-0173	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Startup Heater	92.5 MMBtu/hr	PM	0.002 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
IN-0179	9/25/2013	Ohio Valley Resources, LLC	Spencer County, IN	Ammonia Catalyst Startup Heater	106.3 MMBtu/hr	PM	0.007 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD

IN-0179	9/25/2013	Ohio Valley Resources, LLC	Spencer County, IN	Ammonia Catalyst Startup Heater	106.3 MMBtu/hr	PM	0.007 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
IN-0179	9/25/2013	Ohio Valley Resources, LLC	Spencer County, IN	Ammonia Catalyst Startup Heater	106.3 MMBtu/hr	VOC	0.005 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
IN-0179	9/25/2013	Ohio Valley Resources, LLC	Spencer County, IN	Ammonia Catalyst Startup Heater	106.3 MMBtu/hr	CO	0.037 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
IN-0179	9/25/2013	Ohio Valley Resources, LLC	Spencer County, IN	Ammonia Catalyst Startup Heater	106.3 MMBtu/hr	NOx	0.180 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
IN-0179	9/25/2013	Ohio Valley Resources, LLC	Spencer County, IN	Ammonia Catalyst Startup Heater	106.3 MMBtu/hr	PM	0.002 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
IN-0180	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Startup Heater	92.5 MMBtu/hr	PM	0.007 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
IN-0180	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Startup Heater	92.5 MMBtu/hr	PM	0.007 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
IN-0180	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Startup Heater	92.5 MMBtu/hr	VOC	0.005 lb/MMBtu	GCP	BACT-PSD
IN-0180	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Startup Heater	92.5 MMBtu/hr	CO	0.037 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD

IN-0180	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Startup Heater	92.5 MMBtu/hr	NOx	0.180 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
IN-0180	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Startup Heater	92.5 MMBtu/hr	PM	0.002 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
LA-0231	6/22/2009	Lake Charles Cogeneration, LLC	Calcasieu County, LA	Shift Reactor Startup Heater	34.2 MMBtu/hr	PM	0.007 lb/MMBtu	GCP	BACT-PSD
LA-0231	6/22/2009	Lake Charles Cogeneration, LLC	Calcasieu County, LA	Shift Reactor Startup Heater	34.2 MMBtu/hr	CO	0.082 lb/MMBtu	GCP	BACT-PSD
LA-0231	6/22/2009	Lake Charles Cogeneration, LLC	Calcasieu County, LA	Shift Reactor Startup Heater	34.2 MMBtu/hr	NOx	0.098 lb/MMBtu	GCP	BACT-PSD
LA-0231	6/22/2009	Lake Charles Cogeneration, LLC	Calcasieu County, LA	Shift Reactor Startup Heater	34.2 MMBtu/hr	SO2	0.001 lb/MMBtu	Natural Gas Fuel	BACT-PSD
LA-0231	6/22/2009	Lake Charles Cogeneration, LLC	Calcasieu County, LA	Gasifier Startup Preheater Burners	35 MMBtu/hr	PM	0.001 lb/MMBtu	GCP	BACT-PSD
LA-0231	6/22/2009	Lake Charles Cogeneration, LLC	Calcasieu County, LA	Gasifier Startup Preheater Burners	35 MMBtu/hr	CO	0.056 lb/MMBtu	GCP	BACT-PSD
LA-0231	6/22/2009	Lake Charles Cogeneration, LLC	Calcasieu County, LA	Gasifier Startup Preheater Burners	35 MMBtu/hr	NOx	0.110 lb/MMBtu	GCP	BACT-PSD

LA-0231	6/22/2009	Lake Charles Cogeneration, LLC	Calcasieu County, LA	Gasifier Startup Preheater Burners	35 MMBtu/hr	SO2	0.001 lb/MMBtu	Natural Gas Fuel	BACT-PSD
LA-0231	6/22/2009	Lake Charles Cogeneration, LLC	Calcasieu County, LA	Methanation Startup Heater	56.9 MMBtu/hr	PM	0.007 lb/MMBtu	GCP	BACT-PSD
LA-0231	6/22/2009	Lake Charles Cogeneration, LLC	Calcasieu County, LA	Methanation Startup Heater	56.9 MMBtu/hr	CO	0.082 lb/MMBtu	GCP	BACT-PSD
LA-0231	6/22/2009	Lake Charles Cogeneration, LLC	Calcasieu County, LA	Methanation Startup Heater	56.9 MMBtu/hr	NOx	0.098 lb/MMBtu	GCP	BACT-PSD
LA-0231	6/22/2009	Lake Charles Cogeneration, LLC	Calcasieu County, LA	Methanation Startup Heater	56.9 MMBtu/hr	SO2	0.001 lb/MMBtu	Natural Gas Fuel	BACT-PSD

RBLC ID	Permit Issuance Date	Company	Location	Description	Power	Pollutant	Limit	Control	Basis
TX-0773	11/4/2015	FGE EAGLE PINES, LLC	CHEROKEE, TX	Combustion Turbine	321 MW	PM	0.020 lb/MMBtu		BACT-PSD
TX-0773	11/4/2015	FGE EAGLE PINES, LLC	CHEROKEE, TX	Combustion Turbine	321 MW	PM	0.020 lb/MMBtu		BACT-PSD
TX-0767	10/2/2015	LON C. HILL, L.P.	NUECES, TX	Combustion Turbine	195 MW	PM	0.024 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
TX-0767	10/2/2015	LON C. HILL, L.P.	NUECES, TX	Combustion Turbine	195 MW	PM	0.024 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
TX-0751	6/18/2015	EAGLE MOUNTAIN POWER COMPANY LLC	TARRANT, TX	Combustion Turbine	210 MW	SO2	0.057 lb/MMBtu		BACT-PSD
TX-0751	6/18/2015	EAGLE MOUNTAIN POWER COMPANY LLC	TARRANT, TX	Combustion Turbine	210 MW	PM	0.050 lb/MMBtu		BACT-PSD
TX-0751	6/18/2015	EAGLE MOUNTAIN POWER COMPANY LLC	TARRANT, TX	Combustion Turbine	210 MW	PM	0.050 lb/MMBtu		BACT-PSD
TX-0678	7/16/2014	FREEPORT LNG DEVELOPMENT LP	BRAZORIA, TX	Combustion Turbine	87 MW	SO2	0.012 lb/MMBtu		BACT-PSD
TX-0678	7/16/2014	FREEPORT LNG DEVELOPMENT LP	BRAZORIA, TX	Combustion Turbine	87 MW	PM	0.051 lb/MMBtu		BACT-PSD
MD-0041	4/23/2014	CPV MARYLAND, LLC	CHARLES, MD	Combustion Turbine	725 MW	NOx	0.030 lb/MMBtu	SCR, LNB	LAER
MD-0042	4/8/2014	OLD DOMINION ELECTRIC CORPORATION (ODEC)	CECIL, MD	Combustion Turbine	270 MW	SO2	0.007 lb/MMBtu	Natural Gas Fuel	BACT-PSD

MD-0042	4/8/2014	OLD DOMINION ELECTRIC CORPORATION (ODEC)	CECIL, MD	Combustion Turbine	270 MW	PM	0.016 lb/MMBtu	Natural Gas Fuel	BACT-PSD
MD-0042	4/8/2014	OLD DOMINION ELECTRIC CORPORATION (ODEC)	CECIL, MD	Combustion Turbine	270 MW	PM	0.027 lb/MMBtu	Natural Gas Fuel	BACT-PSD
MD-0042	4/8/2014	OLD DOMINION ELECTRIC CORPORATION (ODEC)	CECIL, MD	Combustion Turbine	270 MW	PM	0.027 lb/MMBtu	Natural Gas Fuel	BACT-PSD
OH-0356	12/18/2012	DUKE ENERGY HANGING ROCK, LLC	LAWRENCE, OH	Combustion Turbine	172 MW	NOx	0.036 lb/MMBtu	SCR, LNB	BACT-PSD
OH-0356	12/18/2012	DUKE ENERGY HANGING ROCK, LLC	LAWRENCE, OH	Combustion Turbine	172 MW	NOx	0.047 lb/MMBtu	SCR, LNB	BACT-PSD
OH-0356	12/18/2012	DUKE ENERGY HANGING ROCK, LLC	LAWRENCE, OH	Combustion Turbine	172 MW	CO	0.044 lb/MMBtu	GCP	BACT-PSD
OH-0356	12/18/2012	DUKE ENERGY HANGING ROCK, LLC	LAWRENCE, OH	Combustion Turbine	172 MW	CO	0.078 lb/MMBtu	GCP	BACT-PSD
OH-0356	12/18/2012	DUKE ENERGY HANGING ROCK, LLC	LAWRENCE, OH	Combustion Turbine	172 MW	SO2	0.002 lb/MMBtu	Natural Gas Fuel	BACT-PSD
OH-0356	12/18/2012	DUKE ENERGY HANGING ROCK, LLC	LAWRENCE, OH	Combustion Turbine	172 MW	SO2	0.002 lb/MMBtu	Natural Gas Fuel	BACT-PSD
OH-0356	12/18/2012	DUKE ENERGY HANGING ROCK, LLC	LAWRENCE, OH	Combustion Turbine	172 MW	PM	0.026 lb/MMBtu	Natural Gas FUel	BACT-PSD
OH-0356	12/18/2012	DUKE ENERGY HANGING ROCK, LLC	LAWRENCE, OH	Combustion Turbine	172 MW	PM	0.034 lb/MMBtu	Natural Gas FUel	BACT-PSD
TX-0618	10/15/2012	CHANNEL ENERGY CENTER LLC	HARRIS, TX	Combustion Turbine	180 MW	PM	0.044 lb/MMBtu	GCP, Gaseous Fuel	BACT-PSD
TX-0618	10/15/2012	CHANNEL ENERGY CENTER LLC	HARRIS, TX	Combustion Turbine	180 MW	PM	0.044 lb/MMBtu	GCP, Gaseous Fuel	BACT-PSD

TX-0618	10/15/2012	CHANNEL ENERGY CENTER LLC	HARRIS, TX	Combustion Turbine	180 MW	PM	0.044 lb/MMBtu	GCP, Gaseous Fuel	BACT-PSD
TX-0619	9/26/2012	DEER PARK ENERGY CENTER LLC	HARRIS, TX	Combustion Turbine	180 MW	PM	0.044 lb/MMBtu	GCP, Gaseous Fuel	BACT-PSD
TX-0619	9/26/2012	DEER PARK ENERGY CENTER LLC	HARRIS, TX	Combustion Turbine	180 MW	PM	0.044 lb/MMBtu	GCP, Gaseous Fuel	BACT-PSD
TX-0619	9/26/2012	DEER PARK ENERGY CENTER LLC	HARRIS, TX	Combustion Turbine	180 MW	PM	0.044 lb/MMBtu		BACT-PSD
TX-0620	9/12/2012	CALHOUN PORT AUTHORITY	CALHOUN, TX	Combustion Turbine	195 MW	PM	0.027 lb/MMBtu		BACT-PSD
TX-0620	9/12/2012	CALHOUN PORT AUTHORITY	CALHOUN, TX	Combustion Turbine	195 MW	PM	0.027 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
TX-0620	9/12/2012	CALHOUN PORT AUTHORITY	CALHOUN, TX	Combustion Turbine	195 MW	PM	0.027 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
WY-0070	8/28/2012	BLACK HILLS POWER, INC.	LARAMIE, WY	Combustion Turbine	40 MW	NOx	0.034 lb/MMBtu	SCR	BACT-PSD
WY-0070	8/28/2012	BLACK HILLS POWER, INC.	LARAMIE, WY	Combustion Turbine	40 MW	NOx	0.034 lb/MMBtu	SCR	BACT-PSD
WY-0070	8/28/2012	BLACK HILLS POWER, INC.	LARAMIE, WY	Combustion Turbine	40 MW	CO	0.027 lb/MMBtu	Oxidation Catalyst	BACT-PSD
WY-0070	8/28/2012	BLACK HILLS POWER, INC.	LARAMIE, WY	Combustion Turbine	40 MW	CO	0.027 lb/MMBtu	Oxidation Catalyst	BACT-PSD
WY-0070	8/28/2012	BLACK HILLS POWER, INC.	LARAMIE, WY	Combustion Turbine	40 MW	PM	0.029 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD

WY-0070	8/28/2012	BLACK HILLS POWER, INC.	LARAMIE, WY	Combustion Turbine	40 MW	PM	0.029 lb/MMBtu	GCP, Natural Gas Fuel	BACT-PSD
MI-0402	11/17/2011	WOLVERINE POWER SUPPLY COOPERATIVE INC.	WAYNE, MI	Combustion Turbine	130 MW	NOx	0.083 lb/MMBtu	SCR, LNB	BACT-PSD
MI-0402	11/17/2011	WOLVERINE POWER SUPPLY COOPERATIVE INC.	WAYNE, MI	Combustion Turbine	130 MW	CO	0.121 lb/MMBtu		Other Case-by-Case
MI-0402	11/17/2011	WOLVERINE POWER SUPPLY COOPERATIVE INC.	WAYNE, MI	Combustion Turbine	130 MW	PM	0.007 lb/MMBtu		Other Case-by-Case
MI-0402	11/17/2011	WOLVERINE POWER SUPPLY COOPERATIVE INC.	WAYNE, MI	Combustion Turbine	130 MW	PM	0.007 lb/MMBtu		BACT-PSD
CA-1212	10/18/2011	CITY OF PALMDALE	LOS ANGELES, CA	Combustion Turbine	154 MW	PM	0.005 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1212	10/18/2011	CITY OF PALMDALE	LOS ANGELES, CA	Combustion Turbine	154 MW	PM	0.005 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1212	10/18/2011	CITY OF PALMDALE	LOS ANGELES, CA	Combustion Turbine	154 MW	PM	0.005 lb/MMBtu	Natural Gas Fuel	BACT-PSD
TX-0600	9/1/2011	LOWER COLORADO RIVER AUTHORITY	LLANO, TX	Combustion Turbine	390 MW	SO2	0.020 lb/MMBtu	Natural Gas Fuel	BACT-PSD
TX-0600	9/1/2011	LOWER COLORADO RIVER AUTHORITY	LLANO, TX	Combustion Turbine	390 MW	PM	0.025 lb/MMBtu	Natural Gas FUel	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	NOx	0.022 lb/MMBtu	SCR, LNB	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	NOx	0.028 lb/MMBtu	SCR, LNB	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	NOx	0.261 lb/MMBtu	SCR, LNB	BACT-PSD

CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	NOx	0.022 lb/MMBtu	SCR, LNB	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	NOx	0.028 lb/MMBtu	SCR, LNB	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	NOx	0.261 lb/MMBtu	SCR, LNB	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	CO	0.010 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	CO	0.016 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	CO	3.146 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	CO	0.010 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	CO	0.016 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	CO	3.097 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	PM	0.015 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	PM	0.015 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	PM	0.019 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	PM	0.019 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	PM	0.015 lb/MMBtu	Natural Gas Fuel	BACT-PSD

CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	PM	0.015 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	PM	0.019 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1192	6/21/2011	AVENAL POWER CENTER LLC	KINGS, CA	Combustion Turbine	180 MW	PM	0.019 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	NOx	0.426 lb/MMBtu	SCR, LNB	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	NOx	0.259 lb/MMBtu	SCR, LNB	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	NOx	0.196 lb/MMBtu	SCR, LNB	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	NOx	0.033 lb/MMBtu	SCR, LNB	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	NOx	0.568 lb/MMBtu	SCR, LNB	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	CO	0.637 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	CO	0.631 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	CO	0.824 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	CO	0.031 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	CO	0.732 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	SO2	0.001 lb/MMBtu		BACT-PSD

CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	SO2	0.001 lb/MMBtu		BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	SO2	0.000 lb/MMBtu		BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	PM	0.020 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	PM	0.020 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	PM	0.020 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	PM	0.020 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	PM	0.010 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	PM	0.010 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	PM	0.023 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	PM	0.023 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	PM	0.020 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1211	3/11/2011	PACIFIC GAS & ELECTRIC COMPANY	COLUSA, CA	Combustion Turbine	172 MW	PM	0.020 lb/MMBtu	Natural Gas Fuel	BACT-PSD
IL-0112	12/28/2010	INVENERGY NELSON, LLC	LEE, IL	Combustion Turbine	220 MW	SO2	0.006 lb/MMBtu		BACT-PSD
IL-0112	12/28/2010	INVENERGY NELSON, LLC	LEE, IL	Combustion Turbine	220 MW	PM	0.012 lb/MMBtu		BACT-PSD
IL-0112	12/28/2010	INVENERGY NELSON, LLC	LEE, IL	Combustion Turbine	220 MW	PM	0.006 lb/MMBtu		BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	NOx	0.100 lb/MMBtu	SCR	BACT-PSD

CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	NOx	0.057 lb/MMBtu	SCR	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	NOx	0.217 lb/MMBtu	SCR	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	NOx	0.022 lb/MMBtu	SCR	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	NOx	0.100 lb/MMBtu	SCR	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	NOx	0.057 lb/MMBtu	SCR	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	NOx	0.217 lb/MMBtu	SCR	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	NOx	0.022 lb/MMBtu	SCR	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	NOx	0.028 lb/MMBtu	SCR	BACT-PSD
CA-1209	3/11/2010	HIGH DESERT POWER PROJECT LLC	SAN BERNADINO, CA	Combustion Turbine	190 MW	NOx	0.028 lb/MMBtu	SCR, LNB	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	CO	0.426 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	CO	0.470 lb/MMBtu	Oxidation Catalyst	BACT-PSD

CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	CO	1.283 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	CO	0.015 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	CO	0.426 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	CO	0.470 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	CO	0.641 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	CO	0.025 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	CO	0.015 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	CO	0.025 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1209	3/11/2010	HIGH DESERT POWER PROJECT LLC	SAN BERNADINO, CA	Combustion Turbine	190 MW	CO	0.027 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	PM	0.023 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	PM	0.023 lb/MMBtu	Natural Gas Fuel	BACT-PSD

CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	PM	0.034 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	PM	0.034 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	PM	0.023 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	PM	0.023 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	PM	0.034 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1191	3/11/2010	CITY OF VICTORVILLE	SAN BERNARDINO, CA	Combustion Turbine	154 MW	PM	0.034 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1198	9/25/2008	DYNERGY MORRO BAY LLC	SAN LUIS OBISPO, CA	Combustion Turbine	180 MW	PM	0.018 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1198	9/25/2008	DYNERGY MORRO BAY LLC	SAN LUIS OBISPO, CA	Combustion Turbine	180 MW	PM	0.018 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1198	9/25/2008	DYNERGY MORRO BAY LLC	SAN LUIS OBISPO, CA	Combustion Turbine	180 MW	PM	0.018 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1198	9/25/2008	DYNERGY MORRO BAY LLC	SAN LUIS OBISPO, CA	Combustion Turbine	180 MW	PM	0.018 lb/MMBtu	Natural Gas Fuel	BACT-PSD
CA-1144	4/25/2007	CAITHNESS BLYTHE II, LLC	RIVERSIDE, CA	Combustion Turbine	170 MW	NOx	0.026 lb/MMBtu	SCR	BACT-PSD

CA-1144	4/25/2007	CAITHNESS BLYTHE II, LLC	RIVERSIDE, CA	Combustion Turbine	170 MW	CO	0.031 lb/MMBtu	Oxidation Catalyst	BACT-PSD
CA-1144	4/25/2007	CAITHNESS BLYTHE II, LLC	RIVERSIDE, CA	Combustion Turbine	170 MW	PM	0.010 lb/MMBtu	Natural Gas Fuel	BACT-PSD
TX-0497	8/29/2006	INEOS USA LLC	BRAZORIA, TX	Combustion Turbine	35 MW	NOx	0.096 lb/MMBtu	SCR, LNB	BACT-PSD
TX-0497	8/29/2006	INEOS USA LLC	BRAZORIA, TX	Combustion Turbine	35 MW	CO	0.559 lb/MMBtu	GCP	BACT-PSD
TX-0497	8/29/2006	INEOS USA LLC	BRAZORIA, TX	Combustion Turbine	35 MW	SO2	0.106 lb/MMBtu	Natural Gas Fuel	BACT-PSD
TX-0497	8/29/2006	INEOS USA LLC	BRAZORIA, TX	Combustion Turbine	35 MW	PM	0.084 lb/MMBtu	Natural Gas FUel	BACT-PSD
TX-0502	6/5/2006	NACOGDOCHES POWER LLC	NACOGDOCHES, TX	Combustion Turbine	190 MW	NOx	0.070 lb/MMBtu	SCR, LNB	BACT-PSD
TX-0502	6/5/2006	NACOGDOCHES POWER LLC	NACOGDOCHES, TX	Combustion Turbine	190 MW	CO	0.169 lb/MMBtu	GCP	BACT-PSD
TX-0502	6/5/2006	NACOGDOCHES POWER LLC	NACOGDOCHES, TX	Combustion Turbine	190 MW	SO2	0.011 lb/MMBtu	Natural Gas Fuel	BACT-PSD
TX-0502	6/5/2006	NACOGDOCHES POWER LLC	NACOGDOCHES, TX	Combustion Turbine	190 MW	PM	0.041 lb/MMBtu	Natural Gas FUel	BACT-PSD
CO-0056	5/2/2006	CALPINE CORP.	WELD, CO	Combustion Turbine	300 MW	NOx	0.013 lb/MMBtu	SCR, LNB	BACT-PSD
CO-0056	5/2/2006	CALPINE CORP.	WELD, CO	Combustion Turbine	300 MW	CO	0.044 lb/MMBtu	GCP	BACT-PSD
CO-0056	5/2/2006	CALPINE CORP.	WELD, CO	Combustion Turbine	300 MW	PM	0.007 lb/MMBtu	Natural Gas, GCP	BACT-PSD
CA-1213	4/21/2006	MOUNTAINVIEW POWER COMPANY LLC	SAN BERNADINO, CA	Combustion Turbine	176 MW	NOx	0.024 lb/MMBtu	SCR, LNB	BACT-PSD
CA-1213	4/21/2006	MOUNTAINVIEW POWER COMPANY LLC	SAN BERNADINO, CA	Combustion Turbine	176 MW	NOx	0.267 lb/MMBtu	SCR, LNB	BACT-PSD

CA-1213	4/21/2006	MOUNTAINVIEW POWER COMPANY LLC	SAN BERNADINO, CA	Combustion Turbine	176 MW	NOx	0.133 lb/MMBtu	SCR, LNB	BACT-PSD
CA-1195	1/12/2006	ELK HILLS POWER LLC	KERN, CA	Combustion Turbine	166 MW	NOx	0.028 lb/MMBtu	SCR, LNB	BACT-PSD
CA-1195	1/12/2006	ELK HILLS POWER LLC	KERN, CA	Combustion Turbine	166 MW	CO	0.022 lb/MMBtu	SCR	BACT-PSD
NV-0035	8/16/2005	SIERRA PACIFIC POWER COMPANY	STOREY COUNTY, NV	Combustion Turbine	306 MW	PM	0.011 lb/MMBtu	GCP	BACT-PSD
NV-0035	8/16/2005	SIERRA PACIFIC POWER COMPANY	STOREY COUNTY, NV	Combustion Turbine	306 MW	PM	0.011 lb/MMBtu	GCP	BACT-PSD

RBLC ID	Permit Issuance Date	Company	Location	Description	Throughput	Pollutant	Limit	Controls	Basis
TX-0754	7/10/2015	THE DOW CHEMICAL COMPANY	BRAZORIA COUNTY, TX	COOLING TOWER	75,000 GPM	VOC		DRIFT ELIMINATORS	BACT-PSD
TX-0756	6/19/2015	CASTLETON COMMODITIES INTERNATIONAL (CCI) CORPUS C	NUECES COUNTY, TX	COOLING TOWER	15,000 GPM	VOC	0.67 LB/MMGAL	LOW DRIFT	BACT-PSD
FL-0318	12/10/2009	VERENIUM	HIGHLAND COUNTY, FL	COOLING TOWER	22,500 GPM	VOC	0.70 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
FL-0293	4/4/2006	PROGRESS ENERGY FLORIDA	CITRUS COUNTY, FL	COOLING TOWER	180,000 GPM	PM	1.11 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
FL-0294	12/22/2006	PROGRESS ENERGY FLORIDA	PASCO COUNTY, FL	COOLING TOWER	660,000 GPM	PM	0.62 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
FL-0316	2/20/2009	PROGRESS ENERGY FLORIDA	LEVY COUNTY, FL	COOLING TOWER	600,000 GPM	PM	3.22 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
FL-0323	12/28/2010	GAINESVILLE REGIONAL UTILITY (GRU) DEERHAVEN	ALACHUA COUNTY, FL	COOLING TOWER	78,000 GPM	PM	0.05 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
ID-0017	2/10/2009	SOUTHEAST IDAHO ENERGY, LLC	POWER COUNTY, ID	COOLING TOWER	121,000 GPM	PM	0.21 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
ID-0017	2/10/2009	SOUTHEAST IDAHO ENERGY, LLC	POWER COUNTY, ID	COOLING TOWER	121,000 GPM	PM	0.21 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD

LA-0148	5/28/2008	RED RIVER ENVIRONMENTAL PRODUCTS LLC	RED RIVER COUNTY, LA	COOLING TOWER	10,750 GPM	PM	0.64 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
LA-0192	6/6/2005	CRESENT CITY POWER, LLC	ORLEANS COUNTY, LA	COOLING TOWER	290,200 GPM	PM	0.15 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
LA-0192	6/6/2005	CRESENT CITY POWER, LLC	ORLEANS COUNTY, LA	COOLING TOWER	35,000 GPM	PM	0.83 LB/MMGAL		BACT-PSD
LA-0204	2/27/2009	SHINTECH LOUISIANA LLC	IBERVILLE COUNTY, LA	COOLING TOWER	38,750 GPM	PM	0.08 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
LA-0204	2/27/2009	SHINTECH LOUISIANA LLC	IBERVILLE COUNTY, LA	COOLING TOWER	106,000 GPM	PM	0.06 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
LA-0204	2/27/2009	SHINTECH LOUISIANA LLC	IBERVILLE COUNTY, LA	COOLING TOWER	43,000 GPM	PM	0.06 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
LA-0224	3/20/2008	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	CADDO COUNTY, LA	COOLING TOWER	140,000 GPM	PM	0.17 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
LA-0229	7/10/2008	SHINTECH LOUISIANA LLC	IBERVILLE COUNTY, LA	COOLING TOWER	38,750 GPM	PM	0.08 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
LA-0229	7/10/2008	SHINTECH LOUISIANA LLC	IBERVILLE COUNTY, LA	COOLING TOWER	106,000 GPM	PM	0.06 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
LA-0248	1/27/2011	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC - NUCOR	ST JAMES PARISH COUNTY, LA	COOLING TOWER	26,857 GPM	PM	0.07 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD

LA-0248	1/27/2011	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC - NUCOR	ST JAMES PARISH COUNTY, LA	COOLING TOWER	26,857 GPM	PM	0.07 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
LA-0248	1/27/2011	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC - NUCOR	ST JAMES PARISH COUNTY, LA	COOLING TOWER	17,611 GPM	PM	0.07 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
LA-0248	1/27/2011	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC - NUCOR	ST JAMES PARISH COUNTY, LA	COOLING TOWER	17,611 GPM	PM	0.07 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
LA-0264	9/4/2012	AIR PRODUCTS AND CHEMICALS, INC.	ST. CHARLES COUNTY, LA	COOLING TOWER	11,200 GPM	PM	1.16 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
NV-0049	8/20/2009	HARRAH'S OPERATING COMPANY, INC.	CLARK COUNTY, NV	COOLING TOWER	20,400 GPM	PM	0.61 LB/MMGAL	DRIFT ELIMINATORS	Other Case-by-Case
NV-0050	11/30/2009	MGM MIRAGE	CLARK COUNTY, NV	COOLING TOWER	10,890 GPM	PM	0.14 LB/MMGAL	DRIFT ELIMINATORS	LAER
TX-0728	4/1/2015	BASF	BRAZORIA COUNTY, TX	COOLING TOWER	40,000 GPM	PM	0.15 LB/MMGAL	DRIFT ELIMINATORS	OTHER CASE-BY-CASE
TX-0728	4/1/2015	BASF	BRAZORIA COUNTY, TX	COOLING TOWER	40,000 GPM	PM	0.13 LB/MMGAL	DRIFT ELIMINATORS	OTHER CASE-BY-CASE
TX-0728	4/1/2015	BASF	BRAZORIA COUNTY, TX	COOLING TOWER	40,000 GPM	PM	0.05 LB/MMGAL	DRIFT ELIMINATORS	OTHER CASE-BY-CASE
VA-0319	8/27/2012	GATEWAY GREEN ENERGY	PRINCE GEORGE COUNTY, VA	COOLING TOWER	55,000 GPM	PM	0.03 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD

VA-0319	8/27/2012	GATEWAY GREEN ENERGY	PRINCE GEORGE COUNTY, VA	COOLING TOWER	55,000 GPM	PM	0.03 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
WV-0024	4/26/2006	WESTERN GREENBRIER CO-GENERATION, LLC	GREENBRIER COUNTY, WV	COOLING TOWER	55,000 GPM	PM	0.24 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
WV-0025	11/21/2014	MOUNDSVILLE POWER, LLC	MARSHALL COUNTY, WV	COOLING TOWER	159,000 GPM	PM	0.08 LB/MMGAL	DRIFT ELIMINATORS	BACT-PSD
WV-0025	11/21/2014	MOUNDSVILLE POWER, LLC	MARSHALL COUNTY, WV	COOLING TOWER	159,000 GPM	PM	0.05 LB/MMGAL		BACT-PSD
WV-0025	11/21/2014	MOUNDSVILLE POWER, LLC	MARSHALL COUNTY, WV	COOLING TOWER	159,000 GPM	PM	0.00 LB/MMGAL		BACT-PSD

RBLC ID	Permit Issuance Date	Company	Location	Description	Throughput	Pollutant	Limit	Controls	Basis
LA-0257	12/6/2011	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	CAMERON COUNTY, LA	Flare	1590 MMBtu/hr	VOC	0.01 lb/MMBtu		BACT-PSD
LA-0257	12/6/2011	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	CAMERON COUNTY, LA	Flare	0.26 MMBtu/hr	VOC	0.04 lb/MMBtu		BACT-PSD
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT COUNTY, MD	Flare	0.10 MMBtu/hr	VOC	0.002 lb/MMBtu	GCP	LAER
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT COUNTY, MD	Flare	0.01 MMBtu/hr	VOC	3.5 lb/MMBtu	GCP	LAER
IN-0166	6/27/2012	INDIANA GASIFICATION, LLC	SPENCER COUNTY, IN	Flare	0.27 MMBtu/hr	NOx	160 lb/MMBtu		BACT-PSD

LA-0257	12/6/2011	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	CAMERON COUNTY, LA	Flare	1590 MMBtu/hr	NOx	0.12 lb/MMBtu		BACT-PSD
LA-0257	12/6/2011	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	CAMERON COUNTY, LA	Flare	0.26 MMBtu/hr	NOx	0.12 lb/MMBtu		BACT-PSD
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT COUNTY, MD	Flare	0.10 MMBtu/hr	NOx	158 lb/MMBtu	GCP	LAER
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT COUNTY, MD	Flare	0.01 MMBtu/hr	NOx	936 lb/MMBtu	GCP	LAER
IN-0166	6/27/2012	INDIANA GASIFICATION, LLC	SPENCER COUNTY, IN	Flare	0.27 MMBtu/hr	SO2			BACT-PSD
IN-0166	6/27/2012	INDIANA GASIFICATION, LLC	SPENCER COUNTY, IN	Flare	0.27 MMBtu/hr	SO2			BACT-PSD

LA-0257	12/6/2011	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	CAMERON COUNTY, LA	Flare	1590 MMBtu/hr	CO	0.44 lb/MMBtu		BACT-PSD
LA-0257	12/6/2011	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	CAMERON COUNTY, LA	Flare	0.26 MMBtu/hr	CO	0.42 lb/MMBtu		BACT-PSD
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT COUNTY, MD	Flare	0.10 MMBtu/hr	CO	71 lb/MMBtu	GCP	BACT-PSD
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT COUNTY, MD	Flare	0.01 MMBtu/hr	CO	420 lb/MMBtu	GCP	BACT-PSD
IN-0166	6/27/2012	INDIANA GASIFICATION, LLC	SPENCER COUNTY, IN	Flare	0.27 MMBtu/hr	PM	11.89 lb/MMBtu		BACT-PSD
IN-0166	6/27/2012	INDIANA GASIFICATION, LLC	SPENCER COUNTY, IN	Flare	0.27 MMBtu/hr	PM	11.89 lb/MMBtu		BACT-PSD

IN-0166	6/27/2012	INDIANA GASIFICATION, LLC	SPENCER COUNTY, IN	Flare	0.27 MMBtu/hr	PM	11.15 lb/MMBtu		BACT-PSD
LA-0257	12/6/2011	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	CAMERON COUNTY, LA	Flare	1590 MMBtu/hr	PM	0.01 lb/MMBtu		BACT-PSD
LA-0257	12/6/2011	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	CAMERON COUNTY, LA	Flare	0.26 MMBtu/hr	PM	0.04 lb/MMBtu		BACT-PSD
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT COUNTY, MD	Flare	0.10 MMBtu/hr	PM	1.60 lb/MMBtu	GCP	BACT-PSD
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT COUNTY, MD	Flare	0.10 MMBtu/hr	PM	6.39 lb/MMBtu	GCP	BACT-PSD
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT COUNTY, MD	Flare	0.10 MMBtu/hr	PM	6.39 lb/MMBtu	GCP	BACT-PSD

MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT COUNTY, MD	Flare	0.01 MMBtu/hr	PM	9.13 lb/MMBtu	GCP	BACT-PSD
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT COUNTY, MD	Flare	0.01 MMBtu/hr	PM	38.81 lb/MMBtu	GCP	BACT-PSD
MD-0044	6/9/2014	DOMINION COVE POINT LNG, LP	CALVERT COUNTY, MD	Flare	0.01 MMBtu/hr	PM	38.81 lb/MMBtu	GCP	BACT-PSD

RBLC ID	Permit Issuance Date	Company	Location	Description	Power	Pollutant	Limit	Controls	Basis
MI-0418	1/14/2015	General Motors Technical Center - Warren	Macomb County, MI	Emergency Generator	3.5 MW	NOx	8.00 g/kW-hr	ITR, low-NOx tuning.	BACT-PSD
MI-0418	1/14/2015	General Motors Technical Center - Warren	Macomb County, MI	Emergency Generator	2.7 MW	NOx	7.13 g/kW-hr	ITR, low-NOx tuning.	BACT-PSD
IL-0114	9/5/2014	Cronus Chemicals, LLC	Douglas County, IL	Emergency Generator	2.8 MW	NOx	0.67 g/kW-hr	Tier IV	BACT-PSD
IL-0114	9/5/2014	Cronus Chemicals, LLC	Douglas County, IL	Emergency Generator	2.8 MW	CO	3.50 g/kW-hr	Tier IV	BACT-PSD
IL-0114	9/5/2014	Cronus Chemicals, LLC	Douglas County, IL	Emergency Generator	2.8 MW	PM	0.10 g/kW-hr	Tier IV	BACT-PSD
IL-0114	9/5/2014	Cronus Chemicals, LLC	Douglas County, IL	Emergency Generator	2.8 MW	PM	0.10 g/kW-hr	Tier IV	BACT-PSD
IL-0114	9/5/2014	Cronus Chemicals, LLC	Douglas County, IL	Emergency Generator	2.8 MW	PM	0.10 g/kW-hr	Tier IV	BACT-PSD
IL-0114	9/5/2014	Cronus Chemicals, LLC	Douglas County, IL	Emergency Generator	2.8 MW	VOC	0.40 g/kW-hr	Tier IV	BACT-PSD
IN-0173	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Emergency Generator	2.7 MW	PM	0.20 g/kW-hr	GCP	BACT-PSD
IN-0173	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Emergency Generator	2.7 MW	PM	0.20 g/kW-hr	GCP	BACT-PSD

IN-0173	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Emergency Generator	2.7 MW	PM	0.20 g/kW-hr	GCP	BACT-PSD
IN-0173	6/4/2014	Midwest Fertilizer	Posey County, IN	Emergency Generator	2.7 MW	NOx	5.98 g/kW-hr	GCP	BACT-PSD
IN-0173	6/4/2014	Midwest Fertilizer	Posey County, IN	Emergency Generator	2.7 MW	CO	3.50 g/kW-hr	GCP	BACT-PSD
IN-0173	6/4/2014	Midwest Fertilizer	Posey County, IN	Emergency Generator	2.7 MW	VOC	0.42 g/kW-hr	GCP	BACT-PSD
IN-0180	6/4/2014	Midwest Fertilizer	Posey County, IN	Emergency Generator	2.7 MW	PM	0.20 g/kW-hr	GCP	BACT-PSD
IN-0180	6/4/2014	Midwest Fertilizer	Posey County, IN	Emergency Generator	2.7 MW	PM	0.20 g/kW-hr	GCP	BACT-PSD
IN-0180	6/4/2014	Midwest Fertilizer	Posey County, IN	Emergency Generator	2.7 MW	PM	0.20 g/kW-hr	GCP	BACT-PSD
IN-0180	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Emergency Generator	2.7 MW	NOx	5.98 g/kW-hr	GCP	BACT-PSD
IN-0180	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Emergency Generator	2.7 MW	CO	3.50 g/kW-hr	GCP	BACT-PSD
IN-0180	6/4/2014	Midwest Fertilizer Corporation	Posey County, IN	Emergency Generator	2.7 MW	VOC	0.42 g/kW-hr	GCP	BACT-PSD
IN-0179	9/25/2013	Ohio Valley Resources, LLC	Spencer County, IN	Emergency Generator	3.5 MW	PM	0.20 g/kW-hr	GCP	BACT-PSD
IN-0179	9/25/2013	Ohio Valley Resources, LLC	Spencer County, IN	Emergency Generator	3.5 MW	PM	0.20 g/kW-hr	GCP	BACT-PSD
IN-0179	9/25/2013	Ohio Valley Resources, LLC	Spencer County, IN	Emergency Generator	3.5 MW	PM	0.20 g/kW-hr	GCP	BACT-PSD

IN-0179	9/25/2013	Ohio Valley Resources, LLC	Spencer County, IN	Emergency Generator	3.5 MW	NOx	5.98 g/kW-hr	GCP	BACT-PSD
IN-0179	9/25/2013	Ohio Valley Resources, LLC	Spencer County, IN	Emergency Generator	3.5 MW	CO	3.50 g/kW-hr	GCP	BACT-PSD
IN-0179	9/25/2013	Ohio Valley Resources, LLC	Spencer County, IN	Emergency Generator	3.5 MW	VOC	0.42 g/kW-hr	GCP	BACT-PSD
MI-0395	7/13/2012	General Motors Technical Center--Warren	Macomb County, MI	Emergency Generator	3.0 MW	NOx	5.98 g/kW-hr	ITR, low-NOx tuning.	BACT-PSD
MI-0395	7/13/2012	General Motors Technical Center--Warren	Macomb County, MI	Emergency Generator	2.5 MW	NOx	7.13 g/kW-hr	ITR, low-NOx tuning.	BACT-PSD
MI-0394	2/29/2012	General Motors Technical Center-Warren	Macomb County, MI	Emergency Generator	3.0 MW	NOx	5.98 g/kW-hr	ITR, low-NOx tuning.	BACT-PSD
CA-1221	12/5/2011	Pacific Bell	San Diego County, CA	Emergency Generator	2.7 MW	NOx	4.69 g/kW-hr	Tier 2 certified and 50 hr/yr for M&T limit	Other Case-by-Case
AK-0072	7/14/2011	City Of Unalaska	Alaska	Emergency Generator	4.4 MW	NOx	9.80 g/kW-hr	Engine has turbo charger and after cooler installed as part of the design.	BACT-PSD
AK-0072	7/14/2011	City Of Unalaska	Alaska	Emergency Generator	4.4 MW	PM	0.50 g/kW-hr	Positive Crankcase Ventilation Installed as part of the design.	BACT-PSD
MI-0400	6/29/2011	Wolverine Power Supply Cooperative, Inc.	Presque Isle County, MI	Emergency Generator	3.0 MW	PM	0.15 g/kW-hr		BACT-PSD
MI-0400	6/29/2011	Wolverine Power Supply Cooperative, Inc.	Presque Isle County, MI	Emergency Generator	3.0 MW	PM	0.27 g/kW-hr		BACT-PSD

MI-0400	6/29/2011	Wolverine Power Supply Cooperative, Inc.	Presque Isle County, MI	Emergency Generator	3.0 MW	PM	0.27 g/kW-hr		BACT-PSD
NH-0015	2/27/2009	Concord Steam Corporation	Merrimack County, NH	Emergency Generator	3.4 MW	NOx	2.66 g/kW-hr	500 hr/yr operation limit.	LAER
FL-0310	1/12/2009	Shady Hills Power Company	Pasco County, FL	Emergency Generator	2.5 MW	PM	0.30 g/kW-hr	ULSD, 500 hr/yr operation limit.	BACT-PSD
FL-0310	1/12/2009	Shady Hills Power Company	Pasco County, FL	Emergency Generator	2.5 MW	SO2	0.0015 wt-% S	ULSD, 500 hr/yr operation limit.	BACT-PSD
FL-0310	1/12/2009	Shady Hills Power Company	Pasco County, FL	Emergency Generator	2.5 MW	PM	0.54 g/kW-hr	ULSD, 500 hr/yr operation limit.	BACT-PSD
FL-0310	1/12/2009	Shady Hills Power Company	Pasco County, FL	Emergency Generator	2.5 MW	NOx	9.25 g/kW-hr		BACT-PSD
FL-0310	1/12/2009	Shady Hills Power Company	Pasco County, FL	Emergency Generator	2.5 MW	CO	11.40 g/kW-hr		BACT-PSD
AZ-0046	4/14/2005	Arizona Clean Fuels Yuma LLC	Yuma County, AZ	Emergency Generator	3.2 MW	NOx	6.40 g/kW-hr		BACT-PSD

AZ-0046	4/14/2005	Arizona Clean Fuels Yuma LLC	Yuma County, AZ	Emergency Generator	3.2 MW	CO	3.50 g/kW-hr		BACT-PSD
AZ-0046	4/14/2005	Arizona Clean Fuels Yuma LLC	Yuma County, AZ	Emergency Generator	3.2 MW	PM	0.02 g/kW-hr		BACT-PSD

ATTACHMENT B: COST EFFECTIVENESS CALCULATIONS

TABLE B-1
COST EFFECTIVENESS CALCULATIONS
Catalytic Oxidation System
Gas-Fired 530 MMBtu/hr Boiler

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Catalytic Oxidizer[1,2]	A	886,304
Sales Tax[1]	0.03A	26,589
Purchased Equipment Cost (PEC)	B	912,893
Direct Installation Costs[1]		
Foundations & Supports	0.08B	73,031
Handling & Erection	0.14B	127,805
Electrical	0.04B	36,516
Piping	0.02B	18,258
Insulation for Ductwork	0.01B	9,129
Painting	0.01B	9,129
Direct Installation Cost		273,868
Total Direct Costs (DC)		1,186,761
Indirect Costs		
Installation[1]		
Engineering	0.10B	91,289
Construction & Field Expenses	0.05B	45,645
Contractor Fees	0.10B	91,289
Start-Up	0.02B	18,258
Performance Test	0.01B	9,129
Contingencies	0.03B	9,129
Indirect Installation		264,739
Total Indirect Costs (IC)		264,739
TOTAL CAPITAL INVESTMENT = DC + IC		**1,451,500**
Direct Annual Costs		
Operating Labor[1,4]		
Operator	0.25 hours/shift	9,661
Supervisor	15% of operator	1,449
Total Operating Labor		11,110
Maintenance[1,4]		
Labor	0.25 hours/shift	9,661
Materials	100% of maintenance labor	9,661
Replacement Catalyst Cost	1 catalyst bed every 4 years	146,274
Total Maintenance		165,595
Utilities[5]		
Electricity	181 kWh @ $0.05/kWh	79,060
Total Utilities		79,060
Total Direct Annual Costs (DAC)		**255,765**
Indirect Annual Costs		
Overhead[1]	60% of operating, supervisor, maintenance labor & materials	106,023
Administrative Charges[1]	0.02TCI	29,030
Property Taxes[1]	0.01TCI	14,515
Insurance[1]	0.01TCI	14,515
Capital Recovery Factor[6]	-----	0.1424
Capital Recovery1	(CRF)(TCI)	206,694
Total Indirect Annual Costs (IAC)		**370,777**
TOTAL ANNUAL COST = DAC + IAC		**626,542**
Total of CO & VOC emissions with good combustion practices	tons/yr	98.24
Total of CO & VOC emissions with catalytic oxidizer	tons/yr	14.84
Percent reduction from baseline		85%
Total emissions reduction	tons/yr	83.41
Cost per Ton Controlled	**$/ton**	**7,512**

[1] Costs were assumed using EPA Air Pollution Control Cost Manual - 6th Edition (EPA-452/B-02-001). The costs used were based on estimates for a Fixed-Bed Catalytic Oxidizer assuming no energy recovery

[2] The costs were also adjusted for inflation using an inflation rate of 40 percent (1999 to 2013), which was determined using a Consumer Price Index (CPI) Inflation Calculator provided by the Bureau of Labor Statistics (http://www.bls.gov/data/inflation_calculator.htm)

[3] Calalyst Replacement was assumed to take place every four years; cost was calcluated using EPA Air Pollution Control Cost Manual - 6th Edition (EPA-452/B-02-001), Section 3.2 (VOC Destruction Controls), Chapter 2 (Incineration), pages 2-34, 35, and 46; assumed a space velocity of 10,000 1/hr, and a catalyst cost of $650/ft3.

[4] Calculations assume 2,190 hours of operation per year, 8 hours per shift, assuming 0.5 hours per shift related to catalytic oxidizer with employees paid at the rate of $35.29 per hour (which is comparable to the wages paid for similar control equipment).

[5] The total utilities cost was caclulated using EPA Air Pollution Control Cost Manual - 6th Edition (EPA-452/B-02-001), Section 3.2 (VOC Destruction Controls), Chapter 2 (Incineration), pages 2-43 and 46. Assumed a pressure drop of 6 in H2O, and an electricity cost of $0.05/kWh

[6] The capital recovery factor was calculated assuming a 10-year equipment life and a 7% interest rate

TABLE B-2
COST EFFECTIVENESS CALCULATIONS
Selective Noncatalytic Reduction System
Natural Gas-Fired 80 MMBtu/hr Process Heater

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Selective Noncatalytic Reduction System[1,2]	A	851,670
Sales Tax[1]	0.03A	25,550
Purchased Equipment Cost (PEC)	B	877,220
Direct Installation Costs[1]		
Foundations & Supports	0.08B	70,178
Handling & Erection	0.14B	122,811
Electrical	0.04B	35,089
Piping	0.02B	17,544
Insulation for Ductwork	0.01B	8,772
Painting	0.01B	8,772
Direct Installation Cost		263,166
Total Direct Costs (DC)		1,140,386
Indirect Costs		
Installation[1]		
Engineering	0.10B	87,722
Construction & Field Expenses	0.05B	43,861
Contractor Fees	0.10B	87,722
Start-Up	0.02B	17,544
Performance Test	0.01B	8,772
Contingencies	0.03B	8,772
Indirect Installation		254,394
Total Indirect Costs (IC)		254,394
TOTAL CAPITAL INVESTMENT = DC + IC		**1,394,779**
Direct Annual Costs		
Operating Labor[1,3]		
Operator	5% of operating time	318
Supervisor	15% of operator	48
Total Operating Labor		365
Maintenance[1,4]		
Labor	5% of operating time	318
Materials	100% of maintenance labor	318
Reagent Cost	1 gal/hr * 180 hr/yr @ $x/gal	136
Total Maintenance		771
Utilities[5]		
Electricity	0.5 kWh * 180 hr/yr @ $0.05/kWh	5
Total Utilities		5
Total Direct Annual Costs (DAC)		**1,141**
Indirect Annual Costs		
Overhead[1]	60% of operating, supervisor, maintenance labor & materials	682
Administrative Charges[1]	0.02TCI	27,896
Property Taxes[1]	0.01TCI	13,948
Insurance[1]	0.01TCI	13,948
Capital Recovery Factor[6]	-----	0.1424
Capital Recovery1	(CRF)(TCI)	198,617
Total Indirect Annual Costs (IAC)		**255,090**
TOTAL ANNUAL COST = DAC + IAC		**256,231**
Total of NOx emissions with good combustion practices	tons/yr	2.23
Total of NOx emissions with selective noncatalytic reduction system	tons/yr	1.10
Percent reduction from baseline		51%
Total emissions reduction	tons/yr	1.13
Cost per Ton Controlled	**$/ton**	**227,717**

[1] Costs were assumed using EPA Air Pollution Control Cost Manual - 6th Edition (EPA-452/B-02-001), Section 4.2 (NOx Post-Combustion), Chapter 1 (Selective Noncatalytic Reduction), page 1-32.

[2] The costs were also adjusted for inflation using an inflation rate of 46 percent (1998 to 2015), which was determined using a Consumer Price Index (CPI) Inflation Calculator provided by the Bureau of Labor Statistics (http://www.bls.gov/data/inflation_calculator.htm)

[3] Calculations assume 180 hours of operation per year, and 5% of that operating time is related to selective noncatalytic system with employees paid at the rate of $35.29 per hour (which is comparable to the wages paid for similar control equipment).

[4] The reagent cost was caclulated using EPA Air Pollution Control Cost Manual - 6th Edition (EPA-452/B-02-001), Section 4.2 (NOx Post-Combustion), Chapter 1 (Selective Noncatalytic Reduction), pages 1-25 through 1-27, and assuming the cost of 25% aqueous ammonia is $X/gallon.

[5] The total utilities cost was caclulated using EPA Air Pollution Control Cost Manual - 6th Edition (EPA-452/B-02-001), Section 4.2 (NOx Post-Combustion), Chapter 1 (Selective Noncatalytic Reduction), page 1-34. Assumed an electricity cost of $0.05/kWh

[6] The capital recovery factor was calculated assuming a 10-year equipment life and a 7% interest rate

TABLE B-3
COST EFFECTIVENESS CALCULATIONS
Flue Gas Recirculation System
Natural Gas-Fired 80 MMBtu/hr Process Heater

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Flue Gas Recirculation System[1]	A	30,000
Sales Tax	0.03A	900
Purchased Equipment Cost (PEC)	B	30,900
Direct Installation Costs		
Foundations & Supports	0.08B	2,472
Handling & Erection	0.14B	4,326
Electrical	0.04B	1,236
Piping	0.02B	618
Insulation for Ductwork	0.01B	309
Painting	0.01B	309
Direct Installation Cost		9,270
Total Direct Costs (DC)		40,170
Indirect Costs		
Installation		
Engineering	0.10B	3,090
Construction & Field Expenses	0.05B	1,545
Contractor Fees	0.10B	3,090
Start-Up	0.02B	618
Performance Test	0.01B	309
Contingencies	0.03B	309
Indirect Installation		8,961
Total Indirect Costs (IC)		8,961
TOTAL CAPITAL INVESTMENT = DC + IC		**49,131**
Direct Annual Costs		
Operating Labor[2]		
Operator	5% of operating time	318
Supervisor	15% of operator	48
Total Operating Labor		365
Maintenance[2]		
Labor	5% of operating time	318
Materials	100% of maintenance labor	318
Total Maintenance		635
Utilities[3]		
Electricity	22.4 kWh * 180 hr/yr @ $0.05/kWh	201
Total Utilities		201
Total Direct Annual Costs (DAC)		**1,202**
Indirect Annual Costs		
Overhead	60% of operating, supervisor, maintenance labor & materials	600
Administrative Charges	0.02TCI	983
Property Taxes	0.01TCI	491
Insurance	0.01TCI	491
Capital Recovery Factor[4]	CRF	0.1424
Capital Recovery	(CRF)(TCI)	6,996
Total Indirect Annual Costs (IAC)		**9,562**
TOTAL ANNUAL COST = DAC + IAC		**10,764**
Total of NOx emissions with good combustion practices[5]	tons/yr	2.23
Total of NOx emissions with flue gas recirculation system[6]	tons/yr	0.783
Percent reduction from baseline		65%
Total emissions reduction	tons/yr	1.44
Cost per Ton Controlled	**$/ton**	**7,458**

[1] Cost provided by Charlie Wadlington of Sigma Thermal.

[2] Calculations assume 180 hours of operation per year, and 5% of that operating time is related to selective noncatalytic system with employees paid at the rate of $35.29 per hour (which is comparable to the wages paid for similar control equipment).

[3] The total utilities cost was caclulated using EPA Air Pollution Control Cost Manual - 6th Edition (EPA-452/B-02-001), Section 4.2 (NOx Post-Combustion), Chapter 1 (Selective Noncatalytic Reduction), page 1-34. Assumed an electricity cost of $0.05/kWh

[4] The capital recovery factor was calculated assuming a 10-year equipment life and a 7% interest rate

TABLE B-4
COST EFFECTIVENESS CALCULATIONS
Low-NOx Burners
Natural Gas-Fired 80 MMBtu/hr Process Heater

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Low-NOx Burners (2/unit)[1]	A	400,000
Sales Tax	0.03A	12,000
Purchased Equipment Cost (PEC)	B	412,000
Direct Installation Costs		
Foundations & Supports	0.08B	32,960
Handling & Erection	0.14B	57,680
Electrical	0.04B	16,480
Piping	0.02B	8,240
Insulation for Ductwork	0.01B	4,120
Painting	0.01B	4,120
Direct Installation Cost		123,600
Total Direct Costs (DC)		535,600
Indirect Costs		
Installation		
Engineering	0.10B	41,200
Construction & Field Expenses	0.05B	20,600
Contractor Fees	0.10B	41,200
Start-Up	0.02B	8,240
Performance Test	0.01B	4,120
Contingencies	0.03B	4,120
Indirect Installation		119,480
Total Indirect Costs (IC)		119,480
TOTAL CAPITAL INVESTMENT = DC + IC		**655,080**
Direct Annual Costs		
Operating Labor[2]		
Operator	5% of operating time	318
Supervisor	15% of operator	48
Total Operating Labor		365
Maintenance[2]		
Labor	5% of operating time	318
Materials	100% of maintenance labor	318
Total Maintenance		635
Utilities		
Electricity	None	0
Total Utilities		0
Total Direct Annual Costs (DAC)		**1,000**
Indirect Annual Costs		
Overhead	60% of operating, supervisor, maintenance labor & materials	600
Administrative Charges	0.02TCI	13,102
Property Taxes	0.01TCI	6,551
Insurance	0.01TCI	6,551
Capital Recovery Factor[3]	CRF	0.1424
Capital Recovery	(CRF)(TCI)	93,283
Total Indirect Annual Costs (IAC)		**120,087**
TOTAL ANNUAL COST = DAC + IAC		**121,087**
Total of NOx emissions with good combustion practices[4]	tons/yr	2.23
Total of NOx emissions with flue gas recirculation system[5]	tons/yr	0.391
Percent reduction from baseline		82%
Total emissions reduction	tons/yr	1.83
Cost per Ton Controlled	**$/ton**	**66,002**

[1] Differential cost between baseline burners and low-NOx burners provided by Charlie Wadlington of Sigma Thermal.

[2] Calculations assume 180 hours of operation per year, and 5% of that operating time is related to selective noncatalytic system with employees paid at the rate of $35.29 per hour (which is comparable to the wages paid for similar control equipment).

[3] The capital recovery factor was calculated assuming a 10-year equipment life and a 7% interest rate

TABLE B-5
COST EFFECTIVENESS CALCULATIONS
Low-NOx Burners & Flue Gas Recirculation System
Natural Gas-Fired 80 MMBtu/hr Process Heater

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Low-NOx Burners (2/unit) & Flue Gas Recirculation System[1]	A	430,000
Sales Tax	0.03A	12,900
Purchased Equipment Cost (PEC)	B	442,900
Direct Installation Costs		
Foundations & Supports	0.08B	35,432
Handling & Erection	0.14B	62,006
Electrical	0.04B	17,716
Piping	0.02B	8,858
Insulation for Ductwork	0.01B	4,429
Painting	0.01B	4,429
Direct Installation Cost		132,870
Total Direct Costs (DC)		575,770
Indirect Costs		
Installation		
Engineering	0.10B	44,290
Construction & Field Expenses	0.05B	22,145
Contractor Fees	0.10B	44,290
Start-Up	0.02B	8,858
Performance Test	0.01B	4,429
Contingencies	0.03B	4,429
Indirect Installation		128,441
Total Indirect Costs (IC)		128,441
TOTAL CAPITAL INVESTMENT = DC + IC		**704,211**
Direct Annual Costs		
Operating Labor[2]		
Operator	5% of operating time	318
Supervisor	15% of operator	48
Total Operating Labor		365
Maintenance[2]		
Labor	5% of operating time	318
Materials	100% of maintenance labor	318
Total Maintenance		635
Utilities[3]		
Electricity	22.4 kWh * 180 hr/yr @ $0.05/kWh	201
Total Utilities		201
Total Direct Annual Costs (DAC)		**1,202**
Indirect Annual Costs		
Overhead	60% of operating, supervisor, maintenance labor & materials	600
Administrative Charges	0.02TCI	14,084
Property Taxes	0.01TCI	7,042
Insurance	0.01TCI	7,042
Capital Recovery Factor[4]	CRF	0.1424
Capital Recovery	(CRF)(TCI)	100,280
Total Indirect Annual Costs (IAC)		**129,048**
TOTAL ANNUAL COST = DAC + IAC		**130,250**
Total of NOx emissions with good combustion practices[5]	tons/yr	2.23
Total of NOx emissions with LNB and FGR[6]	tons/yr	0.245
Percent reduction from baseline		89%
Total emissions reduction	tons/yr	1.98
Cost per Ton Controlled	**$/ton**	**65,738**

[1] Cost provided by Sigma Thermal.

[2] Calculations assume 180 hours of operation per year, and 5% of that operating time is related to selective noncatalytic system with employees paid at the rate of $35.29 per hour (which is comparable to the wages paid for similar control equipment).

[3] The total utilities cost was caclulated using EPA Air Pollution Control Cost Manual - 6th Edition (EPA-452/B-02-001), Section 4.2 (NOx Post-Combustion), Chapter 1 (Selective Noncatalytic Reduction), page 1-34. Assumed an electricity cost of $0.05/kWh

[4] The capital recovery factor was calculated assuming a 10-year equipment life and a 7% interest rate

TABLE B-6
COST EFFECTIVENESS CALCULATIONS
Selective Catalytic Reduction System
Natural Gas-Fired 80 MMBtu/hr Process Heater

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Selective Noncatalytic Reduction System[1,2]	A	1,284,764
Sales Tax[1]	0.03A	38,543
Purchased Equipment Cost (PEC)	B	1,323,307
Direct Installation Costs[1]		
Foundations & Supports	0.08B	105,865
Handling & Erection	0.14B	185,263
Electrical	0.04B	52,932
Piping	0.02B	26,466
Insulation for Ductwork	0.01B	13,233
Painting	0.01B	13,233
Direct Installation Cost		396,992
Total Direct Costs (DC)		1,720,299
Indirect Costs		
Installation[1]		
Engineering	0.10B	132,331
Construction & Field Expenses	0.05B	66,165
Contractor Fees	0.10B	132,331
Start-Up	0.02B	26,466
Performance Test	0.01B	13,233
Contingencies	0.03B	13,233
Indirect Installation		383,759
Total Indirect Costs (IC)		383,759
TOTAL CAPITAL INVESTMENT = DC + IC		**2,104,058**
Direct Annual Costs		
Operating Labor[1,3]		
Operator	5% of operating time	318
Supervisor	15% of operator	48
Total Operating Labor		365
Maintenance[1,4]		
Labor	5% of operating time	318
Materials	100% of maintenance labor	318
Reagent Cost	1.5 gal/hr * 180 hr/yr @ $0.76/gal	204
Total Maintenance		839
Utilities[5]		
Electricity	33.3 kWh * 180 hr/yr @ $0.05/kWh	300
Total Utilities		300
Total Direct Annual Costs (DAC)		**1,504**
Indirect Annual Costs		
Overhead[1]	60% of operating, supervisor, maintenance labor & materials	723
Administrative Charges[1]	0.02TCI	42,081
Property Taxes[1]	0.01TCI	21,041
Insurance[1]	0.01TCI	21,041
Capital Recovery Factor[6]	-----	0.1424
Capital Recovery1	(CRF)(TCI)	299,618
Total Indirect Annual Costs (IAC)		**384,503**
TOTAL ANNUAL COST = DAC + IAC		**386,007**
Total of NOx emissions with good combustion practices	tons/yr	2.23
Total of NOx emissions with selective noncatalytic reduction system	tons/yr	0.12
Percent reduction from baseline		95%
Total emissions reduction	tons/yr	2.10
Cost per Ton Controlled	**$/ton**	**183,492**

[1] Costs were assumed using EPA Air Pollution Control Cost Manual - 6th Edition (EPA-452/B-02-001), Section 4.2 (NOx Post-Combustion), Chapter 2 (Selective Catalytic Reduction), page 2-42.

[2] The costs were also adjusted for inflation using an inflation rate of 38 percent (2000 to 2015), which was determined using a Consumer Price Index (CPI) Inflation Calculator provided by the Bureau of Labor Statistics (http://www.bls.gov/data/inflation_calculator.htm)

[3] Calculations assume 180 hours of operation per year, and 5% of that operating time is related to selective noncatalytic system with employees paid at the rate of $35.29 per hour (which is comparable to the wages paid for similar control equipment).

[4] The reagent cost was caclulated using EPA Air Pollution Control Cost Manual - 6th Edition (EPA-452/B-02-001), Section 4.2 (NOx Post-Combustion), Chapter 1 (Selective Catalytic Reduction), page 2-46, and assuming the cost of 25% aqueous ammonia is $0.76/gallon. Because the catalyst would be used infrequently, it is assumed to never require replacement.

[5] The total utilities cost was caclulated using EPA Air Pollution Control Cost Manual - 6th Edition (EPA-452/B-02-001), Section 4.2 (NOx Post-Combustion), Chapter 2 (Selective Catalytic Reduction), page 2-46. Assumed an electricity cost of $0.05/kWh

[6] The capital recovery factor was calculated assuming a 10-year equipment life and a 7% interest rate

TABLE B-7

COST EFFECTIVNESS CALCULATIONS
Tier 4 (Final) Control System
Diesel-Fired 3.5 MW Emergency Generator

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment[1]	A	196,000
Sales Tax[1]	0.1A	19,600
Purchased Equipment Cost (PEC)	B	215,600
Direct Installation Costs		
Foundations & Supports	-----	-----
Handling & Erection	-----	-----
Electrical	-----	-----
Piping	-----	-----
Insulation for Ductwork	-----	-----
Painting	-----	-----
Direct Installation Cost	0.04B	8,624
Total Direct Costs (DC)		224,224
Indirect Costs		
Installation		
Engineering	-----	-----
Construction & Field Expenses	-----	-----
Contractor Fees	-----	-----
Start-Up	-----	-----
Contingencies	-----	-----
Indirect Installation	0.03B	6,468
Total Indirect Costs (IC)		6,468
TOTAL CAPITAL INVESTMENT = DC + IC		**230,692**
Direct Annual Costs		
Operating Labor[3]		
Operator	5 hours/yr @ 35 $/hr	175
Supervisor	15% of operator	26
Total Operating Labor		201
Maintenance[3]		
Labor	-----	-----
Materials	-----	-----
Total Maintenance	0.10B	21,560
Utilities[4]		
Electricity	1 kWh @ $0.04/kWh	1
Total Utilities		1
Catalyst Cost[5]		
Catalyst Replacement	Catalyst life > SCR Service Life	Negligible
Total Catalyst Cost	-----	-----
Miscellaneous[6]		
Performance Tests	-----	3,000
Record Keeping & Reporting	-----	1,000
Total Miscellaneous Costs		4,000
Total Direct Annual Costs (DAC)		**25,763**
Indirect Annual Costs		
Overhead[7]	60% of operating, supervisor, maintenance labor & materials	13,057
Administrative Charges[7]	0.02TCI	4,614
Property Taxes[7]	0.01TCI	2,307
Insurance[7]	0.01TCI	2,307
Capital Recovery Factor[8]	-----	0.0944
Capital Recovery[7]	(CRF)(TCI)	21,776
Total Indirect Annual Costs (IAC)		**44,060**
TOTAL ANNUAL COST = DAC + IAC		**69,823**
Uncontrolled NOx, CO, VOC, and PM emissions	tons/yr	1.16
NOx, CO, VOC, and PM Emissions with Tier 4 Controls	tons/yr	0.12
Percent reduction from uncontrolled		89%
Total emissions reduction	tons/yr	1.04
Cost per Ton Controlled	**$/ton**	**67,460**

[1] Captial cost provided by the engine vendor (Brant Briody of N C Power Systems Co.)

[2] These factors were approximated using information provided by the engine vendor (Brant Briody of N C Power Systems Co.)

[3] Calculations assume 5 hours per year, with employees paid at the rate of $35 per hour (which is comparable to the wages paid for similar control equipment).

[4] The total utilities cost was caclulated assuming 1 kWh electricity usage at a cost of $0.05/kWh to operate the ammonia pump.

[5] Because of the limited operation schedule for the generator, the initial catalyst charge would last for the projected service life of the unit.

[6] These miscellaneous costs are comparable to costs for similar functions for comparable control equipment.

[7] These factors were taken from Table 6-2 of the Alternative Control Techniques (ACT) Document - Internal Combustion NOx Part 1 & 2 dated 7-21-1997 (EPA-453/R-93-032)

[8] The capital recovery factor was calculated assuming a 20-year equipment life and a 7% interest rate

ATTACHMENT C: REGULATORY AGENCY BACT GUIDELINES

Table B-1: Agency BACT Guidelines for Boilers

Agency	Applies to	Pollutant	Emissions	Controls
BAAQMD	Boiler >= 50 MMBtu.hr	VOC	1. n/d 2. n/s	1. n/d 2. Good combustion practices
		NO$_X$	1. n/d 2. n/d	1. SCR+LNB+FGR 2. ULNB+FGR
		SO$_2$	1. Natural gas<500 ppbv Hydrogen Sulfide and <100 ppmv TRS 2. Natural gas <100 ppmv TRS	1. Fuel Selection 2. Fuel Selection
		CO	1. 10 ppmv @3% O$_2$ Dry 2. 50 ppmv @3% O$_2$ Dry	1. Oxidation Catalyst 2. Good combustion practices + SCR + FGR
		PM	1. n/d 2. Natural gas	1. n/d 2. Fuel selection
TCEQ	Boiler > 40 MMBtu/hr	NO$_X$	0.01 lb/MMBtu (75%-100% natural gas) or 0.015 lb/MMBtu (plant fuel gas)	plant fuel gas may contain up to 75% natural gas plant fuel gas specifics: <50% H2; >920 Btu/dscf
		CO	50 ppmv @3% O$_2$ Dry	fuel oil firing < 760 hrs/yr
		PM	< 5% opacity	
		NH$_3$	10 ppmv @3% O$_2$ Dry	
SCAQMD	Natural Gas Boiler > 20 MMBtu/hr	NO$_X$	1. 7 ppmv @3% O$_2$ Dry 2. 9 ppmv @3% O$_2$ Dry	1. Add-on controls 2. LNB
		SO$_2$	Natural gas	Fuel selection
		CO	100 ppmv @3% O$_2$ Dry for watertube type 50 ppmv @3% O$_2$ Dry for firetube type	
		PM	Natural gas	Fuel selection
		NH$_3$	5 ppmv @3% O$_2$ Dry	If add on controls
MassDEP	Natural Gas Boiler > 250 MMBtu/hr	NO$_X$	0.011 lb/MMBtu	LNB, FGR, SCR
		CO	0.015 lb/MMBtu	
		PM	0.002 lb/MMBtu	
		VOC	0.015 lb/MMBtu	

Table B-2: Agency BACT Guidelines for Combined Cycle Turbines

Agency	Applies to	Pollutant	Emissions	Controls
BAAQMD	Combined Cycle (>= 40 MW)	VOC	1. n/d 2. 2.0 ppmv @15% O_2 Dry	1. n/d 2. Oxidation Catalyst or Efficient Dry Low NOX Combustors
		NO_X	1. 2.0 ppmv @15% O_2 Dry 2. 2.5 ppmv @15% O_2 Dry	1. SCR+LNB, or Steam Inj, or SCONOX 2. SCR+LNB
		SO_2	1. n/d 2. Natural gas (sulfur < 1.0 gran/100 scf)	1. n/d 2. PUC-regulated natural gas
		CO	1. n/d 2. 4.0 ppmv @15% O_2 Dry	1. n/d 2. Oxidation Catalyst
		PM	1. n/d 2. Natural gas (sulfur < 1.0 gran/100 scf)	1. n/d 2. PUC-regulated natural gas
TCEQ	Gas-Fired, Combined Cycle Turbine	NO_X	2.0 ppmv @15% O_2 Dry (24-hr avg)	Dry LNB, water, or steam, SCR
		CO	2-4 ppmv @15% O_2 Dry	
		VOC	4 ppmv @15% O_2 Dry	
		NH_3	7-10 ppmv @15% O_2 Dry	
SCAQMD	Gas Turbine >= 50 MW	NO_X	2.5 ppmv @15% O_2 Dry (1-hr avg) OR 2.0 ppmv@15% O2 Dry (3-hr avg)	
		CO	6 ppmv @15% O_2 Dry (3 hr)	
		VOC	2.0 ppmv @15% O_2 Dry (1 hr) OR 0.0027 lbs/MMBtu	
		NH_3	5 ppmv @15% O_2 Dry	
MassDEP	Combined Cycle >= 10 MW	NO_X	2.0 ppmvd @15% O2	Low NOX Combustor, SCR, Oxidation Catalyst
		CO	2.0 ppmvd @15% O2	
		VOC	1.7 ppmvd @15% O2	
		NH_3	2.0 ppmvd @15% O2	

Table B-3: Agency BACT Guidelines for Process Heaters

Agency	Applies to	Pollutant	Emissions	Controls
BAAQMD	Heater >= 50 MMBtu/hr	VOC	1. n/d 2. n/s	1. n/d 2. Good combustion practices
		NO_X	1. n/d 2. 5 ppmv @3% O_2 Dry	1. n/d 2. SCR+LNB
		SO_2	1. Natural gas<500 ppbv Hydrogen Sulfide and <100 ppmv TRS 2. Natural gas <100 ppmv TRS	1. Fuel Selection 2. Fuel Selection
		CO	1. n/d 2. 10 ppmv @3% O_2 Dry	1. Oxidation Catalyst 2. Good combustion practices + SCR
		PM	1. n/d 2. Natural gas	1. n/d 2. Fuel selection
TCEQ	Boiler/Heater > 40 MMBtu/hr	NO_X	0.01 lb/MMBtu (75%-100% natural gas) or 0.015 lb/MMBtu (plant fuel gas)	plant fuel gas may contain up to 75% natural gas plant fuel gas specifics: <50% H2; >920 Btu/dscf
		CO	50 ppmv @3% O_2 Dry	fuel oil firing < 760 hrs/yr
		PM	< 5% opacity	
		NH_3	10 ppmv @3% O_2 Dry	
SCAQMD	Heater >= 20 MMBtu/hr	VOC		
		NO_X	7 ppmvd @3% O_2 9 ppmvd @3% O_2	SCR or LTO LNB
		SO_2	Natural gas	Fuel selection
		CO	100 ppmv @3% O_2 Dry for watertube type 50 ppmv @3% O_2 Dry for firetube type	
		PM	Natural gas	Fuel selection
		NH_3	5 ppmvd @3% O_2 1 ppmvd @3% O_2	with SCR with LTO

Table B-4: Agency BACT Guidelines for Flares

Agency	Applies to	Pollutant	Emissions	Controls
BAAQMD	Flare - Refinery	VOC	1. Ground level flare, enclosed, steam- or air-assisted, w/ staged combustion; POC destruction efficiency >98.5% (>0.6 sec. retention time at >1400oF); use of natural gas or LPG as pilot fuel. Flare to be operated only during periods of emergency plant upset or breakdown; routine venting of process gases to be routed to fuel gas recovery system 2. Ground level flare, enclosed, steam- or air-assisted, w/ staged combustion; POC destruction efficiency >98% ; use of natural gas or LPG as pilot fuel. Flare to be operated only during periods of emergency plant upset or breakdown; routine venting of process gases to be routed to fuel gas recovery system	1. BAAQMD approved design and operation 2. BAAQMD approved design and operation
		NO_X	1. n/d 2. staged combustion as for VOC	1. n/d 2. BAAQMD approved design and operation
		SO_2	1. n/d 2. n/d	1. n/d 2. n/d
		CO	1. n/d 2. staged combustion as for VOC	1. n/d 2. BAAQMD approved design and operation
		PM	1. n/d 2. staged combustion as for VOC	1. n/d 2. BAAQMD approved design and operation
TCEQ	Flares	VOC	40 CFR 60.18	99% destruction (<= 3 carbons); flow monitoring; composition or BTU analyzer may be required
		Non VOC	Case by case	flow monitoring; composition or BTU analyzer may be required

Table B-5: Agency BACT Guidelines for Cooling Towers

Agency	Applies to	Pollutant	Emissions	Controls
TCEQ	Boiler > 40 MMBtu/hr	VOC	Non-contact design Monthly VOC monitoring Repair identified leaks Shutdown triggered by VOC conc of 0.08 ppmw	
		PM	Drift eliminators Drift < 0.001%	

Table B-6: Agency BACT Guidelines for Organic Liquid Storage Tanks

Agency	Applies to	Pollutant	Emissions	Controls
BAAQMD	Fixed Roof Tank >20,000 gal	VOC	1. n/d 2. vapor recovery system, overall efficiency >=98%	1. n/d 2. thermal incinerator, carbon absorber, condenser, or approved equivalent
	Internal Floating Roof Tank	VOC	1. vapor recovery system, overall efficiency >=98% 2. Approved roof w/ liquid mounted primary seal and zero gap secondary seal, all meeting design criteria of Reg. 8, Rule 5. Also, no ungasketed roof penetrations, no slotted pipe guide pole unless equipped with float and wiper seals, and no adjustable roof legs unless fitted w/ vapor seal boots or equivalent	1. thermal incinerator, carbon absorber, condenser, or approved equivalent 2. Approved roof and seal design
TCEQ	Atmospheric Tank >25 Mgal and 0.5 psia < TVP < 11.0 psia	VOC	Internal floating roof (IFR). White or aluminum uninsulated exterior surfaces exposed to the sun.	Alt 1: mechanical or liquid mounted primary seal Alt 2: vapor mounted primary seal and rim mounted secondary seal Drain dry design
		VOC	External floating roof (EFR). White or aluminum uninsulated exterior surfaces exposed to the sun. Slotted guide pole fittings must have gasketed cover, and at least 2 of the following – wiper, float, or sleeve.	Mechanical or liquid mounted primary seal and rim mounted secondary seal Drain dry design
		VOC	Vent to control	Appropriate control device efficiency
SCAQMD	Internal Floating Roof Tank	VOC	Category A Seals and Compliance with Rule 463	

Table B-7: Agency BACT Guidelines for Ship Loading

Agency	Applies to	Pollutant	Emissions	Controls
BAAQMD	Marine Loading	VOC	1. n/d 2. vapor recovery system, overall efficiency >=98.5%	1. n/d 2. thermal incinerator, carbon absorber, condenser, or approved equivalent
TCEQ	Marine Loading	VOC	Route to VOC control device Vessel leak testing (annual)	95% collection efficiency See specific control device requirements

Table B-8: Agency BACT Guidelines for Emergency Engines

Agency	Applies to	Pollutant	Emissions	Controls
BAAQMD	Emergency ICE, compression, non-direct drive fire pump	VOC (NMHC)	1. n/s 2. CARB ATCM standard	1. n/s 2. Any engine certified or verified to meet standards
		NO_X	1. n/s 2. CARB ATCM standard	1. n/s 2. Any engine certified or verified to meet standards
		SO_2	1. n/s 2. Fuel sulfur content <15 ppmw	1. n/s 2. CARB certified ULSD
		CO	1. n/s 2. CARB ATCM standard	1. n/s 2. Any engine certified or verified to meet standards
		PM	1. n/s 2. 0.15 g/bhp-hr	1. n/s 2. Any engine or technology certified or verified to meet standards
SCAQMD	Compression Ignition, >= 750 hp	NO_X + NMHC	4.8 g/bhp-hr	Tier II Engine
		SO_2	Diesel fuel sulfur content 0.0015% by weight	Fuel selection
		CO	2.6 g/bhp-hr	Tier II Engine
		PM	0.15 g/bhp-hr	Tier II Engine
MassDEP	IC Engines >37kW (Emergency Engines)	All	Non-road engine limitations (40 CFR 89)	Natural Gas or Ultra Low Sulfur Distillate (0.0015%)

ATTACHMENT D: FUGITIVE COMPONENT EMISSIONS REGULATIONS

FUGITIVE EMISSIONS REGULATIONS COMPARISON TABLE

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Stream Applicability	> 5% VHAP by weight In organic HAP service > 300 hrs	> 5% VHAP by weight or as defined in the referencing Subpart	Elastomer Product Process Units	> 5% VHAP by weight In organic HAP service > 300 hrs	5% wt of the sum of Class I and II organics TAPs or >10% wt of the sum of Class I, II and III organic TAPs	> 10% VOC by weight	> 5% VHAP by weight In organic HAP service > 300 hrs	5% wt of the sum of Class I and II organics TAPs or >10% wt of the sum of Class I, II and III organic TAPs	>10% VOC by weight For sources in non-attainment areas for ozone	>10% wt VTAP (vinyl chloride or benzene)	> 10% VOC by weight	> 5% VHAP by weight or as defined in the referencing Subpart	> 10% by weight	>10% VOC by volume (2121)	"In Gasoline Service" (R) or "In Hydrogen Fluoride Service", as defined
Leak Definition	**Valves-Gas/LL:** 500 **HL:** No visual/500 **Pumps-LL:** 1,000 **HL:** No visual/2,000 **Compressors:** 500 **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 500 **Connectors:** 500 **Agitators:** 10,000 **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 500 **HL:** No visual/500 **Pumps-LL:** 5,000 – polymers 2,000 – food/med 1,000 – other **HL:** 5,000 – polymers 2,000 – food/med 2,000 – other **Compressors:** 500 **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 500 **Connectors:**500 **Agitators:** 10,000 **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 500 **HL:** No visual/500 **Pumps-LL:** 1,000 **HL:** No visual/2,000 **Compressors:** 500 **CVS:** 500 **PRVs-Gas:**500 **Liquid:** 500 **Connectors:** 500 **Agitators:** No visual leak **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 500 **HL:** No visual/500 **Pumps-LL:** No visual/2,000 **HL:** No visual/2,000 **Compressors:** 500 **CVS:** 500 **PRVs-Gas:**500 **Liquid:** No visual/ 500 **Connectors:** 500 **Agitators:** No visual/10,000 **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 200 / 500 **HL:** No visual/1,000 **Pumps-LL:** 2,000 **HL:** No visual/2,000 **Compressors:** 5,000 **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 1,000 **Connectors:** 1,000 **Agitators-HL:** 10,000 **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 500 **HL:** No visual/10,000 **Pumps-LL:** 5,000 – monomer 2,000 – other **HL:** No visual/10,000 **Compressors:** Seal system failure **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 10,000 **Connectors-Gas/LL:** 500 **HL:** No visual/10,000 **Agitators:** No visual leak **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 1,000 **HL:** No visual/1,000 **Pumps-LL:** 2,000 **HL:** Reciprocating pumps exempt **Compressors:** 500 **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 500 **Connectors:** 1,000 **Agitators:** 10,000 **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 1,000 **HL:** No visual/1,000 **Pumps-LL:** 2,000 **HL:** No visual/2,000 **Compressors:** 5,000 **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 1,000 **Connectors:** 1,000 **Agitators-HL:** 10,000 **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 1,000 **HL:** No visual/1,000 **Pumps-LL:** 5,000 **HL:** No visual/5,000 **Compressors:** 5,000 **CVS:** No visual **PRVs-Gas:** 1,000 **Liquid:** No visual/ 1,000 **Connectors:** No visual /1,000 **Agitators:** 10,000 **Process Drains:** 1,000 **Sampling Points:** No visual leak	**Valves-Gas/LL:** 10,000 **HL:** No visual /10,000 **Pumps-LL:** 10,000 **HL:** No visual /10,000 **Compressors:** No visual leak **CVS:** 500 **PRVs-Gas:**500 **Liquid:** 10,000 **(HH)All:** 10,000 **Connectors:** No visual leak **Agitators:** No visual leak **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 10,000 **HL:** No visual/10,000 **Pumps-LL:** 10,000 **HL:** No visual/10,000 **Compressors:** Seal system failure **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 10,000 **Connectors:** No visual/10,000 **Agitators:** No visual leak **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 10,000 **HL:** No visual/10,000 **Pumps-LL:** 10,000 **Pumps-HL:** No visual/10,000 **Compressors:** Seal system failure **CVS:** 500 **PRVs-Gas:** 500 **Liquid:** No visual/ 10,000 **Connectors:** No visual/10,000 **Agitators:** No visual leak/10,000 **Process Drains:** No visual leak **Sampling Points:** No visual leak	**Valves-Gas/LL:** 10,000 **HL:** No visual/10,000 **Pumps-LL:** 10,000 **HL:** No visual/10,000 **Compressors:** 10,000 **CVS:** 10,000 **PRVs-Gas:** 10,000 **Liquid:** 10,000 **Connectors:** Visual **Agitators:** No visual leak **Process Drains:** No visual leak **Sampling Points:** No visual leak	**All equipment:** 10,000 Subpart III – annually or after reinstallation	**All equipment:** Evidence of potential leak detected by visual, audible, or olfactory means.

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Leak Definition	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual/500 **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual/500 **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** 500 **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual/500 **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual/1,000 **Open-ended lines:** 1,000	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual leak **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual/1,000 **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual/1,000 **Open-ended lines:** 1,000	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual leak **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual leak **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual leak **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual leak **Open-ended lines:** No visual leak	**SurgeCtrlVessel:** No visual leak **Instrument Systems:** No visual leak **Open-ended lines:** No visual leak	**All equipment:** 10,000	
Monitoring Frequency: Light Liquid valves	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking Every 2 years if <0.25%	Monthly if > 4% Quarterly if < 4%	Monthly If ND leak for 2 successive months = quarterly	**Monthly:** ->5% (with connectors) ->4%(without) **Quarterly:** - <5% (with connectors) - <4% (without) **Semiannual:** - <4% (with) - <3% (without) **Annual:** - <3% (with) - <2% (without)	Monthly if > 4% Quarterly if < 4%	Quarterly	Monthly	Monthly If ND leak for 2 successive months = quarterly	Monthly If ND leak for 2 successive months = quarterly	Monthly If ND leak for 2 successive months = quarterly	Quarterly Annually (pipeline valves)	Monthly (63 R) -or- Once per shift (63 YY)
Monitoring Frequency: Gas Valves	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking	Monthly if >2% leaking Quarterly if <2% leaking Every 2 qtrs if < 1% leaking Every 4 qtrs if <0.5% leaking Every 2 years if <0.25%	Monthly if > 4% Quarterly if < 4%	Monthly If ND leak for 2 successive months = quarterly	**Monthly:** ->5% (with connectors) ->4%(without) **Quarterly:** - <5% (with connectors) - <4% (without) **Semiannual:** - <4% (with) - <3% (without) **Annual:** - <3% (with) - <2% (without)	Monthly if > 4% Quarterly if < 4%	Quarterly	Monthly	Monthly If ND leak for 2 successive months = quarterly	Monthly If ND leak for 2 successive months = quarterly	Monthly If ND leak for 2 successive months = quarterly	Quarterly	Monthly (63 R) -or- Once per shift (63 YY)

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Monitoring Frequency: Gas Pressure Relief Valves	Monitor within 5 days of a release	Monitor within 5 days of a release	Monitor within 5 days of a release	Monitor within 5 days of a release	Monitor within 5 days of a release	Monitor within 5 days of release	Monitor within 5 days of a release	Monitor within 5 days of a release	Quarterly and within 24 hours of an atmospheric release	Monitor within 5 days of release	Monitor within 5 days of release	Monitor within 5 days of release	Monitor within 5 days of release	Quarterly and within 24 hours of an atmospheric release	Monitor within 5 days of detection by sight, sound, or smell
Monitoring Frequency: Liquid Pressure Relief Valves	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of a release or detection by sight, smell, or sound	Monitor within 5 days of a release or detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 24 hours of an atmospheric release	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 24 hours of an atmospheric release	Monitor within 5 days of detection by sight, smell, or sound
Monitoring Frequency: Light Liquid Pumps	Monthly monitor & weekly visual Pump repair not required unless leak > 2000 ppm	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Quarterly if <3% leaking Monthly if <10% or 3 leaking, whichever is greater	Quarterly monitor & weekly visual	Quarterly monitor & weekly visual (seals)	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Quarterly monitor & weekly visual Pump seals (annually)	Monthly (63 R) -or- Once per shift (63 YY)
Monitoring Frequency: Compressors	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Quarterly Or Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Quarterly Or Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Quarterly monitor (seals)	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Requires a seal system including barrier fluid, sensor, & alarm with zero emissions to atmosphere Check sensor daily	Quarterly monitor & weekly visual (seals)	Monthly (63 R) -or- Once per shift (63 YY)

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Monitoring Frequency: Flanges/ Connectors	Initial monitor Monitor annually if >0.5% leaking Monitor biennially if <0.5% leaking Monitor every 4 years if <0.5% leaking for 2 years HL connectors: Monitor within 5 days of detection by sight, smell, or sound	Initial monitor Monitor annually if >0.5% leaking Monitor every 4 years if <0.5% and >0.25% Monitor at least 50% of connectors within four years if <0.25% HL connectors: Monitor within 5 days of detection by sight, smell, or sound	Monitor annually if >0.5% leaking Monitor biennially if <0.5% leaking Monitor every 4 years if <0.5% leaking for 2 years	Initial monitor Monitor annually if >0.5% leaking Monitor biennially if <0.5% leaking Monitor every 4 years if <0.5% leaking for 2 years HL connectors: Monitor within 5 days of detection by sight, smell, or sound	Annually (random 200 or 10% by unit) If <2% leaking = annually If >2% leaking = quarterly until <2% obtained for 4 qrts otherwise monitor all connectors Monitor within 90 days after welding (xray, etc.) or breaking the seal (OVA)	Monitor within 5 days of detection by sight, smell, or sound	**2 Options**(if monitoring connectors): **Random 200** - monitor within 1st 12months after Phs III date - every 6 mos. if >2% - annual if <2% and >1% - biannaul if <1% and >.5% - every 4 years if <0.5% **Inspection Alternative** - monitor all gas/ vapor connctors within 12 months after Phs III date - inspect all light liquid connectors (> 3 drops/minute) - annual if >2% leaking - biannual if ,2% and >1% leaking - every 4 years if <1% leaking	Annually (random 200 or 10% by unit) If <2% leaking = annually If >2% leaking = quarterly until <2% obtained for 4 qrts otherwise monitor all connectors Monitor within 90 days after welding (xray, etc.) or breaking the seal (OVA)	Weekly visual (no records) Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monthly (63 R) -or- Once per shift (63 YY)
Monitoring Frequency: Process Drains	NA	NA	NA	NA	NA	NA	NA	NA	Annually monitor	NA	NA	NA	NA	Annually monitor	NA
Monitoring Frequency: Heavy Liquid Equipment	Monitor within 5 days of detection by sight, smell, or sound. Repaired systems do not require monitoring	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound. Repaired systems do not require monitoring	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound. Repaired systems do not require monitoring	Monitor within 5 days of detection by sight, smell, or sound	Monitor if leak suspected by sight, smell, or sound	NA	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor if leak suspected by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound

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Monitoring Frequency: Closed Vent Systems	Hard piping: Initial monitoring Annual visual Duct Work: Annual monitor	Hard piping: Initial monitoring Annual visual Duct Work: Annual monitor	Hard Piping: Annual visual Duct Work: Annual monitor	Hard piping: Initial monitoring Annual visual Duct Work: Annual monitor	Annually monitor	Hard piping: Initial monitoring Annual visual Duct work: Annual monitor	Hard piping: Initial monitoring Annual visual Duct Work: Annual monitor	Annually monitor	NA	Annually monitor	Hard piping: Initial monitoring Annual visual Duct work: Annual monitor	Hard piping: Initial monitoring Annual visual Duct work: Annual monitor	Hard piping: Initial monitoring Annual visual	Monitor if leak suspected by sight, smell, or sound	Hard piping: Initial monitoring Annual visual Duct Work: Annual monitor
Monitoring Frequency: Open-ended valves/lines	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve Monitor annually	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve	Requires cap, plug, blind flange, or 2nd valve Monitor if leak suspected by sight, smell, or sound	Requires cap, plug, blind flange, or 2nd valve
Monitoring Frequency: Sampling Points/ Connections	Requires closed purge, closed loop, or closed vent system Return or recycle purge	Requires closed purge, closed loop, or closed vent system Return or recycle purge	Requires closed purge, or closed loop system	Requires closed purge, closed loop, or closed vent system Return or recycle purge	Requires closed purge, or closed vent system Return or recycle purge Zero emissions to atm	Requires closed purge system, or closed vent system Return or recycle purge	Requires closed purge, closed loop, or closed vent system Return or recycle purge	Requires closed purge, or closed vent system Return or recycle purge Zero emissions to atm	NA	Requires closed purge, closed vent system Return or recycle purge Zero purge to atm	Requires closed purge system, or closed vent system Return or recycle purge	Requires closed purge system, or closed vent system Return or recycle purge	Requires closed purge system, or closed vent system Return or recycle purge	Monitor within 5 days of detection by sight, smell, or sound	Requires closed purge, closed loop, or closed vent system Return or recycle purge
Monitoring Frequency: Agitators	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Monthly monitor & weekly visual	Within 5 days of detection by sight, smell, or sound	NA	Monthly monitor & weekly visual	Within 5 days of detection by sight, smell, or sound	NA	NA	NA	Monthly monitor & weekly visual	NA	Monitor within 5 days of detection by sight, smell, or sound	Monthly monitor & weekly visual
Monitoring Frequency: Surge Control Vessels and Bottoms Receivers	Requires closed vent system	NA	Requires closed vent system Exempt from requirements if contains a latex and located downstream of stripping operation.	Requires closed vent system	Requires closed vent system	NA	Requires closed vent system	Requires closed vent system	NA	Requires closed vent system	NA	NA	NA	Monitor within 5 days of detection by sight, smell, or sound	Requires closed vent system

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Monitoring Frequency: Visual Leaks	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound			Monitor within 5 days of detection by sight, smell, or sound		Monitor immediately any component leaking based on sight, smell, or sound			Monitor within 5 days of detection by sight, smell, or sound	NA	Monitor immediately any component leaking based on sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound
Monitoring Frequency: Instrument-ation Systems	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	NA	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound	NA	NA	NA	Monitor within 5 days of detection by sight, smell, or sound	NA	Monitor within 5 days of detection by sight, smell, or sound	Monitor within 5 days of detection by sight, smell, or sound
Skip periods	**Valves only:** Initial performance of 2% leaks = quarterly Initial performance of 1% leaks = semi-annually **Pumps only:** No skip period only avoid QIP requirements Batch process monitoring Historical performance acceptable without prior approval	**Valves only:** Monthly if >2% Quarterly if <2% Semiannually if <1% Annually if <0.5% Biennally if <0.25% **Pumps only:** No skip period only avoid QIP requirements	**Valves only:** Initial performance of 2% leaks = quarterly Initial performance of 1% leaks = semi-annually **Pumps only:** No skip period only avoid QIP requirements Batch process monitoring	**Valves only:** Initial performance of 2% leaks = quarterly Initial performance of 1% leaks = semi-annually **Pumps only:** No skip period only avoid QIP requirements Batch process monitoring Historical performance acceptable without prior approval	**Valves only:** Not Allowed	**Valves only:** 2 consecutive quarters <2% = skip 1 quarter 5 consecutive quarters <2% = skip 3 quarters	**Valves (with connectors):** Initial performance of 5% leaks = quarterly Initial performance of 4% leaks = semi-annually **Valves (without connectors):** Initial performance of 4% leaks = quarterly Initial performance of 3% leaks = semi-annually **Pumps only:** No skip period only avoid QIP requirements Historical performance acceptable without prior approval	**Valves only:** 2 consecutive quarters <2% = semi-annual 2 consecutive semi-annual < 2% = annual >2% leaking = increase monitoring Historical performance acceptable without prior approval	**Valves only:** 2 consecutive quarters < 2% = skip 1 quarter 5 consecutive quarters < 2% = skip 3 quarters Total leaking FECs cannot be > 4% Historical performance acceptable without prior approval	**Valves only:** 2 successive months ND = first month of every qtr until leak detected 2 consecutive qtrs < 2% = skip 1 qtr 5 consecutive qtrs < 2% = skip 3 qtrs Vinyl Chloride NESHAP allows 200 or 90% valves if <2%	**Valves only:** 2 consecutive quarters <2% = skip 1 quarter 5 consecutive quarters <2% = skip 3 quarters	**Valves only:** 2 consecutive quarters <2% = skip 1 quarter 5 consecutive quarters <2% = skip 3 quarters Monthly if >2%	**Valves only:** 2 consecutive quarters <2% = skip 1 quarter 5 consecutive quarters <2% = skip 3 quarters	**Valves only:** 2 consecutive quarters <2% = skip 1 qtr for valves and pumps (LL) 5 consecutive quarters <2% = skip 3 qtrs	None for 63 R

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Light/heavy liquid definition and exemptions	Light liquid has VP > 0.3 kPa @ 20 degC	Light liquid has VP > 0.3 kPa @ 20 degC	Light liquid has VP > 0.2 kPa @ 20 degC	Light liquid has VP > 0.3 kPa @ 20 degC & is 20%w of total process stream	Light liquid has VP > 0.3 kPa @ 20 degC or a 10% evaporation point > 150 degC using ASTM D-86	Light liquid has VP > 0.3 kPa @ 20 degC & is 20%w of total process stream	Light liquid has VP > 0.3 kPa @ 20 degC or a 10% evaporation point > 150 degC using ASTM D-86	Light liquid has VP > 0.3 kPa @ 20 degC or a 10% evaporation point > 150 degC using ASTM D-86		Light liquid has VP >0.3 kPa @ 20 degC or a 10% evaporation point > 150 degC using ASTM D-86	Light liquid has VP > 0.3 kPa @ 20 degC & is 20%w of total process stream	Light liquid has VP > 0.3 kPa @ 20 degC	Light liquid has VP > 0.3 kPa @ 20 degC	NA	
Liquid dripping definition										Visible leakage including spraying, misting, clouding and ice formation				Per HON	
Materials included in VOC definition					Consistent with LAC 33:III.2117	TOC excluding methane, ethane, 1-1-1-TCE, methylene chloride, and various CFCs		Consistent with LAC 33:III.2117			TOC excluding methane, ethane, 1-1-1-TCE, methylene chloride, and various CFCs		Consistent with LAC 33:III.2117		
Monitoring Method	Method 21 Calibrate within 2000 ppm	Method 21 Calibrate within 2000 ppm	Method 21	Method 21 Calibrate within 2000 ppm	LAC 33:III.6077	Method 21	LAC 33:III Chapter 60, 61 or 63	LAC 33:III.6077	Method 21	Method 21	Method 21	40 CFR 264.1063 (b)	Method 21	Visual, audible, or olfactory	
Monitoring Distance	Consistent with EPA protocol	Consistent with EPA protocol	Consistent with EPA protocol	Consistent with EPA protocol	Not specified	Consistent with EPA protocol	Consistent with EPA protocol	Not specified	Consistent with EPA protocol	Consistent with EPA protocol	Consistent with EPA protocol	Consistent with EPA protocol	Not specified	NA	
Comments			Comply with Subpart H of SOCMI HON This table outlines HON requirements for Elastomer MACT	Comply with HON except for specific deviations These two regulations are carbon copies of each other											

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Post repair inspection	Valves, after repair, monitored at least once within 3 months Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check	Valves, after repair, monitored at least once within 3 months Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check	Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check	Valves, after repair, monitored at least once within 3 months Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check	Not specified, but assumed to be required immediately after repair to confirm a repair was successful	Not specified, but assumed to be required immediately after repair to confirm a repair was successful	Valves, after repair, monitored at least once within 3 months If monitoring connectors, monitor repaired connector within 2st 3 months after repair. Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check	Not specified, but assumed to be required immediately after repair to confirm a repair was successful	Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check	Not specified, but assumed to be required immediately after repair to confirm a repair was successful	Not specified, but assumed to be required immediately after repair to confirm a repair was successful	Valves, after repair, monitored at least once within 3 months	Not specified, but assumed to be required immediately after repair to confirm a repair was successful	Not specific, but required to maintain date component rechecked after maintenance and instrument reading upon check	No visible leak or holds a test pressure
Repair periods (1st/Final Attempt)	5 day/15 days	5 day/15 days	5 days/15 days	5 days/15 days	5 days*/15 days *Includes monitoring	5 days/15 days	5 day/15 days	5 days/15 days	15 days	5 days/15 days	5 days/15 days	5 days/15 days	5 days/15 days	15 days	5 days/15 days
Calibration gas	Zero air, and mixtures dependent on phase monitored	Zero air, methane or n-hexane and air at a concentration of approximately 2,000 ppm	Zero air, air mixtures dependent of phase monitored	Zero air, methane or n-hexane and air at a concentration of approximately 2,000 ppm	Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm	Zero air, methane or n-hexane and air at a concentration no more than 2,000 ppm above leak definition and highest scale with a calibration gas of approximately 10,000 ppm	Zero air, and mixtures dependent on phase monitored	Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm	Not specified in rule	Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm	Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm	Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm	Zero air, methane or n-hexane and air at a concentration of about but less than 10,000 ppm	Not specified in rule	NA
Calibration Frequency	Before use on each day	Before use on each day	Before use on each day	Before use on each day	Before use on each day	Before use on each day	Before use on each day	Before use on each day	Not specified in rule	Before use each day	Before use on each day	Before use on each day	Before use on each day	Not specified in rule	NA

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Criteria for unsafe to monitor exemption	**Valves & connectors:** Immediate danger Follow written plan to monitor when safe	**Valves & connectors:** Immediate danger Follow written plan to monitor when safe	**Valves & connectors:** Immediate danger Follow written plan to monitor when safe	**Valves & connectors:** Immediate danger Follow written plan to monitor when safe	**Valves, connectors & CVS:** Immediate danger Follow written plan to monitor when safe	**Valves:** Immediate danger Follow written plan to monitor when safe	**Valves & connectors:** Immediate danger Follow written plan to monitor when safe	**Valves, connectors & CVS:** Immediate danger Follow written plan to monitor when safe	No criteria, but monitor when safe	**Valves:** Immediate danger Follows written plan to monitor when safe	**Valves:** Immediate danger Follow written plan to monitor when safe	**Valves & connectors:** Immediate danger Follow written plan to monitor when safe	**Valves:** Immediate danger Follow written plan to monitor when safe	No criteria, but monitor when safe	**Valves & connectors:** Immediate danger Follow written plan to monitor when safe
Criteria for inaccessible components exemption	**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)	**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)	**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)	**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)	**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)	**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)	**Random 200 option** - only accessible connectors **Inspection Alternative** - only accessible connectors	**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)				**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)			**Connector:** Buried, insulated, obstructed, >25 ft scaffold & >2m support surface (referred to as inaccessible)
Criteria for difficult to monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor	Cannot monitor without elevating >2m above support surface Follow written plan to annually monitor

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Exemptions	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor <.75" FECs in instrumentation systems PRVs equipped with rupture disk	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor Equipment in service <300 hours per year	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor Equipment in service <300 hours per year	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor Equipment in service <300 hours per year	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor Equipment in service <300 hours per year	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor <.75" FECs in instrumentation systems PRVs equipped with rupture disk	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor Equipment in service <300 hours per year	Vacuum service Unsafe to monitor Dual Mechanical seals Vapor pressure <0.0435 psia R&D facilities (< 100 FEC) Insulated components	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor Equipment in service <300 hours per year	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system No detectable emissions Difficult to monitor	Vacuum service Unsafe to monitor Dual Mechanical seals Vapor pressure <0.0435 psia R&D facilities (< 100 FEC) Check valves	Vacuum service Unsafe to monitor Dual Mechanical seals with barrier fluid and alarm Closed vent system Difficult to monitor Open ended lines for emergency PRVs equipped with rupture disk
Exemptions (Continued)	Unmanned sites: Monthly visual inspections allowed Compressors operated <300 hrs or tied to CVS or VRU	Open ended lines for emergency PRVs equipped with rupture disk	Open ended lines for emergency PRVs equipped with rupture disk	Open ended lines for emergency PRVs equipped with rupture disk	Open ended lines for emergency PRVs equipped with rupture disk		Unmanned sites: Monthly visual inspections allowed Compressors operated <300 hrs or tied to CVS or VRU	Open ended lines for emergency PRVs equipped with rupture disk	Components of shutdown repair list						Unmanned sites: Monthly visual inspections allowed Compressors operated <300 hrs or tied to CVS or VRU

Item of Comparison	**40 CFR 63 Subpart H - SOCMI HON MACT**	**40 CFR 63 Subpart UU – Equipment Leaks Control Level 2**	**40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT**	**40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT**	**LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements**	**40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)**	**40 CFR 63 Subpart CC - Refinery MACT Modified HON Option**	**LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT**	**LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment**	**40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT**	**40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)**	**40 CFR 63 Subpart TT – Equipment Leaks Control Level 1**	**RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB**	**LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III**	**40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)**
Delay of repair	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of HAP service **Valves, Connectors, Agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of HAP service **Valves, Connectors, Agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of HAP service **Valves, Connector, Agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of HAP service **Valves, Connectors, Agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of VOTAP service **Valves, connectors & agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device Drill and tap required on non-control valves, if feasible, before placing on delay of repair All components on delay of repair must be monitored per routine monitoring **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of VOC service **Valves:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of HAP service **Valves, Connectors, Agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of VOTAP service **Valves, connectors & agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Requires a PU shutdown Isolated or bypassed to reduce leakage Shutdown would create more emissions than repair would eliminate	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of VHAP service **Valves:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of VOC service **Valves:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of HAP service **Valves, Connectors, Agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of VOC service **Valves:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)	**All equipment:** Requires a PU shutdown Isolated or bypassed to reduce leakage Shutdown would create more emissions than repair would eliminate	**All equipment:** Technically infeasible w/o PU shutdown; Isolated and out of HAP service **Valves, Connectors, Agitators:** Purged material from repair causes greater emissions than fugitive leak; recover and destroy in control device **Pumps:** Replacing with DMS (within 6 months)

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Delay of repair beyond PU shutdown	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion.	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion.	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion.	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion.	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion.	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion		**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion.	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion	**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion		**Valves:** Assembly replacement is necessary during PU shutdown, valve assemblies are depleted, and assemblies were sufficiently stocked before depletion.
Tagging	Leaking components	Leaking components	Leaking components	Leaking components	Leaking components	Leaking components	Leaking components	Leaking components	Leaking components	Leaking components and affected components	Leaking components	Leaking components	Physical tag required	Leaking components	None
Use of background concentration data	Subtract for determining compliance	Subtract for determining compliance	Subtract for determining compliance	Subtract for determining compliance	Subtract for determining compliance	Subtract for determining compliance	Subtract for determining compliance	Subtract for determining compliance	Not specified in rule	Subtract for determining compliance	Subtract for determining compliance	Subtract for determining compliance		Not specified in rule	NA

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Recordkeeping	Leak and repair records Component Inventory Connector monitoring schedule DMS records Valves records Exemption data Batch Process Monitoring HL determinations Visual inspection dates Compliance tests CVS system design and operation QIP	Leak and repair records Component Inventory Connector monitoring schedule DMS records Valves records Exemption data Batch Process Monitoring HL determinations Visual inspection dates Compliance tests CVS system design and operation QIP	Leak and repair records Component Inventory Connector monitoring schedule DMS records Valves records Exemption data Batch Process Monitoring HL determinations Visual inspection dates Compliance tests CVS system design and operation QIP	Leak and repair records Component Inventory Connector monitoring schedule DMS records Valves records Exemption data Batch Process Monitoring HL determinations Visual inspection dates Compliance tests CVS system design and operation QIP	Leak and repair records Component Inventory Connector monitoring schedule Valves records Exemption data CVS system design and operation DORs must be signed within 30 days of leak identifcation	Leak and repair records Component Inventory CVS design and operation records Valve records Exemption data	Leak and repair records Component Inventory Connector monitoring schedule DMS records Valves records Exemption data HL determinations Visual inspection dates Compliance tests CVS system design and operation QIP	Leak and repair records Component Inventory Connector monitoring schedule Valves records Exemption data CVS system design and operation	Leak and repair records Component inventory Calibration records	Leak and repair records CVS design and operation records Component Inventory Valve records Exemption data	Leak and repair records Component Inventory CVS design and operation records Valve records Exemption data	Leak and repair records Component Inventory CVS design and operation records Valve records Exemption data	Leak and repair records Component Inventory CVS design and operation records Valve records Exemption data Compliance Test Results	Leak and repair records Component inventory Calibration records	Maintain log book of inspections, and leaking components, with summary descriptions.
Recordkeeping Period	2 years	Per referencing Subpart	2 years	5 years	5 years	2 years	2 years	5 years	2 years	2 years	2 years	Per referencing Subpart (5 years)	2 years	2 years	5 years

Item of Comparison	40 CFR 63 Subpart H - SOCMI HON MACT	40 CFR 63 Subpart UU – Equipment Leaks Control Level 2	40 CFR 63 Subpart U - Polymers and Resins I, Elastomer MACT	40 CFR 63 Subparts GGG and MMM – Pharmaceuticals MACT and Pesticide Active Ingredient MACT	LAC 33:III.Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT With NSR Consent Decree Enhancements	40 CFR 60 Subparts VVa (SOCMI) & GGGa (Refinery)	40 CFR 63 Subpart CC - Refinery MACT Modified HON Option	LAC 33:III Chapter 51- Louisiana Refinery MACT and Louisiana Non-HON MACT	LAC 33:III.2122 Louisiana Fugitive Emission Control for Nonattainment	40 CFR 61 Subparts F, J and V and 40 CFR 63 Subpart HH – PVC, Benzene, and Oil & Natural Gas Production MACT	40 CFR 60 Subparts VV (SOCMI), GGG (Refinery) & KKK (Gas Processing Plants)	40 CFR 63 Subpart TT – Equipment Leaks Control Level 1	RCRA 40 CFR 264 Subpart BB & 40 CFR 265 Subpart BB	LAC 33:III.2121 Louisiana Fugitive Emission Control and 40 CFR 63 Subpart III	40 CFR 63 Subparts R (Gasoline Distribution) and YY (Hydrogen Fluoride Production)
Reporting	LDAR Performance reports semi-annually after Not. of Comp. Initial Notification Initial Notification of Compliance	LDAR Performance reports semi-annually after Not. of Comp. Initial Notification Initial Notification of Compliance	LDAR performance report semi-annually after Not. of Comp. Initial Notification Initial Notification of Compliance	LDAR Performance reports semi-annually after Not. of Comp. Initial Notification Initial Notification of Compliance	Initial notification Quarterly LDAR Performance reports 3 months after initial report	Initial report LDAR Performance reports semi-annually	LDAR Performance reports semi-annually after Not. of Comp. Initial Notification Initial Notification of Compliance	Initial notification Quarterly LDAR Performance reports 3 months after initial report	Quarterly LDAR Performance reports, including repair data	Initial report Semi-annual reports starting 6 months after initial	Initial report LDAR Performance reports semi-annually	Per referencing Subpart	LDAR Performance reports semi-annually	Quarterly LDAR Performance reports, including repair data	63 Subpart R: Quarterly 63 Subpart YY: Records only
Effective dates	Group I Oct 24, 1994 Oct 24, 1995 Apr 24, 1997 Group II Jan 23, 1995 Jan 23, 1996 Jul 23, 1997 Group III Apr 24, 1995 Apr 24, 1996 Oct 24, 1997 Group IV Jul 24, 1995 July 24, 1996 Dec 24, 1997 Group V Oct 23, 1995 Oct 23, 1996 Apr 23, 1997		One year after promulgation for compressors 6 months after promulgation for other equipment		Jan 1, 1995, unlessotherwise specified in Air Toxics Compliance Plan, but no later than Dec 20, 1996	Nov. 16, 2007	New Sources - upon startup Existing Sources - Phase I- Aug 18, 1998 Phase II - Aug 18, 1999 Phase III - Feb 18, 2001	Jan 1, 1995, unlessotherwise specified in Air Toxics Compliance Plan, but no later than Dec 20, 1996	Jan1, 1996	June 6, 1984 Vinyl Chloride NESHAP Oct 21, 1976	Jan 5, 1981		As required by permit		

Note: For this table –

CVS = closed vent systems;
DMS = dual mechanical seal system;
Gas = in gas/vapor service;
HL = in heavy liquid service;
Liquid = in liquid service;
LL = in light liquid service;
ND = no leak is detected;
PRVs = pressure relief valves/devices;
PU = process unit;
QIP = quality improve program;
SurgeCtrlVessel = surge control vessel;
TOC = total volatil organic compounds;
VRU = vapor recovery unit.

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29-36153A

BEST AVAILABLE CONTROL TECHNOLOGY FOR GREENHOUSE GASSES

KALAMA MANUFACTURING AND MARINE EXPORT FACILITY

RAMBOLL ENVIRON

CONTENTS

LIST OF TABLES

1. INTRODUCTION

Northwest Innovation Works, Kalama LLC (NWIWK) and the Port of Kalama (Port) propose to construct and operate a methanol manufacturing and marine export facility (the Facility) on approximately 90 acres at the Port's Northport site, in Cowlitz County near Kalama, Washington. The Facility will be called the Kalama Manufacturing and Marine Export Facility (KMMEF). At full capacity, the facility will produce approximately 10,000 metric tons of AA-grade methanol per day (mt/day) and approximately 3.6 million mt per year.

On June 23, 2014, the Supreme Court ruled, in Utility Air Regulatory Group (UARG) v. U.S. Environmental Protection Agency (EPA), that EPA could not establish regulatory thresholds different from those required under statute, as it had done in the Tailoring Rule, but a new project or modification that triggers review under the Prevention of Significant Deterioration (PSD) program as a result of a criteria pollutant emission increase can be required to implement BACT for greenhouse gases (GHGs). As a result, on August 19, 2015, EPA changed its regulations such that new sources or modifications with potential criteria pollutant emission rate increases that are less than the PSD threshold are not subject to the requirements of the PSD program, regardless of the GHG emission rate increase associated with the project.[1]

The Washington Department of Ecology (Ecology) adopted by reference, with certain changes, relevant portions of the federal PSD regulations in 40 CFR 52.21, as in effect on August 13, 2012. Because the regulations were adopted prior to EPA changing the regulations as described above, new sources in Washington that have the potential to emit (PTE) 100,000 tons per year (tpy) of carbon dioxide equivalent (CO_2e) are subject to review under the state PSD program. Because there are no ambient standards or increments for GHGs, the only PSD requirement that applies to GHGs is that Best Available Control Technology (BACT) must be employed to reduce GHG emissions from the proposed project. NWIW has retained Ramboll

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[1] Prevention of Significant Deterioration and Title V Permitting for Greenhouse Gases: Removal of Certain Vacated Elements, 80 Federal Register 50199 (August 19, 2015).

Environ US Corporation (Ramboll Environ) to prepare this GHG BACT analysis in support of the PSD permit application developed for KMMEF.[2]

1.1 Project Description

Methanol will be manufactured at the Facility using a methane reforming process that converts natural gas and water to a synthesis gas, or "syngas," comprised primarily of hydrogen (H_2), carbon monoxide (CO), and carbon dioxide (CO_2). The technology used to create the syngas is a two-step process. In the first step, saturated, de-sulfurized natural gas and steam are combined and passed through catalyst-filled tubes, where an endothermic reaction converts some of the feedstock to syngas. The partially reformed gas is then sent to an auto-thermal reformer (ATR), where oxygen is added and passed over another catalyst to create more syngas in an exothermic reaction. The hot, fully-reformed syngas is sent to the gas-heated reformer (GHR), which heats the catalyst-filled tubes where the initial, endothermic, syngas reforming reaction took place. The syngas is synthesized and distilled to produce nearly pure methanol, which is stored on site until it is transferred to marine vessels for export.

The Facility will have two methanol production lines, each with the capacity to produce approximately 5,000 mt per day. The production lines are designed to operate on a nearly continuous basis; the only planned shutdown is when the catalysts used to create syngas are deactivated to the point where they must be replaced, which is expected to occur every four or five years. Inevitably, there will be other shutdowns, but the frequency and duration will be kept to a minimum to maximize production.

GHG BACT is evaluated in this document for the overall facility as well as emission units with the potential to emit GHGs:

- Three gas-fired boilers;
- Two natural gas-fired process heaters;
- One power generation unit (PGU) that will consist of two natural gas-fired combined-cycle combustion turbines (CCCTs) with evaporative

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[2] The project is also required to employ BACT for regulated pollutants subject to review under the PSD program, and for all other regulated pollutants, as well as toxic air pollutants (TAPs), as a requirement of the Air Discharge Permit (ADP) application that must be submitted to the Southwest Clean Air Agency (SWCAA) for those pollutants. BACT for these pollutants is addressed in a different document.

cooling capability, two once-through steam generators (OTSGs) with supplemental firing capability, and one steam turbine;

- One flare with a natural gas-fired pilot;
- Two nominal 3.5 megawatt-capacity diesel-fueled emergency generators;
- One nominal 1,600 horsepower-capacity diesel-fueled emergency fire water pump;
- Piping, valves, connectors, pumps, compressors, and other components to move natural gas, methanol, and intermediates throughout the facility;
- One cooling tower with 12 cells ;and
- Electrical switchgear (e.g., circuit breakers).

1.2 BACT Review Process

BACT is defined at 40 CFR 52.21(b)(12)[3] as:

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

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[3] Adopted by reference in WAC 173-400-720(4)(vi)

> *the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."*

In November 2010, EPA issued guidance for conducting BACT analyses for GHGs and updated the guidance in March 2011 (hereafter referred to as "the March 2011 Guidance"). EPA recommended (but did not require) that permitting agencies apply to GHGs the same "top down" process applied to determine criteria pollutant BACT. In this process, potentially available control technologies are identified and evaluated for application to the proposed project. Feasible options are ranked in descending order of control effectiveness. The most stringent alternative is examined and is established as BACT unless the applicant demonstrates and the permitting authority agrees that energy, environmental or economic impacts justify a conclusion that the most stringent technology is not achievable. In that case the next stringent alternative is considered. This top-down BACT analysis process can be considered to contain five basic steps:

- Step 1: Identify all available emission reduction alternatives with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
- Step 2: Eliminate all technically infeasible alternatives;
- Step 3: Rank remaining alternatives by effectiveness;
- Step 4: Evaluate the economic, energy, and environmental impacts starting with the most effective alternative; and
- Step 5: Select BACT, which will be the most effective practical alternative not rejected in the previous steps.

Each step is discussed further in the sections that follow.

1.2.1 Step 1 – Identify Available Control Technologies

The first step in the top-down procedure is to identify all available control technologies and emission reduction options for each subject pollutant. Available control technologies are those with a practical potential for application to the emission unit. For criteria pollutants, applicants typically identify appropriate control technologies by reviewing the following sources of information:

- EPA RACT/BACT/LAER Clearinghouse (RBLC)
- EPA Control Technology Center (CTC)
- Recent permit actions for similar facilities or emission units, and
- Vendor information

Because BACT for GHGs is a relatively new requirement, there are fewer BACT precedents compared to criteria pollutants. In preparing this BACT analysis, analyses for similar facilities were consulted, including the Natgasoline facility in Texas, Yuhuang Chemical Inc. (YCI) facility in Louisiana, and the Celanese Clear Lake facility in Texas. Because methanol production facilities typically do not include a PGU, analyses for facilities that included aero-derivative CCCTs were also consulted, including M&G Resins and Formosa Plastics, both in Texas.

Consistent with these precedents and EPA's March 2011 Guidance, this analysis demonstrates that the design of the proposed facility will achieve a very high degree of energy efficiency. In BACT parlance, this is considered "lower-polluting processes/practices" as opposed to post-combustion or "end-of-stack" controls. Given the limited technological options available for end-of-stack GHG emission controls, EPA's initial BACT guidance emphasizes energy efficiency. In addition to reducing GHG emissions, energy efficiency also minimizes criteria and toxic air pollutant emissions.

A control technology must be "available" to be considered BACT. According to EPA's draft 1990 NSR manual "'[a]vailable' means that the method's systems and techniques are commercially available." BACT also does not require the applicant to participate in a research and development project to determine if a technology is "available" for a particular use.

Theoretical, experimental or developing technologies are not "available" under BACT. Technologies with questionable or dubious reliability are, likewise, not considered "available" under BACT, and the applicant is not required to use them. BACT does not require an applicant to speculate as to whether an undemonstrated technology will effectively control the pollutant in question from the proposed source. Applicants are not required to accept the risk that a theoretically feasible, but unproven, technology will effectively and economically reduce emissions from the proposed source.

In addition, the EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. Considerable argument and litigation has been generated over what constitutes "redefinition of the source." The most recent approach outlined by the Environmental Appeals Board (EAB) is contained in a 2009 ruling to remand a permit issued to Desert Rock Energy Co., LLC. In that ruling, which referred extensively to a previous EAB ruling (Prairie State Generation Co., LLC), the EAB says that the reviewing agency should seek to answer the question: "when does the imposition of control technology require enough of a redesign of the proposed facility that it strays over the dividing line to become an impermissible redefinition of the source?"

In response to its own question, the EAB stated that "the permit applicant initially defines the proposed facility's end, object, aim, or purpose – that is the facility's basic design, although the applicant's definition must be for reasons independent of air permitting." Furthermore, the permit issuer should "take a 'hard look' at the application determination in order to discern which design elements are inherent for the applicant's purpose and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility, while keeping in mind that BACT, in most cases, should not be applied to regulate the applicant's purpose or objective for the proposed facility."

1.2.2 Step 2 – Eliminate Technically Infeasible Control Technologies

The second step in performing the top-down BACT analysis is to eliminate all technically infeasible options. The determination that a control technology is technically infeasible is source-specific and based upon physical, chemical, and engineering principles. Technical feasibility is addressed in EPA's March 2011 Guidance:

EPA generally considers a technology to be technically feasible if it: (1) has been demonstrated and operated successfully on the same type of source under review, or (2) is available and applicable to the source type under review. If a technology has been operated on the same type of source, it is presumed to be technically feasible. An available technology from Step 1, however, cannot be eliminated as infeasible simply because it has not been used on the same type of source that is under review. If the technology has not been operated successfully on the type of source under review, then questions regarding “availability” and “applicability” to the particular source type under review should be considered in order for the technology to be eliminated as technically infeasible.

Prior guidance and judicial decisions confirm that "feasible technology" means design or equipment that has progressed beyond the conceptual and pilot testing phases, is commercially available, and has been demonstrated on a full-scale emission unit of the type of that is the subject of the BACT analysis, for a period of time sufficient to indicate reliable operation. These criteria are especially important for GHG BACT analyses due to the unproven nature of many GHG control schemes.

“Demonstrated in practice” is another important concept that addresses the question of whether a technology should be considered available. In its New Source Review Improvement Rule (issued November 22, 2002), EPA included a definition of “demonstrated in practice.” This definition prescribes which technologies must be considered in BACT and LAER determinations by defining the information that must be reviewed to identify candidate technologies, the amount of time the technology must be in use, and its performance during that time. A technology installed and operating on an emissions unit (or units) must meet the following criteria to be considered “demonstrated in practice:”

- Has operated at a minimum of 50 percent of design capacity for at least 6 months; and
- The pollution control efficiency performance has been verified by either:

  1) a performance test, or

  2) performance data collected at the maximum design capacity of the emissions unit (or units) being controlled, or 90 percent or more of the control technology's designed specifications.

Although this definition of “demonstrated in practice” does not have any regulatory standing in the analysis presented in this report, it does provide some useful guidance for evaluating whether certain technologies are “available,” and therefore worthy of consideration as BACT.

1.2.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The third step in the top-down BACT analysis is to rank all remaining control technologies with respect to control effectiveness (i.e., by emission limit or removal efficiency, as applicable). The emission limit or removal efficiency used in the ranking process is that which the technology has demonstrated can be achieved consistently under reasonably foreseeable worst-case conditions with an adequate margin of safety. A limit or removal efficiency that can be achieved only occasionally under best-case circumstances is not to be considered.

For GHGs, control options are ranked based on total CO_2e rather than the total mass or mass of individual GHGs.

1.2.4 Step 4 – Evaluate Most Effective Controls and Document Results

In this step, an analysis is performed on each remaining control technology to determine whether the energy, economic, or environmental impacts from a given technology outweigh their benefits. Factors such as control efficiency, anticipated emission rate, expected emissions reduction, and economic, environmental, and energy impacts, are to be considered.

If the top-ranked technology is chosen, and there are no significant or unusual environmental impacts associated with that technology that have the potential to affect its selection, the BACT analysis is complete, and no further analysis is required. However, if the chosen technology is not the top-ranked option, the economic, environmental, and energy impacts of the chosen technology, and each more-effective technology, must be evaluated and compared to justify application of the selected technology. In the March 2011 Guidance, EPA suggests that, instead of the more traditional approach where the options are considered and either eliminated or adopted in order of effectiveness, the economic, energy, and environmental impacts of all options should be considered.

In performing economic analyses, EPA's Air Pollution Control Cost Manual, published in January 2002 (EPA/452/B-02-001) provides capital and annual operating cost factors that can be used in determining the installation and operating costs of each control technology. Actual vendor installation and operation costs were used where applicable.

Cost-effectiveness evaluations for greenhouse gases are to be conducted based on reductions in CO_2e. However, as acknowledged by EPA in its March 2011 Guidance, no cost effectiveness criteria have been established for GHGs. Furthermore, there are no means by which to evaluate the environmental impacts of GHG emissions at the stationary source level. Consequently, comparisons of environmental impacts associated with GHG emissions with those of collateral criteria pollutant emissions are not possible.

1.2.5 Step 5 – Select BACT

The final step is selection of the most stringent and technically feasible emission limit and corresponding technology that was not eliminated based upon adverse economic, environmental, and energy impacts. EPA's March 2011 Guidance notes that a GHG permit may limit CO_2e based on a mass emission rate (lb/hr) or other metrics. EPA also notes that "since the environmental concern with greenhouse gases is with their cumulative impact in the environment, metrics should focus on longer-term averages (e.g., 30- or 365-day rolling average) rather than short-term averages (e.g., 3- or 24-hr rolling average)."

Although this process might appear to be tightly prescribed, 20 years of experience with the top-down BACT analysis process has resulted in a number of agency and judicial decisions that have served to guide subsequent BACT determinations:

- BACT determinations are made "on a case-by-case basis," taking into account site-specific and source-specific characteristics. These characteristics may include, among other things, the type of fuel or raw materials that will be used, and the type and size of the emissions unit. A high degree of technical judgment must be exercised in any BACT analysis as there are various sizes and ages of the emissions units covered by an analysis.
- • BACT must be achievable. The Environmental Appeals Board (EAB) has recently stated that, while BACT is forward-looking, "the word 'achievable'…constrains the permit issuer's discretion by prohibiting BACT limits that would require pollution reductions greater than what can be achieved with available methods." The EAB concluded that "the permit issuer may take into account the absence of long-term data, or the unproven long-term effectiveness of the technology, in setting the emissions limitation that is BACT for the facility." The EAB further stated that the BACT analysis "must be solidly grounded on what is presently known about the selected technology's effectiveness," and that "emissions limitations achieved by other facilities, and corresponding

> control technologies used at other facilities are an important source of information in determining" BACT.

EPA's March 2011 Guidance affirms that vendor confidence in emission control efficiency should be considered: "[t]he willingness of vendors to provide guarantees and the limits of these guarantees can be an important factor in determining the level of performance specified in a PSD permit"

Finally, the chosen BACT emission limit must not be less stringent than any applicable federal NSPS, NESHAP, or state-specific emission standard. It should be noted, however, that there are no federal NSPS or NESHAP GHG emission standards that apply to any of the proposed emission units. Washington has an Emission Performance Standard for baseload electric generation facilities (RCW 80.80), which will be addressed.

2. SYNGAS PRODUCTION

Methanol production consists of three primary steps: syngas production, methanol synthesis, and methanol distillation. The syngas production step uses a reforming process to convert a hydrocarbon feedstock, in this case natural gas, steam, and oxygen to syngas. The syngas is synthesized to create raw methanol, which is distilled to create nearly pure methanol. Because the majority of the GHG emissions associated with the production of methanol are generated by the syngas production process it is necessary to consider not only the magnitude of the heat input required to create the syngas, but also the efficiency with which the feedstock is converted to methanol. This section considers how the efficiency of the overall design of the syngas production system affects facility-wide GHG emissions.

2.1 Identify Commercially-Available Reforming Alternatives

Using natural gas as a hydrocarbon feedstock, syngas can be created a number of ways:

Steam Methane Reforming (SMR) – The most common reforming design process, which uses steam and a catalyst to create syngas that features a high H_2-to-CO ratio. A 90 percent conversion rate is typical, meaning 10 percent of the feedstock and excess hydrogen cannot be converted to product, and is most often combusted as fuel to heat the reforming process.

Auto-Thermal Reforming (ATR) – Oxygen and steam or CO_2, are used to partially oxidize methane in an exothermic reaction that converts more feedstock to syngas than SMR. By varying the quantities of steam and CO_2, the composition of the syngas can be tailored to suit the application.

Combined Reforming (SMR and ATR) – Sending partially reformed syngas from an SMR to an ATR results in a more completely reformed syngas, and allows the composition of the syngas to be optimized for downstream uses.

Combined Gas-Heated Reforming (GHR and ATR) – Similar in concept to combined reforming using SMR and ATR, but the hot syngas exiting the ATR is used to heat the preliminary reforming step in a heat-exchanger configuration, instead of using gas-fired heaters as with SMR.

Partial Oxidation (POX) – The feedstock is mixed with oxygen and heated to a high temperature with no catalyst. The exothermic process converts more feedstock to syngas than either SMR or ATR, but produces a syngas with a lower H_2-to-CO ratio than that produced by SMR or ATR.

2.2 Eliminate Technically Infeasible Alternatives

SMR is commonly used to produce syngas for many purposes, including methanol production. ATR is not as common as SMR, but is technically feasible for creating syngas that can be synthesized to methanol. Combined Reforming, like SMR and ATR separately, is also technically feasible. Combined GHR is technically feasible, but, to date, has only been employed for methanol production at a single small-scale facility in Australia. According to the EPA, POX is a proprietary technology that has not been commercially demonstrated for methanol production, and is, therefore, eliminated as being technically infeasible.[4]

2.3 Rank Technically Feasible Alternatives

This analysis assumes that all technically feasible alternatives would be executed using natural gas as both a feedstock and a fuel.[5] This assumption of a consistent fuel means the alternatives can be compared, using not only heat input rates, but fuel consumption rates, or energy input rates. Table 2-1 presents the technically feasible alternatives ranked by the quantity of energy required to produce a metric ton of methanol, starting with the most effective.

Table 2-1: Syngas Production Alternative Comparison

Syngas Production Alternative	Heat Input per Unit of Methanol Production (MMBtu/mt)
GHR + ATR[1]	3.45
SMR + ATR[2]	5.85
ATR[2]	6.14
SMR[2]	6.44

1. Based on the total annual heat input assuming continuous normal operation of two boilers, the PGU, and the flare pilot. If the PGU is excluded, the heat input per unit of methanol production is 2.55 MMBtu/mt.

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[4] EPA Region 6. Statement of Basis – Greenhouse Gas Prevention of Significant Deterioration Preconstruction Draft Permit for New Natural Gas to Gasoline Facility, Permit Number: PSD-TX-1340-GHG. August 2014. Page 10.

[5] Most, if not all, methanol production operations use process offgas as a fuel to heat the process. Because these gases are ultimately derived from natural gas, their use as a fuel is consistent with the assumption that natural gas is used to heat the process.

2. From the Statement of Basis issued by EPA Region 6 for the Greenhouse Gas Prevention of Signficant Deterioration Preconstruction Draft Permit for New Natural Gas to Gasoline Facility. Permit Number: PSD-TX-1340-GHG. August 2014.

2.4 Evaluate Economic, Energy, and Environmental Impacts

The proposed methanol production operation would create syngas using a combined GHR and ATR design that is the most energy-efficient available, and, therefore, the most effective GHG emission reduction alternative. Because the most effective alternative has been selected, it is not necessary to compare the economic, energy, and environmental impacts of the technically feasible alternatives.

2.5 Selection of BACT

NWIWK proposes that BACT for a syngas production operation at the proposed Facility is a combined GHR and ATR design. NWIWK believes that emission rate limits are not appropriate for the overall design, and, therefore, does not propose any such limits as BACT.

3. POWER GENERATION UNIT

A PGU will be used to generate electricity that will be used to power one of the two proposed methanol production lines. The proposed PGU will consist of two natural gas-fired combined-cycle combustion turbines (CCCTs), each of which will be paired with a power generator and an OTSG that will include supplemental heating (i.e., a “duct burner”). The CCCTs will be GE LM6000-PF+, or equivalent. Steam from the two OTSGs will be sent to a single steam turbine that will turn a third power generator. The combustion turbines, as well as the duct burners, will be fueled exclusively by pipeline quality natural gas and will emit only the GHGs associated with fossil fuel combustion (i.e., CO_2, CH_4, and N_2O).

3.1 Identify Commercially-Available Emission Reduction Alternatives

The first step of a top-down BACT analysis is to identify all available pollutant reduction options. Options typically fall into three categories: inherently low-emitting processes, clean fuels, and add-on control technologies. While Step 1 is intended to include all possibilities, there are limits to the scope of the first two option categories (i.e., inherently low-emitting processes and clean fuels). As discussed in Section 1.2.1, the list of options in Step 1 need not include those that fundamentally redefine the nature of the proposed source or modification.

In the March 2011 Guidance document, EPA acknowledges that, although “clean fuels” are to be considered in Step 1 of the BACT analysis, the initial list of control options does not need to include “clean fuel” options that that would fundamentally redefine the source. In this case, use of pipeline natural gas is part of the original design of the project, and is one of the, if not the, lowest-carbon fuel available. Clearly, substitution of any other fuel would drastically alter the proposed project. As a result, no electrical generation technology other than natural gas-fired combined cycle combustion turbine systems are considered in the BACT analysis.

Each of the methanol production lines will require 125 MW to startup, and 100 MW to operate at full capacity. Because the Clark County PUD is not able to provide sufficient power for both production lines, NWIWK proposes to install and operate a PGU that would be capable of providing a maximum of 125 MW. The PGU LM6000 units were chosen for their high reliability and availability, as well as their generating capacity. Because each unit is capable of generating approximately 50 MW, the PGU will be able to provide sufficient power for one methanol production line to operate at approximately 70 percent of full capacity if one of the two combustion turbines is not operating. Because the proposed LM6000-PF+ units, or equivalent, are “aero-derivative” combustion turbines (i.e., those adapted from aircraft engine designs), only projects with aero-derivative engines were considered. Projects that included heavy-duty industrial combustion turbines designed specifically as power generation units were not considered.

3.1.1 Carbon Dioxide

Carbon dioxide (CO_2) is a by-product of complete combustion. Altering the combustion process to reduce CO_2 emissions would increase emissions of “traditional” air pollutants such as carbon monoxide (CO) and volatile organic compounds (VOCs). Maximizing the combustion, heat transfer, and mechanical efficiencies of all equipment minimizes the quantity of fuel combusted, and therefore the quantity of CO_2 generated.

Post-combustion CO_2 reduction is typically referred to as “carbon capture and sequestration or storage” (CCS), which consists of three stages: (1) removing CO_2 from the exhaust stream, (2) compressing and transporting the CO_2, and (3) permanently storing the CO_2. Technology exists for all three components of CCS, but they have not yet been deployed at a scale necessary to achieve GHG reduction targets. While components of CCS have been used commercially to produce CO_2 from coal-fired power plants, applications have been limited to capturing relatively small fractions of the CO_2 present in the exhaust to produce food and chemical grade CO_2. Scaling up of current CCS technology to capture the majority of the CO_2 produced by a power plant, or a methanol production facility, poses significant engineering challenges, and is not expected to become a commercial reality for over a decade. Nevertheless, per the March 2011 Guidance, CCS technology is considered an available add-on control technology for reducing CO_2 emissions from the PGU and the rest of the gas combustion units at the proposed methanol production facility.

3.1.2 Methane

Like carbon monoxide (CO) and volatile organic compounds (VOCs), methane (CH_4) emissions are the result of incomplete fuel combustion. In the case of natural gas, CH_4 emissions would result from fuel that escapes combustion due to improper mixing with oxygen or from being confined to a zone of relatively low temperature.

Proper combustion practices and use of properly designed equipment maximizes complete combustion, which minimizes formation of CH_4. Add-on controls used to remove CH_4 from gas streams include activated carbon adsorption systems and thermal or catalytic oxidation systems. Adsorption systems pass the gas stream though canisters filled with activated carbon, and the CH_4 is trapped in pores located on the carbon particles. When the carbon approaches saturation, the canister is replaced and processed to remove the CH_4, which is recovered or destroyed. Oxidation systems increase the temperature of the gas stream until the CH_4 oxidizes, forming CO_2 and water. Thermal oxidizers destroy CH_4 using a flame, while catalytic oxidation uses a catalyst to promote the oxidation reaction at a temperature lower than the combustion temperature of CH_4.

3.1.3 Nitrous Oxide

Unlike nitric oxide (NO), which is the product of high combustion temperatures (greater than 730 °C or 1,350 °F), nitrous oxide (N_2O) is the result of lower combustion temperatures (less than 800 °C or 1,475 °F). Its formation can be limited to some extent by using proper combustion techniques and properly designed combustion systems that promote complete combustion. Typically, conditions that favor CH_4 formation, also favor N_2O formation.

Add-on controls to reduce N_2O emissions include: non-selective catalytic reduction (NSCR), thermal destruction, and catalytic destruction. In the 1970s, NSCR systems were widely used to control N_2O (and NO_X) emissions from adipic and nitric acid production operations, but high energy costs reduced the popularity of this approach. Currently, NSCR systems have been used to reduce emissions from reciprocating engines operated in a rich-burn or stoichiometric mode. In general, NSCR systems pass the exhaust gases over catalysts, which use metals (e.g., platinum, rhodium, and palladium) to convert NO_X, CO, and VOCs to water, nitrogen, and carbon dioxide. Unburned hydrocarbons in the exhaust are used as a reducing agent to enable one catalyst to convert N_2O and NO_X, while CO and VOCs are oxidized by another catalyst. In cases where the option to consistently operate in a fuel-rich or stoichiometric mode to provide the reducing agent is not available, natural gas can be injected to act as the reducing agent.

Thermal destruction of N_2O is achieved using a reducing flame burner combusting premixed methane or natural gas. The flame temperature must be maintained high enough to destroy the N_2O, but below 1,500 °C to minimize NO_X formation.

Catalytic destruction is accomplished at lower temperatures (400 to 700 °C) using metal- or zeolite-based N_2O-decomposing catalysts.

Conventional commercially-available selective catalytic reduction (SCR) systems (i.e., those using titanium, tungsten, and vanadium-based catalysts) used to reduce emissions of nitric oxide (NO) and nitrogen dioxide (NO_2), as well as selective non-catalytic reduction (SNCR) systems, generate N_2O, so removal of such control systems would reduce N_2O emissions. However, at least two companies (BASF and Heraeus) have developed catalysts designed to simultaneously remove both N_2O as well as NO and NO_2.

3.2 Eliminate Technically Infeasible Alternatives

In the second step of a top-down BACT analysis, the available pollutant reduction options listed in Step 1 are considered, and, if found to be technically infeasible for the specific emission unit under review, eliminated.

3.2.1 Carbon Dioxide

In Step 1, energy efficiency and CCS were identified as potential control technologies.

3.2.1.1 Energy Efficiency

Maximizing the quantity of steam and electricity generated per unit of fuel combusted is the goal of most power plant designers and operators. Striving for energy efficiency is technically feasible within the limitations of the second law of thermodynamics.

3.2.1.2 Carbon Capture and Sequestration/Storage

As stated previously, CCS consists of three stages: (1) removing CO_2 from the exhaust stream, (2) compressing and transporting the CO_2, and (3) permanently storing the CO_2.

There are three approaches to CO_2 capture that are generally applicable to power generation:

- Pre-combustion systems designed to separate CO_2 and hydrogen (H_2) from produced syngas,
- Post-combustion systems designed to separate CO_2 from flue gas, and

- Oxy-combustion that uses high-purity oxygen (O_2) instead of air, which produces flue gas composed largely of CO_2.

The first approach is really applicable to pipeline natural gas, which has had most of the CO_2 removed from the raw gas prior to being placed the pipeline for consumption. The third option, while technically feasible, is still in the development phase, and, therefore, not available commercially. Only post-combustion systems will be considered for application to the proposed PGU.

Compression and transport of CO_2 is a mature technology, and is therefore considered technically feasible.

There are four endpoints for captured CO_2: (1) geologic sequestration, (2) ocean sequestration, (3) mineral carbonation, and (4) industrial use. Some forms of geologic sequestration, such as injection into depleted oil and gas reservoirs, use in enhanced oil and gas recovery, and injection into underground saline formations are technically feasible. Others, like enhanced coal bed methane recovery, are still being developed and demonstrated. Ocean sequestration, either by injecting and dissolving CO_2 into the water column, or depositing it on the ocean floor where CO_2 is denser than water, is still in the research phase, and therefore not technically feasible. Similarly, mineral carbonation, where CO_2 is reacted with metal oxides to form stable carbonates is in the demonstration phase, and is therefore not technically feasible. There are many mature industrial uses for CO_2, but the demand is limited, and most uses do not permanently store the CO_2, emitting it later in a product lifecycle.

In summary, there are technically feasible approaches to each of the three phases required for a CCS system; therefore, CCS is considered technically feasible for reducing CO_2 emissions from the proposed PGU.

3.2.2 Methane

In Step 1, proper combustion, thermal oxidation, and catalytic oxidation were identified as possible alternatives for CH_4 reduction.

3.2.2.1 Proper Combustion

For natural gas-fired combustion turbines and boilers, proper combustion is a ubiquitous control technology used to reduce CO and hydrocarbon (including CH_4)

emissions, therefore it is considered technically feasible for control of CH_4 emissions.

3.2.2.2 Thermal Destruction

To thermally oxidize a pollutant in an exhaust stream, a combustor is located in the exhaust duct, and fuel (typically natural gas) and enough supplemental air to support a flame are introduced. While the thermal oxidizer may destroy CH_4 in the exhaust, the combustor itself will generate a certain quantity of air pollutants, including CH_4. Because a thermal oxidizer has never been used to reduce CH_4 emissions from a combined-cycle combustion turbine, and it is not clear that use of such a system would result in a net reduction in CH_4 in the exhaust stream, this technology is considered technically infeasible for reducing CH_4 emissions from the proposed PGU.

3.2.2.3 Catalytic Destruction

When applied to combined-cycle combustion turbines, the intent of a catalytic oxidation system is to reduce CO and, to a lesser extent, VOC emissions. As discussed in the criteria pollutant BACT analysis submitted with the PSD permit application, the proposed PGU will employ an oxidation catalyst, which is considered technically feasible.

3.2.3 Nitrous Oxide

In Step 1, proper combustion, thermal destruction, catalytic destruction, NSCR, removal of SCR systems, and addition of N_2O-abating SCR systems were identified as possible alternatives for N_2O reduction.

3.2.3.1 Proper Combustion

For natural gas-fired combustion turbines and boilers, proper combustion is a ubiquitous control technology used to reduce CO and hydrocarbon emissions, therefore it is considered technically feasible for control of N_2O emissions, though adjustments and techniques used to reduce CO and hydrocarbon emissions may not necessarily also reduce N_2O emissions.

3.2.3.2 Thermal Destruction

To thermally oxidize a pollutant in an exhaust stream, a combustor is located in the exhaust duct, and fuel (typically natural gas) and enough supplemental air to support a flame are introduced. While the thermal oxidizer may destroy N_2O in the exhaust, the combustor itself will generate a certain quantity of air pollutants, including N_2O. Because a thermal oxidizer has never been used to reduce N_2O emissions from a combined-cycle combustion turbine, and it is not clear that use of such a system would result in a net reduction in N_2O in the exhaust stream, this technology is considered technically infeasible for reducing N_2O emissions from the proposed PGU.

3.2.3.3 Catalytic Destruction

When applied to combined-cycle combustion turbines, the intent of a catalytic oxidation system is to reduce CO and, to a lesser extent, VOC emissions. As discussed in the criteria pollutant BACT analysis submitted with the PSD permit application, the proposed PGU will employ an oxidation catalyst, which is therefore considered technically feasible.

3.2.3.4 Non-Selective Catalytic Reduction Systems

NSCR systems have primarily been developed to reduce N_2O emissions from adipic and nitric acid production operations, though they are also employed to reduce both NO_X and N_2O emissions from reciprocating engines. To achieve emission reductions from a reciprocating engine, the engine must be operated in a fuel-rich mode (i.e., less than 4 percent oxygen). Because combustion turbines operate with high levels of excess air (i.e., approximately 15 percent oxygen), NSCR is considered technically infeasible for control of N_2O from the proposed PGU.

3.2.3.5 Removal of Conventional Selective Catalytic Reduction Systems

The proposed PGU will employ an SCR system to reduce NO_X emissions. Removal of the SCR system is technically feasible.

3.2.3.6 Addition of N_2O-Abating Selective Catalytic Reduction Systems

Catalyst systems that employ ammonia injection to achieve reductions in both NO_X and N_2O are under development for application to exhausts from nitric acid and adipic acid plants. In addition to being the developmental phase, there is no indication that the technology could be applied to combined-cycle combustion turbines; therefore, the technology is considered technically infeasible for application to the proposed PGU.

3.3 Rank Technically Feasible Alternatives

In Step 3, the remaining alternatives that have not been removed from consideration due to technical infeasibility, are ranked, starting with the most effective. The March 2011 Guidance says that "to best reflect the impact on the environment, the ranking of control options should be based on the total CO_2e rather than the total mass or mass for the individual GHGs." Before ranking all feasible control alternatives from the previous section, the effectiveness of each on a CO_2e basis is discussed.

3.3.1 Proper Combustion/Energy Efficiency

The proposed project would operate in a manner that minimizes emissions of all pollutants, and maximizes the energy derived from the fuel consumed. Thus, these measures, in combination, are considered the baseline from which all other alternatives will be evaluated, and it is assumed that all other options would be applied in addition to these measures. The manufacturer indicates that the proposed PGU will be capable of achieving a net efficiency of 52.5 percent, and a net heat rate of 6,498 British thermal units per kilowatt-hour (Btu/kWh) at design conditions.[6]

Maximum energy efficiency is the goal of every power generation facility, but some designs are able to achieve more efficient operation than others. Table 3-1 presents the heat rates and efficiencies of several aero-derivative combustion turbine models when operated as simple-cycle units.

Table 3-1: Aero-Derivative Combustion Turbine Comparison

Manufacturer	Model	Power Generation Capacity (MW)	Heat Rate (Btu/kWe-hr)	Efficiency (%)
Rolls-Royce	RB211	32.1	8,681	39.3
	Trent 60	66	8,260	41.3
Pratt & Whitney	FT8	30.4	9,312	37
		61.2	9,266	37
GE	LM6000-PF+	50.6	8,400	40.6
	LM2500+G4	33.6	9,870	34.6
	LMS100-PB	102	7,786	43.8

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[6] The efficiency and heat rate provided by the manufacturer for the proposed units are for a specific application, while the values in Table 3-1, which are from sales brochures, are for general application of the units.

Of the units listed in Table 3-1, NWIWK's preferred PGU design (i.e., 2 x 1 combined cycle, totaling approximately 125 MW) could be met only by the Rolls-Royce (R-R) Trent 60, the Pratt & Whitney (P&W) FT8 (61.2 MW configuration), and the GE LM6000-PF+. Based on the heat rate values in Table 3-1, which were taken from sales brochures, the R-R Trent 60 and the GE LM6000-PF+ are the most efficient.

The Pasadena Department of Water and Power (PWP) considered LM6000 and Trent 60 units, each operating in a combined cycle configuration, for the Glenarm Repowering Project in 2012. In the GHG emissions section of the Environmental Impact Analysis, PWP determined that GHG emissions from the LM6000 would be slightly less than from the Trent 60 (1,050 lb CO_2e/MWh vs. 1,084 lb CO_2e/MWh), and ultimately chose the LM6000 for the project. A PGU employing either unit would be the most efficient available, and is considered the baseline from which all other GHG emission reduction alternatives are considered.

3.3.2 Carbon Capture and Sequestration

A CCS system is comprised of three parts: (1) capturing the CO_2, (2) transporting the CO_2, and (3) permanently storing the CO_2. The effectiveness of the system to reduce CO_2 emissions is determined by the removal rate of CO_2 from the flue gas, and degree to which the CO_2 is retained while being transported and stored. Currently available technology can capture approximately 90 percent of the post-combustion CO_2 in flue gas. However, due to the considerable energy requirements for the capture and compression of the CO_2, the electrical generating capacity of the proposed cogeneration unit would have to be increased by up to 40 percent. Although 90 percent of the additional CO_2 generated would also be captured, the net CO_2 reduction would be reduced from 90 percent to 86 percent.

Transport of CO_2 by pipeline is a mature technology, and expected losses of CO_2 in a pipeline would be minimal. Experimental observations and models suggest that properly selected and maintained geological storage sites could trap over 99 percent of injected CO_2 for at least 100, and up to 1 million, years.

A CCS system would have no impact on CH_4 or N_2O in the exhaust; the increase in emissions of those GHG compounds as a result of the additional capacity needed to power the CCS systems would further degrade the net GHG reduction, but because the quantities of those GHGs is so small, the degradation is slight. On a CO_2e basis, CCS has the potential to reduce GHG emissions by approximately 86 percent.

3.3.3 Catalytic Destruction

Catalysts are a relatively ineffective means of destroying CH_4 at typical exhaust temperatures (i.e., less than 700 °C), and the low availability of oxygen in combustion exhaust compared with combustion air drawn from the atmosphere would further degrade the effectiveness. At best, a 20 percent reduction in CH_4 emissions has been documented when applied to internal combustion engines.

When applied to exhaust from an adipic acid operation, catalytic destruction systems are effective, reducing N_2O emissions by up to 95 percent. Although it is unclear that the same reductions would be realized when similar catalysts are applied to a combined-cycle combustion turbine exhaust stream, the stated levels of control will be assumed valid. The catalyst would have no effect on CO_2 in the exhaust. Applying these catalysts together would result in a potential GHG emission reduction of, at most, 0.06 percent on a CO_2e basis.

3.3.4 Removal of NO_X Control System (SCR)

Conversion of NO_X to N_2O by SCR systems is typically less than 5 percent, and never greater than 8 percent. In most state-of-the-art applications, the conversion rate is below 1 to 2 percent.[7] SCR systems do not generate any CO_2 or CH_4, so elimination of the system would not affect concentrations of these compounds in the exhaust gas. Assuming the SCR system accounts for all of the N_2O generated by the PGU (a conservative assumption), and that removal of the SCR system would eliminate all N_2O emissions, the reduction in GHG emissions associated with removal of the SCR system would be 0.06 percent on a CO_2e basis.

3.3.5 Ranking GHG Control Alternatives by Effectiveness

Below is a ranking of the technically feasible GHG control alternatives, starting with the most effective, on a CO_2e basis:

- Carbon Capture and Sequestration – 86 percent reduction in emitted GHGs on a CO_2e basis

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[7] Grosso, Mario and Lucia Rigamonti. Experimental Assessment of N_2O Emissions from Waste Incineration: The Role of NO_X Control Technology. Politecnico di Milano – DIIAR – Environmental Section.

- Catalytic Destruction – 0.06 percent reduction in emitted GHGs on a CO_2e basis
- Removal of NO_X Control System (SCR) – 0.06 percent reduction in emitted GHGs on a CO_2e basis
- Proper Combustion/Energy Efficiency – Baseline

3.4 Evaluate Economic, Energy, and Environmental Impacts

In the March 2011 Guidance, EPA suggests that, instead of the more traditional approach where the options are considered and either eliminated or adopted in order of effectiveness, the economic, energy, and environmental impacts of all options should be considered. In light of this guidance, each technically feasible option was evaluated, regardless of the Step 3 ranking.

3.4.1 Carbon Capture and Sequestration/Storage

As discussed in Step 3, CCS systems require additional energy to remove CO_2 from the PGU flue gas, as well as to compress it for transport and storage. In the case of a combined-cycle combustion turbine, the concentration of CO_2 in the exhaust gas is dilute (i.e., between 4 and 6 percent by weight), which would require a strong solvent to capture the CO_2, as well as a considerable amount of energy to regenerate the solvent. The economic impacts of this additional energy requirement would be in addition to the capital and operating costs associated with equipping and maintaining a CCS system.

In the Statement of Basis (SOB) developed by EPA Region 6 for the Natgasoline facility in Beaumont, Texas, capital costs for a CCS system for a 5,500-mt/day methanol plant would be approximately $1.18 billion.[8] This cost does not include the equipment, including control equipment to reduce the additional criteria pollutants associated with the equipment, necessary for additional onsite power generation to operate the CCS system. Scaling the Natgasoline CCS capital cost for a 10,000-mt/day methanol plant using a conservative 0.6 exponential factor applied to the ratio of the daily production rates yields a CCS system capital cost of approximately $1.69 billion.[9] The capital cost of the Facility is expected to be $1.8

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[8] EPA Region 6. Statement of Basis – Greenhouse Gas Prevention of Significant Deterioration Preconstruction Draft Permit for New Natural Gas to Gasoline Facility, Permit Number: PSD-TX-1340-GHG. August 2014. Page 16.

[9] Scaling factor from Martin B. Hocking, "Handbook of Chemical Technology and Pollution Control," Third Edition, 2005. Page 9.

billion, thus, the addition of a CCS system would approximately double the capital cost.

The considerable monetary and energy requirements of a CCS system suggest unacceptable collateral economic, energy, and environmental impacts. As a result, CCS systems are removed from consideration as BACT for GHGs emitted by the proposed PGU.

3.4.2 Catalytic Destruction

The criteria pollutant BACT analysis proposes that catalytic oxidation is BACT for CO and VOC emissions, and will be installed to reduce emissions of those pollutants in the PGU exhaust, but because reductions in CH_4 and N_2O emissions are likely to be minimal and therefore not cost effective, the system is not considered to be BACT for reducing GHG emissions.

3.4.3 Removal of NO_X Control System (SCR)

The criteria pollutant BACT analysis proposes SCR as BACT for NO_X emissions from the PGU. Elimination of the SCR system would increase NO_X emissions by at least 2.5 times to achieve a 0.06 percent decrease in GHG emissions. The collateral increase in NO_X emissions is considered unacceptable, and elimination of the SCR system is removed from consideration as BACT for GHG emissions from the proposed PGU.

3.4.4 Proper Combustion/Energy Efficiency

Utilizing an efficient design and operating the PGU to produce the maximum quantity of electricity per unit of fuel combusted are control alternatives that NWIWK proposes to incorporate in the project. As stated previously, these options are considered the baseline for the BACT analysis, and all other options were considered to be applied over and above these two. These alternatives have a positive energy and environmental, and most likely economic, impact, and are considered to be BACT for GHG emissions from the proposed PGU.

The PGU will feature the LM6000-PF+ combustion turbine, or equivalent, which is the most efficient unit (up to 40.6 percent in simple-cycle configuration) available in its class. GE offers an aero-derivative unit with an efficiency approaching 44 percent in simple-cycle configuration (i.e., the LMS100), but it is a larger unit not suitable for use in the proposed PGU.

3.5 Selection of BACT

Based on the analysis presented here, NWIWK proposes that BACT for GHGs from the proposed PGU is energy-efficient system design and proper combustion practices. NWIWK proposes a rolling 12-month average GHG emissions limit of 490,600 tons of CO_2e per year (ton CO_2e/yr), which is based on continuous operation with duct firing and a degradation factor of 5 percent. In addition, NWIWK proposes to maintain the PGU such that the net heat rate does not exceed 7,323 British thermal units per kilowatt-hour (Btu/kWh – LHV), with is based on operation with duct firing and a degradation factor of 5 percent.

4. GAS-FIRED BOILERS

The gas-fired boilers that will supply steam required by the reforming process to create syngas from natural gas will emit only GHGs associated with fossil fuel combustion (i.e., CO_2, CH_4, and N_2O).

4.1 Identify Commercially-Available Emission Reduction Alternatives

The first step of a top-down BACT analysis is to identify all available pollutant reduction options. Options typically fall into three categories: inherently low-emitting processes, clean fuels, and add-on control technologies. As in the PGU section, “clean fuel” options that that would fundamentally redefine the source are not considered. In this case, use of process offgas, supplemented when necessary by pipeline natural gas, is part of the original design of the project. The process offgas is derived from natural gas, and has a GHG emissions profile similar to natural gas. Substitution of any other fuel would drastically alter the proposed project.

4.1.1 Carbon Dioxide

CO_2 is a by-product of complete combustion. Maximizing the overall efficiency of the boilers minimizes the fuel combusted per unit of steam generated, which minimizes the quantity of CO_2 generated per unit of steam. In the case of GHGs, a “clean fuel,” or “low-carbon fuel” is one that generates the least amount of CO_2 when combusted. The fuel that produces the least CO_2 while making efficient use of the unusable portion of product feedstock is process offgas, supplemented by natural gas. No other alternative fuels will be considered in the BACT analysis. As discussed in the PGU BACT analysis, the only add-on control available to reduce CO_2 is CCS.

4.1.2 Methane

Methane emissions from a gas-fired boiler are the result of fuel that is not combusted. Proper combustion practices and properly designed equipment can minimize CH_4 emissions by ensuring a sufficient combustion temperature and adequate mixing of fuel with combustion air. Add-on control systems include thermal oxidizers which destroy CH_4 using a flame, and oxidation catalysts which promote oxidation of CH_4 at temperatures less than the normal combustion temperature. It should be noted that the process offgas that will be the primary fuel of the boilers contains a much smaller fraction of CH_4 (~25 percent) than is typical of natural gas (~95 percent).

4.1.3 Nitrous Oxide

Low combustion temperatures favor creation of N_2O. As for CH_4, proper combustion practices and properly designed equipment can minimize N_2O emissions by ensuring a sufficient combustion temperature and adequate mixing of fuel with combustion air. Add-on controls for reducing N_2O emissions include: NSCR, thermal destruction, and catalytic oxidation. To reduce N_2O emissions created by combustion a catalyst uses unburned hydrocarbons in the exhaust to reduce the N_2O. Thermal destruction uses a reducing flame to destroy N_2O, while catalytic destruction uses catalysts to decompose N_2O at flue gas temperatures. While not an add-on control per se, conventional SCR systems used to reduce NO_X emissions create a small amount of N_2O, so removal of an SCR system would reduce N_2O emissions. There are also SCR systems under development for nitric acid and adipic acid plants that use injected ammonia to reduce both NO_X and N_2O.

4.2 Eliminate Technically Infeasible Alternatives

In the second step of a top-down BACT analysis, the available pollutant reduction options listed in Step 1 are considered, and, if found to be technically infeasible for the specific emission unit under review, eliminated.

4.2.1 Carbon Dioxide

In Step 1, use of energy efficiency, use of a low-carbon fuel, and CCS were identified as potential control technologies.

4.2.1.1 Energy Efficiency

Maximizing the quantity of steam generated per unit of fuel combusted is the goal of most boiler designers and operators. Striving for energy efficiency is technically feasible within the limitations of the second law of thermodynamics.

4.2.1.2 Carbon Capture and Sequestration/Storage

As discussed in the PGU BACT analysis, CCS systems that feature post-combustion CO_2 capture schemes are considered technically feasible for reducing CO_2 emitted by combustion units.

4.2.2 Methane

In Step 1, proper combustion, thermal oxidation, and catalytic oxidation were identified as possible alternatives for CH_4 reduction.

4.2.2.1 Proper Combustion

For gas-fired boilers, proper combustion is a ubiquitous control technology used to reduce CO and hydrocarbon emissions (including CH_4), therefore it is considered technically feasible for control of CH_4 emissions.

4.2.2.2 Thermal Destruction

To thermally oxidize a pollutant in an exhaust stream, a combustor is located in the exhaust duct, and fuel (typically natural gas) and enough supplemental air to support a flame are introduced. While the thermal oxidizer may destroy CH_4 in the exhaust, the combustor itself will generate a certain quantity of air pollutants, including CH_4. Because a thermal oxidizer has never been used to reduce CH_4 emissions from a natural gas-fired boiler, and it is not clear that use of such a system would result in a net reduction in CH_4 in the exhaust stream, this technology is considered technically infeasible for reducing CH_4 emissions from the proposed boilers.

4.2.2.3 Catalytic Destruction

The intent of a catalytic oxidation system is to reduce CO and, to a lesser extent, VOC emissions (including CH_4). Low-molecular weight compounds, such as CH_4, are not easily oxidized by catalysts. As a result, the relatively small quantity of CH_4 in the process offgas that will be the primary boiler fuel will result in an even smaller quantity of CH_4 in the boiler exhaust, further reducing the potential emission reduction. Nevertheless, use of an oxidation catalyst to reduce CH_4 emissions is considered technically feasible.

4.2.3 Nitrous Oxide

In Step 1, proper combustion, thermal destruction, catalytic destruction, NSCR, removal of SCR systems, and addition of N_2O-abating SCR systems were identified as possible alternatives for N_2O reduction.

4.2.3.1 Proper Combustion

Proper combustion is a ubiquitous control technology used to reduce CO and hydrocarbon emissions from gas-fired boilers, and, therefore, it is considered technically feasible for control of N_2O emissions from the proposed boilers, though adjustments and techniques used to reduce CO and hydrocarbon emissions may not necessarily also reduce N_2O emissions.

4.2.3.2 Thermal Destruction

To thermally reduce a pollutant in an exhaust stream, a combustor with a reducing flame is located in the exhaust duct, and fuel (typically natural gas) and enough supplemental air to support the flame are introduced. While the reducing flame may destroy N_2O in the exhaust, the combustor itself will generate a certain quantity of air pollutants, including N_2O. Because a thermal oxidizer has never been used to reduce N_2O emissions from a gas-fired boiler, and it is not clear that use of such a system would result in a net reduction in N_2O in the exhaust stream, this technology is considered technically infeasible for reducing N_2O emissions from the proposed boilers.

4.2.3.3 Catalytic Destruction and Non-Selective Catalytic Reduction Systems

NSCR systems have primarily been developed to reduce N_2O emissions from adipic and nitric acid production operations, though they are also employed to reduce both NO_X and N_2O emissions from reciprocating engines. To achieve emission reductions from a reciprocating engine, the engine must be operated in a fuel-rich mode to provide hydrocarbons to use as a reducing agent. Natural gas-fired boilers are operated using proper combustion practices, which attempts to minimize unburned hydrocarbons in the exhaust. Furthermore, catalytic reduction systems have never been used on a natural gas-fired boiler, and it is unclear that such a system would reduce N_2O emissions from such a boiler. Catalytic reduction systems, including NSCR, are considered technically infeasible for control of N_2O emitted by the proposed boilers.

4.2.3.4 Removal of Conventional Selective Catalytic Reduction Systems

The proposed boilers will employ a conventional SCR system to reduce NO_X emissions. Removal of such a system is a technically feasible alternative for reducing GHG emissions from the proposed boilers.

4.2.3.5 Addition of N_2O-Abating Selective Catalytic Reduction Systems

Catalyst systems that employ ammonia injection to achieve reductions in both NO_X and N_2O are under development for application to exhausts from nitric acid and adipic acid plants. In addition to being the developmental phase, there is no indication that the technology could be applied to natural gas-fired boilers;

therefore, the technology is considered technically infeasible for application to the proposed boilers.

4.3 Rank Technically Feasible Alternatives

In Step 3, the remaining alternatives that have not been removed from consideration due to technical infeasibility are ranked, starting with the most effective. The March 2011 Guidance says that “to best reflect the impact on the environment, the ranking of control options should be based on the total CO_2e rather than the total mass or mass for the individual GHGs. Before ranking all feasible control alternatives from the previous section, the effectiveness of each on a CO_2e basis is discussed.

4.3.1 Proper Combustion/Energy Efficiency

The proposed project would operate in a manner that minimizes emissions of all pollutants, and maximizes the energy derived from the fuel consumed. Thus, these measures, in combination, are considered the baseline from which all other alternatives will be evaluated, and it is assumed that all other options would be applied in addition to these measures.

4.3.2 Carbon Capture and Sequestration

A CCS system is comprised of three parts: (1) capturing the CO_2, (2) transporting the CO_2, and (3) permanently storing the CO_2. The effectiveness of the system to reduce CO_2 emissions is determined by the removal rate of CO_2 from the flue gas, and degree to which the CO_2 is retained while being transported and stored. Currently available technology can capture approximately 90 percent of the post-combustion CO_2 in flue gas. However, due to the considerable energy requirements for the capture and compression of the CO_2, the electrical generating capacity of the proposed cogeneration unit would have to be increased by up to 40 percent. Although 90 percent of the additional CO_2 generated would also be captured, the net CO_2 reduction would be reduced from 90 percent to 86 percent.

Transport of CO_2 by pipeline is a mature technology, and expected losses of CO_2 in a pipeline would be minimal. Experimental observations and models suggest that properly selected and maintained geological storage sites could trap over 99 percent of injected CO_2 for at least 100, and up to 1 million, years.

A CCS system would have no impact on CH_4 or N_2O in the exhaust; the increase in emissions of those GHG compounds as a result of the additional capacity needed to power the CCS systems would further degrade the net GHG reduction. On a CO_2e basis, CCS has the potential to reduce GHG emissions by approximately 86 percent.

4.3.3 Catalytic Destruction

Catalysts are a notoriously ineffective means of destroying CH_4 at typical exhaust temperatures (i.e., less than 700 °C), and the small quantity of uncombusted CH_4 expected as a result of combusting process offgases with relatively a low CH_4 fraction would further degrade the effectiveness. A 20 percent reduction in CH_4 emissions has been documented when applied to internal combustion engines, and no better performance would be expected when applied to the proposed boilers. Catalysts would have no effect on CO_2 in the exhaust, and is assumed to have little or no effect on N_2O concentrations as well. Applying an oxidation catalyst would result in a potential GHG emission reduction of, at most, 0.06 percent on a CO_2e basis.

4.3.4 Removal of NO_X Control System (SCR)

SCR systems convert, depending upon the reagent and furnace conditions, between 10 and 20 percent of NO_X in the exhaust to N_2O. SCR systems do not generate any CO_2 or CH_4, so elimination of the system would not affect concentrations of these compounds in the exhaust gas. Assuming the SCR system accounts for all of the N_2O generated by the boiler, and that removal of the SCR system would reduce N_2O emissions to zero, the reduction in GHG emissions would be 0.06 percent on a CO_2e basis.

4.3.5 Ranking GHG Control Alternatives by Effectiveness

Below is a ranking of the technically feasible GHG control alternatives, starting with the most effective, on a CO_2e basis:

- Carbon Capture and Sequestration – 86 percent reduction in emitted GHGs on a CO_2e basis
- Catalytic Destruction – 0.06 percent reduction in emitted GHGs on a CO_2e basis
- Removal of NOX Control System (SCR) – 0.06 percent reduction in emitted GHGs on a CO_2e basis
- Proper Combustion/Energy Efficiency – Baseline

4.4 Evaluate Economic, Energy, and Environmental Impacts

In the March 2011 Guidance, EPA suggests that, instead of the more traditional approach where options are considered and either eliminated or adopted in decreasing order of effectiveness, the economic, energy, and environmental impacts of all options be considered. In light of this guidance, each technically feasible option was evaluated, regardless of the Step 3 ranking.

4.4.1 Carbon Capture and Sequestration

As discussed in Step 3, CCS systems require additional energy to remove CO_2 from the boiler flue gas, as well as to compress it for transport and storage. Because the process offgas combusted by the boilers contains CO_2 from the syngas creation process, the exhaust from the boilers will contain more CO_2 than is typical for a natural gas-fired boiler (i.e., approximately 15 percent by weight, compared to approximately 5 percent by weight). Nevertheless, a solvent is required to capture the CO_2, and a considerable amount of energy is required to extract the CO_2 and regenerate the solvent. The economic impacts of this additional energy requirement would be in addition to the capital and operating costs associated with equipping and maintaining a CCS system.

As outlined in Section 3.4.1, a comprehensive CCS system would cost approximately $1.69 billion, increase on-site energy usage, and increase criteria, toxic, and hazardous air pollutant emissions associated with the project. CCS systems are removed from consideration as BACT for GHGs emitted by the proposed boilers.

4.4.2 Catalytic Destruction

The criteria pollutant BACT analysis for a catalytic oxidation system to reduce CO and VOC emissions indicated that the economic impact of an oxidation catalyst is not justified by the emission reduction that would be realized. Because the GHG reduction associated with these systems (on a percent basis) is less than the expected reduction in CO associated with an oxidation catalyst system, and the BACT cost-effectiveness threshold for GHGs is less than what is typical for CO, this alternative is considered to also have an unacceptably high collateral economic impact for reducing GHG emissions.

As a result of the economic impacts, catalytic destruction is removed from consideration as BACT for GHG emissions from the proposed boilers. However, the boilers will feature oxidation catalysts, which are expected to provide small reductions in CH_4 emissions.

4.4.3 Removal of NO_X Control System (SCR)

The criteria pollutant BACT analysis proposes SCR as BACT for NO_X emissions from the PGU. Elimination of the SCR system would increase NO_X emissions by at least 2.5 times to achieve a 0.06 percent decrease in GHG emissions. The collateral increase in NO_X emissions is considered unacceptable, and elimination of the SCR system is removed from consideration as BACT for GHG emissions from the proposed PGU.

4.4.4 Proper Combustion/Energy Efficiency

Utilizing an efficient boiler design, operating the boiler to produce the most steam per unit of fuel combusted, and use of a low-carbon fuel are control alternatives that NWIWK proposes to incorporate in the boilers. As stated previously, these options are considered the baseline for the BACT analysis, and all other options were considered to be applied over and above these two. These alternatives have a positive energy and environmental, and most likely economic, impact, and are considered to be BACT for GHG emissions from the proposed boilers.

4.5 Selection of BACT

Based on the analysis presented here, NWIWK proposes that BACT for GHGs from the gas-fired boilers is energy-efficient system design, and proper combustion practices. The boilers are expected to generate approximately 190 pounds of CO_2e per thousand pounds of steam produced (lb/klb steam). However, the process offgas will be approximately 17.5 percent CO_2, which will pass through the boiler and be emitted to the atmosphere. The emission rate of the pass-through CO_2 is expected to be approximately 205 lb/klb steam. NWIWK proposes a rolling 12-month average GHG emissions limit of 395 pounds of CO_2e per thousand pounds of steam produced (lb/klb steam).

5. PROCESS HEATERS

As described in Section 1.1, the heat created in the ATR during the second step of the reforming process is used to heat the first step of the reforming process in the GHR. With the addition of natural gas, steam, and oxygen, this reaction is essentially self-sustaining, but an external heat source is required to initiate the process. Each methanol production line will have a dedicated process heater to provide the heat needed during production line startup.

Because new catalysts in the GHR and ATR must be de-oxygenated with nitrogen, the duration of the initial startup is expected to between 76 and 88 hours. The process heater will operate between 25 and 90 percent load for approximately 64 to 76 hours of that period. These long-duration starts with fresh catalyst are expected to occur once every 4 to 5 years, depending on the life of the catalysts. With an already de-oxygenated catalyst, approximately 40 hours are required to start a production line, with the process heater operating between 25 and 90 percent load for approximately 28 of the 40 hours.

It is likely that the process heater will also be used during an orderly shutdown to maximize the quantity of methanol produced and minimize the quantity of intermediate gases that must be sent to the flare. In a hypothetical worst-case year, which would include one initial startup lasting 80 hours and six “normal” startups and shutdowns, the process heater would operate approximately 260 hours (just less than 11 days).

5.1 Identify Commercially-Available Emission Reduction Alternatives

Emission reduction alternatives available for reducing pollutants emitted by the natural gas-fired process heaters are identical to those listed in the Section 4.1 as potentially available for the gas-fired boilers.

5.2 Eliminate Technically Infeasible Alternatives

The technical feasibility determinations for each of the emission reduction alternatives are the same as those presented in Section 4.2 for the gas-fired boilers, with the exception of the removal of the NO_X control system. Because no NO_X control system is proposed for the process heaters, it is not feasible to propose to remove such a system.

5.3 Ranking of Remaining Alternatives

The effectiveness and ranking of the technically feasible alternatives identified in the previous section are the same as those presented in Section 4.3 for the gas-fired boilers, with the exception of the removal of the NO_X control system.

5.4 Evaluate Economic, Energy, and Environmental Impacts

As in Section 4.4, each technically feasible option was evaluated, regardless of the Step 3 ranking.

5.4.1 Carbon Capture and Sequestration

The cost evaluation presented in Section 3.4.1 was for a comprehensive CCS system. Installing a system to capture CO_2 in the process heater exhaust would not improve the cost effectiveness of the CCS system. As for the PGU and the gas-fired boilers, a CCS system is removed from consideration as BACT for GHGs emitted by the process heaters.

5.4.2 Catalytic Destruction

The criteria pollutant BACT analysis concluded that oxidation catalysts are not BACT for reducing CO and VOC emissions from the process heaters. As with the gas-fired boilers, an oxidation catalyst would provide a small CH_4 reduction when applied to the process heater exhaust, though the effectiveness would be even less due to the reduced scale and limited hours of operation.

5.4.3 Proper Combustion/Energy Efficiency

As for the gas-fired boilers, the process heaters will utilize an efficient design, be operated to deliver the most heat per unit of fuel combusted to the process, and to use a low-carbon fuel (i.e., natural gas).

5.5 Selection of BACT

Based on the analysis presented here, NWIWK proposes that BACT for GHGs from the process heaters is an energy-efficient system design, and proper combustion practices.

6. FLARE

The facility will utilize a flare to control emissions from process startups, shutdowns, maintenance turnarounds, and malfunctions. In the event of a plant upset or during a power failure, the flare will process any hydrocarbon vapor released from the pressure relief mechanisms. The hydrocarbons controlled by the flare will consist primarily of methanol as well as a small amounts of other hydrocarbons. These vapors are conditioned, as needed, with natural gas to ensure a safe concentration in excess of the upper flammable limit. The flare will be equipped with a small pilot, which will combust pipeline natural gas, and operate at all times. Pollutant emissions from the flare will include the GHGs associated with combustion (i.e., CO_2, CH_4, and N_2O).

6.1 Identify Commercially-Available Emission Reduction Alternatives

A broad review of permitted flares, vapor combustion units (VCUs), and thermal oxidizers (TOs), included in the federal RBLC database indicates that emission reduction alternatives are limited to:

- Good combustion practices
- Proper design and operation
- Use of gaseous fuels and/or pipeline natural gas

Pollutant emissions from the flare fall into two categories: 1) vapors, typically volatile compounds (e.g., CH_4) that escape the flare without being destroyed as intended; and 2) combustion products of the destroyed vapors and any supplemental fuel used to ensure sufficient flame temperature (e.g., CO_2 and N_2O). Some combustion products are desirable, while others are not. CO_2 is a desirable combustion product, because it is the result of complete combustion, while N_2O is an undesirable combustion product. Proper flare design and operation using good combustion practices are intended to minimize the quantity of CH_4 that is not converted to CO_2, and to minimize the production of N_2O.

The gas stream that a given vapor combustion unit, thermal oxidizer, or flare controls is typically of variable composition and concentration. As a result, the associated burner must be designed to handle a wide range of combustion conditions, and cannot be fully optimized. In contrast, gas-fired burners associated with boilers or process heaters are designed to minimize pollutant emissions (e.g., “low-NO_X burners”).

The flare pilot will use natural gas and, when utilized, the flare will combust intermediate process gases that are derived from natural gas.

6.2 Eliminate Technically Infeasible Alternatives

Because no GHG-specific emission reduction alternatives were identified, all GHGs will be considered together in this and the following sections.

The emission reduction alternatives identified in the previous sections are all considered technically feasible for flares.

6.3 Ranking of Available Control Measures

Good combustion practices, proper design and operation, and use of low-carbon gaseous fuels are all considered baseline controls for flares; therefore, it is not possible to rank the remaining alternatives.

6.4 Consideration of Energy, Environmental and Cost Factors

Because the facility proposes to use the most effective alternatives, no evaluation of energy, environmental, or cost was conducted.

6.5 Selection of BACT

The facility proposes that BACT for reducing GHG emissions from the proposed flare is achieved by implementing good combustion practices, proper design and operation, and use of natural gas as an assist gas and for pilot flames.

7. ENGINES POWERING EMERGENCY EQUIPMENT

NWIWK proposes to install 2 diesel-fueled generator sets, rated at approximately 3.5 MW each, to assist with an orderly shutdown of the Facility in the unusual situation that electrical power is not available from the grid. Additionally, a diesel-fueled engine rated at approximately 1,600 hp will be available to power a firewater pump, which will provide pressurized water for fire protection to the Facility in the unexpected situation that a fire coincides with a power outage.

7.1 Identify Commercially-Available Emission Reduction Alternatives

The purpose of the proposed engines associated with the project is to provide quickly-deployable sources of power that rely on an immediately-available fuel source for use during emergency situations. The limited non-emergency operation proposed for the engines is solely to maintain the engines in proper working order, and enable them to fulfill their emergency role should that become necessary. Emission reduction options for any source of emissions typically fall into three categories: inherently low-emitting processes, clean fuels, and add-on control technologies.

Diesel engines are a well-developed technology with a long-standing reputation for reliability, and diesel fuel is a stable, easily stored source of energy. These qualities make diesel engines the ideal candidates to supply the critical power needs of the Facility when grid power is unavailable. While lower emitting processes and cleaner (i.e., lower carbon-containing) fuels undoubtedly exist, none offer the unique qualities that a diesel engine can provide for emergency power services. For this reason, no alternative processes or fuels are considered for this analysis. However, within the category of reliable diesel engines that provide sufficient power for the assigned task, use of the most efficient available model will result in the least GHG emissions.

GHG-reducing add-on technologies exist, and have been discussed at length in this document for application to a natural gas-fired combustion turbine and a gas-fired boiler. Because the engines must be available quickly and reliably, add-on controls that complicate operation and potentially reduce engine readiness compromise the emergency role of the engines, and are therefore unacceptable for consideration as GHG-reducing technologies for emergency diesel engines.

7.2 Eliminate Technically Infeasible Alternatives

Use of the most efficient diesel engine that is capable of reliably providing sufficient power in timely manner is a technically feasible means of limiting GHG emissions from the emergency diesel engines.

7.3 Ranking of Remaining Alternatives

The only alternative considered is the use of the most efficient diesel engines that do not compromise the availability and rapid deployment of the engines for emergency duty.

7.4 Consideration of Energy, Environmental and Cost Factors

Because only one alternative is considered, there is no opportunity to compare and contrast the collateral impacts of competing technologies.

7.5 Proposed BACT Level and Control Option

Based on the analysis presented here, NWIWK proposes that BACT for GHGs from the diesel-fueled emergency engines is the use of the most efficient engines capable of providing reliable and timely operation to fulfill the assigned emergency roles. At this evolutionary stage of the project, specific units have not yet been identified, but they will be similar in size and design to the following:

- Emergency Back-Up Generator – Caterpillar C175 Standby 4,000 ekW 5,000 kVA
- Emergency Firewater Pump Engine – Clarke JW6H-UFADF0

8. COMPONENT LOSSES

The proposed project will include piping, valves, connectors, pumps, compressors, and other components to transfer and methanol, natural gas, syngas, and other hydrocarbons. All components are subject to some level of leakage, and fugitive CO_2 and CH_4 emissions are expected to occur when components are in service.

8.1 Identify Commercially-Available Emission Reduction Alternatives

A broad review of permitted operations included in the federal RBLC database and other permitted sources indicates that fugitive emissions from leaking components are reduced through a combination of proper equipment selection and a leak detection and repair (LDAR) program. Identified alternatives include:

- Use of components using leakless technology
- Implementation of an LDAR program
- Audio/visual/olfactory (AVO) monitoring
- Proper equipment selection

LDAR programs involve periodic monitoring of components with a hydrocarbon analyzer, identification of components that leak above the leak definition levels specified in the equipment leak standard, and subsequent repair of the leaking components. LDAR programs are frequently defined by regulations; those deemed to represent BACT for other facilities permitted in the past ten years that were found in the RBLC include:

- 40 CFR 63 Subpart H (National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks)
- 40 CFR 63 Subpart CC (National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries)
- 40 CFR 63 Subpart UU (National Emission Standards for Equipment Leaks—Control Level 2 Standards)
- 40 CFR 60 Subpart VVa (Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006)
- 40 CFR 60 Subpart GGGa (Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006)

- 40 CFR 61 Subpart V (National Emission Standard for Equipment Leaks (Fugitive Emission Sources))
- Louisiana Refinery MACT (Louisiana Administrative Code §2121, §2122, and Chapter 51)
- TCEQ LDAR Programs

8.2 Eliminate Technically Infeasible Alternatives

Because leakless technology components cannot be repaired without a unit shutdown, they are typically used only in situations where highly toxic or otherwise hazardous materials are present. Because GHGs are not considered highly toxic or hazardous materials, it is not necessary to employ components that require a full unit shutdown for maintenance or repair. Therefore leakless technology components are considered technically infeasible.

AVO programs are applicable for inorganic/odorous and low vapor pressure compounds such as chlorine, ammonia, hydrogen sulfide, hydrogen fluoride, and hydrogen cyanide, or when natural gas is used onsite with an odorant. Because the components at the Facility will not contain appreciable amounts of any of these compounds, an AVO program is considered technically infeasible.

Proper equipment selection and implementing an LDAR program based on any of the regulations identified in the previous section are considered technically feasible for reducing fugitive GHG emissions from component leaks.

8.3 Ranking of Available Control Measures

There are many LDAR programs available, some codified in regulations (e.g., NSPS, NESHAP, etc.), some developed by state agencies for consent decrees, and others developed by industry groups. Some of the non-regulatory alternatives include:

- LDAR programs
- Proper equipment selection

It should be noted that the majority of LDAR programs are designed to limit VOC emissions to varying degrees, and CO_2 and CH_4 are not considered VOCs. The streams at the Facility will contain negligible amounts of GHGs, so consideration of an LDAR program to limit GHGs is likely inappropriate and not cost effective. However, an LDAR program has been proposed as BACT for reducing fugitive VOC emissions from components, and this program will coincidentally provide reductions in GHG emissions from the same components.

8.4 Consideration of Energy, Environmental and Cost Factors

Because NWIWK proposes to use the most effective alternatives, no evaluation of energy, environmental, or cost was conducted. As indicated in the previous section, implementing an LDAR program solely to realize a reduction in GHG emissions would likely not be cost effective, but, because the LDAR program is proposed as BACT for fugitive VOC emissions reduction, it is also proposed as BACT for fugitive GHG emissions reduction.

8.5 Proposed BACT Level and Control Options

NWIWK proposes that implementation of an LDAR program that meets the requirements of 40 CFR 63 Subpart H represents BACT for GHG component leaks at the proposed facility. NWIWK believes that emission limits are not appropriate for a fugitive source, and, therefore, does not propose any such limits as BACT. It should be noted that the proposed facility is not subject to the requirements of Subpart H as a result of the regulatory applicability criteria, but would meet the requirements of the rule, as appropriate, because it represents the most stringent implementation of an LDAR program.

APPENDIX D: MODELING SCENARIO DETAILS

Source Emission Rates by Scenario[a]

Averaging Period	Emission Sources	Boiler #1	Boiler #1 Annual Startup/Shutdown	Boiler #1 Shutdown	Boiler #1 Startup	Boiler #2	Boiler #2 Annual Startup/Shutdown	Boiler #2 Shutdown	Boiler #2 Startup	Boiler #3	Boiler Non-process Startup	Combustion Turbine #1 Continuous	Combustion Turbine #1 Duct Firing	Combustion Turbine #1 Shutdown	Combustion Turbine #1 Startup	Combustion Turbine #2 Continuous	Combustion Turbine #2 Duct Firing	Combustion Turbine #2 Shutdown	Combustion Turbine #2 Startup	Emergency Generator #1	Emergency Generator #2	Fire Pump	Firebox #1	Firebox #1 Shutdown	Firebox #1 Startup	Firebox #2	Firebox #2 Shutdown	Firebox #2 Startup	Flare Emergency	Flare Shutdown	Flare Startup	Flare Upset
Annual	Annual Continuous	1	0	0	0	1	0	0	0	1	0	1	0	0	0	1	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0
	Annual w/PGU SU/SD	0	1	0	0	0	1	0	0	0	0	1	0	1	1	1	0	1	1	1	1	1	1	0	0	1	0	0	0	1	1	0
	Annual w/Production SU/SD	0	1	0	0	0	1	0	0	0	0	1	0	0	0	1	0	0	0	1	1	1	1	0	0	1	0	0	0	1	1	0
Short-term	PGU CT1 SU/SD	0	0	0	0	1	0	0	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	PGU CT2 SU/SD	0	0	0	0	1	0	0	0	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
	Duct Firing	0	0	0	0	1	0	0	0	1	0	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Flare Emergency	0	0	0	0	1	0	0	0	1	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0
	Flare Upset	0	0	0	0	1	0	0	0	1	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	Normal Operation	0	0	0	0	1	0	0	0	1	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Normal w/ Boiler Startup	0	0	0	0	1	0	0	0	1	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Normal with Emergency Gen Set #1 Test	0	0	0	0	1	0	0	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
	Normal with Emergency Gen Set #2 Test	0	0	0	0	1	0	0	0	1	0	1	0	0	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
	Normal with Fire Pump Test	0	0	0	0	1	0	0	0	1	0	1	0	0	0	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
	Shutdown Line #1	0	0	1	0	1	0	0	0	0	1	1	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	1	0	0
	Shutdown Line #2	0	0	0	0	0	0	1	0	1	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1	0	0	1	0	0
	Startup Line #1	0	0	0	1	1	0	0	0	0	1	1	0	0	0	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0	1	0
	Startup Line #2	0	0	0	0	0	0	0	1	1	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1	0

[a] *Operation of cooling towers, flares, ship scrubbers, tank scrubbers, tanks sources, and fugitive leaks is consistent across all scenarios.*

APPENDIX E: REGIONAL INDUSTRIAL SOURCE EMISSION INVENTORY

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Project Number:
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REGIONAL INDUSTRIAL SOURCE EMISSION INVENTORY

KALAMA MANUFACTURING AND MARINE EXPORT FACILITY

RAMBOLL ENVIRON

CONTENTS

TABLES

1. INTRODUCTION

An overall approach for developing a regional industrial source inventory, should one be needed to assess compliance with ambient standards and PSD increments, was discussed during the pre-application meeting for the Kalama Manufacturing and Marine Export Facility (KMMEF) at Washington Department of Ecology (Ecology), on October 13, 2015. Because the project will emit greater than 100,000 tons per year of carbon dioxide equivalent (CO_2e), the project is subject to New Source Review (NSR) under the state Prevention of Significant Deterioration (PSD) regulations. Among the criteria pollutants, NO_2, PM_{10}, and $PM_{2.5}$ will exceed the PSD Significant Emission Rates (SERs), meaning a cumulative analysis is required to demonstrate compliance with the ambient standard if the modeled project-only concentration of one of those pollutants exceeds the applicable Significant Impact Level (SIL).

Modeling results predicted that the 1-hour and annual average NO_2, 1-hour average SO_2, 24-hour and annual average PM_{10}, and 24-hour and annual average $PM_{2.5}$ concentrations exceed the applicable SILs. Discussions at the October 2015 pre-application meeting indicated that, because we would be using the NW AIRQUEST design values for background,[1] it would be sufficient for the regional emissions inventory to include industrial sources no more than 20 kilometers (km) of the proposed facility.

We obtained industrial source information from Southwest Clean Air Agency (SWCAA), Oregon Department of Environmental Quality (ODEQ), and Ecology's Industrial Section. The SWCAA information included allowable emissions for each facility, while the information from Ecology included 2013 actual emission rates. We also obtained a modeling emission inventory developed in 2006 by the Western Regional Air Partnership (WRAP) for regional haze modeling. On January 18th, 2016, Ramboll Environ proposed the methodology described here to remove insignificant sources from the emission inventory, leaving only those that should be included in

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[1] Representative background concentrations for 1-hour average NO_2 and SO_2, 24-hour average $PM_{2.5}$ and PM_{10}, and annual average NO_2 and $PM_{2.5}$ were obtained using an online tool, available at the Northwest International Air Quality Environmental Science and Technology (NW-AIRQUEST) Consortium website (http://www.lar.wsu.edu/nw-airquest/lookup.html) which interpolates modeled and monitored concentrations to obtain pollutant concentration estimates at a given location.

the cumulative analysis. Ecology approved this methodology in an email received from Clint Bowman on January 19th.

2. INVENTORY DEVELOPMENT AND SCREENING

Of the 434 facilities provided by SWCAA, 106 facilities are located closer than 20 km of the proposed facility. Of those 106 facilities, any that were not included in the 2006 WRAP inventory, and had allowable NO_X, PM_{10}, and $PM_{2.5}$ emissions all less than 1 ton per year, or had allowable emissions of either NO_X or PM greater than 1 tpy, but less than 5 tpy. Table 1 presents the 49 facilities eliminated using these criteria, the majority of which are school districts, auto body shops, or small commercial facilities.

Table 1. Facilities eliminated from modeling consideration

SWCAA ID	Facility Name	Distance to KMMEF (km)	Emission rates all below 1 ton?	In 2006 WRAP Inventory
2089	Centurylink QCC / Kalama AMP	2.97	Yes	No
825	City of Kalama – Public Works	4.82	No (NOx 2.5 tpy)	No
565	Kalama School District	4.82	No (NOx 1.5 tpy)	No
1009	Chemtrade Performance Chemicals LLC	6.17	No (NOx 1.35 tpy)	No
2310	AT&T Communications	6.92	No (NOx 2.1 tpy)	No
1264	Arch Wood Protection, INc.	7.15	Yes	No
1158	Glacier Northwest, Inc. – Port of Longview Concrete	8.07	Yes	No
2395	Randco Tanks	8.32	No (NOx 1.29 tpy)	No
206	Steel Painters, Inc	8.44	No (PM10 3.86 tpy, PM2.5 2.16 tpy)	No
731	R.D Olson Manufacturing	8.68	No (PM10, PM2.5 1.6 tpy)	No
2356	Western Fabrication Center	8.70	Yes	No
2090	Centurylink QCC / Kelso AMP	8.71	Yes	No
517	Humane Society of Cowlitz County	8.97	Yes	No

2450	Haven Energy Terminals LLC	9.02	No (NOx 2.4 tpy)	No
750	Pacific Door and Window	9.30	Yes	No
2423	Longview Collision Center	9.58	Yes	No
1014	Waite Specialty Machine	9.73	Yes	No
830	Northwest Motor Service	9.73	Yes	No
1298	ALS Environmental	9.92	Yes	No
1929	R and T Enterprises	9.99	No (PM10 1.69 tpy)	No
870	Selix Cabinets	10.05	Yes	No
2471	Comcast Cable	10.31	NO (NOx 1.99 tpy)	No
2304	Superior Tire Service, Inc	10.36	Yes	No
1799	City of Longview Fire Station	10.45	Yes	No
1087	YMCA Longview	10.70	No (NOx 2.48 tpy)	No
2386	Kaiser Longview	10.75	No (NOx 1.76 tpy)	No
2387	Cowlitz PUD	10.77	Yes	No
2321	Heritage Bank	10.80	Yes	No
1756	Bud Clary Paint and Collision Center	10.92	Yes	No
2325	Max Autobody	10.98	Yes	No
171	Behrend's Body Shop	11.05	Yes	No
696	Mackins of Longview	11.27	Yes	No
2333	Northwest Coffee Roasters LLC	11.44	Yes	No
2449	Lexington Flood Control Zone District	11.54	No (NOx 1.44 tpy)	No
1771	City of Longview - City Hall	11.56	Yes	No
2254	Centurylink QCC / Longview CO	11.69	Yes	No
2442	GT Collision Center	11.71	Yes	No
482	Green Hills Memorial Gardens, Inc.	13.05	Yes	No

2237	Eagle US 2 LLC	13.15	Yes	No
1932	Graymont Western US, Inc.	13.18	Yes	No
1748	City of Longview - Water Treatment Plant - Mint Farm	13.18	Yes	No
1728	Lowe's Home Improvement Warehouse 1887 - Longview	13.30	Yes	No
2457	Drainage Improvement District No 1	13.93	Yes	No
2233	Advanced Comfort Products, Inc.	13.97	No (NOx 1.67 tpy)	No
1844	Mt. Solo Landfill, Inc.	16.60	Yes	No
2408	Lineage Columbia LLC	17.13	Yes	No
2086	Refuge Wholesale Refinishing	17.44	Yes	No
1268	Longview Memorial Park	17.63	No (NOx 2.1 tpy)	No
1172	Fuel Processors, Inc.	18.37	Yes	No

Eight of the 57 remaining facilities in the SWCAA inventory were found in the 2006 WRAP inventory, which features actual emission rates and stack parameters at the emission unit level. Allowable emissions provided in the SWCAA inventory were apportioned among the emission units for that facility in the WRAP inventory, weighted using the actual emission rates for those emission units from the WRAP inventory. PM_{10} emissions were used to apportion the allowable $PM_{2.5}$ emissions in the SWCAA inventory among the WRAP inventory emission units for cases where $PM_{2.5}$ emission rates were not available from the WRAP inventory. Table 2 summarizes these eight facilities. Emission units in the WRAP inventory for which stack parameters were not provided were assumed to be fugitive emissions; these emissions were added to the point source with the maximum emission rate at that facility.

Table 2. Facilities from 2006 WRAP Inventory

SWCAA ID	Facility Name	Distance from KMMEF (km)	Number of sources onsite	WRAP Inventory Actual Emissions (tpy)			2016 SWCAA PTE (tpy)		
				NO_x	PM_{10}	$PM_{2.5}$	NO_x	PM_{10}	$PM_{2.5}$
1947	Steelscape, Inc.	0.38	17	28.1	6.9	5.7	70.9	15.6	14.1
1124	Kalama Export Company, LLC	2.07	20	0	28.7	5.0	0	53.5	8.9
564	Emerald Kalama Chemical, LLC	2.85	31	99.9	27.0	21.6	147.6	110.8	110.8
225	RSG Forest Products, Inc.	3.74	2	0	28.0	28.0	0.19	28.9	14.10
711	TEMCO, LLC	7.34	14	0	23.1	12.1	0	43.6	7.4
346	Three Rivers Regional Wastewater Plant	7.71	7	0.47	0.026	0.026	6.6	4.3	4.3
1846	Northwest Hardwoods Inc. - Longview	8.51	6	35.5	11.8	4.9	66.0	22.6	12.6
778	Port of Longview - Berth 1, 2, 5, 6 and 7	9.49	26	0	2.0	1.0	0	53	53

PSE's Mint Farm Generating Station is present in both the SWCAA inventory and the WRAP inventory, but the WRAP inventory does not include emissions data. The SWCAA inventory indicates that the majority of the emissions at the Mint Farm Generating Station are emitted by the Combustion Turbine; for purposes of the regional inventory, we assumed that all facility emissions are exhausted through the combustion turbine stack.

The WRAP inventory was compiled in 2006, and the Owens-Brockway Glass facility (then Cameron Family Glass Packaging) was permitted in 2007, so it does not appear in the WRAP inventory. We obtained stack parameters from a 2010 permit application, when the facility was restarted as Bennu Glass. In that case, the majority of facility emissions are associated with the melt furnace; for purposes of the regional inventory, we assumed that all facility emissions are exhausted through the melt furnace stack. The stack parameters and PTE for both Mint Farm Generation and Owens-Brockway Glass are presented in Table 3.

Table 3. Mint Farm and Owens-Brockway Emissions and Stack Parameters

SWCAA ID	Facility Name	Distance from KMMEF (km)	2016 SWCAA PTE (tpy)			Height (m)	Diameter (m)	Exit Flowrate (acfm)	Exit Velocity (m/s)	Exit Temp. (°C)
			NO_x	PM_{10}	$PM_{2.5}$					
2284	Owens-Brockway Glass Container, Inc. – Plant 2	1.6	53.2	20.0	19.8	30.5	0.9	24,126	17.3	214.0
2111	Mint Farm Generating Station	13.8	98.8	99.7	99.1	60.4	5.5	1,429,380	28.5	110.0

The remaining 47 facilities in the SWCAA inventory that meet the criteria outlined above are not represented in the WRAP inventory, meaning no stack parameter information or actual emissions to apportion the allowable was available for those facilities. A single stack was used to represent each of these facilities, with generic stack parameters assigned according to the emissions profile of the facility. Facilities with non-zero NO_X emissions were assigned stack parameters typical of a combustion emission unit:

- Stack height – 10 meters
- Stack diameter – 1 meter
- Stack gas exit temperature – 394 K
- Stack gas exit velocity – 1 meter per second (m/s)

Facilities with only PM/PM_{10}/$PM_{2.5}$, and no NO_X emissions were assigned stack parameters typical of a materials processing facility:

- Stack height – 5 meters
- Stack diameter – 3 meters
- Stack gas exit temperature – 293 K
- Stack gas exit velocity – 0.15 meter per second (m/s)

Table 4 presents the SWCAA ID, facility name, distance from KMMEF, and the potential emissions from each of the facility.

Table 4. Facilities Not In the 2006 WRAP Inventory

SWCAA ID	Facility Name	Distance from KMMEF (km)	2016 SWCAA PTE (tpy)		
			NO_x	PM_{10}	$PM_{2.5}$
473	Gram Lumber Company	3.54	0	20.67	4.93
2289	Nor-Tech Fabricating, LLC	7.45	3.14	6.88	0.24
2311	Kerr Contractors, Inc.	7.48	30.96	8.41	7.07
1120	Cowlitz County Landfill	7.64	8	4.4	4.4
2439	J. L. Storedahl and Sons, Inc. / K500 Portable	8.27	0	4.97	0.77
156	Lakeside Industries, Inc. / Longview	8.27	3.45	2.85	2.25
2292	EGT, LLC	8.29	0	53.63	9.01
2337	Knife River / Con-E-Co Concrete	8.39	14.56	3.43	2.17
1391	Knife River / Kelso Ready Mix	8.41	0.187	1.89	0.727
2330	F. H. Sullivan Company, Inc. - Kelso	8.45	5.3	0.43	0.42
933	Stowe Woodward / Mount Hope	8.55	2.82	5.26	0.26
1230	Pacific Fibre Products, Inc.	8.96	0	12	0
1246	Foster Farms - Kelso Plant	9.13	3.39	4.21	4.21
238	Interfor US, Inc. - Longview Division	9.33	0	24.17	12.41
838	Roemer Electric Steel Foundry	9.76	0.16	7.66	7.66
2368	City of Longview - Wastewater Pump Stations - Public Works	9.91	4.13	0.063	0.063

770	Peterson Manufacturing Company	9.93	0	16.3	3.75
129	Kemira Water Solutions, Inc.	10.06	3.57	0.27	0.27
1036	Wayron, LLC	10.11	0.07	2.24	2.24
348	Glacier Northwest, Inc. - Longview Ready Mix	10.23	1	7.5	0.5
1905	Waste Control Recycling, Inc.	10.43	0	2.5	2.5
1792	Consolidated Diking Improvement District No 3	10.64	3.84	0.15	0.15
914	St. John Medical Center / Delaware Campus	10.91	14.59	1.36	1.33
575	Kelso School District No 458	10.96	18.11	1.726	1.726
1024	WA Dept of Fish and Wildlife - Hatcheries	10.96	5.27	0.37	0.37
678	St. John Medical Center / Broadway Campus	10.99	7.09	0.3	0.3
635	Lower Columbia College	11.86	21.24	3.1	3.1
632	Longview School District No 122	12.56	14.3	1.83	1.83
1557	Specialty Minerals Inc. / Longview	13.14	0	7.92	0
1225	Solvay Chemicals, Inc.	13.44	23.58	1.66	1.66
2236	Northwest Demolition and Dismantling - Portable	14.15	2.5	1.22	0.25
2279	Millennium Bulk Terminals - Longview	14.56	6.51	20.38	16.21
2274	3 B's Land and Gravel, LLC	15.66	14.01	1.86	0.47
1901	US Natural Resources, Inc.	15.84	7.33	1.86	1.86
1327	LifePort, Inc.	16.01	6.13	1.41	1.2
2242	Northwood Cabinets, Inc.	16.62	0.89	3.25	3.17
1886	Glacier Northwest, Inc. - Woodland Ready Mix	16.86	1.85	2.37	0.114
2245	Sonoco Products Company	17.12	1.57	2.57	1.35
1977	Down River	17.33	0.5	5.54	5.54
2066	Hamilton Materials LLC	17.48	0	3.5	0
498	Hayes Cabinets, Inc.	17.48	0.6	7.92	4.31
1286	Northwest Pet Products, Inc.	17.49	5	1.08	0.38

1175	Columbia River Carbonates	17.77	1.77	27.43	27.43
1928	GT Collision Center - Woodland	18.21	1	4	4
1079	Woodland School District No 404	18.31	6.78	0.54	0.54
1080	City of Woodland - Public Works	18.64	3.26	0.018	0.18
2425	Portco Packaging - Woodland	18.68	12.24	0.19	0.19

The inventory provided by Ecology’s Industrial Section included only two facilities that are located less than 20 km of the site: KapStone (formerly Longview Fibre) and Weyerhaeuser Longview. The Industrial Section inventory does not include stack parameters or allowable emission rates, so the stack parameters and actual emission rates in the WRAP inventory were used as a starting point for developing these facilities in the regional inventory. Information obtained during conversations with Roberto Artiga of KapStone, form the Best Available Retrofit Technology (BART) modeling report issued by Weyerhaeuser in 2008 for the Longview facility, and the current Air Operating Permits (AOPs) were used to develop estimated allowable emission rates and stack parameters.

ODEQ provided an emission inventory that included four sources: PGE Port Westward, PGE Beaver, Georgia Pacific Wauna, and Boise Paper St. Helens. All of these facilities were excluded from the regional source inventory on the basis that they are located more than 20 km from the proposed site.

The final regional industrial source emission inventory is provided in Attachment A.

3. SIGNIFICANCE SCREENING

Air dispersion modeling was used to determine whether each of the facilities included in the regional inventory has the potential to contribute significantly to an exceedance of an ambient standard or increment at the same location and time period that the proposed facility has the potential to contribute significantly to an exceedance of an ambient standard or increment. The AERMOD dispersion model was employed, using a methodology identical to that used to predict ambient concentrations attributable to the facility, with the exception of the included receptors. Only receptors predicted by the proposed project-only modeling to have a design concentration that exceeds the applicable SIL were included.

Ambient concentrations calculated by the by model were aggregated for each facility and compared to the applicable SILs. Emissions attributable to a facility were predicted to result in an ambient concentration that exceeded the SIL at the same location that emissions attributable to the proposed facility were predicted to exceed the SIL were included in the cumulative compliance demonstration modeling for that pollutant and averaging period. The results of the initial regional screening analysis are summarized in Table 5. Concentrations that exceed the applicable SIL are shaded.

Table 5. Results of Initial Regional Facility Screening Analysis

Modeling ID	Facility Name	1-hour NO_2	Annual NO_2	24-hour PM_{10}	Annual PM_{10}	24-hour $PM_{2.5}$	Annual $PM_{2.5}$
SIL (µg/m^3)		**7.5**	**1**	**5**	**1**	**1.2**	**0.3**
KS	KapStone	217.1	1.57	6.57	0.515	6.79	0.733
WH	Weyerhaeuser	288.4	0.776	3.91	0.103	1.79	0.142
STL	Steelscape, Inc.	53.9	0.255	3.98	0.134	3.68	0.693
KEC	Kalama Export Company, LLC	--	--	5.43	0.477	2.47	0.287
EKC	Emerald Kalama Chemical, LLC	185.9	0.757	5.14	0.474	9.40	1.052
RSG	RSG Forest Products, Inc.	--	--	0.987	0.114	1.42	0.193
TEM	TEMCO, LLC	--	--	0.00141	0.000220	0.000740	0.000140

TRR	Three Rivers Regional Wastewater Plant	--	--	0.0832	0.00882	0.0971	0.00930
NWHW	Northwest Hardwoods Inc. - Longview	24.5	0.151	0.480	0.0563	0.271	0.0346
POL	Port of Longview - Berth 1, 2, 5, 6 and 7	--	--	0.835	0.0631	0.371	0.0354
OBG	Owens-Brockway Glass Container, Inc. – Plant 2	73.9	0.130	0.660	0.0584	2.66	0.300
MFG	Mint Farm Generating Station	2.99	0.00712	0.0785	0.00758	0.130	0.00846
473	Gram Lumber Company	--	--	1.15	0.201	0.525	0.115
2289	Nor-Tech Fabricating, LLC	1.77	0.0180	0.385	0.0440	0.0119	0.00173
2311	Kerr Contractors, Inc.	21.0	0.143	0.379	0.0438	0.278	0.0416
1120	Cowlitz County Landfill	3.57	0.0310	0.168	0.0190	0.168	0.0211
2439	J. L. Storedahl and Sons, Inc. / K500 Portable	--	--	0.142	0.0135	0.0179	0.00290
156	Lakeside Industries, Inc. / Longview	1.93	0.0124	0.104	0.0115	0.0836	0.0100
2292	EGT, LLC	--	--	2.01	0.144	0.269	0.0268
2337	Knife River / Con-E-Co Concrete	6.69	0.0693	0.141	0.0181	0.0805	0.0127
1391	Knife River / Kelso Ready Mix	0.0834	0.000880	0.0757	0.00984	0.0263	0.00422

2330	F. H. Sullivan Company, Inc. - Kelso	2.21	0.0244	0.0165	0.00219	0.0144	0.00239
933	Stowe Woodward / Mount Hope	1.08	0.0128	0.198	0.0263	0.00866	0.00145
1230	Pacific Fibre Products, Inc.	--	--	0.300	0.0311	0.262	0.0325
1246	Foster Farms - Kelso Plant	1.29	0.0133	0.137	0.0183	0.111	0.0202
238	Interfor US, Inc. - Longview Division	--	--	0.849	0.0589	0.320	0.0313
838	Roemer Electric Steel Foundry	0.0658	0.000380	0.230	0.0197	0.164	0.0213
2368	City of Longview - Wastewater Pump Stations - Public Works	1.73	0.00791	0.00137	0.000130	0.00143	0.000140
770	Peterson Manufacturing Company	--	--	0.329	0.0350	0.0682	0.00831
129	Kemira Water Solutions, Inc.	1.64	0.00910	0.00713	0.000750	0.00787	0.000810
1036	Wayron, LLC	0.0304	0.000150	0.0551	0.00529	0.0437	0.00566
348	Glacier Northwest, Inc. - Longview Ready Mix	0.424	0.00250	0.185	0.0205	0.0144	0.00147
1905	Waste Control Recycling, Inc.	--	--	0.0475	0.00542	0.0632	0.00563
1792	Consolidated Diking Improvement District No 3	1.16	0.0135	0.00486	0.000570	0.00373	0.000620
914	St. John Medical Center / Delaware Campus	5.31	0.0291	0.0357	0.00294	0.0243	0.00308
575	Kelso School District No 458	5.40	0.0632	0.0553	0.00646	0.0435	0.00693

1024	WA Dept of Fish and Wildlife - Hatcheries	0.644	0.00287	0.00142	0.000200	0.00208	0.000270
678	St. John Medical Center / Broadway Campus	2.20	0.0167	0.00638	0.000770	0.00725	0.000830
635	Lower Columbia College	6.98	0.0412	0.0808	0.00637	0.0693	0.00675
632	Longview School District No 122	4.67	0.0225	0.0343	0.00308	0.0239	0.00321
1557	Specialty Minerals Inc. / Longview	--	--	0.236	0.00977	0.143	0.0103
1225	Solvay Chemicals, Inc.	5.82	0.0280	0.0350	0.00207	0.0245	0.00222
2236	Northwest Demolition and Dismantling - Portable	0.711	0.00265	0.0229	0.00135	0.00326	0.000290
2279	Millennium Bulk Terminals - Longview	1.63	0.00654	0.315	0.0214	0.195	0.0179
2274	3 B's Land and Gravel, LLC	1.68	0.0108	0.0154	0.00149	0.00522	0.000430
1901	US Natural Resources, Inc.	0.611	0.00502	0.00994	0.00130	0.0101	0.00147
1327	LifePort, Inc.	0.541	0.00442	0.00789	0.00103	0.00651	0.000990
2242	Northwood Cabinets, Inc.	0.0736	0.000650	0.0189	0.00238	0.0173	0.00258
1886	Glacier Northwest, Inc. - Woodland Ready Mix	0.151	0.00131	0.0134	0.00169	0.000600	0.0000900
2245	Sonoco Products Company	0.130	0.000980	0.0124	0.00162	0.00687	0.000930
1977	Down River	0.0376	0.000320	0.0262	0.00362	0.0272	0.00397

2066	Hamilton Materials LLC	--	--	0.0214	0.00298	0.0215	0.00337
498	Hayes Cabinets, Inc.	0.0473	0.000370	0.0370	0.00495	0.0213	0.00295
1286	Northwest Pet Products, Inc.	0.384	0.00336	0.00564	0.000730	0.00188	0.000280
1175	Columbia River Carbonates	0.137	0.00118	0.146	0.0184	0.136	0.0203
1928	GT Collision Center - Woodland	0.0788	0.000570	0.0177	0.00232	0.0189	0.00253
1079	Woodland School District No 404	0.485	0.00408	0.00235	0.000330	0.00250	0.000360
1080	City of Woodland - Public Works	0.254	0.00179	0.0000800	0.0000100	0.000820	0.000110
2425	Portco Packaging - Woodland	0.888	0.00774	0.000960	0.000120	0.000890	0.000130

3.1 Short Term Cumulative Modeling

As shown in Table 5, nine facilities were identified as having the potential for a significant contribution at the same location that the proposed Facility is predicted to have a significant contribution. These facilities were included in the cumulative modeling with the proposed Facility, and combined with representative background concentrations to assess compliance with the ambient standard at all receptors and time periods.

The three facilities in Table 5 that exceeded the 24-hour PM_{10} SIL were modeled with the proposed Facility. For each modeling scenario, the design concentration (i.e., the highest fourth high over three years) was combined with a representative background concentration, and compared with the ambient standard. As shown in Table 6, compliance was demonstrated for all scenarios.

Table 6. 24-hour Cumulative Analysis for PM_{10}

Scenario	Pollutant	Modeled Concentration ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Over NAAQS?
P00	PM_{10}	12.2	27	39.2	150	No
P02	PM_{10}	12.6	27	39.6	150	No
P03	PM_{10}	12.5	27	39.5	150	No
P04	PM_{10}	12.5	27	39.5	150	No
P05	PM_{10}	12.3	27	39.3	150	No
P07	PM_{10}	12.2	27	39.2	150	No
P08	PM_{10}	12.2	27	39.2	150	No
P09	PM_{10}	14.9	27	41.9	150	No
P10	PM_{10}	12.2	27	39.2	150	No
P11	PM_{10}	12.2	27	39.2	150	No
P12	PM_{10}	12.0	27	39.0	150	No
P13	PM_{10}	12.0	27	39.0	150	No
P14	PM_{10}	12.4	27	39.4	150	No
P16	PM_{10}	12.4	27	39.4	150	No

Facilities in Table 5 that were predicted to exceed the SILs for NO_2 and $PM_{2.5}$ were modeled with the proposed Facility. The highest 8th through 28th high cumulative 1-hour average NO_2 and 24-hour average $PM_{2.5}$ concentrations, averaged over three years, were combined with background and compared to the ambient standard. Receptors and time periods predicted to exceed the ambient standards were further examined to determine whether the predicted impact attributable to the proposed Facility was significant (i.e., exceeds the SIL) at that same location and time period. As shown in Table 7, in all cases, the proposed Facility was not significant at any receptor and time period predicted by the cumulative modeling analysis to exceed the ambient standard.

Table 7. Cause and Contribution Modeling Results Summary

Scenario	Pollutant	Avg. Period	UTM Location		Modeled Result[1] $(\mu g/m^3)$	Background Conc. $(\mu g/m^3)$	Total Conc. $(\mu g/m^3)$	Less than NAAQS ?	KMMEF Cont. $(\mu g/m^3)$	SIL $(\mu g/m^3)$	Below SIL?
			East (m)	North (m)							
P00	$PM_{2.5}$	24-hr	510550	5097700	7.32	18	25.3	Yes	--	1.2	--
P02	$PM_{2.5}$	24-hr	510550	5097700	7.32	18	25.3	Yes	--	1.2	--
P03	$PM_{2.5}$	24-hr	510550	5097700	7.32	18	25.3	Yes	--	1.2	--
P04	$PM_{2.5}$	24-hr	510550	5097700	7.32	18	25.3	Yes	--	1.2	--
P05	$PM_{2.5}$	24-hr	510550	5097700	7.32	18	25.3	Yes	--	1.2	--
P07	$PM_{2.5}$	24-hr	510550	5097700	7.32	18	25.3	Yes	--	1.2	--
P08	$PM_{2.5}$	24-hr	510550	5097700	7.32	18	25.3	Yes	--	1.2	--
P09	$PM_{2.5}$	24-hr	510550	5097700	7.32	18	25.3	Yes	--	1.2	--
P10	$PM_{2.5}$	24-hr	510550	5097700	7.32	18	25.3	Yes	--	1.2	--
P11	$PM_{2.5}$	24-hr	510550	5097700	7.32	18	25.3	Yes	--	1.2	--
P12	$PM_{2.5}$	24-hr	510550	5097700	7.32	18	25.3	Yes	--	1.2	--
P13	$PM_{2.5}$	24-hr	510550	5097700	7.32	18	25.3	Yes	--	1.2	--
P14	$PM_{2.5}$	24-hr	510550	5097700	7.32	18	25.3	Yes	--	1.2	--
P16	$PM_{2.5}$	24-hr	510550	5097700	7.32	18	25.3	Yes	--	1.2	--
P00	NO_2	1-hr	512700	5095200	126.1	62	188.1	No	5.81	7.5	Yes
P02	NO_2	1-hr	512700	5095200	126.3	62	188.3	No	6.17	7.5	Yes
P03	NO_2	1-hr	512700	5095200	126.2	62	188.2	No	5.90	7.5	Yes
P04	NO_2	1-hr	512700	5095200	126.2	62	188.2	No	6.11	7.5	Yes
P05	NO_2	1-hr	512700	5095200	126.2	62	188.2	No	5.87	7.5	Yes
P07	NO_2	1-hr	512700	5095200	126.1	62	188.1	No	5.81	7.5	Yes
P08	NO_2	1-hr	512700	5095200	126.1	62	188.1	No	5.81	7.5	Yes
P09	NO_2	1-hr	512700	5095200	126.1	62	188.1	No	5.81	7.5	Yes
P10	NO_2	1-hr	512700	5095200	126.2	62	188.2	No	5.95	7.5	Yes
P11	NO_2	1-hr	512700	5095200	126.2	62	188.2	No	5.85	7.5	Yes
P12	NO_2	1-hr	512700	5095200	126.6	62	188.6	No	7.22	7.5	Yes
P13	NO_2	1-hr	512700	5095200	126.6	62	188.6	No	7.22	7.5	Yes
P14	NO_2	1-hr	512700	5095200	126.2	62	188.2	No	5.94	7.5	Yes
P16	NO_2	1-hr	512700	5095200	126.2	62	188.2	No	6.05	7.5	Yes

Notes:

1. The overall modeled result corresponds to KMMEF’s maximum contribution to a NAAQS exceedance. There are results for the overall model that are greater than this value.

3.2 Long Term Cumulative Modeling

Facilities in Table 5 predicted to exceed the annual average NO_2 and $PM_{2.5}$ SILs were modeled with the KMMEF facility sources for the receptors that were greater than the SILs for each pollutant. The results of the modeling were combined with a representative background concentration, and compared with the ambient standard to determine compliance. As shown in Table 8, none of the predicted cumulative concentrations exceed the ambient standard.

Table 8. Annual Cumulative Analysis for $PM_{2.5}$ and NO_2

Scenario	Pollutant	Modeled Concentration ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Over NAAQS?
P01	$PM_{2.5}$	4.08	5.7	9.78	12	No
P06	$PM_{2.5}$	4.05	5.7	9.75	12	No
P15	$PM_{2.5}$	4.09	5.7	9.79	12	No
P01	NO_2	2.30	9.8	12.1	100	No
P06	NO_2	2.04	9.8	11.8	100	No
P15	NO_2	2.30	9.8	12.1	100	No

ATTACHMENT A – MODELING AND EMISSIONS TABLES

Source	UTMx (m)	UTMy (m)	Stack Height (ft)	Elev (m)	Temp (F)	V (ft/s)	D (ft)
OBG	510468	5097632	100	5.46	417	56.8	3.0
MFG	501144	5109641	198	2.75	230	93.5	18.0
STLSRC1	510586	5098346	15	5.57	70	169.0	0.5
STLSRC2	510586	5098346	100	5.57	72	32.2	1.5
STLSRC3	510586	5098346	100	5.57	712	33.7	7.0
STLSRC4	510586	5098346	100	5.57	108	16.6	3.0
STLSRC5	510586	5098346	100	5.57	72	32.3	1.5
STLSRC6	510586	5098346	89	5.57	75	47.5	5.9
STLSRC7	510586	5098346	111	5.57	1046	33.8	5.0
STLSRC8	510586	5098346	46	5.57	335	16.9	3.7
STLSRC9	510586	5098346	46	5.57	335	16.9	3.7
STLSRC10	510586	5098346	15	5.57	800	295.0	0.8
KECSRC1	510866	5097072	10	3.84	77	88.0	2.8
KECSRC2	510866	5097072	10	3.84	77	53.1	2.8
KECSRC3	510866	5097072	10	3.84	77	10.2	4.0
KECSRC4	510866	5097072	10	3.84	77	7.5	2.8
KECSRC5	510866	5097072	10	3.84	77	4.0	2.8
KECSRC6	510866	5097072	10	3.84	77	67.2	2.5
KECSRC7	510866	5097072	10	3.84	77	45.8	2.5
KECSRC8	510866	5097072	10	3.84	77	88.0	2.8
KECSRC9	510866	5097072	10	3.84	77	19.5	3.4
KECSRC10	510866	5097072	10	3.84	77	36.0	3.4

KECSRC11	510866	5097072	10	3.84	77	29.2	3.4
KECSRC12	510866	5097072	10	3.84	77	46.3	3.4
KECSRC13	510866	5097072	10	3.84	77	40.2	3.4
KECSRC14	510866	5097072	10	3.84	77	73.2	3.4
KECSRC15	510866	5097072	10	3.84	77	68.2	2.8
EKCSRC1	511067	5096500	30	8.0	100	5.1	0.5
EKCSRC2	511067	5096500	24	8.0	120	858.5	1.5
EKCSRC3	511067	5096500	10	8.0	55	5.3	2.0
EKCSRC4	511067	5096500	12	8.0	350	8.5	4.0
EKCSRC5	511067	5096500	25	8.0	500	10.6	2.5
EKCSRC6	511067	5096500	24	8.0	250	70.7	1.5
EKCSRC7	511067	5096500	24	8.0	250	47.5	1.5
EKCSRC8	511067	5096500	15	8.0	300	22.4	2.5
EKCSRC9	511067	5096500	15	8.0	600	29.7	2.5
EKCSRC10	511067	5096500	20	8.0	350	12.6	2.8
EKCSRC11	511067	5096500	20	8.0	350	14.2	3.0
EKCSRC12	511067	5096500	25	8.0	600	84.9	1.5
EKCSRC13	511067	5096500	30	8.0	579	31.0	2.7
EKCSRC14	511067	5096500	30	8.0	300	52.2	2.5
EKCSRC15	511067	5096500	29	8.0	520	22.4	2.5
EKCSRC16	511067	5096500	72	8.0	400	98.0	1.0
EKCSRC17	511067	5096500	16	8.0	240	30.7	3.0
NWHWSRC1	506476	5106708	30	5.46	300	53.2	2.0
NWHWSRC2	506476	5106708	20	5.46	300	38.3	2.0
TRRSRC1	504946	5106609	13	5.03	922	179.0	1.2
TRRSRC2	504946	5106609	4	5.03	1102	237.2	0.3
TRRSRC3	504946	5106609	38	5.03	0	15.1	1.3
POLSRC1	503277	5105764	48	2.32	65	5.0	3.8
POLSRC2	503277	5105764	17	2.32	65	29.0	4.3
POLSRC3	503277	5105764	2	2.32	65	51.0	2.5

POLSRC4	503277	5105764	55	2.32	65	12.0	4.3
POLSRC5	503277	5105764	25	2.32	65	197.0	1.8
POLSRC6	503277	5105764	123	2.32	65	50.0	1.3
POLSRC7	503277	5105764	14	2.32	65	49.0	3.6
POLSRC8	503277	5105764	17	2.32	65	60.0	0.7
POLSRC9	503277	5105764	17	2.32	65	60.0	0.7
POLSRC10	503277	5105764	17	2.32	65	60.0	0.7
POLSRC11	503277	5105764	21	2.32	65	60.0	0.7
TEMSRC1	512875	5092366	15	9.03	55	52.0	2.8
TEMSRC2	512875	5092366	50	9.03	55	33.1	3.6
TEMSRC3	512875	5092366	30	9.03	55	89.8	3.0
TEMSRC4	512875	5092366	15	9.03	55	35.1	4.4
TEMSRC5	512875	5092366	10	9.03	55	36.7	4.5
RSGSRC1	511535	5095296	25	2.98	70	231.0	1.7
KSSRC1	506052	5105345	198	5.73	252	38.6	13.5
KSSRC2	506052	5105345	198	5.73	252	38.6	13.5
KSSRC3	506052	5105345	136	5.73	139	82.1	8
KSSRC4	506052	5105345	101	5.73	146	9.8	7
KSSRC5	506052	5105345	101	5.73	146	9.8	7
KSSRC6	506052	5105345	101	5.73	146	9.8	7
WHSRC1	501885	5107873	90	3.92	245	0.033	1
WHSRC2	501885	5107873	107	3.92	396	94.3	4
WHSRC3	501885	5107873	250	3.92	373	55.56	14
WHSRC4	501885	5107873	200	3.92	163	12.89	8
WHSRC5	501885	5107873	107	3.92	396	94.3	4
WHSRC6	501885	5107873	83	3.92	68	5.3	2
WHSRC7	501885	5107873	128	3.92	300	35.3	7
WHSRC9	501885	5107873	128	3.92	300	43.3	7
WHSRC11	501885	5107873	128	3.92	300	87.5	7
WHSRC12	501885	5107873	123.6	3.92	306	53.04	6

473	511331.1	5095848	16.4	6.87	68	0.5	9.8
2289	508621.3	5106478	32.8	6.16	250	3.3	3.3
2311	507648.2	5106237	32.8	5.54	250	3.3	3.3
1120	506990.3	5106137	32.8	6.88	250	3.3	3.3
2439	510729.1	5107449	16.4	273.06	68	0.5	9.8
156	506948.9	5106801	32.8	6.48	250	3.3	3.3
2292	504917.2	5105592	16.4	6.57	68	0.5	9.8
2337	508300	5107377	32.8	3.88	250	3.3	3.3
1391	508250.4	5107384	32.8	3.92	250	3.3	3.3
2330	508159.6	5107403	32.8	3.99	250	3.3	3.3
933	508121.8	5107490	32.8	3.24	250	3.3	3.3
1230	505384.3	5106761	16.4	4.66	68	0.5	9.8
1246	507776.3	5107999	32.8	4.58	250	3.3	3.3
238	505633.8	5107342	16.4	6.04	68	0.5	9.8
838	505119	5107536	32.8	4.63	250	3.3	3.3
2368	504054.8	5106972	32.8	4.19	250	3.3	3.3
770	504820.1	5107543	16.4	5.03	68	0.5	9.8
129	505929.9	5108314	32.8	6.54	250	3.3	3.3
1036	504779.3	5107734	32.8	4.84	250	3.3	3.3
348	505913.3	5108486	32.8	6.36	250	3.3	3.3
1905	505973.7	5108736	16.4	5.87	68	0.5	9.8
1792	508168.5	5109640	32.8	3.66	250	3.3	3.3
914	504494.6	5108499	32.8	4.13	250	3.3	3.3
575	508392.5	5110011	32.8	3.16	250	3.3	3.3
1024	520661.7	5095921	32.8	68.77	250	3.3	3.3
678	505838.8	5109290	32.8	5.08	250	3.3	3.3
635	504831.3	5109778	32.8	6.95	250	3.3	3.3
632	503431.8	5109781	32.8	6.49	250	3.3	3.3
1557	501346.7	5108908	16.4	5.31	68	0.5	9.8
1225	501327.7	5109296	32.8	3.28	250	3.3	3.3

2236	500323.6	5109340	32.8	3.8	250	3.3	3.3
2279	499902.2	5109492	32.8	3.73	250	3.3	3.3
2274	499755.5	5110865	32.8	98.8	250	3.3	3.3
1901	518539.5	5085737	32.8	4.85	250	3.3	3.3
1327	518291.5	5085384	32.8	5.26	250	3.3	3.3
2242	518292.3	5084686	32.8	7.18	250	3.3	3.3
1886	518447.4	5084492	32.8	7.53	250	3.3	3.3
2245	519252.1	5084668	32.8	8.7	250	3.3	3.3
1977	519040.3	5084297	32.8	8.56	250	3.3	3.3
2066	518548.8	5083841	16.4	7.72	68	0.5	9.8
498	519330.8	5084290	32.8	8.45	250	3.3	3.3
1286	518817	5083979	32.8	6.96	250	3.3	3.3
1175	518808.5	5083654	32.8	7.95	250	3.3	3.3
1928	519811.3	5083730	32.8	9.9	250	3.3	3.3
1079	519517.5	5083443	32.8	9.43	250	3.3	3.3
1080	520125.9	5083428	32.8	10.21	250	3.3	3.3
2425	519137.2	5082799	32.8	7.84	250	3.3	3.3

Source	**NO$_x$ (tpy)**	**PM$_{10}$ (tpy)**	**PM$_{2.5}$ (tpy)**	**NOx (g/s)**	**PM$_{10}$ (g/s)**	**PM$_{2.5}$ (g/s)**
OBG	53.2	20.0	19.8	1.53E+00	5.76E-01	5.68E-01
MFG	98.8	99.7	99.1	2.84E+00	2.87E+00	2.85E+00
STLSRC1	0.0	0.022	0.022	0.00E+00	6.47E-04	6.47E-04
STLSRC2	0.0	0.067	0.049	0.00E+00	1.94E-03	1.41E-03
STLSRC3	54.1	2.9	2.4	1.56E+00	8.29E-02	6.91E-02
STLSRC4	0.0	0.427	0.367	0.00E+00	1.23E-02	1.06E-02
STLSRC5	0.2	0.202	0.171	6.55E-03	5.82E-03	4.93E-03
STLSRC6	0.0	11.7	10.6	0.00E+00	3.37E-01	3.05E-01
STLSRC7	11.7	0.135	0.147	3.37E-01	3.88E-03	4.23E-03
STLSRC8	2.0	0.270	0.245	5.75E-02	7.76E-03	7.05E-03

STLSRC9	2.3	0.180	0.147	6.47E-02	5.17E-03	4.23E-03
STLSRC10	0.6	0.002	0.002	1.82E-02	6.47E-05	6.47E-05
KECSRC1	0.0	5.0	0.827	0.00E+00	1.44E-01	2.38E-02
KECSRC2	0.0	3.1	0.503	0.00E+00	8.89E-02	1.45E-02
KECSRC3	0.0	0.056	0.018	0.00E+00	1.61E-03	5.17E-04
KECSRC4	0.0	0.428	0.072	0.00E+00	1.23E-02	2.07E-03
KECSRC5	0.0	0.503	0.090	0.00E+00	1.45E-02	2.59E-03
KECSRC6	0.0	0.04	0.04	0.00E+00	1.07E-03	1.07E-03
KECSRC7	0.0	0.02	0.02	0.00E+00	5.36E-04	5.36E-04
KECSRC8	0.0	5.0	0.827	0.00E+00	1.44E-01	2.38E-02
KECSRC9	0.0	1.7	0.270	0.00E+00	4.82E-02	7.76E-03
KECSRC10	0.0	3.1	0.503	0.00E+00	8.89E-02	1.45E-02
KECSRC11	0.0	2.5	0.414	0.00E+00	7.23E-02	1.19E-02
KECSRC12	0.0	4.0	0.647	0.00E+00	1.14E-01	1.86E-02
KECSRC13	0.0	3.4	0.575	0.00E+00	9.91E-02	1.66E-02
KECSRC14	0.0	20.7	3.5	0.00E+00	5.95E-01	1.01E-01
KECSRC15	0.0	4.0	0.6	0.00E+00	1.14E-01	1.86E-02
EKCSRC1	1.0	0.369	0.460	2.76E-02	1.06E-02	1.32E-02
EKCSRC2	0.0	29.6	36.9	0.00E+00	8.52E-01	1.06E+00
EKCSRC3	0.0	0.0082	0.010	0.00E+00	2.36E-04	2.94E-04
EKCSRC4	4.9	0.943	1.2	1.42E-01	2.71E-02	3.38E-02
EKCSRC5	0.6	0.410	0.512	1.61E-02	1.18E-02	1.47E-02
EKCSRC6	0.0	5.1	6.3	0.00E+00	1.46E-01	1.82E-01
EKCSRC7	0.0	2.3	2.9	0.00E+00	6.72E-02	8.39E-02
EKCSRC8	22.6	2.4	3.0	6.51E-01	6.96E-02	8.53E-02
EKCSRC9	16.2	27.6	17.3	4.66E-01	7.94E-01	4.97E-01
EKCSRC10	9.4	2.5	3.1	2.69E-01	7.19E-02	8.98E-02
EKCSRC11	6.5	1.9	2.4	1.86E-01	5.43E-02	6.77E-02
EKCSRC12	6.4	5.3	6.6	1.84E-01	1.53E-01	1.91E-01
EKCSRC13	3.9	2.9	3.6	1.12E-01	8.26E-02	1.03E-01

EKCSRC14	3.9	16.8	10.7	1.11E-01	4.82E-01	3.08E-01
EKCSRC15	10.4	3.0	3.7	2.98E-01	8.61E-02	1.07E-01
EKCSRC16	5.8	2.9	3.6	1.67E-01	8.26E-02	1.03E-01
EKCSRC17	55.5	6.8	8.5	1.60E+00	1.96E-01	2.44E-01
NWHWSRC1	65.5	22.4	12.4	1.88E+00	6.46E-01	3.57E-01
NWHWSRC2	0.5	0.16	0.22	1.55E-02	4.63E-03	6.27E-03
TRRSRC1	0.4	0.32	0.32	1.08E-02	9.10E-03	9.10E-03
TRRSRC2	0.1	0.050	0.050	1.50E-03	1.44E-03	1.44E-03
TRRSRC3	6.2	3.3	3.3	1.77E-01	9.57E-02	9.57E-02
POLSRC1	0.0	3.9	1.6	0.00E+00	1.12E-01	4.48E-02
POLSRC2	0.0	2.1	1.0	0.00E+00	5.98E-02	2.99E-02
POLSRC3	0.0	3.4	1.6	0.00E+00	9.72E-02	4.48E-02
POLSRC4	0.0	19.7	11.4	0.00E+00	5.68E-01	3.29E-01
POLSRC5	0.0	9.1	4.4	0.00E+00	2.62E-01	1.26E-01
POLSRC6	0.0	3.4	1.6	0.00E+00	9.72E-02	4.48E-02
POLSRC7	0.0	0.5196	0.2598	0.00E+00	1.49E-02	7.47E-03
POLSRC8	0.0	0.052	0.052	0.00E+00	1.49E-03	1.49E-03
POLSRC9	0.0	0.052	0.052	0.00E+00	1.49E-03	1.49E-03
POLSRC10	0.0	0.052	0.052	0.00E+00	1.49E-03	1.49E-03
POLSRC11	0.0	0.052	0.052	0.00E+00	1.49E-03	1.49E-03
TEMSRC1	0.0	0.0360	0.0026	0.00E+00	1.03E-03	7.53E-05
TEMSRC2	0.0	0.0016	0.0004	0.00E+00	4.63E-05	1.29E-05
TEMSRC3	0.0	0.0087	0.0002	0.00E+00	2.49E-04	6.55E-06
TEMSRC4	0.0	0.0378	0.0378	0.00E+00	1.09E-03	1.09E-03
TEMSRC5	0.0	0.0016	0.0004	0.00E+00	4.63E-05	1.29E-05
RSGSRC1	0.0	28.9	28.9	0.00E+00	8.33E-01	8.33E-01
KSSRC1	452	13.0	219	6.3	219	6.3
KSSRC2	452	13.0	219	6.3	219	6.3
KSSRC3	591	17.0	394.2	11.3	394.2	11.3
KSSRC4	238	6.8	34	1.0	34	1.0

KSSRC5	248	7.1	35.6	1.0	35.6	1.0
KSSRC6	262	7.5	69	2.0	69	2.0
WHSRC1	0	0.0	3	0.073	3	0.073
WHSRC2	218	6.3	0	0	0	0.000
WHSRC3	1179	33.9	73	2.1	51	1.5
WHSRC4	0	0.0	46	1.3	46	1.3
WHSRC5	0	0.0	3	0.073	3	0.073
WHSRC6	0	0.0	18	0.51	18	0.51
WHSRC7	38	1.1	0	0.00	0	0
WHSRC9	83	2.4	0	0.00	0	0
WHSRC11	384	11.0	5	0.15	5	0.15
WHSRC12	3115	89.6	328	9.4	132	3.8
473	0.0	20.7	4.9	0.00E+00	5.95E-01	1.42E-01
2289	3.1	6.9	0.2	9.03E-02	1.98E-01	6.90E-03
2311	31.0	8.4	7.1	8.91E-01	2.42E-01	2.03E-01
1120	8.0	4.4	4.4	2.30E-01	1.27E-01	1.27E-01
2439	0.0	5.0	0.8	0.00E+00	1.43E-01	2.22E-02
156	3.5	2.9	2.3	9.92E-02	8.20E-02	6.47E-02
2292	0.0	53.6	9.0	0.00E+00	1.54E+00	2.59E-01
2337	14.6	3.4	2.2	4.19E-01	9.87E-02	6.24E-02
1391	0.2	1.9	0.7	5.38E-03	5.44E-02	2.09E-02
2330	5.3	0.4	0.4	1.52E-01	1.24E-02	1.21E-02
933	2.8	5.3	0.3	8.11E-02	1.51E-01	7.48E-03
1230	0.0	12.0	12.0	0.00E+00	3.45E-01	3.45E-01
1246	3.4	4.2	4.2	9.75E-02	1.21E-01	1.21E-01
238	0.0	24.2	12.4	0.00E+00	6.95E-01	3.57E-01
838	0.2	7.7	7.7	4.60E-03	2.20E-01	2.20E-01
2368	4.1	0.1	0.1	1.19E-01	1.81E-03	1.81E-03
770	0.0	16.3	3.8	0.00E+00	4.69E-01	1.08E-01
129	3.6	0.27	0.27	1.03E-01	7.77E-03	7.77E-03

1036	0.1	2.2	2.2	2.01E-03	6.44E-02	6.44E-02
348	1.0	7.5	0.5	2.88E-02	2.16E-01	1.44E-02
1905	0.0	2.5	2.5	0.00E+00	7.19E-02	7.19E-02
1792	3.8	0.15	0.15	1.10E-01	4.32E-03	4.32E-03
914	14.6	1.4	1.3	4.20E-01	3.91E-02	3.83E-02
575	18.1	1.7	1.7	5.21E-01	4.97E-02	4.97E-02
1024	5.3	0.4	0.4	1.52E-01	1.06E-02	1.06E-02
678	7.1	0.3	0.3	2.04E-01	8.63E-03	8.63E-03
635	21.2	3.1	3.1	6.11E-01	8.92E-02	8.92E-02
632	14.3	1.8	1.8	4.11E-01	5.26E-02	5.26E-02
1557	0.0	7.9	7.9	0.00E+00	2.28E-01	2.28E-01
1225	23.6	1.7	1.7	6.78E-01	4.78E-02	4.78E-02
2236	2.5	1.2	0.3	7.19E-02	3.51E-02	7.19E-03
2279	6.5	20.4	16.2	1.87E-01	5.86E-01	4.66E-01
2274	14.0	1.9	0.5	4.03E-01	5.35E-02	1.35E-02
1901	7.3	1.9	1.9	2.11E-01	5.35E-02	5.35E-02
1327	6.1	1.4	1.2	1.76E-01	4.06E-02	3.45E-02
2242	0.9	3.3	3.2	2.56E-02	9.35E-02	9.12E-02
1886	1.9	2.4	0.1	5.32E-02	6.82E-02	3.28E-03
2245	1.6	2.6	1.4	4.52E-02	7.39E-02	3.88E-02
1977	0.5	5.5	5.5	1.44E-02	1.59E-01	1.59E-01
2066	0.0	3.5	3.5	0.00E+00	1.01E-01	1.01E-01
498	0.6	7.9	4.3	1.73E-02	2.28E-01	1.24E-01
1286	5.0	1.1	0.4	1.44E-01	3.11E-02	1.09E-02
1175	1.8	27.4	27.4	5.09E-02	7.89E-01	7.89E-01
1928	1.0	4.0	4.0	2.88E-02	1.15E-01	1.15E-01
1079	6.8	0.54	0.54	1.95E-01	1.55E-02	1.55E-02
1080	3.3	0.02	0.18	9.38E-02	5.18E-04	5.18E-03
2425	12.2	0.19	0.19	3.52E-01	5.47E-03	5.47E-03