



DEPARTMENT OF
ECOLOGY
State of Washington

Technical Support Document for Prevention of Significant Deterioration (PSD) Permit 10-01

**BP Cherry Point Refinery
Clean Fuels Project
Blaine, Washington**

October 28, 2010

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1. EXECUTIVE SUMMARY

To meet upcoming federal mobile source fuel specifications for diesel and gasoline, the BP Cherry Point Refinery (BP) proposes to add a new hydrogen production unit, a new diesel hydro-desulfurization unit, and to retrofit an ultra-low NO_x burner (ULNB) into the largest of their existing Hydrocracker heaters. The project will reduce the sulfur content of diesel fuel currently sold for off-road diesel-fueled engines, which will reduce both sulfur dioxide (SO₂) emissions and diesel particulate matter due to sulfate emitted by these engines. The project will also reduce benzene emissions from gasoline fuel. The project will not provide an increase in total refinery fuel production capacity. The project is referred to as the Clean Fuels Project.

The new hydrogen plant will provide 40 million standard cubic foot per day (MMSCFPD) synthesized hydrogen production facility, which will provide additional diesel hydrotreating capacity to 25,000 barrels per day of existing diesel fuel production. Removing sulfur from this fuel that will be sold in Washington will avoid an estimated 3,200 to 9,600 tons per year of SO₂ and about 100 tons of sulfate particulate emissions from the state airsheds when estimated at current fuel consumption rates.

BP is also proposing to retrofit the existing 1st Stage Fractionator Reboiler (one of four heaters at the Hydrocracker) with ULNBs. These new burners will reduce NO_x and CO from the Hydrocracker, even with an expected increase in its utilization. As a result, the Clean Fuels Project will reduce annual refinery emissions of oxides of nitrogen (NO_x).

The Washington State Department of Ecology's (Ecology) review of BP's applicability analysis of the Clean Fuels Project indicates that no air pollutants are subject to federal PSD requirements. The review does indicate that due to the different treatment of condensable particulates, the project is subject to PSD permitting under the state PSD requirements for PM₁₀ emissions. No other regulated pollutant is PSD-applicable under either set of PSD regulations. Ecology will prepare a draft PSD permit that addresses the PM₁₀ for the project. The Northwest Clean Air Agency (NWCAA) will address all other air pollutant emissions through their Notice of Construction permit.

Ecology finds that BP has satisfied all requirements for approval of the proposed PSD permit for the Clean Fuels Project and now sends the proposed permit for public comment.

2. INTRODUCTION

2.1. The PSD Process

The Prevention of Significant Deterioration (PSD) procedure is established in Title 40, Code of Federal Regulations (CFR), Part 52.21 and in Washington Administrative Code 173-400-700. Federal rules require PSD review of all new or modified air pollution sources that meet certain overall size and pollution rate criteria. The objective of the PSD program is to prevent serious adverse environmental impact from emissions into the atmosphere by a proposed new or modified source. PSD rules require that an applicant use the most effective air pollution control equipment and procedures after considering environmental, economic, and energy factors. The program sets up a mechanism for evaluating and controlling air emissions from a proposed source to minimize the impacts on air quality, visibility, soils, and vegetation.

The United States Environmental Protection Agency (EPA) delegated the authority to implement the PSD program described in Title 40 CFR. 52.21 and its supporting guidance and procedures documents to the Engineering Unit staff¹ of Ecology's Air Quality Program.²

The current Federal PSD regulations (40 CFR 52.21(b)(50)(vi)) include a temporary exemption from considering condensable emissions particulate when calculating PSD applicability for PM, PM₁₀, and PM_{2.5}. This exemption is set to expire on January 1, 2011.

Ecology's PSD regulation incorporates an earlier version of the federal program (as in effect October 1, 2006) that does not include the exemption for condensable particulate material when making applicability determinations. As a result, condensable particulates continue to be included in PSD applicability determinations under the state PSD regulation.

A September 28, 2008, letter from EPA to Ecology addresses the changes to 52.21 adopted by EPA on July 15, 2008. One item in this rule amendment was to insert the temporary exemption for condensable particulate matter for PSD applicability determinations. The letter amendment recognizes the Ecology version of the PSD regulation, but does not include the July 2008 rule change. This confirms that PM_{2.5} is not a PSD pollutant regulated under current Washington PSD regulations, only under the federal PSD regulation.

2.2. The Project

2.2.1. The Site

BP operates a refinery at Cherry Point in Whatcom County, Washington. The refinery is located in a rural setting near Blaine and Birch Bay, Washington. The surrounding land use is zoned heavy impact industrial and is mostly vacant. Historical uses were agricultural (dairy farming). Immediately to the west is the Puget Sound Energy's Whitehorn gas-turbine power generating station. About two miles west northwest of the refinery is Birch Bay State Park. UTM coordinates are Zone 10 519600E and 5414800N.

2.2.2. The Proposal

The two primary components of the Clean Fuels Project are a new diesel hydrotreater to provide additional sulfur removal capacity for 25,000 barrels per day (BPD) from the current diesel fuel production, and a 40 million standard cubic feet per day (MMSCFPD) synthesized hydrogen plant.

The project also includes retrofitting the 1st Stage Fractionator Reboiler (one of the four Hydrocracker heaters) with ULNBs, piping changes at the existing diesel blending skid, wastewater treatment plant upgrades, and extensive tie-ins to existing refinery utility systems

¹ An organizational unit in the Science and Engineering Section.

² Agreement for the Delegation of the Federal Prevention of Significant Deterioration (PSD) Regulations by the United States Environmental Protection Agency, Region 10 to the State of Washington Department of Ecology (February 23, 2005).

New Diesel Hydro-Desulfurization Unit #3

The new diesel hydrotreater, referred to as #3 diesel hydro-desulfurization unit (or #3 DHDS), will produce 25,000 BPD of ultra-low sulfur distillate. The purpose of this unit is to remove additional sulfur from currently produced diesel fuel to meet the new 15 ppm non-road diesel sulfur specification.

Hydrotreating is the process where hydrocarbons containing sulfur, nitrogen and metals are purified by catalytic reaction in a hydrogen rich atmosphere. Sulfur compounds are catalytically converted to hydrogen sulfide and nitrogen compounds are catalytically converted to ammonia.

The basic process steps of the unit are feed preheating, reaction, separation, stripping, drying, and compression. The new unit would be configured to accept straight run and cracked feedstocks. New tie-ins to the Crude Unit and Coker would be constructed to facilitate the transfer of hot feeds.

The ability to direct any of these feedstocks to any of the diesel hydrotreaters is planned as a means to facilitate periodic turnarounds of individual units. The ability to process a variety of cold feeds from tankage would also be constructed. Aside from component leaks, the only source of emissions associated with #3 DHDS is a 28 million British thermal units per hour (MMBtu/hr) Charge Heater. The Charge Heater will be equipped with ULNBs to control emissions of NO_x. The burner pilots would be fired with natural gas and the heater would combust refinery fuel gas from the existing refinery mix drum.

Although the Charge Heater will be designed with a maximum heat input of 28 MMBtu/hr, this firing rate will only be required during startup because hydro-desulfurization is exothermic. BP anticipates the typical firing rate of this heater will be substantially lower, approximately 12 MMBtu/hour. At lower operating rates, mass emissions are lower but pollutant concentrations may be higher.

New Hydrogen Plant #2

Removal of additional sulfur to meet the ULSD fuel specification requires additional hydrogen. Hydrogen is also required to convert benzene into less harmful gasoline blending components.

Cherry Point Refinery currently generates hydrogen by two methods: steam-methane reforming is used in the existing Hydrogen Unit (#1 Hydrogen); and catalytic reforming is used in the two existing semi-regenerative reformers.

BP is proposing to construct and operate a new plant (#2 Hydrogen) consisting of a steam methane reformer (SMR) with pressure swing adsorption purification (PSA) system. PSA technology is more efficient than the existing hydrogen plant's method of purification and will produce higher purity hydrogen than the existing plant. Feedstocks will include natural gas and certain high hydrogen content refinery off gas streams. The proposed SMR would synthesize 40 MMSCFD of hydrogen from natural gas and would purify an additional 4 MMSCFD of hydrogen from refinery off gas streams (ROG).

The new Hydrogen Plant will consist of feed knock out pots, feed conditioning reactors, a product compressor, a furnace, a hot shift reactor, PSA vessels, purge gas vessel, steam production equipment, motor control center, pipe racks and ancillary equipment. The unit would be equipped with an elevated flare that would combust minute quantities of volatile compounds during normal operation but would be sized to accommodate much higher volumes during startup, shutdown and malfunction events.

SMRs produce hydrogen by reacting superheated steam with a source of light hydrocarbons in the presence of a nickel catalyst where most of the hydrocarbon is converted to CO₂ and H₂. Carbon monoxide (CO) is produced as a reaction byproduct. CO and H₂O are converted to CO₂ and H₂ in the hot shift reactor, which contains a catalyst.

The hydrogen is then purified by separating it from the other gases in the PSA vessels; these vessels contain an adsorbent that collects all gases except hydrogen, which passes through. Periodically, the gases collected on the adsorbent are removed. This material is known as PSA residue and is burned as fuel in the SMR furnace. The high purity hydrogen exiting the PSA vessels is then compressed and distributed for use within the refinery.

Sulfur is harmful to the catalyst used to synthesize hydrogen. To prevent catalyst degradation, the unit will be equipped with chloride and sulfur guard beds. The chloride guard bed would contain activated alumina. The sulfur guard beds would contain a catalyst where sulfur species would be converted to hydrogen sulfide (H₂S) and zinc oxide (ZnO) beds, which would adsorb the H₂S. The unit would be equipped with a ZnO bed. The guard bed will reduce the sulfur content of the natural gas feed to the SMR to less than one tenth of one part per million by volume. As a result, the PSA residue used as fuel will have extremely low sulfur content.

The SMR furnace would be top-fired, downward-flow and co-current configuration. It would have a heat input capacity of 430 MMBtu/hour (HHV) during normal operations and a maximum heat input capacity of 496 MMBtu/hour. The furnace would be fired by pipeline grade natural gas and PSA residue. Approximately, 90% of the heat input to the furnace would be from PSA residue and 10% from natural gas. Refinery fuel gas from the existing fuel gas mix drum would not be used.³ The majority of sulfur emissions would be because of natural gas combustion.

The furnace will be equipped with ULNBs and a selective catalytic reduction unit (SCR) with aqueous ammonia injection system will be used to control NO_x emissions from the SMR furnace. Ammonia for the SCR would be supplied from the existing aqueous ammonia storage tank that serves #6 and #7 Boilers.

The new Hydrogen Plant would produce steam to support the reforming reaction and for export for use elsewhere in the refinery. Approximately 140 KPPH (thousand pounds per hour) of steam would be exported to the refinery. Thus, the Clean Fuels Project would be a net producer of steam and would reduce utilization of the refinery's existing steam generating units. However, no emission netting credit is taken for emission reductions from the boilers.

³ PSA reject gas or "residue" would be regulated as "refinery fuel gas" under NSPS Subpart Ja. A SO₂ CEMS could also be installed on the stack to demonstrate compliance.

A new flare would continuously combust small flows (anticipated to be approximately 4,600 scf/hr) but would be designed for higher flows associated with startup, shutdown and malfunction events. The flare would be of an elevated torch configuration attached to the stack of the SMR furnace. Only the new hydrogen plant would be served by the new flare. The primary function of the flare is to combust off-spec hydrogen during startup.

The flare will have uninterruptible natural gas to operate the pilot burners. Flaring will be minimized to the extent practicable and will include nitrogen purges from compressor seals and compressor distance piece vents and natural gas sweep gas to maintain the collection header free of oxygen.

Hydrocracker Burner Retrofit

As part of the Clean Fuels Project, BP proposes to retrofit ULNBs in the 1st Stage Fractionator Reboiler. The Reboiler is one of four heaters associated with the Hydrocracker Unit, and is the heater with the highest rated firing capacity. As a result of the retrofit, potential NO_x and CO emissions from the Reboiler would decrease by approximately 80 and 40 percent, respectively.

2.2.3. Project Effects on Existing Units

The following subsections identify how the Clean Fuels Project affects operation of and emissions from existing refinery emission units. This step is necessary because increases in emissions from existing units attributable to a project must be considered when evaluating PSD applicability.

Compared with existing sources of hydrogen, the new hydrogen plant will cost less to operate and use less energy per unit of production, and provide a product of higher purity. Given these economic incentives, the new plant would be used preferentially over the existing hydrogen-producing units. The distribution of the higher purity material would be through new dedicated piping.

Hydrocracker

The Hydrocracker converts gas oils from the coker and vacuum section of the crude unit to jet fuel and gasoline blending stocks. The unit is comprised of two reaction stages and two fractionation stages. Reaction stages change the molecular structure of the feed. Fractionation stages use distillation to separate the material that is converted by the reactors. The unit contains four heaters, one for each stage. All heaters are fired by refinery fuel gas. As part of the proposed Clean Fuels Project, BP will retrofit the existing 1st Stage Fractionator Reboiler with ULNBs, which will significantly reduce potential NO_x and CO emissions from the existing heater.

From a regulatory perspective, the availability of additional hydrogen from #2 Hydrogen will debottleneck the Hydrocracker because it will alleviate existing hydrogen shortages resulting from production dips from Reformer regeneration events and the gradual reduction in Reformer hydrogen production over its turnaround cycle. The net effect will be increases in annual firing

and emissions from the Hydrocracker's four RFG-fired heaters. There would be no increase in the potential hourly emissions from any of the heaters because they currently fire at capacity under certain operating conditions and because the heaters will not be modified. Because the 1st Stage Fractionator Reboiler will be retrofitted with ULNBs, BP expects potential hourly and annual NO_x and CO emission rates to decrease compared to the existing conventional burners; emissions of other pollutants would not change.

Reformers

The purpose of the Catalytic Reforming Units (CRU or Reformers) is to convert low octane naphtha range feedstocks into a stabilized high octane gasoline blending stock. The octane number of the feed is increased by passing it over a platinum-rhenium catalyst at high temperatures in a hydrogen-rich atmosphere. Reforming consists of four primary chemical reactions: cyclization, dehydrogenation, isomerization, and cracking. Cyclization and dehydrogenation are the dominant reactions making the overall process endothermic. These two reactions result in the production of a hydrogen rich byproduct stream, which is compressed and distributed throughout the refinery on the 460# hydrogen header for use in various other process units. The Hydrocracker consumes the vast majority of the 460# hydrogen.

The Reformers are of semi-regenerative configuration meaning that they are taken out of service periodically for catalyst regeneration. The volume of hydrogen produced declines throughout the production cycle. As a result, the production rate of the Hydrocracker is limited by the Reformers ability to provide hydrogen.

The proposed hydrogen plant would be used to remedy the end of run hydrogen shortage at the Hydrocracker by providing a new continuous supply of high purity hydrogen. The resulting operational severity of the Reformers would be reduced, resulting in substantial emissions reductions from the heaters and High Pressure Flare. Although emissions will decrease, there is no modification to the reformers and no PSD netting credit is requested

Isomerization Unit

The Isomerization Unit #45 (ISOM) processes light naphtha feed stocks to produce a gasoline blending component that has essentially no benzene, olefins, or sulfur and is higher in octane than its feed. It does this by isomerizing low octane C5 paraffins to their higher octane isomers and by saturating gasoline component streams containing higher benzene concentrations in the BenSat section.

In 2011, the allowable benzene content in gasoline will be reduced to 0.62% volume on a company-wide annual average basis. To meet the tighter benzene standard, a portion of hydrogen generated by the #2 Hydrogen Plant will be directed to ISOM (see Figure 2-8). The availability of additional hydrogen will enable BP to produce gasoline that meets the new benzene standard.

Emissions from the ISOM unit occur as a result of combustion of refinery fuel gas in its heater and from component leaks. No increase in emissions from component leaks is expected as a

result of the Clean Fuels Project. Benzene saturation is an exothermic reaction, which occurs downstream from the IHT Heater. As a result, no increase in firing of the IHT charge heater will be necessary.

Diesel Units

BP currently operates two diesel hydrotreaters. The #1 diesel unit (#1DHDS, Unit #13) has a small reactor and its design is not suitable for producing ultra-low sulfur products from a wide range of feedstocks. #1DHDS currently produces high sulfur diesel (500-5,000 ppm wt %) from straight run and cracked feedstocks.

In order for the small reactor to hydrotreat the incoming feedstock to the 15 ppm S level, the feed rate must be reduced with the remaining volume filled with recycled ULSD from #2DHDS or #3DHDS. The ULSD recycle stream is necessary to control reactor temperatures since the process is exothermic. New lines from #2DHDS and #3DHDS would be installed to deliver finished ULSD to be used as recycle feed to #1DHDS.

#1DHDS unit is currently capable of operating in this manner but the ULSD recycle feed is pumped from tankage. No changes are proposed for #1DHDS, so no emissions increases or decreases from operation of #1DHDS are included with the overall project emissions inventory.

The #2 diesel unit commenced operation in 2006. It was designed to meet the EPA ultra-low diesel specification now in place for on-road vehicles. No changes in operation of #2DHDS are planned, so no emission increases or decreases from operation of #2DHDS are included in the emission inventory

Sulfur Recovery Unit and Lean & Rich Amine Systems

Existing unused capacity within the amine regeneration unit will be used to recover the additional sulfur from #3DHDS. The two new scrubbers in #3DHDS would be connected to these existing units.

The scope of work within the amine regeneration unit includes minor re-piping around the amine filter system, and tie-ins from the new diesel unit to both the amine and sour water headers. No other capital investment in the amine regeneration unit is planned as part of the proposed Clean Fuels Project. There are no emissions from the amine regeneration unit.

The Sulfur Recovery Unit has the capacity to accommodate the additional sour gas load. The current production of elemental sulfur will increase by up to 15 long tons per day. No physical or operational changes to the Sulfur Recovery Unit are required. No changes in existing permit conditions are required. **Increases in annual emissions from the Sulfur Recovery Unit are considered in the PSD applicability and ambient impact analyses.**

Sour Water Unit

Existing unused capacity within the sour water unit will be used to strip the H₂S and NH₃ from the sour water generated by #3DHDS. The existing sulfur recovery unit will be used to recover the additional sulfur. The new sources of sour water include the feed surge drum, cold high pressure separator, stripper overhead drum and vacuum dryer separator drum. The additional sour water would be directed to the sour water unit for stripping.

A separate project, called the Sour Water Handling Upgrade Project (SWHU), was permitted and approved by the NWCAA in May 2009. Construction is ongoing. Although that project had independent utility, the upgrade provided capacity needed to accommodate #3DHDS. **The contemporaneous emission increases are included with the Clean Fuels Project PSD applicability determination and ambient impact analysis.**

The extent of changes affecting the sour water unit is limited to tie-ins to the sour water header from the new diesel hydrotreater. No other capital investment is planned as part of the proposed Clean Fuels Project. As stated previously, no increase in allowable emissions from the sulfur plant will be requested. The sulfur recovery complex will continue to be operated within existing permitted emission limits.

Flare Gas Recovery Unit

Several new flare connections would be made from #3DHDS into the existing High Pressure Flare. Examples of the types of connections include, but are not limited to, pump seals, compressor seals, compressor distance piece vents, instrument purges and sweep gas used to keep the flare header free of oxygen. Although the flare header is used as a means of collecting the gases, both flare headers are equipped with flare gas recovery compressors. During normal operation, the collected gases are treated for H₂S in a shared amine absorber and routed to the refinery fuel gas. The flare gas recovery system has excess capacity to handle all normal operation flows from #3 DHDS. The Clean Fuels Project would not result in any increases in routine flaring of the High Pressure Flare. However, #3 DHDS would be depressurized to the High Pressure Flare in preparation for turnarounds. Emissions from planned startup and shutdown events are included in the emission inventory.

High Pressure Flare

#3DHDS would be connected to the existing high pressure flare system. Any new or modified flare would be subject to New Source Performance Standard Subpart Ja.

It is anticipated that applicability of Subpart Ja for the existing flares would be triggered prior to construction of the Clean Fuels Project and the existing flares would be brought into compliance with emission standards, monitoring, recordkeeping, and reporting requirements under a separate capital project that would be completed prior to startup of the Clean Fuels Project. As of this writing, the flare provisions are not yet finalized. Note, however, that the flare project would reduce (not increase) emissions so it is not necessary to consider whether the flare project should be aggregated with the Clean Fuels Project.

Steam

The refinery has different steam distribution networks named for the various delivery pressures. The #3DHDS would consume 6,000 lb/hour of high-pressure steam for the stripper and 2,600 lb/hour of lower pressure steam for the lean amine heater. The proposed hydrogen plant would produce enough steam to support the steam-methane reforming reactions that produce hydrogen as well as export 140,000 lb/hour of steam onto the refinery distribution header. As a result, the existing boilers would be used less, resulting in an emissions reduction. No netting credit is requested.

2.3. PSD Applicability and Air Pollutant Emissions

BP is an existing major source⁴ of a regulated pollutant.⁵ The facility has several existing PSD permits for refinery processes and equipment. It has minor new source review permits and a Title V air permit issued by the Northwest Clean Air Agency (NWCAA).

A project is a major modification for a federal PSD regulated NSR pollutant at an existing source if it causes two types of emissions increases: (1) a significant emissions increase, and (2) a significant net emissions increase.⁶ The first step includes emissions increases due to new equipment, and any emissions increases in other refinery operations due to the project. The second step applies to regulated pollutants that are found to be significant from the first step. This step considers any emissions decreases due to the project, and any contemporaneous increases and decreases at the refinery during the previous 5-year contemporaneous period. Additions and modifications to the refinery that increase a pollutant's emissions more than the second step's PSD Significant Net Emission Rate (SER) are considered "major modifications" and are subject to the PSD permitting process.

Two PSD programs operate concurrently in Washington State. A state PSD program is defined in the state regulation WAC 173-400-700 to 750. The Federal PSD program is implemented by the Washington State Department of Ecology's Air Quality Program under a delegation agreement dated February 23, 2005, which authorizes implementation of PSD regulations in 52.21 as of July 1, 2004 (with several restrictions). Authority for federal PSD regulatory requirements newer than that date is achieved by EPA cosigning each PSD permit.

⁴ Petroleum Refineries are a major source under PSD regulations if they, in total, have the potential to emit more than 100 tons per year of a pollutant regulated by the PSD permitting program. WAC 173-400-720(4)(a)(v) and 40 CFR 52.21(b)(1)(i)(a).

⁵ The PSD program directly regulates a list of specific pollutants listed in 40 CFR 52.21(b)(23). These are referred to as "regulated pollutants." PSD regulates other pollutants indirectly through the broad categories of "regulated" pollutants such as VOC and particulates. In Washington State, the local air authority issues its own permit that complements the PSD permit and includes all emissions regulated by state and local regulations. WAC 173-400-113.

⁶ 40 CFR 52.21(a)(2)(iv)

Determination of PSD Applicable Pollutants

The proposed Clean Fuels Project will result in addition of two new process units, retrofitting one Hydrocracker heater with ULNBs, and affect the utilization of seven existing process units at the Cherry Point Refinery. This section summarizes the emission rate increases attributable to the proposed project including potential emission rates for the new emission units and annual emission rate increases for existing emission units. It also describes potential emissions decreases due to the project, and contemporaneous increases and decreases in five other projects that occurred during the 5 year contemporaneous period. More detailed calculation of these emission increases and decreases are included in Appendix A.

This analysis fulfills the requirements of the two-step PSD applicability determination procedure referenced above. Table 1 lists the emissions increases due to the new equipment and increased utilization of existing refinery processes. Table 2 lists the decreases due to the project and the contemporaneous increases and decreases.

Table 1. Regulated Pollutant Emission Increase for Clean Fuels Project

	#2 H2 Plant SMR ^a	#2 H2 Plant Flare ^a	#3DHDS Charge Heater ^a	Component Fugitives ^a	Sulfur Recovery Plant ^b	HC R-1 Heater ^b	HC R-4 Heater ^b	HC 1 st Stage Frac. Rblr. ^c	HC 2 nd Stage Frac. Rblr. ^b	#2 Cool. Tower ^b	WWT P ^b	HP Flare ^b	Total Emission Increase	PSD SER ^d
Pollutant	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)
NO _x	15.5	2.5	4.3	--	2.4	0.1	12.6	0	23.4	--	--	0.01	61	40
CO	18.9	6.5	4.5	1.3	9.3	10.8	3.9	16.7	4.6	--	--	0.1	77	100
SO ₂	6.3	0.081	3.2	--	4.6	5.4	2.5	10.8	3.0	--	--	0.4	36	40
PM (filterable)	5.4	0.09	0.3	--	0.03	0.5	0.2	1.0	0.3	0.7	--	3.8E-04	9	25
PM ₁₀ (filterable)	5.4	0.09	0.3	--	0.03	0.5	0.2	1.0	0.3	0.7	--	3.8E-04	9	15
PM ₁₀ (total)	21.7	0.37	1.2	--	0.13	2.1	1.0	4.2	1.2	0.1	--	1.5E-03	32	15
PM _{2.5} (filterable) ^e	5.4	0.09	0.3	--	0.03	0.5	0.2	1.0	0.3	0.0009	--	3.8E-04	8	10
VOC	11.7	3.8	0.7	2.4	0.07	1.1	0.5	2.3	0.6	1.24	10.5	0.02	35	40
Pb	1.1E-03	1.8E-05	6.0E-05	--	6.6E-06	1.0E-04	4.8E-05	2.1E-04	5.7E-05	--	--	7.5E-08	1.6E-03	0.6
H ₂ SO ₄	0.3	0.0033	0.1	--	0.2	0.2	0.1	0.5	0.1	--	--	0.02	1.5	7
Fluorides	--	--	--	--	--	--	--	--	--	--	--	--	negligible	3
H ₂ S	--	--	--	--	--	--	--	--	--	--	--	--	negligible	10
TRS	--	--	--	--	--	--	--	--	--	--	--	--	negligible	10
Reduced Sulfur Compounds	--	--	--	--	--	--	--	--	--	--	--	--	negligible	10
Municipal Waste Comb. – Organics	--	--	--	--	--	--	--	--	--	--	--	--	0	3.5E-6
Municipal Waste Comb. – Metals	--	--	--	--	--	--	--	--	--	--	--	--	0	15
Municipal Waste Comb. – Acid Gases	--	--	--	--	--	--	--	--	--	--	--	--	0	40
Municipal Solid Waste Landfill – NMOC Emissions	--	--	--	--	--	--	--	--	--	--	--	--	0	50

Notes:

- a. New emission unit (Potential Annual Emission Rates).
- b. Increased utilization and debottlenecking of existing emission units (Projected Actual Emissions minus Baseline Actual Emission Rates).
- c. Projected actual NO_x emissions (after Clean Fuels Project completion) for the 1st Stage Fractionator Reboiler are estimated to be 43.3 tpy and baseline actual NO_x emissions are 131.1 tpy (2003 – 2004 annual average), which results in a projected decrease in emissions (87.7 tpy NO_x reduction, PAE – BAE). However, no decrease was taken into account in Step 1 of the PSD Applicability Calculation (Project Emission Increase). Step 2 of the PSD Applicability Calculation incorporates the NO_x reduction associated with the 1st Stage Fractionator Reboiler ULNB retrofit.
- d. Prevention of Significant Deterioration (PSD) Significant Emission Rates 40 CFR 52.21(b)(23).
- e. Current federal PSD regulations defer the inclusion of condensable particulate matter until the end of a transition period ending January 1, 2011 (40 CFR 52.21(b)(50)(vi)).

Table 2. Clean Fuels Project PSD—NO_x and PM₁₀ Netting Analysis

	Clean Fuels Project ^a	1 st Stage Frac. Reboiler ULNB Retrofit ^b	R1 Heater Project ^c	Sour Water Upgrade Project ^d	#6 & #7 Boilers Project ^e	#1 Reformer Recycle Gas Dryer Project ^f	#2 TGU Project ^g	#2 DHDS Project ^h			Significant?
Startup	--	Concurrent with Clean Fuels Project	Projected 2010	2010	March 2009	May 2007	June 2006	May 2006	Net Increase	PSD SER ⁱ	
Pollutant	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)	(TPY)	
NO _x	61	-87.7	5.4	--	34.4	4.0	11.0	6.1	34	40	No
PM ₁₀ (total)	32	--	0.0	0.1	--	--	--	--	32	15	Yes

Notes:

- a. Proposed Clean Fuels Project (See Table 1 for summary of emissions increases).
- b. Proposed Clean Fuels Project includes the ULNB retrofit of the 1st Stage Fractionator Reboiler (See Appendix B for summary of Hydrocracker emission calculations).
- c. NO_x emission increase for R1 Heater Project is based on NO_x PTE for the R1 Heater (4.6 lb/hr and 8,760 hr/yr) and baseline actual emissions for the heater. Part of the NO_x emission increase and all of the PM₁₀ emission increase for the R1 Heater has already been accounted for in Step 1 of the PSD applicability calculations (Project Emission Increases) for the Clean Fuels Project. Therefore, portions of the R1 Heater Project emission increases are not double counted in Step 2 of the PSD applicability calculations (PSD netting analysis).
- d. PM₁₀ emission increase from Sour Water Upgrade Project is based on increased utilization of Sulfur Recovery Plant (Tail Gas Units 1 and 2). Increased steam utilization for project is not included because Boilers 5, 6 and 7 went through PSD review for PM₁₀ and received PSD permits. No NO_x emissions are incorporated because NO_x PTE is presented in the #6 & #7 Boilers Project and Boiler 5 went through PSD review for NO_x and received a PSD permit. NO_x PTE is already included in the #2 TGU project. NWCAA issued OAC #1043 (Sour Water Upgrade Project) on May 29, 2009.
- e. NO_x emissions based on Two Boilers NOC/PSD permit application (dated May 2007), Boilers 6 and 7 went through PSD review for PM₁₀ and received a PSD permit (PSD 07-01, Amendment 1).
- f. NO_x emissions based on revised #1 Reformer Recycle Gas Dryer NOC permit application (dated December 2006). PM₁₀ emissions were included in the Boilers 6 and 7 PSD review.
- g. NO_x emissions based on Second Tail Gas Unit NOC application (dated July 22, 2004). PM₁₀ emissions were included in the Boilers 6 and 7 PSD review.
- h. NO_x emissions based on #2 DHDS NOC application (dated December 2006). PM₁₀ emissions were included in the Boilers 6 and 7 PSD review. NO_x emissions attributable to Boiler 5 were not included because Boilers 5 went through PSD Review for NO_x and received a PSD Permit. PM₁₀ emissions attributable to Boiler 5 were not included because Boilers 5 PM₁₀ emissions were included in Boilers 6 and 7 PSD review.
- i. Prevention of Significant Deterioration (PSD) Significant Emission Rates 40 CFR 52.21(b)(23).

See Appendix B for more emissions calculation details for the new units and increased utilization/debottlenecking emissions.

The PSD applicability analysis summarized in Tables 1 and 2 shows that total PM_{10} (including condensables) is the only PSD regulated pollutant from the Clean Fuels Project with a significant net emission rate (i.e., that exceeds its PSD SER). Since all particulates from the project are from combustion of gaseous fuels, the total PM_{10} emission rate represents the emission rate of $PM_{2.5}$ and PM also. The emission rate of the filterable only portion of particulate does not exceed the SILs for $PM_{2.5}$, PM_{10} , or PM. This is an important point for PSD applicability for this project because condensable particulate is currently excluded from the federal PSD definition of particulates.⁷

The current federal definition of PM_{10} is given in 40 CFR 52.21(b)(50)(vi):

Particulate matter (PM) emissions, $PM_{2.5}$ emissions and PM_{10} emissions shall include gaseous emissions from a source or activity which condense to form particulate matter at ambient temperatures. On or after January 1, 2011 (or any earlier date established in the upcoming rulemaking codifying test methods), such condensable particulate matter shall be accounted for in applicability determinations and in establishing emissions limitations for PM, $PM_{2.5}$ and PM_{10} in PSD permits. Compliance with emissions limitations for PM, $PM_{2.5}$ and PM_{10} issued prior to this date shall not be based on condensable particular matter unless required by the terms and conditions of the permit or the applicable implementation plan. Applicability determinations made prior to this date without accounting for condensable particular matter shall not be considered in violation of this section unless the applicable implementation plan required condensable particular matter to be included.

Since this project is being newly permitted, there is no existing permit to require consideration of condensable particulates. Ecology does not have an “applicable implementation plan” that requires condensable particulate material to be included. The plain reading of wording of this regulation says that federal PSD applicability determinations made prior to the January 1, 2011 date shall not be based on inclusion of particulate condensables.

Washington State regulations include a state PSD program as stated above. Washington implements its PSD program using the definitions in 40 CFR 52.21 as of October 1, 2006. At this date, the applicable federal definition of PM_{10} adopted by reference into Washington State regulations included condensables, so that definition is currently implemented for the state PSD program. $PM_{2.5}$ was not included at that time. After review of the applicability analysis proposed by BP, Ecology agrees with the BP analysis and proposal that under Washington State PSD regulations, a state only PSD permit for PM_{10} is required for the BP Clean Fuels Project, and under current federal PSD regulations, no federal PSD permit is required.

Particulate Matter (PM/ PM_{10}) Emissions

PM_{10} emissions were estimated using an emission factor that was based on the results of recent BP stack testing for PM_{10} on similar on site boilers and heaters burning the refinery gas fuel. The emission factor is 0.0100 lb of total particulate (filterable plus condensable) per million Btu

⁷ See 40 CFR 52.21(b)(50)(vi).

of refinery gas fuel combusted (0.0100 lb/MMBtu). Particulate emissions from the #2 Hydrogen plant SMR Furnace and Flare, and the #3 DHDS are shown in Tables 3 and 4.

Table 3. #2 Hydrogen Plant—Design Basis and Monitoring Methods

Pollutant	BACT, NSPS or MACT - Basis for Limits	Short-Term Limit	Long-Term Limit	Compliance Method
SMR Furnace				
PM ₁₀	Fuel selection & combustion controls Source testing @ Cherry Point Design Basis: 0.01 lb/MMBtu HHV	Limit: 4.96 lb/hr calendar day average	None	EPA Method 5 - front half (filterables) EPA Method 202 - back half (condensables)
Firing Rate	SMR design basis Surrogate for pollutant w/o CEMS & missing data periods Evaluated all modes of operation	496 MMBtu/hr HHV 30-day average	--	Fuel flow F-factor calculation
Flare				
NO _x , CO, PM, VOC	Design to NSPS & MACT specifications. Use of natural gas as pilot fuel & header sweep gas. Good combustion practice, proper design, operation and maintenance.	--	--	Initial demo based on relief calculations and design basis. Ongoing demo based on flows & composition of flaring events using EPA emission factors & periodic sampling.

Table 4. #3 DHDS—Design Basis and Monitoring Methods

Pollutant	BACT, NSPS or MACT - Basis for Limits	Short-Term Limit	Long-Term Limit	Compliance Method
PM ₁₀	Fuel selection & combustion controls	Limit: 0.28 lb/hr calendar day average	None	EPA Method 5 - front half (filterables) EPA Method 202 - back half (condensables)
Firing Rate	Charge heater design basis	28 MMBtu/hour HHV 30-day average	None	Fuel flow F-factor calculation

Because particulate matter emissions result from gas combustion, it is appropriate to assume that all particulate matter is PM₁₀, or smaller, and the PM₁₀ emission rates represent PM emission rates, so the permit will permit PM₁₀ as representing both PM and PM₁₀.

2.4. 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 usually represent a minimum level of control that is required on a new source. A summary of possibly applicable NSPS is given in Table 5.

Table 5. Clean Fuels Project—NSPS Applicability Summary

NSPS Subpart	#2 Hydrogen Plant (Unit 46)	#3 DHDS (Unit 27)	Hydrocracker (Unit 15)	Sulfur Recovery Unit (Units 17/19/25)	HP Flare (Unit 29)
A (General Provisions)	Yes (#2 H2 Flare – 60.18)	Yes	Already Subject	Already Subject	Yes (Flare – 60.18)
Db (Steam Generating Units)	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable
J (Petroleum Refineries)	Already Subject	Already Subject	Already Subject	Not Applicable	Not Applicable
Ja (Petroleum Refineries)	Yes (Process Heater and #2 H2 Flare)	Yes (Process Heater)	Not Applicable	Not Applicable	Yes
Kb (Volatile Organic Liquid Storage Vessels)	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable
UU (Asphalt Processing)	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable
XX (Bulk Gasoline Terminals)	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable
GGGa (VOC Leaks - Petroleum Refineries)	Yes (Components), Compressor is Exempt	Yes (Components), Compressor is Exempt	Not Applicable	Not Applicable Unit 17 (Sour Water Handling Unit already subject)	Not Applicable
NNN (Synthetic Organic Chemical Manufacturing - Distillation)	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable
QQQ (Wastewater VOC Emissions - Petroleum Refineries)	Yes (40CFR61 for compliance)	Yes (40CFR61 for compliance)	Not Applicable	Not Applicable	Not Applicable
RRR (Synthetic Organic Chemical Manufacturing - Reactors)	Not Applicable	Not Applicable	Not Applicable	Not Applicable	Not Applicable

None of the referenced NSPS standards has applicable requirements for particulate emissions. This is typical of NSPS for gas fired heaters and boilers. NSPS require many other limitations, but they are for pollutants that are not regulated by this PSD action.

2.5. Minor NSR and Other State Regulations

BP is subject to Notice of Construction (NOC) permitting requirements under state of Washington regulations Chapters 173-400 and 173-460. NWCAA is the permitting authority for all air emission regulatory requirements not included in PSD permitting. This includes the NSR permitting of air toxics issues under federal MACT and state 173-460 WAC, and Title V permitting requirements. The proposed project will trigger requirements for NWCAA permitting NWCAA Regulation Section 300 as well as WAC 173-400-110.

NWCAA will be responsible for enforcement of all provisions of the PSD after they are included in the facility's Title V permit, and in the interim between permit issuance and that time.

3. DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY

All new and significantly modified sources are required to use Best Available Control Technology (BACT), which is defined in 40 CFR 52.21(b)(12) as an emissions limitation based on the maximum degree of reduction for each pollutant subject to regulation, emitted from any proposed major stationary source or major modification, on a case-by-case basis, taking into account cost effectiveness, economic, energy, environmental, and other impacts.

The "top down" BACT process starts by considering the most stringent form of emissions reduction technology possible, then determines if that technology is technically feasible and economically justifiable. If the technology is proven infeasible or unjustifiable, then the next less stringent level of reduction is considered. When an emission reduction technology meets the stringency, and technical and economical feasibility criteria, it is determined to be BACT.

As determined in Section 2.3, PM₁₀ emissions from the Clean Fuels Project are subject to PSD permitting. This requires a BACT determination for PM₁₀ from each emissions unit that triggers a BACT review. In the new #2 Hydrogen Plant, this includes the SMR Furnace and the Flare. In the #3 DHDS, this includes the Charge Heater.

3.1. Particulate Matter (PM) BACT Analysis for the #3 DHDS Charge Heater and the #2 H₂ Plant SMR Furnace

Particulate matter is produced by combustion processes as unburned solid carbon (soot), unburned vapors or gases that subsequently condense, and the unburnable portion of the fuel (ash).

The BACT analyses for particulate matter emissions from the #3DHDS charge heater, the reformer furnace, and the flare refer to PM₁₀ but are intended to address PM, PM₁₀ and PM_{2.5}. Because the particulate matter emitted by each of these units is a product of combustion, it is likely that virtually all of the filterable component will be less than 2.5 microns. The only

distinction is that PM_{10} is evaluated based on filterable and condensable fractions, whereas PM and $PM_{2.5}$ are currently evaluated only on the filterable portion for this permit application.

Identification of Possible Control Alternatives

Particulates can be controlled through prevention oriented controls such as “good combustion practices” and fuel selection and fuel quality. Gaseous fuels such as natural gas and refinery fuel gas produce the lowest particulate levels compared to liquid and solid fuels. Minimizing the sulfur content of gaseous fuels further minimizes PM_{10} emissions.

Typical add-on control devices for PM_{10} include the following:

- Electrostatic Precipitators (ESP)
- Baghouse/Fabric Filters
- Wet Gas Scrubber

Control Alternative Review

The concept of applying combustion controls or “proper combustion” to minimize PM_{10} emissions is similar to the strategy used to control CO and includes adequate fuel residence time, proper fuel-air mixing, and temperature control to ensure complete combustion. Optimization of these factors for PM_{10} control can result in an increase in the NO_x . Thus, operators strive to balance the factors under their control to achieve the lowest possible emissions of all pollutants.

Fuel selection and minimizing sulfur content can also help minimize PM_{10} emissions. Gaseous fuels tend to result in the lowest particulate emissions compared to liquid or solid fuels. In addition, SO_2 emissions have been shown to contribute to fine particulate emissions. Therefore, controlling or minimizing the sulfur content of the fuel will also minimize PM_{10} emissions.

The two most popular add-on control technologies for control of PM_{10} emissions from a process heater are electrostatic precipitators (ESP) and baghouses. ESPs remove particles 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.

Baghouses, or fabric filters, use various types of materials (generally fabrics) to trap particles 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. Often a mechanical collector, such as a cyclone, is used to remove larger particulate matter before the exhaust reaches the primary control device.

Wet scrubbers, such as venturi scrubbers are less common because they typically have lower control efficiencies than either ESPs or baghouses. They also complicate ash disposal by introducing liquids that create sludge when combined with the removed PM_{10} . A venturi is a narrowed section of duct followed by an expanded section of duct, with scrubbing liquid injected

at the constricted section. The liquid is atomized by the increased velocity exhaust flow, and the particles impact the droplets and are collected. Because the liquid must be atomized to ensure high collection efficiency, a high-energy exhaust flow is required.

Technical Feasibility of Control Alternatives

None of the add-on control devices is suitable for heaters or boilers burning gaseous fuels due to both the extremely low particulate emission concentrations and the physical characteristics of the particles. For example, ESPs operate on the principle of charge migration. The low particle concentration would not allow significant charge buildup on the particles, resulting in poor migration to the collecting plates. Particulates produced by gas combustion are usually less than one micron in size. This makes them too small to be collected by baghouse fabric filters or cyclones. They just go on through. Wet gas scrubbers do not physically collect these low concentration, small particulates effectively either.

The concept of applying combustion controls and appropriate furnace design, or “proper combustion,” to minimize PM₁₀, CO, and VOC emissions includes adequate fuel residence time, proper fuel-air mixing, and temperature control to ensure the maximum amount of fuel is combusted. Optimization of these factors for PM₁₀, CO, and VOC control can result in an increase in the NO_x emissions. Thus, boiler designers strive to balance the factors under their control to achieve the lowest possible emissions of all pollutants.

Effectiveness of Remaining Technologies

A review of the RBLC as well as other databases indicates that the most stringent control technologies for PM₁₀ are “good combustion practices” and “use of gaseous fuel” (see Tables 4 and 9 in Appendix A of this TSD).

The proposed emission rates for the #3 DHDS charge Heater and the #2 H₂ Plant SMR Furnace in this permit is based on the results of recent BP stack testing for PM₁₀ on similar on site boilers and heaters burning the refinery gas fuel. Based on a PM₁₀ emission factor of 12.74 lb/MMscf and an energy content of 1,352 Btu/scf of RFG, this is equivalent to a total (filterable plus condensable) PM₁₀ emission rate of 0.0094 lb/MMBtu. Other tests revealed an emission rate of about 0.008 MMBtu/hour.

Selection of BACT for PM₁₀

BP proposes, and Ecology agrees, that BACT for PM₁₀ emissions from the #3 DHDS charge Heater and the #2 H₂ Plant SMR Furnace is use of “good combustion practice” to combust the gaseous fuel. An emission rate based on an emission factor of 0.0100 lb/MMBtu is appropriate. Based on heater design heat capacity, this results in a total PM₁₀ particulate emission rate of 0.28 lb/hr for the #3 DHDS charge Heater and 4.96 lb/hr for the #2 H₂ Plant SMR Furnace.

3.2. Particulate Matter (PM) BACT Analysis for the #2 H₂ Plant Flare

As part of the Clean Diesel Project, BP is proposing to install a dedicated flare for the hydrogen plant. The flare will be designed to handle hydrogen plant flows during startup, shutdown, and malfunction events, but the flare will handle much smaller flows on a continuous basis. The primary function of the flare is to combust off-spec hydrogen during startup conditions. Although the initial hydrogen plant startup could last 48 hours, subsequent startups are estimated to last 8 – 24 hours per startup. BP anticipates the flare will operate under startup conditions for no more than 100 hours per year.

The flare will have uninterrupted natural gas as the pilot gas. Although continuous flaring will be minimized to the extent practicable, nitrogen purges from compressor seals and compressor distance piece vents and natural gas sweep gas used to maintain the collection header free of oxygen would be routinely combusted. The flare will be elevated torch configuration attached to the stack of the reformer furnace. Only the proposed hydrogen plant will be served by the new flare.

A review of databases and agency workbooks was conducted for the refinery flares. The search included all entries made in the last ten years for refinery flares. Because the RBLC contains few control options for flares, the BACT analysis relied heavily on flare control and monitoring rules from the EPA's existing and proposed New Source Performance Standards (NSPS) General Provisions (NSPS Subpart A) and Petroleum Refineries (NSPS Subpart Ja) as well as the National Emission Standards for Hazardous Air Pollutants (NESHAP) General Provisions (NESHAP Subpart A). In addition, the requirements of several permitting agencies, such as the TCEQ, SCAQMD, SJVUAPCD and the BAAQMD were utilized.

Emissions from flares are minimized primarily in two ways: first by reducing the frequency and amount of gas flared, and second, by promoting good combustion. BACT for refinery flares is generally expressed as design and work practice standards rather than emission limits or rates.

Identification of Possible Control Alternatives

A search of the RBLC database and emission control literature was performed to find available technologies to control flare emissions. In the RBLC, more than forty entries were found regarding refinery flares. Only a few of the BACT determinations specified control methods for PM₁₀. The methods specified included:

- Air assisted smokeless flare technology;
- Air assisted combustion or sonic design and smokeless tips;
- Compliance with 40 CFR 63.11;
- Compliance with 40 CFR 60.18; and
- Good combustion practice.

No add-on control technologies were found or are known to be in commercial use. All of the listed control methods are to promote the proper operation of the flare, thereby increasing the destruction efficiency and reducing the amount of PM₁₀ emitted.

TCEQ BACT determination for PM₁₀ emissions from flares is on a case by case basis. For the SJVUAPCD and BAAQMD, technologically feasible BACT has not been determined. The achieved in practice BACT for the BAAQMD is the same achieved in practice requirements for VOC as noted above. The achieved in practice BACT for the SJVUAPCD includes:

- Engineered flare design for and operated without visible emissions (except as provided for by 40 CFR 60.18(c)(1));
- Equipped with air or steam assisted combustion;
- Flare shall be equipped with a flare gas recovery system for non-emergency releases; and
- Pilot and sweep fuel shall be natural gas, treated refinery gas, or LPG.

In addition to the PM₁₀ controls, almost all flares are required to limit the emission of visible emissions. Often times, limiting visible emissions is considered an indicator of efficient combustion. Almost all of the RBLC BACT determinations for visible emissions consist of an opacity limit of 20% (except for three minutes in any one hour). The most stringent visible emission limit is for the Marathon, Garyville refinery Hydrogen Plant Flare, which has a limit of 0% opacity (except for a total of five minutes during any two consecutive hours).

Control Alternative Review

The complete list of possible PM₁₀ control alternatives for refinery flares, as identified in the federal requirements, the RBLC, and the BAAQMD, SJVUAPCD, and TCEQ BACT determinations is as follows:

- Opacity limits;
- Compliance with the applicable federal NSPS (40 CFR 60.18) and NESHAP requirements (40 CFR 63.11);
- Good combustion practice;
- Proper operation and maintenance;
- Air or steam assisted smokeless flare technology;
- Use of natural gas or LPG as pilot fuel, a continuous pilot and a method for detection;
- Development of a written flare management plan;
- Flares only to be operated during periods of emergency plant upsets or breakdown; and
- Routine venting of process gases to be routed to a fuel gas recovery system.

Technical Feasibility of Control Alternatives

Most of the identified control alternatives are technically feasible.

Cost-Effectiveness of Alternatives

BP proposes to implement all of the technically feasible control alternatives except for flare gas recovery, which was deemed not cost effective.

Selection of BACT for PM₁₀ for the Flare

BP proposes and Ecology agrees that the design and operation of the hydrogen flare in compliance with all applicable Washington State and federal requirements as well as the applicable technically achievable BACT standards identified by the BAAQMD/SJVUAPCD and TCEQ should be BACT for the BP flare. These controls are the most stringent applicable control methods identified, and therefore these control requirements represent BACT for the flare. The proposed flare will have limits on visible emissions by limiting opacity to 20% (except for three minutes in any one hour). The anticipated PM₁₀ emissions from the flare during normal operations are 0.064 lb/hr.

4. AIR QUALITY IMPACTS ANALYSIS

The PSD permitting program requires that an Ambient Air Quality Impacts Analysis (AQIA) be made for pollutants emitted in significant quantities. The AQIA determines if emissions of any pollutant will cause or contribute to an exceedance of a National Ambient Air Quality Standard (NAAQS). It also determines if the change in Air Quality since the applicable baseline dates is greater than the Class I and Class II PSD Increment Levels.

An air quality analysis can include up to three parts: Significant Impact analysis, National Ambient Air Quality Standards (NAAQS) analysis, and PSD Increment analysis. The first step in the air quality analysis is to determine if emissions from the proposed project result in impacts greater than the modeling significant impact levels (SILs). Then, for those pollutants and averaging periods that have impacts greater than their SIL, a cumulative full impacts analysis is used to determine if the proposed project will cause or contribute to an exceedance of a NAAQS. A PSD Increment analysis for those pollutants is also used to determine if the change in the Air Quality since the applicable baseline dates is greater than the Class I and Class II PSD Increment Levels.

This section will discuss the AQIA of the nearby Class II area. The AQIA for the Class I areas will be discussed along with the Air Quality Related Values (AQRVs) in Section 5.

4.1. Model Selection and Procedures

The terrain in the immediate vicinity of the BP facility is rolling land historically used as farmland. For the purposes of regulatory dispersion modeling, intermediate terrain and complex terrain are defined as elevations above stack height and plume height, respectively. For the facility as proposed, intermediate terrain starts at an elevation of 120 feet (36.6m) above the highest stack base and complex terrain would range upwards from an elevation of about 380 feet (116 m) above the stack base for stable conditions. Such terrain features exist within the vicinity

of the refinery. The dispersion model selected for the analysis needs to consider both complex terrain and building downwash effects.

The Guidelines recommend the use of the AERMOD (Version 09292) air dispersion model to estimate ground-level impacts of air pollutants in areas containing both simple and complex terrain and is therefore appropriate to evaluate potential impacts from the Clean Fuels Project sources.⁸ AERMOD also includes the PRIME downwash algorithms to estimate effects of surrounding buildings on the dispersion of plumes.

Local meteorological data are needed to characterize dispersion conditions near the site. The dispersion modeling techniques used to simulate transport and diffusion require an hourly meteorological database. In this case, representative meteorological data are available from an on-site 10-meter tower operated by BP. The data meet PSD-quality specifications, as specified in Part 51 of the Guidelines. ENVIRON used this on-site meteorological data to create AERMOD-ready meteorological files for the period between 2004 and 2008.

The EPA meteorological program AERMET (Version 06341) was used to combine the Cherry Point refinery meteorological station data, National Weather Service (NWS) surface meteorological observations from Bellingham, Washington (used when on-site data are missing), and twice-daily upper air soundings from Quillayute, WA to derive the necessary meteorological variables and profiles for AERMOD.

4.2. Dispersion Modeling Pollutant Emission Rates

BP modeled the criteria pollutant concentrations using the emission rates presented in Tables 3 and 4 of this TSD. The reduction in NO_x emissions from retrofitting the 1st Stage Fractionator Reboiler with ULNBs was conservatively modeled as zero, so only increases in NO_x emissions were evaluated in the modeling. All emissions are modeled, not just the PSD applicable total PM₁₀.

4.3. Maximum Concentrations From the Project

Table 6 summarizes the predicted maximum concentrations due to emissions associated with the Project and compares them to both the applicable monitoring de minimis concentrations and the SILs. The SILs represent incremental, project-specific impact levels that the state of Washington accepts as insignificant with respect to maintaining compliance with the NAAQS or WAAQS.

⁸ Note: EPA established AERMOD as the preferred air dispersion model in the Agency's "Guideline on Air Quality Models" (Appendix W) in place of the ISCST3 air dispersion model. The package was signed by the Administrator of the US EPA on October 21, 2005, and published in the Federal Register on November 9, 2005.

Table 6. Maximum Predicted Criteria Air Pollutant Concentrations

Criteria Pollutant	Averaging Period	Max. AERMOD Concentration ($\mu\text{g}/\text{m}^3$)	Modeling Significance Level ($\mu\text{g}/\text{m}^3$)	Background ^d ($\mu\text{g}/\text{m}^3$)	Total ^e ($\mu\text{g}/\text{m}^3$)	Standard ^f ($\mu\text{g}/\text{m}^3$)	Monitoring De Minimus Concentration ($\mu\text{g}/\text{m}^3$)
NO ₂ ^a	1-hr	6.26	8 ^b	82	88	188	None
	Annual	0.37	1	--	--	100	14
NO ₂ ^a (No SCR)	1-hr	12.72	8 ^b	82	95	188	None
	Annual	0.39	1	--	--	100	14
SO ₂	1-hr	11.28	None ^c	103.6	114.8	196	None
	3-hr	4.23	25	--	--	1,300	None
	24-hr	1.65	5	--	--	262	13
	Annual	0.20	1	--	--	52	None
CO	1-hr	69.50	2,000	--	--	40,000	None
	8-hr	14.51	500	--	--	10,000	575
Total PM ₁₀	24-hr	0.80	5	--	--	150	10
	Annual	0.14	1	--	--	50	None
Filterable PM _{2.5}	24-hr	0.20	None	--	--	--	--
	Annual	0.035	None	--	--	--	--
Total PM _{2.5}	24-hr	0.80	None ^g	--	--	35	None
	Annual	0.14	None ^g	--	--	15	None

Notes:

- a. NO₂ concentrations are assumed to be 100 percent of NO_x. The 1-hour NO₂ (No SCR) AERMOD-predicted concentration is the highest five-year receptor average of the yearly maximum 1-hour NO₂ concentrations. All other AERMOD-predicted concentrations are the maximum concentration predicted in any model year.
- b. The 1-hour NO₂ standard has been set (188 $\mu\text{g}/\text{m}^3$, or 100 ppb), EPA provided an interim SIL of 8 $\mu\text{g}/\text{m}^3$ (1-hr).
- c. The 1-hour SO₂ standard has been set (196 $\mu\text{g}/\text{m}^3$, or 75 ppb) but SILs have not yet been proposed.
- d. The background 1-hour NO₂ concentration was the highest observation over a three year period (2006 – 2008) at the Langley, British Columbia monitoring site (data provided by Ministry of Environment). The background 1-hour SO₂ concentration is the highest 99th percentile daily maximum 1-hour concentration observed over a five year period (2004 – 2008) at the BP Cherry Point monitoring site.
- e. The total concentration is the sum of the maximum AERMOD-predicted concentration and the background concentration.
- f. The ambient air quality standards shown are the more stringent standards from the NAAQS and the WAAQS.
- g. Several SILs for Total PM_{2.5} have been proposed; the most stringent are 1.2 $\mu\text{g}/\text{m}^3$ (24-hour) and 0.3 $\mu\text{g}/\text{m}^3$ (annual).

4.4. Analysis of Results

As shown in Table 6, PM₁₀ particulate emissions did not exceed the 24 hour or annual SILs. This means that the PSD rules do not require a full impacts NAAQS analysis and PSD increment consumption analysis for the only PSD applicable pollutant for the Clean Fuels Project, PM₁₀.

4.5. Toxic Air Pollutants

PSD rules require the applicant to consider emissions of toxic air pollutants during the course of BACT analysis. One reason for this requirement is to ensure the source does not employ an emission control technique that controls the main pollutant of concern, but emits a new toxic air pollutant in serious quantities. The use of ammonia during the control of NO_x is a good example.

Washington State regulations (Chapter 173-460 WAC) require an ambient air quality analysis of Toxic Air Pollutant (TAP) emissions, which usually serves the purpose of PSD toxics review in Washington State. The Notice of Construction proposed by the Northwest Clean Air Agency in conjunction with this PSD permit fulfills all requirements of WAC 173-460.

5. CLASS I AREA IMPACT ANALYSIS

Federal⁹ and Washington State¹⁰ PSD regulations require the impact of a proposed facility on federal Class I areas be analyzed. Class I Areas are areas of special national or regional value from a natural, scenic, recreational, or historic perspective and are afforded the highest level of protection under the PSD rules. They include certain national parks, national wilderness areas, and national memorial parks.

This section presents an assessment of the potential impacts to air quality related values (AQRVs) in Class I areas caused by increased emissions from the Project. The AQRVs of concern include visibility, soil, flora, fauna, and aquatic resources. For long-range transport modeling of Class I areas, the CALPUFF modeling system is currently recommended for evaluating effect on AQRVs. Potential impacts are characterized based on predictions of total nitrogen and/or sulfur deposition flux, change in light extinction, and pollutant concentrations. The project's impact on regional haze was also evaluated.

For projects subject to PSD review, an AQRV analysis is required for Federal Class I areas within 100 km of the site. In the Pacific Northwest, the Federal Land Managers (FLMs) and state agencies have historically requested the model domain be extended to include additional Class I areas within 200 km. Pacific Northwest states agencies recently requested assessments for regional haze include Class I areas within 300 km of the source.¹¹

There are two Class I areas within 100 km of the facility, and three others within 200 km. The Mount Rainier National Park and the Goat Rocks and Mount Adams Wilderness Areas are beyond the 200-km range, but all three were included in the analysis. The Mount Baker Wilderness Area was also included in the analysis even though it is not a Class I area because Ecology and the FLMs typically request its inclusion in AQRV assessments.

⁹ 40 CFR 52.21 (p)

¹⁰ WAC 173-400-117

¹¹ Idaho DEQ, 2006. *Modeling Protocol for Washington, Oregon, and Idaho: Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulations*. Obtained from http://www.deq.idaho.gov/air/prog_issues/pollutants/haze_BART_modeling_protocol.pdf.

Table 7. Class I Areas and Q/D Analysis

ID	Name	Distance to Class I area (km)	Q/D Value (TPY/km)
MOBA ^a	Mount Baker WA	55	0.6
NCAS	North Cascades NP	78	0.4
OLYM	Olympic NP	102	0.3
GLAC	Glacier Peak WA	108	0.3
PASA	Pasayten WA	123	0.3
ALPL	Alpine Lakes WA	157	0.2
RAIN	Mt. Rainier NP	213	0.1
GOAT	Goat Rocks WA	255	0.1
ADAM	Mt. Adams NP	291	0.1

Notes:

- a. Mount Baker Wilderness Area is not a Class I area, it is included in the analysis because FLMs have requested its inclusion in previous permit applications.

5.1. Model Selection and Procedures

On April 15, 2003, EPA adopted the CALPUFF modeling system as the EPA's preferred model for long-range transport assessments and for evaluating potential impacts to Class I areas by including CALPUFF in Appendix A of the Guidelines. 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. As is currently required, CALPUFF Version 5.8 (release date June 23, 2007) was used.

The modeling procedures used for the Class I area analyses followed the recommendations of the Interagency Agency Workgroup on Air Quality Modeling (IWAQM) and the FLM Air Quality Related Values Workgroup (FLAG), outlined in the FLAG Phase I Report (December 2000). EPA endorsed these procedures in advance in the IWAQM Phase II report (December 1998), and reiterated this endorsement in the April 15, 2003 Federal Register notice (Volume 68, Number 72) that adopted CALPUFF as a Guideline model. EPA further clarified their required CALMET settings in a memo issued on August 31, 2009 (Fox 2009).

5.2. Criteria Pollutant Concentrations

The CALPUFF modeling system was used to predict concentrations of NO₂, SO₂, and PM₁₀ in regional Class I areas. Table 8 summarizes the predicted maximum concentrations and compares them to the Class I SILs and the Class I PSD increments. At this point, there are two sets of Class I SILs: those proposed by EPA, and those recommended by the FLMs. These proposed and recommended SILs were obtained from the Federal Register, Vol. 61, No. 143, p. 38292, July 23, 1996. As shown in Table 8, the CALPUFF simulations indicate neither the SILs nor the increments will be exceeded.

Table 8. Predicted Class I Area Criteria Pollutant Concentrations

Class I Area of Interest	Maximum Predicted Concentration ($\mu\text{g}/\text{m}^3$)					
	NO ₂ ^a	PM ₁₀		SO ₂		
	Annual Average	24-Hour Average	Annual Average	3-Hour Average	24-Hour Average	Annual Average
Alpine Lakes Wilderness	1.45E-04	0.0115	0.0005	0.0109	0.0041	0.0001
Glacier Peak Wilderness	0.00085	0.0193	0.0010	0.0603	0.0143	0.0005
Goat Rocks Wilderness	1.62E-05	0.0037	0.0001	0.0032	0.0010	3.21e-05
Mount Adams Wilderness	9.15E-06	0.0030	0.0001	0.0019	0.0008	2.34e-05
Mount Baker Wilderness ^d	0.00324	0.0397	0.0024	0.1478	0.0358	0.0018
Mount Rainier National Park	3.44E-05	0.0070	0.0002	0.0045	0.0017	5.26e-05
N Cascades National Park	0.00177	0.0265	0.0019	0.0654	0.0178	0.0011
Olympic National Park	0.00198	0.0680	0.0021	0.0783	0.0221	0.0011
Pasayten Wilderness	0.00096	0.0174	0.0014	0.0268	0.0090	0.0006
Class I Area & Mt. Baker Maximum Concentration	0.00324	0.0680	0.0024	0.1478	0.0358	0.0018
EPA Proposed SIL ^b	0.1	0.3	0.2	1	0.2	0.1
FLM Recommended SIL ^b	0.03	0.27	0.08	0.48	0.07	0.03
Class I Area PSD Increment ^c	2.5	8	4	25	5	2

Notes:

- a. NO₂ concentrations are conservatively based on 100% conversion of NO_x.
- b. SIL = Significant Impact Level; EPA proposed and FLM recommended from the Federal Register, Vol. 61, No. 142, p. 38292, July 23, 1996.
- c. PSD = Prevention of Significant Deterioration; from 40 CFR 52.21(c), adopted by reference in WAC 173-400-720(4)(a)(v).
- d. Mount Baker Wilderness Area is not a Class I area, it is included in the analysis because FLMs have requested its inclusion in previous permit applications.

5.3. Nitrogen and Sulfur Deposition

CALPUFF was also used to predict the impacts of acid-forming compounds emitted by the project on soils and vegetation in regional Class I areas. The deposition analysis results are shown in Table 10. There are no promulgated standards for evaluation of these incremental impacts to soils and vegetation in Washington. However, the National Park Service has established Deposition Analysis Thresholds (DATs) for nitrogen and sulfur of 0.005 kg/ha/yr.¹² These “thresholds” are based on natural background deposition estimates culled from various research efforts, a variability factor, and a safety factor that accounts for cumulative effects. The DATs are not adverse impact thresholds, but are intended as conservative screening criteria that allow the FLMs to identify potential deposition fluxes that require their consideration on a case-by-case basis. As shown in Table 9, predicted maximum nitrogen and sulfur deposition fluxes do not exceed the DATs.

¹² Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds, available on the FLAG internet site at <http://www2.nature.nps.gov/ard/flagfree/NSDATGuidance.htm>

Table 9. Predicted Class I Area Deposition Fluxes

Class I Area of Interest	Nitrogen Deposition (kg/ha/yr)	Sulfur Deposition (kg/ha/yr)
Alpine Lakes Wilderness Area	0.0001	0.0002
Glacier Peak Wilderness Area	0.0003	0.0003
Goat Rocks Wilderness Area	0.00003	0.00004
Mount Adams Wilderness Area	0.00003	0.00003
Mount Baker Wilderness Area ^a	0.0009	0.0011
Mount Rainier National Park	0.00005	0.0001
N. Cascades National Park	0.0007	0.0009
Olympic National Park	0.0003	0.0004
Pasayten Wilderness Area	0.0005	0.0006
NPS DAT	0.005	0.005
Notes:		
a. Mount Baker Wilderness Area is not a Class I area, it is included in the analysis because FLMs have requested its inclusion in previous permit applications.		

Please note that the Cherry Point Refinery’s compliance with EPA’s fuel regulations has the potential to reduce mobile source sulfur dioxide emissions by up to 12,264 tons per year. This modeling analysis did not take into account the regional benefit of the Clean Fuels Project.

5.4. Visibility—Regional Haze

Compliance with the FLMs recommendations for regional visibility impacts was assessed by calculating the percent change in extinction for each Class I receptor. CALPUFF modeling was used to predict both the extinction coefficient attributable to emissions from the project and the background extinction coefficients. The FLMs recommend in the FLAG Phase I Report that a 5% change in extinction be used to indicate a “just perceptible” change to a landscape. Sources that equal or exceed this threshold must perform a cumulative visibility analysis for PSD increment consuming sources. The threshold for the cumulative analysis is a 10% change, and the threshold for the new source is a contribution of 0.4% of the change on those days.

Pollutant concentrations and regional haze impacts (24 hour visibility) were calculated two ways. The first uses the traditional settings of the CALPOST processor (CALPOST 2) to calculate extinction coefficients.

The second uses the 2008 proposed revisions to the FLM FLAG procedures. The revised procedures employ the IMPROVE extinction equation to calculate b_{ext} . This updated equation

for extinction uses monthly relative humidity adjustment factors with relative humidity capped at 95 percent. It uses annual background aerosol concentrations recommended by the FLMs for each Class I area,¹³ and assess the visibility using the 98th percentile modeled values at each receptor. In order to use Method 8, CALPOST Version 6.221 (Level 080724) was used to post-process the CALPUFF output files.

¹³ The necessary monthly relative humidity adjustment factors and background aerosol concentrations for Mount Baker WA were assumed the same as recommended for the Pasayten Wilderness.

Table 10. Maximum Predicted Extinction Change by Class I Area, Method 2

Class I Area	Date	b _{ext} ^a (1/Mm)			Change (%)	f(RH)	b _{ext} by Component ^c (1/Mm)					
		Project	Bckgrnd ^b	Total			SO4	NO3	OC	EC	PMC	PMF
Olympic NP	11/22/2005	1.112	19.500	20.612	5.7 ^d	8.333	0.507	0.567	0.022	0	0	0.015
Mt. Baker WA ^e	9/26/2004	0.660	20.332	20.993	3.25	9.721	0.350	0.281	0.020	0	0	0.009
North Cascades NP	4/5/2004	0.427	18.460	18.887	2.31	6.600	0.205	0.196	0.019	0	0	0.007
Glacier Peak WA	9/26/2005	0.221	17.584	17.805	1.26	5.140	0.092	0.118	0.008	0	0	0.003
Pasayten WA	2/28/2004	0.188	17.999	18.187	1.04	5.832	0.073	0.109	0.004	0	0	0.002
Alpine Lakes WA	4/21/2003	0.140	18.967	19.107	0.74	7.445	0.069	0.066	0.004	0	0	0.001
Mt. Rainier NP	3/3/2003	0.078	19.752	19.831	0.40	8.754	0.032	0.044	0.001	0	0	0.001
Goat Rocks WA	3/3/2003	0.043	19.752	19.795	0.22	8.754	0.016	0.026	0.001	0	0	0
Mt. Adams WA	9/25/2005	0.013	15.513	15.526	0.08	1.688	0.005	0.006	0.001	0	0	0.001

Notes:

- a. Project and background extinction values for daily period that resulted in the maximum percent change in extinction.
- b. Background extinction derived from default annual average Western U.S. extinction components provided in FLAG 2000 guidance document.
- c. Extinction coefficient components are: SO4 = fine sulfate, NO3 = fine nitrate, OC = fine organic carbon, EC = fine elemental carbon, PMC = coarse mass, PMF = fine crustal mass.
- d. 11/22/2005 was naturally obscured. Next highest obscuration at Olympic NP was 11/21/2005, with 3.26 percent change.
- e. Mount Baker Wilderness Area is not a Class I area, it is included in the analysis because FLMs have requested its inclusion in previous applications.

Table 11. Maximum Predicted Extinction Change by Class I Area, Method 8

Class I Area	Date	b _{ext} ^a (1/Mm)			Change (%)
		Project	Bckgrnd ^b	Total	
Olympic NP	11/21/2005	0.700	18.615	19.315	3.76
Mt. Baker WA ^c	9/25/2005	0.269	16.106	16.375	1.67
North Cascades NP	4/4/2004	0.165	16.013	16.178	1.03
Glacier Peak WA	2/27/2004	0.111	15.720	15.831	0.70
Pasayten WA	4/5/2004	0.105	15.987	16.092	0.66
Alpine Lakes WA	9/28/2003	0.085	16.528	16.613	0.51
Mt. Rainier NP	2/26/2003	0.047	17.800	17.847	0.27
Goat Rocks WA	2/26/2003	0.028	15.719	15.747	0.18
Mt. Adams WA	9/24/2005	0.020	15.14	15.160	0.14

Notes:

- Project and background extinction values for daily period that resulted in the maximum percent change in extinction.
- Background extinction derived from default annual average extinction components provided in FLAG 2008 Tables.
- Mount Baker Wilderness Area is not a Class I area, it is included in the analysis because FLMs have requested its inclusion in previous applications.

The FLMs recommend in the FLAG Phase I Report that a five percent change in extinction be used to indicate a “just perceptible” change to a landscape. As shown in Tables 10 and 11, the maximum predicted change in extinction on any day of the simulation was 3.26 percent using Method 2, and 3.76 percent using Method 8. These results are less than the 5 percent threshold established by the FLMs.

5.5. Conclusion Concerning AQRVs

Ecology determines that increased emissions from the project are not expected to significantly impact deposition or degrade visibility in the North Cascades National Park, the Olympic National Park, or any other Class I area. Ecology also realizes that by removing a substantial tonnage of sulfur from the area’s fuel supply, AQRVs will be positively affected.

6. ADDITIONAL IMPACTS ANALYSIS

Under 40 CFR 52.21(o), PSD applications must provide: “an analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification.” In accordance with these requirements, the following analysis of additional impacts from the proposed project has been prepared.

6.1. Class II Area Growth

Construction of the Clean Fuels Project would span approximately two years. During peak construction, there would be as many as 450 workers employed at the site. Laydown and worker parking areas are located on BP property. The temporary increases in vehicle miles traveled and vehicular emissions would be insignificant. During construction, local demand for skilled crafts people would increase. However, this demand would be temporary (less than two years). Once operational, BP expects to employ 10 additional full time refinery operations and maintenance positions.

BP estimates that for each new refinery job, eight additional jobs are created locally. BP does not expect the Clean Fuels Project to cause significant population growth in the area nor significant secondary air quality impacts because of that growth.

6.2. Class II Visibility

On a large spatial scale, visibility is typically evaluated as “regional haze” and is addressed as part of the Class I air quality related values (Section 5.4). On a local scale, “visibility” is usually evaluated by considering perceptibility of a plume from a stack or cooling tower.

The new combustion units (SMR Furnace and Charge Heater) and the projected increases in emissions from other combustion units (i.e. Hydrocracker heaters) will be the largest sources of emissions associated with the Clean Fuels Project. Although state and local regulations restrict visible emissions to a 20 percent opacity limit, emissions from gas-fired combustion units are typically less than 5 percent and are rarely visible.

As a result of the project, BP projects a slight increase in Cooling Tower #2 circulation water usage (less than 10 percent increase). The cooling tower produces visible water vapor clouds that vary in size depending on meteorology and operational factors. Cooling tower plumes are most visible when the ambient air is nearly saturated with water, when visibility is already poor. The slight increase in cooling tower recirculation water will not result in any noticeable changes to visible water vapor clouds that are created by the cooling tower.

6.3. Soils and Vegetation

Air quality permitting regulations require proponents of major modifications to existing major sources to provide an evaluation of potential impacts to air quality related values. These include impacts to visibility, soils and vegetation. In virtually all cases, the impact analysis for soils and vegetation has focused on impacts to Class I areas. The focus on Class I areas occurs because these areas often include sensitive environments, such as alpine lakes and streams, high-elevation vegetation, and sensitive habitat for threatened or endangered species. Section 5.2 and 5.3 addresses impacts to soils and vegetation in Class I areas. Such impacts were judged insignificant based on impact criteria established by Federal Land Managers.

For Class II areas, the concern for soil and vegetation impacts is different from Class I areas. Generally, it is not a sensitive habitat that is of concern, but rather the economic well-being of

the soils and vegetation for the area. Impacts to agriculture or forestry are the major concerns. There have been instances elsewhere in the U.S. where high levels of sulfur emissions from coal fired power plants, or smelters have caused localized impacts to vegetation and soils near the facility. In fact, the NAAQS were established to protect the public health and welfare, and secondary standards were identified specifically to protect ecological properties such as soils and vegetation.

The Class II air quality assessment results (Section 4.3) indicate that the maximum ambient impacts due to the proposed Clean Fuels Project will be less than the applicable Significant Impact Levels (SILs) for both NO_x and SO₂. Because ambient concentrations attributable to the Project would be so low, deposition of nitrogen and sulfur compounds would also be very low. Overall, the Project could potentially reduce mobile source SO₂ emissions by up to 12,264 tons per year, a net benefit on regional soils and vegetation.

BP discussed the project emissions with the director of the Washington State University Extension Service.¹⁴ The director indicated that if a farmer wanted to acidify his land, a minimum of three tons of sulfur would be added per acre; in other words, it takes a lot of sulfur to have a significant effect on the pH of the soil. His personal opinion, without doing extensive additional research, was that the project contribution to soil acidity would be nil.

Based on the CALPUFF modeling described in Chapter 5, deposition of sulfur and nitrogen in the vicinity of the refinery would each be less than 1 lb/acre/year. This very low deposition rate supports the Director's personal opinion that impacts to commercial farms would be nil.

6.4. Ozone Analysis

BP has conducted an ozone modeling study using the increase of emissions from the BP Cherry Point refinery attributable to the Clean Fuels Project. This simulation used the US EPA's Community Multi-scale Air Quality model (CMAQ) to simulate July 25-30, 1998. This is one of the more severe historical ozone episodes, and similar modeling analyses have been used several times to estimate the impacts of increases in emissions of NO_x + VOCs > 100 TPY on ozone formation.

The modeling simulations were based on those developed by Washington State University (WSU) Laboratory for Atmospheric Research in support of a state implementation plan (SIP) for Ozone for the Portland, OR/Vancouver, WA region.¹⁵ This is essentially the same dataset used by WSU as the base case scenario to analyze future emission scenarios for the Puget Sound Clean Air Agency (PSCAA).¹⁶ In those analyses, as well as this, a three-day period beginning

¹⁴ Telephone communication between Eric Hansen of ENVIRON and Craig McConnell, Director of WSU Extension Service for Whatcom County. January 11, 2010.

¹⁵ *Historical and Future Ozone Simulations using the MM5/SMOKE/CMAQ System in the Portland/Vancouver Area*, Ying Xie and Brian Lamb, Laboratory of Atmospheric Research, Department of Civil & Environmental Engineering, WSU. December 31, 2005.

¹⁶ *Modeling Analysis of Future Emission Scenarios for Ozone Impacts in the Puget Sound Area*, Brian Lamb and Ying Xie, Laboratory of Atmospheric Research, Department of Civil & Environmental Engineering, WSU; Clint Bowman, Sally Otterson, and Doug Schneider, Washington State Department of Ecology; and Kathy Himes, John

July 26, 1998 was selected because the episode had the highest observed ozone levels in recent years for the Seattle/Portland airshed.

Two cases were run: a base case using all the sources in the emission inventory used by WSU, and a "PTE" case that also include the increased emissions associated with the project. The difference between the ozone concentrations predicted by the two runs is used to evaluate the implications to regional ozone due to the project.

Generally speaking, ozone concentrations decreased in the region close to the facility due to "NO_x titration," where $\text{NO} + \text{O}_3 \rightarrow \text{NO}_2 + \text{O}_2$. Increases in ozone concentration were predicted to be very small, typically less than 1 ppb, and limited to the area within about 75 km of the facility. The increase in ozone concentration at the Enumclaw monitoring site, which for the period 2006-2008 did not attain the NAAQS of 75 ppb, was less than 0.1 ppb.

BP suggested from the above information that the project will have an insignificant effect on regional ozone concentrations. Ecology agrees with that assessment.

7. CONCLUSION

The project will have no significant adverse impact on air quality or air quality related values. The Washington State Department of Ecology finds the applicant, the BP Cherry Point Refinery, has satisfied all requirements for approval of their application for a PSD permit for the proposed Clean Fuels Project.

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APPENDIX A. RBLC and District Permitting and BACT Guidance Summary Tables

Table 4: Summary of Previous BACT Determinations for Particulate Matter Compared to the Proposed Limit for the BP Cherry Point Clean Fuels Project - #3DHDS Charge Heater

Facility Name/ Location	Date of Permit	Heat Input (MMBtu/ hr)	Fuel	Emission Rate (lb/MMBtu)	Control Technology	Basis	Notes
Proposed Charge Heater							
BP - Cherry Point, WA		28	Fuel Gas/ Natural Gas	0.28 lb/hr (0.010lb/MMBtu, filterable and condensable)	Good Combustion Practice and Fuel Sulfur Limits	BACT-PSD	BP refinery source test data
Units for Which Limits Have Been Verified							
UNITED REFINERY CO.	8/20/2007	9	Mixture (see note)	0.07 lb/hr (0.29 TPY) (calculated EF of 0.0078)	NONE	Case by Case	ONLY REFINERY GAS TO BE USED FOR THIS SOURCE: 6 MCF/HR NATURAL GAS; 9 CF/HR PROPANE; 8.823 MCF/HR REFINERY GAS; 60 GAL/HR #6 OIL
UNITED REFINERY CO.	8/20/2007	35.7	Mixture (see note)	4.2 LB/H (18.6 TPY) (calculated EF of 0.12 lb/MMBtu)	GOOD COMBUSTION PRACTICE	Case by Case	264 GAL/HR REFINERY FUEL OIL; 35.7 MCF/HR REFINERY GAS; 35.7 MCF/HR NATURAL GAS; 51 CF/HR PROPANE; 264 GAL/HR REFINERY OIL; 264 GAL/HR #5 OIL; 35 MCF/HR REFINERY GAS
Units for Which Limits Have Not Been Verified							
ARIZONA CLEAN FUELS - YUMA, AZ	8/25/2006	70	Refinery Fuel Gas or Natural Gas	0.0075 LB/MMBtu (3 HR AVG)		BACT-PSD	
TOTAL REFINING - PORT ARTHUR, TX	11/6/2009	50	FUEL GAS	0.37 LB/HR; 1.47 TPY (PM10 FILTERABLE)	GOOD BURNER TECHNOLOGY	BACT-PSD	Permit Pending; ; (calculated EF of 0.0074 lb/MMBtu)
TOTAL REFINING - PORT ARTHUR, TX	11/6/2009	42	FUEL GAS	0.31 LB/HR; 0.34 TPY; (PM10 FILTERABLE)	GOOD BURNER TECHNOLOGY	BACT-PSD	Permit Pending; (calculated EF of 0.0074 lb/MMBtu)
VALERO - ST CHARLES, LA	6/29/2009	70	REFINERY FUEL GAS OR NATURAL GAS		GASEOUS FUELS	BACT-PSD	
MOTIVA ENTERPRISES, CONVENT - St. James Parish, LA	8/21/2003	68	REFINERY GAS	0.49 LB/HR; 1.53 TPY	GOOD COMBUSTION PRACTICES	BACT-PSD	
ARIZONA CLEAN FUELS YUMA	8/25/2006	21.4	REFINERY FUEL GAS OR NG	0.0075 LB/MMBtu, 3-HOUR AVERAGE		BACT-PSD	
ARIZONA CLEAN FUELS YUMA	8/25/2006	25	REFINERY FUEL GAS OR NATURAL GAS	0.0075 LB/MMBtu, 3-HOUR AVERAGE		BACT-PSD	
DIAMOND SHAMROCK MCKEE PLANT	1/4/2005	30.1	FUEL GAS	0.25 LB/H (1.09 TPY)	NONE INDICATED	BACT-PSD	Calculated EF of 0.008 LB/ MMBtu
CITGO CORPUS CHRISTI REFINERY- WEST PLANT	1/4/2005	62		0.46 LB/H (2.0 TPY)		BACT-PSD	Calculated EF of 0.0074 LB/ MMBtu
DIAMOND SHAMROCK MCKEE PLANT	8/26/2004	63.4	REFINERY GAS	0.68 LB/H (2.96 TPY)		BACT-PSD	Calculated EF of 0.011 lb/MMBtu
BIG WEST OF CALIFORNIA	11/1/2007	47 AND 35		0.0074 LB/ MMBtu	CONTROL OF SULFUR CONTENT OF FUEL (SEE SO2)	BACT-PSD	
Agency BACT Determinations							
TCEQ							
BAAQMD - Tech Feasible/Cost Effective	8/12/1994			n/d	n/d		Heaters (<50 MMBtu/hr, natural draft)
BAAQMD - Achieved in Practice	8/12/1994				Natural gas or treated refinery gas fuel; Fuel selection		Heaters (<50 MMBtu/hr, natural draft)
SCAQMD	11/7/2002						Heater (<50 MMBtu/hr)
SJVUAPCD - RESCINDED	10/26/2009				Treated natural gas or refinery gas < 0.0621 grains H2S/dscf (100 ppmv H2S)		Heater (<50 MMBtu/hr)
<p>Notes:</p> <p>¹ The SJVUAPCD BACT determination for refinery heaters was rescinded on 10/26/2009. The information presented in the table represents the previous BACT determinations for similar units permitted in the District.</p>							

Table 9: Summary of Previous BACT Determinations for Particulate Matter Compared to the Proposed Limit for the BP Cherry Point Clean Fuels Project - #2 Hydrogen Plant Reformer Furnace

Facility Name/ Location	Date of Permit	Heat Input (MMBtu/ hr)	Fuel	Emission Rate (lb/MMBtu)	Control Technology	Basis	Notes
Proposed Reformer Furnace							
BP - Cherry Point, WA		496	PSA Offgas and Natural Gas	4.96 lb/hr (0.010lb/MMBtu, filterable and condensable)	Good Combustion Practice, Low Sulfur Content of Fuel (see SO2)		BP refinery source test data
Units for Which Limits Have Been Verified							
UNITED REFINERY CO. - Warren, PA	8/20/2007	105	REFINERY GAS	6.3 LB/HR (15.6), BASED ON 24-HR DAILY AVG	GOOD COMBUSTION PRACTICE	Case-by-Case	Calculated EF of 0.06 lb/MMBtu
UNITED REFINERY CO. - Warren, PA	8/20/2007	112	REFINERY FUEL OIL	0.8 LB/HR (2.0 TPY)	GOOD COMBUSTION PRACTICE	Case-by-Case	Calculated EF of 0.007 lb/MMBtu by ENVIRON)
TESORO ALASKA COMPANY, KENAI - Nikiski, AK	8/27/2008	152.3	NATURAL GAS, REFINERY GAS, AND LPG	0.005 lb/MMBtu	NONE INDICATED	OPERATING PERMIT	
CHEVRON PRODUCTS CO - El Segundo, CA	2/28/2000	653	Refinery Gas, Natural Gas	4.9 LB/HR (FILTERABLE PM10)	USE OF NITROGEN GAS OR TREATED REFINERY GAS. PERMIT LIMITS SET IN LB/H, STANDARD UNITS NOT AVAILABLE.	RECLAIM	
Units for Which Limits Have Not Been Verified							
BP-HUSKY REFINING LLC - Lucas, OH	11/6/2009	519	REFINERY FUEL GAS	3.9 LB/HR; 16.94 TPY (ROLLING 12 MO)	NO ADD ON CONTROLS WERE REASONABLY COST-EFFECTIVE		Draft Permit; BASED ON AP-42 EF 7.6 LB/ MMBtu (TOTAL PM10)
NAVAJO REFINING COMPANY LLC - ARTESIA REFINERY - Eddy, NM	8/1/2008	337	NATURAL GAS AND REFORMER OFF-GAS	0.075 LB/MMBtu (HOURLY); 2.5 LB/HR; (FILTER. PM10)	GASEOUS FUEL COMBUSTION ONLY	BACT-PSD	
UNITED REFINERY CO. - Warren, PA	2/2/2009	344	REFINERY GAS	1.6 LB/HR (TSP AND FILTER. PM10)	GOOD COMBUSTION PRACTICE	Case-by-Case	Calculated EF of 0.0047 lb/MMBtu
AIR LIQUIDE-FREEPORT HYCO - Brazoria, TX	1/4/2005	286	H2 OFF-GAS AND SWEET NATURAL GAS	3.3 LB/HR; 14.46 TPY; (PM)	NONE INDICATED		Calculated EF of 0.0115 lb/MMBtu
EXXONMOBIL - BATON ROUGE REGINERY, LA	8/9/2007	64		0.08 LB/MMBtu (FILTERABLE PM10)	GOOD ENGINEERING DESIGN AND PROPER COMBUSTION PRACTICES	BACT-PSD	
MARATHON PETROLEUM CO LLC - GARYVILLE REFINERY - St John The Baptist County, LA	7/16/2008	1412.5	Purge Gas	0.0075 lb/MMBtu - 3-HOUR AVERAGE	PROPER DESIGN, OPERATION, AND GOOD ENGINEERING PRACTICES	BACT-PSD	
ARIZONA CLEAN FUELS - Yuma, AZ	8/25/2006	1435	REFINERY FUEL GAS OR NATURAL GAS	0.0075 LB/MMBtu, 3-HR AVERAGE		BACT-PSD	
DIAMOND SHAMROCK MCKEE PLANT - Moore Co, TX	1/4/2005	160.4	FUEL GAS	1.35 LB/HR (6.78 TPY)		BACT-PSD	Calculated EF of 0.008 LB/MMBtu
DIAMOND SHAMROCK MCKEE PLANT - Moore Co, TX	8/26/2004	248	REFINERY GAS	2.64 LB/HR (11.56 TPY)		BACT-PSD	Calculated EF of 0.011 lb/MMBtu
CONOCO PHILLIPS REFINERY - AIR LIQUIDE OWNS H2 PLANT AT REFINERY - Rodeo, CA	10/5/2007	975	~85% PSA AND ~15% REFINERY FUEL GAS	3.8 LB/MMCF NATURAL GAS	GOOD COMBUSTION PRACTICES	BACT-PSD	Using AP-42 EF of 0.0074lb/MMBtu and multiplying by 0.5 since 50% of fuel is H2, the resulting EF is 0.0037 LB/MMBtu
BIG WEST OF CALIFORNIA - Bakersfield, CA	11/1/2007	641			GOOD COMBUSTION PRACTICE; LOW-SULFUR CONTENT FUEL		0.0074 lb/MMBtu Annual
CHEVRON CO REFINERY - Richmond, CA	9/19/2008	950	NATURAL GAS AND PSA TAIL GAS		GOOD COMBUSTION PRACTICE; LOW-SULFUR CONTENT FUEL	BACT-PSD	
Agency BACT Determinations							
TCEQ	10/17/2006						Process Furnaces
BAAQMD - Tech Feasible/Cost Effective	1/14/2008			n/d	n/d		Heater - Refinery Process (> 50 MMBtu/hr)
BAAQMD - Achieved in Practice	1/14/2008				Natural gas or treated refinery gas fuel; Fuel selection		Heater - Refinery Process (> 50 MMBtu/hr)
SCAQMD	5/19/2004						Reformer Furnace
SJVUAPCD - RESCINDED	10/26/2009				Treated natural gas or refinery gas < 0.0621 grains H2S/dscf (100 ppmv H2S)		Heater (>50 MMBtu/hr)
Notes:							
1 The SJVUAPCD BACT determination for refinery heaters/furnaces was rescinded on 10/26/2009. The information presented in the table represents the previous BACT determinations for similar units permitted in the District.							

APPENDIX B. Detailed Emission Calculations

Summary of Fuel Gas Characteristics

Fuel	Heat Content (gross Btu/cf)	Heat Content (net Btu/cf)	F-Factor (dscf/MMBtu)
Refinery Fuel Gas ^a	1268	1153	8628
Natural Gas	1036	934	8638

a – Refinery Fuel Gas Characteristics based on average of 2007 – 2008 analyses.

Refinery Fuel Gas - Sulfur Concentrations

SO2 Averaging Period	Mercaptan Conc. (ppm S)	H2S Conc. (ppm S)	Total Sulfur Conc. (ppm S)	Emis. Factor ¹ (lb SO2/MMBtu)	Emis. Factor ² (lb H2SO4/MMBtu)
1-hour	688.0	162	850.0	0.1101	0.0046
24-hour	412.0	50	462.0	0.0598	0.0025
Annual	200.0	0	200.0	0.0259	0.0011

1 - Emission Factor (lb SO2/MMBtu) = (X ppm Total S) x (0.9737 partition to SO2) x (lbmol S/379.5 mmscf) x (1 lbmol SO2/1 lbmol S) x (64 lb SO2/lbmol SO2) x (1 mmscf/1268 MMBtu)

2 - Emission Factor (lb H2SO4/MMBtu) = (X ppm S) x (0.0263 converts to H2SO4) x (lbmol S/379.5 mmscf) x (1 lbmol H2SO4/1 lbmol S) x (98 lb H2SO4/lbmol H2SO4) x (1 mmscf/1268 MMBtu)

- Total sulfur conversion to SO2 (0.9737) and conversion to H2SO4 (0.0263) is based on #1 Reformer source test average results (06/26/2007).

Pipeline Natural Gas - Sulfur Concentrations

SO2 Averaging Period	Sulfur Conc. ³ (gr S/mmscf)	Emis. Factor ¹ (lb SO2/MMBtu)	Emis. Factor ² (lb H2SO4/MMBtu)	Sulfur Conc. ⁴ (ppm S)
3-hour	20,700	0.00571	0.000230	35.1
24-hour	19,090	0.00526	0.000212	32.3
Annual	10,490	0.00289	0.000117	17.8

1 - Emission Factor (lb SO2/MMBtu) = (gr S/mmscf) x (1 lb S/ 7,000 gr S) x (1 lbmol S/32 lb S) x (1 lbmol SO2/1 lbmol S) x (64 lb SO2/lbmol SO2) x (1 mmscf/1,036 MMBtu)

2 - Conservatively assume 0.0263 of sulfur in NG is converted to H2SO4 (same as RFG, #1 Reformer source test on 06/26/2007).
 Emission Factor (lb H2SO4/MMBtu) = (gr S/mmscf) x (1 lb S/ 7,000 gr S) x (0.0263 converts to H2SO4) x (1 lbmol S/32 lb S) x (1 lbmol H2SO4/1 lbmol S) x (98 lb H2SO4/lbmol H2SO4) x (1 mmscf/1,036 MMBtu)

3- Based on actual measurements at Huntingdon metering station

4- Sulfur (ppm) = (gr S/mmscf) x (1 lb S/ 7,000 gr S) x (1 lbmol S/32 lb S) x (379.5 mmscf/lbmol)

PSA Residual Gas – Sulfur Concentration

SO2 Averaging Period	Total Sulfur Conc. (ppm S)	Emis. Factor ¹ (lb SO2/MMBtu)	Emis. Factor ² (lb H2SO4/MMBtu)
All	0.10	4.19E-05	1.73E-06

1 - Emission Factor (lb SO2/MMBtu) = (0.1 ppm S) x (0.9737 partition to SO2) x (lbmol S/379.5 mmscf) x (1 lbmol SO2/1 lbmol S) x (64 lb SO2/lbmol SO2) x (1 mmscf/392 MMBtu)

2 - Emission Factor (lb H2SO4/MMBtu) = (0.1 ppm S) x (0.0263 converts to H2SO4) x (lbmol S/379.5 mmscf) x (1 lbmol H2SO4/1 lbmol S) x (98 lb H2SO4/lbmol H2SO4) x (1 mmscf/392 MMBtu)

- Total sulfur conversion to SO2 (0.9737) and conversion to H2SO4 (0.0263) is based on #1 Reformer source test average results (06/26/2007).

BP - Cherry Point Clean Fuels Project - #2 Hydrogen Plant SMR Combustion Emissions

		H2 Plant Specifications	
H2 SMR operating hours		8,760 hours/year	
H2 SCR maintenance period		100 hours/year	
H2 SMR firing rate		496 MMBtu/hr	HHV
Natural gas heat value		1,036 GBtu/scf	Source: Fuel Gas Analyses
CB&I - Total Flue Gas Normal Operation	98,902 scfm		Source: CB&I Spec. Sheet for Maximum Operation

Criteria and PSD Pollutant Emissions

Pollutant	#2 Hydrogen Plant – SMR Furnace			
	Emission Factor		Emission Rate	
	ppmvd	lb/MMBtu	lb/hr	tpy
NO _x ^a	5 (3% O ₂)	0.0071	3.54	15.52
NO _x (without SCR) ^a	--	0.035	17.36	16.21
CO ^a	10 (3% O ₂)	0.0087	4.31	18.89
SO ₂ (1-hr) ^b	--	0.006	2.83	--
SO ₂ (24-hr) ^b	--	0.005	2.61	--
SO ₂ (Annual) ^b	--	0.003	--	6.29
PM (Filt.) ^c	--	0.0025	1.24	5.43
PM ₁₀ (Filt. & Cond.) ^c	--	0.0100	4.96	21.72
PM _{2.5} (Filt.) ^c	--	0.0025	1.24	5.43
VOC ^d	--	0.0054	2.67	11.71
Lead ^d	--	4.9E-07	2.4E-04	1.1E-03
H ₂ SO ₄ ^e	--	0.0002 / 0.00012	0.11	0.25

notes:

a - NO_x and CO emission rates based on proposed BACT. NO_x and CO ppmvd limits are based on 3% Oxygen. NO_x (no SCR case) emission rate based on ULNB NO_x emission factor of 0.035 lb/MMBtu (CB&I) and conservative 100 hours of maintenance per year..

b - SO₂ emission factors based on variable sulfur content of natural gas; 3-hr, 24-hr, and annual emission factors calculations based on natural gas composition.

c - PM₁₀ emission factor based on refinery source test data. PM and PM_{2.5} emission factors based on 25 percent of PM₁₀ emission rate (#2 DHDS Charge Heater and #7 Boiler Source Test Results, fraction of filterable particulate in total particulate).

d - VOC and Lead emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/MMBtu using natural gas heat content (1,020 btu/cf)

e - H₂SO₄ emission factors based on 2.63 percent of fuel gas sulfur converting to H₂SO₄ (Source Test of #1 Reformer firing RFG), hourly and annual emission factors calculated on natural gas composition.

BP - Cherry Point Clean Fuels Project - New Hydrogen Plant Methanol Emissions

Degasifier Vent Flow Rate	H2 Plant Specifications
H2 Plant operating hours	45.8 MSCFH
	8,760 hours/year

Methanol Emissions from #2 Hydrogen Plant

Pollutant	H2 Plant Degasifier Vent			
	Emission Factor ppm	lb/hr	Emission Rate lb/day	lb/year
Methanol ^a	0.014	0.00	0.00	0.47

notes:

a - Potential methanol emissions based on concentration (0.014 ppm) in degasifier vent flow (45.8 Mscf/hr).

**BP - Cherry Point
 Clean Fuels Project - #2 Hydrogen Plant Flare Emissions**

H2 Plant Flare Emission Calculations

- Emissions based on normal startup (50 percent of H2 Plant feed gases)

	H2 Plant	
Number of Startups	100 hrs/yr	
VOC and CO Control Eff.	98%	Basis: BACT
Natural Gas Pilot Flare Pilot and Normal H2 Plant Operations	1.6 MMBtu/hr	maximum capacity HHV
Total S in H2 Plant PSA Gas	8,760 hrs/yr	
Normal H2 Plant gas to flare	100 ppb S	Source: BP
Normal H2 Plant gas heat content	77 scfm	Source: CB&I
Normal H2 Plant flowrate	1,036 Btu/scf	Natural Gas
	4.8 MMBtu/hr	

Sulfur Dioxide and Sulfuric Acid Emission Factors for H2 Plant PSA Gas

Emission Factor (lb SO2/MMBtu) = (0.10 ppm S) x (0.9737 partition to SO2) x (lbmol S/379.5 mmscf) x (1 lbmol SO2/1 lbmol S) x (64 lb SO2/lbmol SO2) x (1 mmscf/392 MMBtu)

Conservatively assume 0.0263 of sulfur in H2 plant feed gas is converted to H2SO4 (same as RFG, #1 Reformer source test on 06/26/2007). Emission Factor (lb H2SO4/MMBtu) = (0.10 ppm S) x (0.0263 converts to H2SO4) x (lbmol S/379.5 mmscf) x (1 lbmol H2SO4/1 lbmol S) x (98 lb H2SO4/lbmol H2SO4) x (1 mmscf/392 MMBtu)

H2 Plant Flare Criteria and PSD Pollutant Emissions

Pollutant	Flare - N.G. Pilots			Flare - Normal H2 Plant Operation			Flare - H2 Plant Startup Operation			Flare - Potential Emissions	
	Emission Factor lb/MMBtu	Emission Rate ^g		Emission Factor lb/MMBtu	Emission Rate ^h		Emission Factor lb/MMBtu	Emission Rate ⁱ		Emission Rate ^j	
		lb/hr	tpy		lb/hr	tpy		lb/hr	tpy	lb/hr	tpy
NOx ^a	0.068	0.1	0.48	0.068	0.3	1.42	0.068	12.9	0.64	13	2.5
CO ^b	0.37	0.6	2.59	0.0074	0.035	0.15	--	75	3.77	76	6.5
SO2 (1-hr) ^c	0.0057	0.009	--	0.0057	0.027	--	4.19E-05	0.008	--	0.017	--
SO2 (24-hr) ^c	0.0053	0.008	--	0.0053	0.025	--	4.19E-05	0.008	--	0.016	--
SO2 (Annual) ^c	0.0029	--	0.02	0.0029	--	0.06	4.19E-05	--	0.0004	--	0.08
PM (Filt.) ^d	0.0025	0.004	0.02	0.0025	0.012	0.05	0.0025	0.5	0.02	0.5	0.09
PM10 (Filt. & Cond.) ^d	0.0100	0.016	0.07	0.0100	0.048	0.21	0.0100	1.9	0.09	1.9	0.37
PM2.5 ^d	0.0025	0.004	0.02	0.0025	0.012	0.05	0.0025	0.5	0.02	0.5	0.09
VOC (as CH4) ^b	0.14	0.2	0.98	0.0028	0.013	0.06	--	54	2.72	55	3.8
Lead ^e	4.9E-07	7.8E-07	3.4E-06	4.9E-07	2.3E-06	1.0E-05	4.9E-07	9.3E-05	4.6E-06	9.4E-05	1.8E-05
H2SO4 ^f	0.0002 / 0.00012	0.0004	0.0008	0.0002 / 0.00012	0.0011	0.0024	1.73E-06	3.28E-04	1.64E-05	0.0004	0.0033

notes:

a - NOx emission factor based on AP-42, Secion 13.5 (Industrial Flares).

b - CO and VOC natural gas pilot and normal H2 Plant operation feed to flare emisison factors based on AP-42, Section 13.5 (Industrial Flares), and H2 Plant startup emission rates (lb/hr) based on CO and hydrocarbon concentrations in 50% PSA feed (not including CH4). H2 plant feeds to flare (startup and normal operation) include a 98 percent control efficiency for CO and VOC emission rates.

c - SO2 pilot and normal H2 plant operation feed emission factors based on variable sulfur content of natural gas; 3-hr, 24-hr, and annual emission factors, and H2 Plant startup feed emission rate (lb/hr) based on total sulfur content in PSA gas (0.1 ppm S).

d - PM10 emission factor based on refinery source test data. PM and PM2.5 emission factors based on 25 percent of PM10 emission rate (#2 DHDS Charge Heater and No.7 Boiler Source Test Results, fraction of filterable particulate in total particulate).

e - Lead emission factor based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/MMBtu using natural gas heat content (1,020 btu/cf).

f - H2SO4 emission factors based on 2.63 percent of hourly and annual average sulfur content of fuel gas converting to H2SO4 (Source Test of #1 Reformer firing RFG).

g - Hourly and annual emission rates based on 1.6 MMBtu/hr and 8,760 hours per year of natural gas pilot.

h - Hourly and annual emission rates based on 4.8 MMBtu/hr and 8,760 hours per year of normal H2 plant operation feed to flare.

i - Hourly and annual emission rates based on 189 MMBtu/hr and 100 hours of H2 plant startup per year.

j - Potential hourly emissions based on N.G. pilot and H2 Plant startup conditions (50% PSA Feed). Potential annual emission rates based on continuous N.G. pilot, normal H2 Plant operation feed to flare, and 100 hours of H2 plant startup per year.

BP - Cherry Point Clean Fuels Project - Hydrocracker Debottleneck Emissions

Criteria and PSD Pollutant Emissions

Baseline Heat Input for Hydrocracker

	R1 Heater	1st Frac Reboiler	R4 Heater	2nd Frac Reboiler	Total
2003 Heat Input (MMBtu/yr)	315,966	1,021,949	381,819	936,304	2,656,037
2004 Heat Input (MMBtu/yr)	443,148	919,718	308,015	1,008,558	2,679,439
2005 Heat Input (MMBtu/yr)	678,852	872,714	363,774	1,266,419	3,181,758
2006 Heat Input (MMBtu/yr)	601,272	736,158	360,780	1,132,797	2,831,008
2007 Heat Input (MMBtu/yr)	564,335	954,713	315,643	1,441,294	3,275,985
2008 Heat Input (MMBtu/yr)	720,816	837,805	342,662	1,306,786	3,208,068
2009 Heat Input (MMBtu/yr)	432,764	725,367	335,581	1,113,552	2,607,264
Future Projected (MMBtu/yr)	1,059,084	1,732,728	524,724	1,605,708	4,922,244

Baseline Emissions and Future Projected Actual Emissions for Hydrocracker Heaters

NO _x Emission Increase	R1 Heater ^a	1st Frac Reboiler ^b	R4 Heater ^c	2nd Frac Reboiler ^d	Total
2003 Emissions (tpy)	15.5	138.0	26.7	32.8	212.9
2004 Emissions (tpy)	15.8	124.2	21.6	32.8	194.3
2005 Emissions (tpy)	15.8	117.8	25.5	41.2	200.2
2006 Emissions (tpy)	6.0	99.4	25.3	36.8	167.4
2007 Emissions (tpy)	9.0	128.9	22.1	42.6	202.5
2008 Emissions (tpy)	10.9	113.1	24.0	41.3	189.3
2009 Emissions (tpy)	6.2	97.9	23.5	39.2	166.9
Baseline Average (tpy) (2003 – 2004)	15.6	131.1	24.1	32.8	203.6
Baseline EF (lb/MMBtu)	0.04	0.27	0.14	0.065	--
Future EF (lb/MMBtu)	--	0.05	0.14	0.07	--
Projected Emissions (tpy)	15.8	43.3	36.7	56.2	153.0
Step 1 – NO _x Emission Increase (tpy)	0.1	0	12.6	23.4	36.2
Step 2 – NO _x Emission Reduction (tpy)	--	87.7	--	--	87.7

a - R1 Heater baseline 2007 - 2009 NO_x emissions based on CEMS data, 2000 - 2006 emissions based on emission factor and RFG use (complying with OAC #966a emission limit of 3.6 lb NO_x/hr). Future potential emissions based on hourly NO_x emission limit and continuous operation (8,760 hrs/yr).

b - 1st Frac Reboiler NO_x emissions based on past actual fuel use, projected actual heat input requirements, and engineering estimate emission factor. Projected actual emission rate (post project) based on ULNB emission factor (0.05 lb/MMBtu). Step 1 of PSD Applicability only includes project emission increases. Emission reduction included in Step 2 "Netting Analysis."

c - R4 Heater NO_x emissions based on past actual fuel use, projected actual heat input requirements, and engineering estimate emission factor.

d - 2nd Frac Reboiler baseline NO_x emissions based on emission factor and RFG use (complying with OAC #847a NO_x emission limit of 0.07 lb/MMBtu and 56.2 tpy). Future actual emissions based on annual NO_x emission limit.

Hydrocracker Debottleneck Emissions

CO Emission Increase	R1 Heater ^a	1st Frac Reboiler ^b	R4 Heater ^c	2nd Frac Reboiler ^d	Total
2003 Emissions (tpy)	6.3	20.4	7.6	18.7	53.1
2004 Emissions (tpy)	8.9	18.4	6.2	20.2	53.6
2005 Emissions (tpy)	13.6	17.5	7.3	25.3	63.6
2006 Emissions (tpy)	12.0	14.7	7.2	22.7	56.6
2007 Emissions (tpy)	11.3	19.1	6.3	28.8	65.5
2008 Emissions (tpy)	14.4	16.8	6.9	26.1	64.2
2009 Emissions (tpy)	8.7	14.5	6.7	22.3	52.1
Baseline Average (tpy) (2007-2008)	12.9	17.9	6.6	27.5	64.8
Baseline EF (lb/MMBtu)	0.040	0.040	0.040	0.040	--
Future EF (lb/MMBtu)	--	0.040	0.040	0.040	--
Projected Emissions (tpy)	23.7	34.7	10.5	32.1	100.9
CO Emission Increase (tpy)	10.8	16.7	3.9	4.6	36.1

a - R1 Heater baseline CO emissions based on 50 ppm CO emission rate (0.040 lb/MMBtu) and past actual fuel usage (complying with OAC #966a emission CO emission limit of 5.4 lb/hr). Future potential emissions based on hourly CO emission limit and continuous operation (8,760 hrs/yr). Numerous source test have been conducted on the hydrocracker heaters and almost all runs have been less than the CO analyzer detection level; therefore, BP has elected to use a conservative 50 ppm CO emission factor (0.040 lb/MMBtu) to calculate baseline actual and projected actual emission rates. The AP-42 Section 1.4 default CO emission factor converts to roughly 100 ppm CO.

b - 1st Frac Reboiler CO emissions based on past actual fuel use, projected actual heat input requirements, and 50 ppm CO emission rate (0.040 lb/MMBtu).

c - R4 Heater CO emissions based on past actual fuel use, projected actual heat input requirements, and 50 ppm CO emission rate (0.040 lb/MMBtu).

d - 2nd Frac Reboiler CO emissions based on past actual fuel use, projected actual heat input requirements, and 50 ppm CO emission rate (0.040 lb/MMBtu).

SO2 Emission Increase	R1 Heater ^a	1st Frac Reboiler ^a	R4 Heater ^a	2nd Frac Reboiler ^a	Total
2003 Emissions (tpy)	4.1	13.2	4.9	12.1	34.4
2004 Emissions (tpy)	5.7	11.9	4.0	13.1	34.7
2005 Emissions (tpy)	8.8	11.3	4.7	16.4	41.2
2006 Emissions (tpy)	7.8	9.5	4.7	14.7	36.7
2007 Emissions (tpy)	7.3	12.4	4.1	18.7	42.4
2008 Emissions (tpy)	9.3	10.9	4.4	16.9	41.6
2009 Emissions (tpy)	5.6	9.4	4.3	14.4	33.8
Baseline Average (tpy) (2007 – 2008)	8.3	11.6	4.3	17.8	42.0
Emission Factor (lb/MMBtu)	0.0259	0.0259	0.0259	0.0259	--
Projected Emissions (tpy)	13.7	22.4	6.8	20.8	63.8
SO2 Emission Increase (tpy)	5.40	10.84	2.53	3.00	21.8

a - SO2 emissions based past actual fuel use, projected heat input requirements, and annual RFG SO2 emission factor.

Hydrocracker Debottleneck Emissions

PM Emission Increase	R1 Heater ^a	1st Frac Reboiler ^a	R4 Heater ^a	2nd Frac Reboiler ^a	Total
2003 Emissions (tpy)	0.4	1.3	0.5	1.2	3.3
2004 Emissions (tpy)	0.6	1.1	0.4	1.3	3.3
2005 Emissions (tpy)	0.8	1.1	0.5	1.6	4.0
2006 Emissions (tpy)	0.8	0.9	0.5	1.4	3.5
2007 Emissions (tpy)	0.7	1.2	0.4	1.8	4.1
2008 Emissions (tpy)	0.9	1.0	0.4	1.6	4.0
2009 Emissions (tpy)	0.5	0.9	0.4	1.4	3.3
Baseline Average (tpy) (2007 – 2008)	0.8	1.1	0.4	1.7	4.1
Emission Factor (lb/MMBtu)	0.0025	0.0025	0.0025	0.0025	--
Projected Emissions (tpy)	1.3	2.2	0.7	2.0	6.2
PM Emission Increase (tpy)	0.521	1.046	0.244	0.290	2.1

a - PM emissions based past actual fuel use, potential heat input requirements, and an emission factor based on source test results (25 percent of total particulate is filterable).

PM10 Emission Increase	R1 Heater ^a	1st Frac Reboiler ^a	R4 Heater ^a	2nd Frac Reboiler ^a	Total
2003 Emissions (tpy)	1.6	5.1	1.9	4.7	13.3
2004 Emissions (tpy)	2.2	4.6	1.5	5.0	13.4
2005 Emissions (tpy)	3.4	4.4	1.8	6.3	15.9
2006 Emissions (tpy)	3.0	3.7	1.8	5.7	14.2
2007 Emissions (tpy)	2.8	4.8	1.6	7.2	16.4
2008 Emissions (tpy)	3.6	4.2	1.7	6.5	16.0
2009 Emissions (tpy)	2.2	3.6	1.7	5.6	13.0
Baseline Average (tpy) (2007 – 2008)	3.2	4.5	1.6	6.9	16.2
Emission Factor (lb/MMBtu)	0.010	0.010	0.010	0.010	--
Projected Emissions (tpy)	5.3	8.7	2.6	8.0	24.6
PM10 Emission Increase (tpy)	2.08	4.182	0.98	1.16	8.4

a - PM10 emissions based past actual fuel use, potential heat input requirements, and an emission factor based on source test results.

PM2.5 Emission Increase	R1 Heater ^a	1st Frac Reboiler ^a	R4 Heater ^a	2nd Frac Reboiler ^a	Total
2003 Emissions (tpy)	0.4	1.3	0.5	1.2	3.3
2004 Emissions (tpy)	0.6	1.1	0.4	1.3	3.3
2005 Emissions (tpy)	0.8	1.1	0.5	1.6	4.0
2006 Emissions (tpy)	0.8	0.9	0.5	1.4	3.5
2007 Emissions (tpy)	0.7	1.2	0.4	1.8	4.1
2008 Emissions (tpy)	0.9	1.0	0.4	1.6	4.0
2009 Emissions (tpy)	0.5	0.9	0.4	1.4	3.3
Baseline Average (tpy) (2007 – 2008)	0.8	1.1	0.4	1.7	4.1
Emission Factor (lb/MMBtu)	0.0025	0.0025	0.0025	0.0025	--
Projected Emissions (tpy)	1.3	2.2	0.7	2.0	6.2
PM2.5 Emission Increase (tpy)	0.521	1.046	0.244	0.290	2.1

a - PM2.5 emissions based past actual fuel use, potential heat input requirements, and an emission factor based on source test results (25 percent of total particulate is filterable).

Hydrocracker Debottleneck Emissions

VOC Emission Increase	R1 Heater ^a	1st Frac Reboiler ^a	R4 Heater ^a	2nd Frac Reboiler ^a	Total
2003 Emissions (tpy)	0.9	2.8	1.0	2.5	7.2
2004 Emissions (tpy)	1.2	2.5	0.8	2.7	7.2
2005 Emissions (tpy)	1.8	2.4	1.0	3.4	8.6
2006 Emissions (tpy)	1.6	2.0	1.0	3.1	7.6
2007 Emissions (tpy)	1.5	2.6	0.9	3.9	8.8
2008 Emissions (tpy)	1.9	2.3	0.9	3.5	8.6
2009 Emissions (tpy)	1.2	2.0	0.9	3.0	7.0
Baseline Average (tpy) (2007 – 2008)	1.7	2.4	0.9	3.7	8.7
Emission Factor (lb/MMBtu)	0.0054	0.0054	0.0054	0.0054	--
Projected Emissions (tpy)	2.9	4.7	1.4	4.3	13.3
VOC Emission Increase (tpy)	1.123	2.255	0.527	0.625	4.5

a - VOC emissions based on past actual fuel use, potential heat input requirements, and AP-42 Section 1.4 VOC emission factor converted to lb/MMBtu.

Pb Emission Increase	R1 Heater ^a	1st Frac Reboiler ^a	R4 Heater ^a	2nd Frac Reboiler ^a	Total
2007 Emissions (tpy)	1.4E-04	2.3E-04	7.7E-05	3.5E-04	8.0E-04
2008 Emissions (tpy)	1.8E-04	2.1E-04	8.4E-05	3.2E-04	7.9E-04
2009 Emissions (tpy)	1.1E-04	1.8E-04	8.2E-05	2.7E-04	6.4E-04
Baseline Average (tpy) (2007 – 2008)	1.6E-04	2.2E-04	8.1E-05	3.4E-04	7.9E-04
Emission Factor (lb/MMBtu)	4.9E-07	4.9E-07	4.9E-07	4.9E-07	--
Potential Emissions (tpy)	2.6E-04	4.2E-04	1.3E-04	3.9E-04	1.2E-03
Pb Emission Increase (tpy)	1.0E-04	2.1E-04	4.8E-05	5.7E-05	4.1E-04

a - Lead emissions based on past actual fuel use, potential heat input requirements, and AP-42 Section 1.4 lead emission factor converted to lb/MMBtu.

H2SO4 Emission Increase	R1 Heater ^a	1st Frac Reboiler ^a	R4 Heater ^a	2nd Frac Reboiler ^a	Total
2007 Emissions (tpy)	0.3	0.5	0.2	0.8	1.7
2008 Emissions (tpy)	0.4	0.4	0.2	0.7	1.7
2009 Emissions (tpy)	0.2	0.4	0.2	0.6	1.4
Baseline Average (tpy) (2007 – 2008)	3.4E-01	4.7E-01	1.7E-01	7.2E-01	1.7
Emission Factor (lb/MMBtu)	0.0011	0.0011	0.0011	0.0011	--
Projected Emissions (tpy)	0.6	0.9	0.3	0.9	2.6
H2SO4 Emission Increase (tpy)	0.232	0.461	0.109	0.143	0.9

a - H2SO4 emissions based on past actual fuel use, potential heat input requirements, and 2.63 percent of SO2 converting to H2SO4 (Source Test of #1 Reformer firing RFG).

BP - Cherry Point Clean Fuels Project - SRU Increase Utilization Emissions

Increase in Total Criteria Pollutant Emission Increases Attributable to Project

Fuel Characteristics

Energy value of natural gas	1,036 Btu/scf	Source: Natural Gas Analyses
Energy value of tail gas	15.6 Btu/scf	Source: Tail Gas Analysis
Energy value of hydrogen gas	345.7 Btu/scf	Source: Hydrogen Gas Analysis

Sulfur Production

Annual Average Sulfur Production During 2007 & 2008	71,266 lt/yr	Source: SRU emission inventory calculations for 2007 and 2008
Projected Increase in Sulfur Production	15 lt/day	Source: BP, assume 365 days/yr
Projected Annual Average Daily Sulfur Production Rate	76,741 lt/yr	

Baseline Heat Input for Sulfur Plant

	SRU Incinerator	TGU #2	Total	Baseline Heat Input	Period
2003 Heat Input (MMBtu/yr)	209,360	--	209,360	--	--
2004 Heat Input (MMBtu/yr)	188,373	--	188,373	198,867	2003-2004
2005 Heat Input (MMBtu/yr)	190,359	--	190,359	189,366	2004-2005
2006 Heat Input (MMBtu/yr)	258,869	2,476	261,345	225,852	2005-2006
2007 Heat Input (MMBtu/yr)	337,582	2,932	340,514	300,930	2006-2007
2008 Heat Input (MMBtu/yr)	341,487	20,887	362,374	351,444	2007-2008

2007- 2008 Baseline =351,444 MMBtu/yr

Projected Heat Input Increase based on Baseline Operations

Projected annual heat input Increase (MMBtu/yr) 26,999 MMBtu/yr Basis: (2007 – 2008 Baseline heat input / 2007-2008 Baseline sulfur production) X Projected Annual Increase in sulfur production

SRU Increase Utilization Emissions

Baseline Sulfur Plant Emissions

Year	Sulfur Production (lt/yr)	SRU Incinerator (tons/year)			#2 TGU (tons/year)		
		NOx	CO	SO2	NOx	CO	SO2
2003	67,017	8.32	141.91	37.91	--	--	--
2004	56,736	8.18	139.45	105.33	--	--	--
2005	59,228	8.32	141.91	26.85	--	--	--
2006	61,138	8.2	139.9	37.91	3.35	3.32	11.47
2007	68,463	8.32	141.91	49.55	0.39	0.39	1.34
2008	74,070	8.34	142.3	55.18	1.93	2.41	13.02

Increase annual sulfur dioxide emissions in proportion to increased daily elemental sulfur production:

Baseline SO2 Emissions (2007-2008) = 59.5 tons SO2/yr Basis: SRU Incinerator and #2 TGU
 Projected SO2 Emissions based on Sulfur Prod. Increase = 64.1 tons SO2/yr Basis: = 59.5 tpy SO2*(76,741 lt/yr sulfur/71,266 lt/yr sulfur)
 Projected SO2 Emission Increase = 4.6 tons SO2/yr

SRU Increase Utilization Emissions

Criteria and PSD Pollutant Emission Increases

Pollutant	Sulfur Plant Emission Factors			Projected Actual Emissions (tpy)	Baseline Emissions (tpy)	Emission Increase (tpy)	Baseline Period (24-month period)
	SRU Incinerator Max. Emission Factor	TGU #2 Emission Factor	Maximum Emission Factor				
NO _x ^a	1.9 lb/hr	2.3 lb/hr	2.3 lb/hr	10.6	8.3	2.4	2003-2004
CO ^a	32.4 lb/hr	2.80 lb/hr	32.4 lb/hr	152.8	143.5	9.3	2007-2008
SO ₂ ^b	--	--	--	64.1	59.5	4.6	2007-2008
PM (Filt.) ^c	0.0025 lb/MMBtu	0.0025 lb/MMBtu	0.0025 lb/MMBtu	0.47	0.44	0.03	2007-2008
PM10 (Filt. & C) ^c	0.0100 lb/MMBtu	0.0100 lb/MMBtu	0.0100 lb/MMBtu	1.89	1.76	0.13	2007-2008
PM2.5 (Filt.) ^c	0.0025 lb/MMBtu	0.0025 lb/MMBtu	0.0025 lb/MMBtu	0.47	0.44	0.03	2007-2008
VOC ^d	0.0054 lb/MMBtu	0.0054 lb/MMBtu	0.0054 lb/MMBtu	1.02	0.95	0.07	2007-2008
Lead ^d	4.9E-07 lb/MMBtu	4.9E-07 lb/MMBtu	4.9E-07 lb/MMBtu	9.3E-05	8.6E-05	6.6E-06	2007-2008
H ₂ SO ₄ ^e	2.63% of sulfur	0.22 lb/hr	2.63% of sulfur	2.6	2.4	0.18	2007-2008

- notes:
- a - NO_x and CO emission rates (lb/hr) based on source tests (SRU - 3/13/2008 and TGU - 8/26/2006 & 10/14/2008), projected actual emission rates are based on maximum emission factor scaled by the increase in sulfur production (5,475 lt/yr compared to 2007-2008 average 71,266 lt/yr sulfur) and annual operations of 8,760 hours/year.
 - b - Baseline annual SO₂ emission rate based on 2007-2008 emissions. Future emission rate increase based on 2007 - 2008 sulfur production and potential increase in elemental sulfur production.
 - c - PM10 emission factor based on refinery source test data. PM and PM2.5 emission factors based on 25 percent of PM10 emission rate (#2 DHDS Charge Heater and #7 Boiler Source Test Results, fraction of filterable particulate in total particulate). Baseline emissions based on 2007-2008 baseline heat input rate (351,444 MMBtu/yr), and future emission rate based on baseline heat input and projected annual increase in heat input rate (26,999 MMBtu/yr).
 - d - VOC and Lead emission factors based on AP-42, Section 1.4 (Natural Gas Combustion) corrected to lb/MMBtu using natural gas heat content (1,020 btu/cf). Baseline emissions based on 2007-2008 baseline heat input rate (351,444 MMBtu/yr), and future emission rate based on baseline heat input and projected annual increase in heat input rate (26,999 MMBtu/yr).
 - e - SRU H₂SO₄ emission factor based on 2.63 percent of sulfur converting to H₂SO₄ (Source Test of #1 Reformer firing RFG) and 8,760 hours/year. TGU #2 emission rate (lb/hr) based on average from source tests (8/24/2006 & 10/14/2008). Baseline and future emission rates based on SO₂ emissions.