

COMMONWEALTH OF PENNSYLVANIA
Department of Environmental Protection
Southwest Regional Office

MEMO

TO Air Quality Permit File PA-04-00740A

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DATE April 1, 2015

RE Plan Approval Application
Shell Chemical Appalachia LLC
Petrochemicals Complex, Ethylene and Polyethylene Manufacturing
Potter and Center Townships, Beaver County
APS # 841785, Auth # 1024467, PF # 775836

BACKGROUND

RTP Environmental Associates, Inc. ("RTP") has submitted a plan approval application on behalf of Shell Chemical Appalachia LLC ("Shell") on May 1, 2014, for the construction of a petrochemicals complex to be located in Potter Township, Beaver County. A relatively small part of the property is to be located in neighboring Center Township. This site has historically been used for industrial purposes and is located on the southern bank of the Ohio River approximately 2.5 miles southwest of the town of Monaca. Shell proposes to construct the following air contamination sources and controls under PA-04-00740A authorization at this site:

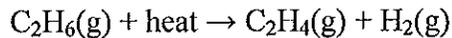
- Seven (7) tail gas- and natural gas-fired ethane cracking furnaces, 620 MMBtu/hr heat input rating each; equipped with low-NO_x burners and controlled by selective catalytic reduction (SCR).
- One (1) ethylene manufacturing line, 1,500,000 metric tons/yr; compressor seal vents and startup/shutdown/maintenance/upsets controlled by the high pressure header system (HP System).
- Two (2) gas phase polyethylene manufacturing lines, 550,000 metric tons/yr each; VOC emission points controlled by the low pressure header system (LP System) or HP System, PM emission points controlled by filters.
- One (1) slurry technology polyethylene manufacturing line, 500,000 metric tons/yr; VOC emission points controlled by the LP System or HP System, PM emission points controlled by filters.

- One (1) LP System; routed to the LP incinerator, 10 metric tons/hr capacity, with backup multipoint ground flare (MPGF), 74 metric tons/hr total capacity.
- One (1) HP System; routed to two (2) HP enclosed ground flares 150 metric tons/hr capacity each, with backup emergency elevated flare, 1,500 metric tons/hr capacity.
- Three (3) General Electric, Frame 6B, natural gas-fired combustion turbines, 40.6 MW (475 MMBtu/hr heat input rating) each, including natural gas- or tail gas-fired duct burners, 189 MMBtu/hr heat input rating each; controlled by SCR and oxidation catalysts.
- Four (4) diesel-fired emergency generator engines, 5,028 bhp rating each.
- Three (3) diesel-fired fire pump engines, 700 bhp rating each.
- One (1) process cooling tower, 28 cell counter-flow mechanical draft, 18.3 MMgal/hr water flow capacity; controlled by drift eliminators.
- One (1) cogen cooling tower, 6 cell counter-flow mechanical draft, 4.44 MMgal/hr water flow capacity; controlled by drift eliminators.
- Polyethylene pellet blending, handling, storage, and loadout; controlled by fabric filters.
- Liquid loadout, coke residue/tar and recovered oil; controlled by vapor capture and routing back to the process or Spent Caustic Vent incinerator, and low-leak couplings.
- Liquid loadout, pyrolysis fuel oil and light gasoline; controlled by vapor capture and routing to the LP System, and low-leak couplings.
- Liquid loadout, C₃+; controlled by pressurized transfer with vapor balance and low-leak couplings.
- One (1) recovered oil, one (1) spent caustic, and two (2) equalization wastewater storage tanks, 23,775 to 742,324 gallon capacities; controlled by internal floating roofs (IFR) and vapor capture routed to the Spent Caustic Vent incinerator, 8 metric tons/hr capacity.
- One (1) light gasoline, and two (2) hexene storage tanks; 85,856 and 607,596 gallon capacities; controlled by IFR and vapor capture routed to the LP System.
- Two (2) pyrolysis fuel oil storage tanks; 85,856 gallon capacity; controlled by vapor capture routed to the LP System.
- Miscellaneous storage tanks, diesel fuel, 1,849 to 10,038 gallon capacities; controlled by carbon canisters.
- Miscellaneous components in gas, light liquid, and heavy liquid service; controlled by leak detection and repair (LDAR).
- Wastewater treatment plant (WWTP).
- Plant roadways; controlled by paving and a road dust control plan including sweeping and watering (as necessary).

This is the former site of Horsehead Corporation's Monaca Zinc Smelter plant. The Monaca Zinc Smelter originally began operating in the 1930's and was authorized for operation under TV-04-00044 issued on November 20, 2000. The associated G.F. Wheaton Power Plant was closed on September 11, 2011, and all other remaining air contamination sources including the smelter ceased operations by April 26, 2014. There are currently three active air quality authorizations at this site. Brandenburg Industrial Service Company is authorized under GP3-04-00739A and GP9-04-00739A to operate a portable nonmetallic mineral processing plant to crush and screen concrete, brick, and block material created from the demolition of the Monaca Zinc Smelter plant. Horsehead Corporation is authorized under GP11-04-00044 to operate a

nonroad diesel-fired generator engine for on-site power during demolition. Demolition activities will be completed and any associated air contamination sources will cease operation before construction of this new facility commences.

Shell intends to convert ethane feedstock into ethylene for manufacturing on site into various grades of linear low density and high density polyethylene as the facility's final product. Ethane will be heated in the presence of steam within seven tail/natural gas-fired furnaces in order to "crack" the molecule into hydrogen and ethylene. The primary desired reaction is:



Six furnaces will be cracking ethane at any one time with a seventh rotated out for decoking, hot-standby, or maintenance. Byproducts of the ethylene production process include coke residue/tar, light gasoline, pyrolysis fuel oil, and a C₃+ mixture. These byproducts will be removed from the site for disposal or use as appropriate. Any unreacted ethane will be recycled back into the furnaces. Hydrogen (including some methane) tail gas will be recovered and primarily utilized as the majority fuel for the furnaces. All produced ethylene will be routed to one of three polyethylene manufacturing lines at the facility.

Polyethylene will be manufactured in either one of two gas phase or one slurry technology polyethylene manufacturing lines. Produced ethylene will be reacted with imported and purified co-monomers and hydrogen to form a resin which will then be degassed, mixed with additives, and then pelletized. Finished polyethylene pellets are dried, blended, and transported to silos prior to final transport from the facility via truck or rail. Multiple production lines will allow the manufacture of varying grades of low and high density polyethylene polymers. Design production capacity of this facility will be 1.6 million metric tons of polyethylene per year.

An electric and steam cogeneration plant will be co-located at this facility for providing all the steam and electricity necessary for the ethane cracking process and ethylene/polyethylene manufacturing lines. The plant will consist of three General Electric Frame 6B natural gas-fired turbines with duct burners and heat recovery steam generators (HRSG). Total electric generating capacity of the cogeneration plant will be 250.4 MW from three turbine generators at 40.6 MW and two HRSG steam turbine generators at 64.3 MW. Excess electricity generated at this facility will be sold to the grid in quantities sufficient to classify this facility as an electric utility.

Primary air contaminants of concern from this facility will be NO_x, CO, PM₁₀, PM_{2.5}, VOC, HAP, and CO₂ products of combustion from the cracking furnaces, combined cycle turbines, flares, and incinerators; and VOC and HAP from the polyethylene units, liquid loadout, component fugitives, and process cooling tower. This will be a Title V facility because potential to emit (PTE) from multiple pollutants will exceed the major source thresholds.

The application was hand delivered on May 1, 2014, after final pre-application meetings and preparation at the Pennsylvania Department of Environmental Protection's ("Department's") Southwest Regional Offices on April 30 and May 1, 2014. Application materials were determined to be Administrative Complete by May 15, 2014, including a determination of completeness for the air quality analysis for Prevention of Significant Deterioration (PSD) by

Andrew Fleck of the Department's Air Quality Modeling Section. A letter of Administrative Completeness was mailed to the applicant on May 15, 2014.

A meeting was held with the applicant on August 20, 2014, to discuss intended updates to the plan approval application including addition of the MPGF, selection of the General Electric turbines, committing to on-site oxidation and treatment of spent caustic, and other process design updates. The above-referenced application updates were received as a formal technical supplement on September 25, 2014. A site visit of Shell Chemical LP's Deer Park olefins plant in Houston, TX was conducted by myself on September 30, 2014, including primarily cracking furnaces and downstream processing steps which are similar to this proposed project. Previously submitted application updates were discussed in further detail as well as requirements related to the cracking furnaces. An update to the application's air quality analysis for PSD was received on October 15, 2014, including the addition of a refined air quality analysis for CO and PM₁₀. Draft plan approval conditions were shared with the applicant on November 7, 2014. A meeting was held with the applicant on December 4 and 5, 2014, to discuss draft plan approval conditions and the ongoing application review process. An inhalation risk assessment was received on January 28, 2015, evaluating the chronic and acute risks due to exposure to compounds of potential concern from the project. An economic impact analysis conducted by the Robert Morris University – School of Business was received on February 5, 2015, as a supplement to the original analysis included in Appendix E of the application. An updated application was received by the Department on March 3, 2015 (titled February 2015 Update), incorporating all prior application changes to date. The Department's Air Quality Modeling Section completed an independent air quality analysis for a risk assessment, and the Department's Air Toxics and risk Assessment Section completed an independent risk assessment for this facility on March 19, 2015. The Department's Air Quality Modeling Section completed a technical review of the air quality analysis for PSD for this facility on March 19, 2015.

Inventory data related to other air contamination source in the Southwest PA regional area was collected and shared with the applicant both prior to and during the course of this application review for the purpose of multi-source modeling of NO_x, CO, and PM₁₀. Additional information was requested from the applicant during the course of this application review. This included regulatory applicability, requirements, and references; emission rate calculations and supporting documentation; air toxics modeling; single source determination; and testing and monitoring methods. All requested information was received by January 30, 2015.

REGULATORY ANALYSIS

Per 25 Pa. Code §127.1, new sources shall control emissions to the maximum extent, consistent with the best available technology (BAT) as determined by the Department as of the date of issuance of the plan approval for the new source. The proposed ethane cracking furnaces, ethylene and polyethylene manufacturing processes, turbines, duct burners, cooling towers, flares, incinerators, liquids loadout, emergency engines, process components, storage tanks, WWTP, and roadway traffic meet the definition of a *New source* under 25 Pa. Code §121.1.

Per 25 Pa. Code §127.11, approval by the Department is required to allow the construction of an air contamination source or installation of an air cleaning device on an air contamination source.

The proposed ethane cracking furnaces, ethylene and polyethylene manufacturing processes, turbines, duct burners, cooling towers, flares, incinerators, liquids loadout, emergency engines, process components, storage tanks, WWTP, and roadway traffic meet the definition of *Air contamination source* as defined under 25 Pa. Code §121.1. The proposed SCR, oxidation catalysts, HP System, LP System, incinerators, ground flares, MPGF, elevated flare, fabric filters, carbon canisters, IFR, drift eliminators, and roadway dust suppression meet the definition of *Air cleaning device* as defined under 25 Pa. Code §121.1.

The applicant intends to, and is expected to be capable of, meeting the plan approval exemption criteria of 25 Pa. Code §127.14(d) and listed as No. 6 in the Department's Plan Approval and Operating Permit Exemptions list under 25 Pa. Code § 127.14(a)(8)¹ for the collection of all diesel-fired engines to be located at this site. This exemption is based upon actual short and long term NO_x emissions, and includes the four emergency generator and three fire pump engines. Each engine has been accounted for in this plan approval application and evaluated for regulatory applicability. Applicable requirements will still be included as plan approval conditions for convenience and later incorporation into an operating permit.

25 Pa. Code §§123.1, 123.2 relating to fugitive emissions will apply to this facility and have been included as plan approval conditions.

25 Pa. Code §123.11(a) relating to particulate matter emissions from combustion units applies to the proposed furnaces. The applicable particulate matter limitation of 0.10 lb/MMBtu of heat input is superseded by a more stringent limit of 0.005 lb/MMBtu through the application of Lowest Achievable Emission Rate (LAER) requirements to PM_{2.5} and Best Available Control Technology (BACT) requirements to PM₁₀. The more stringent limitation has been included as a plan approval condition. Compliance with the 25 Pa. Code §123.11(a) limitation would be expected in any case due to combustion of tail gas or natural gas.

25 Pa. Code §123.12 relating to particulate matter emissions from incinerators applies to the proposed incinerators. The applicable particulate matter limitation of 0.1 grain/dscf at 12% CO₂ is superseded by a more stringent limit of 0.0075 lb/MMBtu through the application of LAER requirements to PM_{2.5} and BACT requirements to PM₁₀. The more stringent limitation has been included as a plan approval condition. Compliance with the 25 Pa. Code §123.12 limitation would be expected in any case because the incinerators will combust gaseous waste streams.

25 Pa. Code §123.13 relating to particulate matter emissions from processes applies to all processes except combustion units, incinerators, and pulp mill smelt dissolving tanks. Limits ranging between 0.04 gr/dscf (for processes with effluent gas volume less than 150,000 dscfm) and 0.02 gr/dscf (for processes with effluent gas volume greater than 300,000 dscfm) apply to the turbines, duct burners, diesel-fired engines, flares, process vents, cooling towers and polyethylene pellet handling vents. These limits however are superseded by more stringent LAER and BACT limits which have been included as plan approval conditions.

¹ Pennsylvania Department of Environmental Protection Air Quality, Document No. 275-2101-003, *Air Quality Permit Exemptions*, Effective July 26, 2003, and August 10, 2013, p.4.

Per 25 Pa. Code §123.21(b), "No person may permit the emission into the outdoor atmosphere of sulfur oxides from a source in a manner that the concentration of the sulfur oxides, expressed as SO₂, in the effluent gas exceeds 500 parts per million, by volume, dry basis." The proposed turbines, duct burners, engines, flares, and incinerators will be subject to this limitation; while the proposed furnaces will be subject to a different limit for combustion units. Diesel-fired engines will be subject to the requirements of 40 CFR Part 60 Subpart IIII which applies a more stringent fuel sulfur content of 15 ppm. Compliance with this limitation will be achieved by other sources through the combustion of tail gas, natural gas, or gaseous waste streams.

Per 25 Pa. Code §123.22(d)(1), "...A person may permit the emission into the outdoor atmosphere of sulfur oxides, expressed as SO₂, from a combustion unit in excess of... (ii) The rate determined by the following formula: $A = 1.7E^{-0.14}$ where: A = Allowable emissions in pounds per million Btu of heat input, and E = Heat input to the combustion unit in millions of Btus per hour when E is equal to or greater than 50 but less than 2,000." The proposed furnaces will be located in the Lower Beaver Valley air basin, be rated at 620 MMBtu/hr each, and meet the definition of a *Combustion unit* under 25 Pa. Code §121.1. The calculated limit at 620 MMBtu/hr is 0.69 lb/MMBtu. These combustion units will be in compliance with this emission limitation through the combustion of only tail gas or natural gas.

25 Pa. Code §§123.31 relating to malodors will apply to this facility and has been included as a plan approval condition.

Per 25 Pa. Code §123.41, visible air emissions are limited to less than 20% opacity in any three minute period in any hour and to less than 60% at any time. Recent BAT determinations however have resulted in limiting visible air emissions from natural gas-fired process heaters (combustion units), and diesel-fired engines to less than 10% opacity in any three minute period in any hour and to less than 30% at any time. Additionally, Federal control device requirements for flares prohibit visible air emissions except for up to five minutes in any consecutive two-hour period. This prohibition of visible air emissions has been extended to the incinerators which are expected to have more complete combustion. The more stringent visible emission limitations have been included as plan approval conditions for the appropriate source categories.

Facility-wide inspections for the presence of visible stack emissions, fugitive emissions, or potentially objectionable odors have been conditioned into the plan approval. This is consistent with recent plan approvals issued by the Department and for purposes of demonstrating compliance with visible stack emission, fugitive emission, and malodor limitations. The Department has final responsibility for determining if an odor is objectionable to the public and therefore a *malodor* as defined under 25 Pa. Code §121.1

25 Pa. Code §123.46 relating to continuous opacity monitoring will not apply to this facility. Potentially affected combustion sources, including the ethane cracking furnaces and combined cycle turbines, will be restricted to firing natural gas and/or a combination of natural gas, hydrogen, and methane. Exemption from continuous opacity monitoring is granted per 25 Pa. Code §123.46(a)(1)(i) in any case where natural gas is the only fuel burned. Combustion of natural gas in combination with hydrogen and methane will have less potential to emit particulate matter and visible emissions compared to combustion natural gas alone. Water is the product of combustion for hydrogen fuel while methane is already both the primary constituent of and

lightest hydrocarbon present in natural gas. Exemption from continuous opacity monitoring is also granted per 25 Pa. Code §123.46(a)(1)(ii) where “Oil or a mixture of gas and oil are the fuels burned and the source is able to comply with the applicable particulate matter and opacity regulations without utilization of particulate matter collection equipment and the source has not been found, within the 5 years previous to the applicability of this section, through any administrative or judicial proceedings to be in violation of any visible emissions standard.” Shell will be required to conduct observations for the presence of any visible stack emissions and keep records of these observations. All records will be required to be maintained for a minimum of five years.

25 Pa. Code §123.51 related to nitrogen compounds monitoring applies to the furnaces and combined cycle turbines. The furnaces and combined cycle turbines are each combustion units rated at least 250 MMBtu/hr with an annual capacity factor greater than 30%. The combined cycle turbines will qualify as combustion units because exhaust gases from both the combustion turbine and duct burners will primarily produce steam by indirect heat transfer in heat recovery steam generators. Requirements under this section include installation of NO_x continuous emissions monitoring systems (CEMS), and results submittals and minimum data availability in accordance with 25 Pa. Code Chapter 139 Subchapter C. These requirements have been included as plan approval conditions.

25 Pa. Code §129.14 related to open burning applies to this facility and has been included as a plan approval condition. This facility will be located in the Lower Beaver Valley air basin and specific requirements for facilities located outside of an air basin have been omitted from the condition.

25 Pa. Code §129.56 – Storage tanks greater than 40,000 gallons capacity containing VOCs, will apply to various storage tanks to be located at this facility. Per 25 Pa. Code §129.56, “No person may permit the placing, storing or holding in a stationary tank, reservoir or other container with a capacity greater than 40,000 gallons of volatile organic compounds with a vapor pressure greater than 1.5 psia (10.5 kilopascals) under actual storage conditions unless the tank, reservoir or other container is a pressure tank capable of maintaining working pressures sufficient at all times to prevent vapor or gas loss to the atmosphere or is designed and equipped with one of the following vapor loss control devices... an external or internal floating roof... [or a] vapor recovery system...” These control requirements are expected to apply to the light gasoline, hexene, and heated pyrolysis fuel oil tanks; but will be superseded by more stringent LAER control requirements. All other storage tanks at this facility will be pressurized, sized at or less than 40,000 gallons (~151.4 m³), not contain VOC, or have a vapor pressure at or less than 1.5 psia.

25 Pa. Code §129.57 – Storage tanks less than or equal to 40,000 gallons capacity containing VOCs, will apply to any atmospheric pressure truck or railcar storage tank to which light gasoline will be transferred. Per 25 Pa. Code Section 129.57, “The provisions of this section apply to above ground stationary storage tanks with a capacity equal to or greater than 2,000 gallons which contain volatile organic compounds with vapor pressure greater than 1.5 psia (10.5 kilopascals) under actual storage conditions.” Each truck or railcar storage tank is expected to have a storage capacity between 2,000 and of 40,000 gallons and the vapor pressure of the light gasoline has been identified as approximately 7.5 psia. Also, per 25 Pa. Code Section 121.1,

“Mobile air contamination source... does not include a source mounted on a vehicle, whether the mounting is permanent or temporary, which source is not used to supply power to the vehicle.” During loading of light gasoline to the trucks or railcars, each tank is controlled by a vapor recovery to the LP System and incinerator. This meets the more stringent requirements of 25 Pa. Code Section 129.56 and therefore exceeds the requirements of 129.57. This section will not apply to the dimethyl disulfide storage tank at this facility because it will be pressurized. This section will not apply to the diesel fuel or recovered oil storage tanks at this facility because each will have a vapor pressure below 1.5 psia under actual storage conditions. Diesel fuel storage tanks are to be controlled by carbon canisters while the recovered oil storage tank is to be controlled by the Spent Caustic Vent incinerator in any case.

Per 25 Pa. Code §129.65, “No person may permit the emission into the outdoor atmosphere of a waste gas stream from an ethylene production plant or facility unless the gas stream is properly burned at no less than 1,300°F for at least [0.3] seconds; except that no person may permit the emission of volatile organic compounds in gaseous form into the outdoor atmosphere from a vapor blowdown system unless these gases are burned by smokeless flares.” This facility will be subject to these requirements and this citation has been included as a plan approval condition. Installation and operation of the HP System with MPGF and emergency elevated flare shall be capable of meeting this requirement.

25 Pa. Code §129.71 applies LDAR requirements to ethylene (listed in 40 CFR 60.489) and polyethylene manufacturing fugitive sources. Shell’s proposed ethylene and polyethylene manufacturing facility will be subject to these requirements. However, per 25 Pa. Code §129.71(d), “The owner or operator of a facility subject to this section may submit to the Department an alternative plan for the control of leaks from components. If the Department finds that the alternative plan will achieve an emission reduction which is equivalent to or greater than the reduction which can be achieved under this section and that the alternative plan is as enforceable as this section, the Department may approve the alternative plan.” These LDAR requirements are superseded by more stringent LAER control requirements for sources of VOC at this facility which have been included as plan approval conditions.

25 Pa. Code §129.93 applies presumptive reasonably achievable control technology (RACT) emission limitations to sources at a major NO_x emitting facility. Presumptive RACT will be satisfied through the application of LAER control requirements for sources of NO_x at this facility in accordance with 25 Pa. Code §129.93(c)(6). Emergency generator and fire pump engines will also meet presumptive RACT through limited operational hours in accordance with 25 Pa. Code §129.93(c)(5).

Per 25 Pa. Code §145.4(a)(iii), any unit commencing operation on or after January 1, 1999, and serving a generator at any time that has a nameplate capacity greater than 25 MWe and produces electricity for sale, is a NO_x budget unit subject to the requirements of this subchapter. However, per 25 Pa. Code §145.8(c), “The emission limitations and monitoring requirements established in Subchapter A (relating to NO_x Budget Trading Program) are replaced by the requirements in Subchapter D beginning with the May 1, 2010, control period.” Subchapter D incorporates by reference the Clean Air Interstate Rule (CAIR) NO_x Annual Trading Program and CAIR NO_x Ozone Season Trading Program as a means of mitigating the interstate transport of fine particulates and NO_x, and the CAIR SO₂ Trading Program as a means of mitigating the interstate

transport of fine particulates and SO₂. CAIR was briefly replaced by the Cross-State Air Pollution Rule (CSAPR) when it was finalized on July 6, 2011, before CSAPR was stayed and then subsequently vacated by the U.S. Court of Appeals for the D.C. Circuit in a second ruling on August 21, 2012. The U.S. Court of Appeals for the D.C. Circuit's judgment was reversed by the U.S. Supreme Court on April 29, 2014, and the stay on CSAPR was later lifted on October 23, 2014. CAIR and 25 Pa. Code Chapter 145 Subchapter D, which incorporates CAIR by reference, are now both superseded by CSAPR. Implementation dates for CSAPR have been reset by EPA in an interim final rule published on December 3, 2014.² Shell will therefore be required to comply with CSAPR as set forth in 40 CFR Part 97 Subparts AAAAA through CCCCC and required under 40 CFR §§52.38 and 52.39.

New Source Performance Standards (NSPS) from 40 CFR Part 60 Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators will not apply to this facility. Per 40 CFR §60.40(e), “Any facility subject to either subpart Da or KKKK of this part is not subject to this subpart.” The proposed combustion turbines with associated heat recovery steam generators and duct burners will be subject to the requirements of 40 CFR Part 60 Subpart KKKK and therefore not subject to 40 CFR Part 60 Subpart D.

NSPS from 40 CFR Part 60 Subpart Da – Standards of Performance for Electric Utility Steam Generating Units will not apply to this facility. Per 40 CFR §60.40Da(e)(1), “Affected facilities (*i.e.* heat recovery steam generators used with duct burners) associated with a stationary combustion turbine that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel are subject to this subpart except in cases when the affected facility (*i.e.* heat recovery steam generator) meets the applicability requirements of and is subject to subpart KKKK of this part.” The proposed combustion turbines with associated heat recovery steam generators and duct burners will be subject to the requirements of 40 CFR Part 60 Subpart KKKK and therefore not subject to 40 CFR Part 60 Subpart Da.

NSPS from 40 CFR Part 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units will not apply to this facility. Per 40 CFR §60.40b(i), “Affected facilities (*i.e.*, heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart.” The proposed combustion turbines with associated heat recovery steam generators and duct burners will be subject to the requirements of 40 CFR Part 60 Subpart KKKK and therefore not subject to 40 CFR Part 60 Subpart Db.

NSPS from 40 CFR Part 60 Subpart E – Standards of Performance for Incinerators will not apply to this facility. Per 40 CFR §60.51(a), “*Incinerator* means any furnace used in the process of burning solid waste for the purpose of reducing the volume of the waste by removing combustible matter.” The proposed incinerators will burn gaseous waste collected from process vents and the LP System and are therefore not subject to 40 CFR Part 60 Subpart E.

NSPS from 40 CFR Part 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 will apply

² *Federal Register*, Vol. 79, No. 232 Wednesday, December 3, 2014, Rules and Regulations, p. 71663.

to the two hexene and two pyrolysis fuel oil storage tanks at this facility. Per 40 CFR §60.110b, “(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m³) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.” Paragraph (b), as well as paragraph (d), under the same section identifies storage vessel subcategories for which this subpart does not apply. An additional exemption from compliance with this subpart is found under 40 CFR §63.1100(g)(1)(ii) for storage vessels subject to the control requirements of 40 CFR Part 63 Subpart YY. The hexene storage tanks capacity will be 2,300 m³ each and the maximum true vapor pressure of hexene is approximately 41.3 kPa. The pyrolysis fuel oil storage tanks capacity will be 325 m³ each and the maximum true vapor pressure is expected to exceed 3.5 kPa because the contents will be heated. All other storage tanks to be installed at this facility will not be subject to or required to comply with 40 CFR Part 60 Subpart Kb because they do not fall within the applicable capacity and vapor pressure ranges or meet other exemption criteria as pressure vessels or storage vessels subject to control requirements of 40 CFR Part 63 Subpart YY.

The hexene storage tanks will be equipped with IFRs in accordance with the requirements and specifications of 40 CFR §60.112b(a)(1). Shell states that the hexene will also be blanketed with nitrogen with tank vapors captured by the LP System and routed to an incinerator. This second level of control will surpass the specifications of 40 CFR §60.112b(a)(3); however, the additional controls are being installed through implementation of LAER for sources of VOC at the facility. Shell will not be required to comply with testing, reporting, or recordkeeping requirements of NSPS Subpart Kb related to a closed vent system and control device because installation of IFR alone will meet the requirements of 40 CFR §60.112b(a). Other applicable requirements for these ASTs include notification, monitoring, reporting, recordkeeping, and work practice standards related to the IFR.

The pyrolysis fuel oil storage tanks will not be equipped with IFR (discussed further in the BACT/LAER analysis) but will include vapor capture by the LP System routed to an incinerator. This level of control will surpass the specifications of 40 CFR §60.112b(a)(3); however, the additional controls are being installed through implementation of LAER for sources of VOC at the facility. Shell will be required to comply with testing, reporting, and recordkeeping requirements of NSPS Subpart Kb related to a closed vent system and control device.

NSPS from 40 CFR Part 60 Subpart GG – Standards of Performance for Stationary Gas Turbines will not apply to this facility. Per 40 CFR §60.330, “The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.” The proposed turbines will have a LHV heat input exceeding 10 MMBtu/hr, however; the turbines will be subject to the requirements of 40 CFR Part 60 Subpart KKKK and are therefore exempt from 40 CFR Part 60 Subpart GG per 40 CFR §60.4305(b).

NSPS from 40 CFR Part 60 Subpart VV - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006 will apply to this facility. Per 40 CFR §60.480(b), “Any affected

facility under paragraph (a) of this section that commences construction, reconstruction, or modification after January 5, 1981, and on or before November 7, 2006, shall be subject to the requirements of this subpart.” No potentially affected facility has commenced construction, reconstruction, or modification before November 7, 2006; however, this facility will be subject to these provisions through 40 CFR Part 60 Subpart DDD which incorporates the majority of 40 CFR Part 60 Subpart VV by reference.

Specific requirements of 40 CFR Part 60 Subpart VV are applicable to pumps in light liquid service; compressors; pressure relief devices in gas/vapor service; sampling connection systems; open-ended valves or lines; valves in gas/vapor service and in light liquid service; pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors; and closed vent systems and control devices. These requirements generally include LDAR, or operation of a closed vent system with a control device along with associated recordkeeping and reporting. A compliance demonstration for all equipment will be required within 180 days of initial startup. Shell may request a determination of equivalence of a means of emission limitation to the requirements of §§60.482-2, 60.482-3, 60.482-5, 60.482-6, 60.482-7, 60.482-8, and 60.482-10 as provided in §60.484. Applicable LDAR requirements of 40 CFR Part 60 Subpart VV will be superseded by more stringent VOC LAER requirements.

NSPS from 40 CFR Part 60 Subpart VVa - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 will apply to this facility. Per 40 CFR §60.480a(a)(1), “The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.” The proposed petrochemicals complex will meet the definition of *Synthetic organic chemicals manufacturing industry* under 40 CFR §60.481a because it will produce ethylene as an intermediate product. Affected facilities include all equipment within a process unit as defined under 40 CFR §60.481a.

Specific requirements of 40 CFR Part 60 Subpart VVa are applicable to pumps in light liquid service; compressors; pressure relief devices in gas/vapor service; sampling connection systems; open-ended valves or lines; valves in gas/vapor service and in light liquid service; pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service; closed vent systems and control devices; and connectors in gas/vapor service and in light liquid service. These requirements generally include LDAR, or operation of a closed vent system with a control device, along with associated recordkeeping and reporting. A compliance demonstration for all equipment will be required within 180 days of initial startup. Shell may request a determination of equivalence of a means of emission limitation to the requirements of §§60.482-2a, 60.482-3a, 60.482-5a, 60.482-6a, 60.482-7a, 60.482-8a, and 60.482-10a as provided in §60.484a. Applicable LDAR requirements of 40 CFR Part 60 Subpart VVa will be superseded by more stringent VOC LAER requirements.

NSPS from 40 CFR Part 60 Subpart DDD - Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry will apply to this facility. Per 40 CFR §60.560(a), “*Affected facilities.* The provisions of this subpart apply to affected facilities involved in the manufacture of polypropylene, polyethylene, polystyrene, or poly (ethylene terephthalate) as defined in §60.561 of this subpart...” Three polyethylene

manufacturing lines will be located at this facility. Standards are applicable to process emissions and fugitive equipment leaks beginning from raw materials preparation through product storage. Shell will capture and route process vent VOC emissions to an incinerator or flare and limit residual VOC content of the manufactured resin. Equipment leak standards incorporate the standards from 40 CFR Part 60 Subpart VV by reference. Other applicable requirements include monitoring, recordkeeping, and reporting. Applicable standards will be superseded by more stringent VOC LAER requirements.

NSPS from 40 CFR Part 60 Subpart NNN- Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations will apply to this facility. Per 40 CFR §60.660(a), “The provisions of this subpart apply to each affected facility designated in paragraph (b) of this section that is part of a process unit that produces any of the chemicals listed in §60.667 as a product, co-product, by-product, or intermediate, except as provided in paragraph (c).” Ethylene will be produced as an intermediate product at this facility and is a listed chemical under 40 CFR §60.667. Distillation units (and any associated vent stream recovery systems) that are part of the ethylene manufacturing process unit are therefore subject to this subpart. Shell will be required to comply with applicable distillation unit vent stream control requirements or maintain the vent stream’s total resource effectiveness (TRE) index value (as defined under 40 CFR §60.661) greater than 1.0 without the use of a control device. Other applicable requirements may include testing and will include notification, monitoring, recordkeeping, and reporting. Applicable control requirements will be met by VOC LAER requirements.

NSPS from 40 CFR Part 60 Subpart RRR- Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes will apply to this facility. Per 40 CFR §60.700(a), “The provisions of this subpart apply to each affected facility designated in paragraph (b) of this section that is part of a process unit that produces any of the chemicals listed in §60.707 as a product, co-product, by-product, or intermediate, except as provided in paragraph (c) of this section.” Ethylene will be produced as an intermediate product at this facility and is a listed chemical under 40 CFR §60.707. Reactor processes (and any associated vent stream recovery systems) that are part of the ethylene manufacturing process unit are therefore subject to this subpart. This will include the ethane cracking furnaces and C₂ hydrogenation unit. Shell will be required to comply with applicable distillation unit vent stream control requirements or maintain the vent stream’s TRE index value (as defined under 40 CFR §60.701) greater than 1.0 without the use of a control device. Other applicable requirements may include testing and will include notification, monitoring, recordkeeping, and reporting. Applicable control requirements will be met by VOC LAER requirements.

NSPS from 40 CFR Part 60 Subpart YYY- Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Wastewater was originally proposed on September 12, 1994, but has yet to be promulgated as a final rule. If and when the final rule is promulgated it will likely apply to this facility. Per 40 CFR §60.770(a) of the proposed rule, “The provisions of this subpart apply to each Synthetic Organic Chemical Manufacturing Industry (SOCMI) chemical process unit (CPU) and affected facility and any devices or systems required by this subpart. An affected facility is a designated chemical process unit (DCPU) in the synthetic organic chemical

manufacturing industry which commences or commenced construction, reconstruction, or modification after September 12, 1994.” Requirements would be applicable to process wastewater, maintenance wastewater, and/or an aqueous in-process stream located at an affected facility. Shell will be required to comply with any applicable requirements in the event that the final rule is promulgated.

NSPS from 40 CFR Part 60 Subpart III- Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE) will apply to the diesel-fired emergency generator engines and diesel-fired fire pump engines at this facility. Per 40 CFR §60.4200(a)(2), “The provisions of this subpart are applicable to... Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

- (i) Manufactured after April 1, 2006, and are not fire pump engines, or
- (ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.”

The following table lists each CI ICE proposed to be installed as part of the project and the applicability determination.

Table 1: Compression Ignition Internal Combustion Engines NSPS Subpart III Applicability

CI ICE	Model Year ^a	Manufacture Date ^a	Commencement of Construction Date ^a	Subject to NSPS III?
Emergency Generator Engines, ~5,028 bhp (3,000 KW) x 4	≥ 2006	> 4/1/2006	> 7/11/2005	Yes
Fire Pump Engines, 700 bhp x 3	≥ 2009	> 7/1/2006	> 7/11/2005	Yes

^a These dates are TBD but will all be greater than the applicability thresholds for Subpart III and the most stringent requirements therein for these sources.

Applicable requirements for the emergency generator and fire pump engines include emission, diesel fuel, and work practice standards; and monitoring and recordkeeping. The emergency generator engines will be subject to the emission standards under 40 CFR § 89.112 while the fire pump engines will be subject to the emission standards under Table 4 to Subpart III of Part 60. Non-resettable hour meters will be required to be installed per the requirements of 40 CFR § 60.4209(a) on each engine. Each engine’s hours of operation are not limited during use in emergency situations, but shall otherwise limited to 100 hours or less annually according to the qualifications under 40 CFR § 60.4211(f)(2).

NSPS from 40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines will apply to the turbines with associated heat recovery steam generators and duct burners. Per 40 CFR §60.4305, “If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart.

Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.” The proposed turbines will commence construction after the above date, have a fuel heat input of 475 MMBtu/hr (HHV) excluding the duct burners, and therefore be subject to this subpart. Applicable requirements from this subpart include emission limitations; testing, reporting, and recordkeeping requirements; and work practice standards.

Per 40 CFR §60.4320(a), turbines subject to NSPS Subpart KKKK are required to meet the emission limits for NO_x specified in Table 1 to this subpart. Table 1 to Subpart KKKK establishes a NO_x emission limit of 25 ppm at 15% O₂ or 150 ng/J of useful output (1.2 lb/MWh) for new turbines rated greater than 50 MMBtu/hr and less than or equal to 850 MMBtu/hr firing natural gas. However, implementation of LAER for NO_x results in a more stringent emission limit of 2 ppmv at 15% O₂. The more stringent NO_x LAER limit will be included as a plan approval condition.

Per 40 CFR §60.4330(a), turbines subject to NSPS Subpart KKKK are required to limit SO₂ emissions to not exceed 110 ng/J (0.90 lb/MWh) gross output or not burn any fuel containing total potential sulfur emissions in excess of 26 ng/J (0.060 lb/MMBtu) of heat input. Compliance with this requirement will be achieved through the combustion of only pipeline quality natural gas in the turbines which by definition is limited to not exceed 0.5 grains sulfur/100 dscf (0.0007 lb/MMBtu). The more stringent 0.5 grains sulfur/100 dscf limit will be included as a plan approval condition.

Per 40 CFR §60.4340(a), turbines subject to an emission limit under 40 CFR Subpart KKKK shall perform annual performance tests for NO_x in accordance with 40 CFR §60.4400 to demonstrate compliance with the applicable NO_x emission limit from Table 1 of 40 CFR Subpart KKKK. However, per 40 CFR §60.4340(b), “As an alternative [to NO_x performance testing], you may install, calibrate, maintain and operate one of the following continuous monitoring systems: (1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345...” Shell will utilize NO_x CEMS as an alternative to the NO_x performance testing requirements of 40 CFR Part 60 Subpart KKKK.

NSPS from 40 CFR Part 60 Subpart TTTT- Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units was re-proposed on January 8, 2014, but has yet to be promulgated as a final rule. If and when the final rule is promulgated it will likely apply to this facility. Per 40 CFR §60.5509(a)(2) of the proposed rule, the subpart applies to “A stationary combustion turbine that has a design heat input to the turbine engine greater than 73 MW (250 MMBtu/hr), combusts fossil fuel for more than 10.0 percent of the average annual heat input during a 3 year rolling average basis, combusts over 90% natural gas on a heat input basis on a 3 year rolling average basis, and was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system on a 3 year rolling average basis.” The proposed turbines will have a design heat input of at least 475 MMBtu/hr (HHV), and meet all other proposed applicability criteria. Applicable requirements would include a CO₂ emission standard of 1,100 lb/MWh which the turbines will be able to

meet. Shell will be required to comply with any applicable requirements in the event that the final rule is promulgated.

National Emissions Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene from 40 CFR Part 61 Subpart J will apply to this facility. Per 40 CFR §61.110(a), "The provisions of this subpart apply to each of the following sources that are intended to operate in benzene service: pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems required by this subpart." The water wash system, gasoline distillation systems, and other areas of the ethylene production line will contain sources operating in benzene service. Compliance with 40 CFR Part 61 Subpart J will be achieved by compliance with the requirements of 40 CFR Part 61 Subpart V.

National Emissions Standard for Equipment Leaks (Fugitive Emission Sources) from 40 CFR Part 61 Subpart V will apply to this facility. Per 40 CFR §61.240(a), "The provisions of this subpart apply to each of the following sources that are intended to operate in volatile hazardous air pollutant (VHAP) service: pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems required by this subpart." Any of the above-listed equipment which handles at least 10% benzene by weight will be subject to the requirements of this subpart. These requirements generally include leak detection and repair (LDAR), or operation of a closed vent system with a control device along with associated recordkeeping and reporting. Applicable LDAR requirements of 40 CFR Part 61 Subpart V will be superseded by more stringent VOC LAER requirements.

National Emission Standard for Benzene Emissions From Benzene Storage Vessels from 40 CFR Part 61 Subpart Y will not apply to this facility. Per 40 CFR §61.270(a), "The source to which this subpart applies is each storage vessel that is storing benzene..." No benzene storage vessels will be located at this facility and it is therefore not subject to 40 CFR Part 61 Subpart Y.

National Emissions Standard for Benzene Waste Operations from 40 CFR Part 61 Subpart FF will apply to this facility. Per 40 CFR §61.340(a), "The provisions of this subpart apply to owners and operators of chemical manufacturing plants..." The provisions of this subpart also apply to owners and operators of hazardous waste treatment, storage, and disposal facilities that treat, store or dispose of benzene-containing hazardous waste generated by a chemical manufacturing plant. However, per 40 CFR §61.342(a), "An owner or operator of a facility at which the total annual benzene quantity from facility waste is less than 10 megagrams per year (Mg/yr) (11 ton/yr) shall be exempt from the requirements of paragraphs (b) and (c) of this section..." Shell intends to generate less than 11 tons of benzene waste per year and therefore be exempt from the majority of requirements under this subpart. Applicable requirements will include periodic demonstrations of the amount of benzene waste generated and recordkeeping and reporting.

National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry from 40 CFR Part 63 Subpart F will not apply to this facility. Per 40 CFR §63.100(b), "Except as provided in paragraphs (b)(4) and (c) of this section, the provisions of subparts F, G, and H of this part apply to chemical manufacturing

process units that meet all the criteria specified in paragraphs (b)(1), (b)(2), and (b)(3) of this section...” This facility will not manufacture one or more of the chemicals listed in table 1 of this subpart, tetrahydrobenzaldehyde, or crotonaldehyde; and is therefore not subject to 40 CFR Part 63 Subparts F, G, or H.

National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Industrial Process Cooling Towers from 40 CFR Part 63 Subpart Q will not apply to this facility. Per 40 CFR §63.400(a), “The provisions of this subpart apply to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals...” The proposed process cooling tower will not be operated with chromium-based water treatment chemicals and will therefore not be subject to 40 CFR Part 63 Subpart Q.

National Emission Standards for Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process from 40 CFR Part 63 Subpart SS will apply to this facility. Per 40 CFR §63.980, “The provisions of this subpart include requirements for closed vent systems, control devices and routing of air emissions to a fuel gas system or process. These provisions apply when another subpart references the use of this subpart for such air emission control...” This facility will be subject to these provisions through 40 CFR Part 63 Subpart UU which references use of this subpart. References to this subpart are also made in sections of 40 CFR Part 63 Subpart FFFF. The LP System, HP System, and Spent Caustic Vent incinerator will have requirements applicable to both the closed vent system and flares. Additional requirements include notification, recordkeeping, and reporting.

National Emission Standards for Equipment Leaks – Control Level 2 Standards from 40 CFR Part 63 Subpart UU will apply to this facility. Per 40 CFR §63.1019, “The provisions of this subpart apply to the control of air emissions from equipment leaks for which another subpart references the use of this subpart for such air emission control...” This facility will be subject to these provisions through 40 CFR Part 63 Subpart YY which references use of this subpart. Affected equipment will be that which is part of the ethylene production process and contains or contacts ≥ 5 wt% organic HAP (if not in vacuum service). Applicable requirements generally include leak detection and repair (LDAR), or operation of a closed vent system with a control device along with associated recordkeeping and reporting. Applicable LDAR requirements of 40 CFR Part 63 Subpart UU will be superseded by more stringent VOC LAER requirements.

National Emission Standards for Storage Vessels (Tanks) – Control Level 2 from 40 CFR Part 63 Subpart WW will not apply to this facility. Per 40 CFR §63.1060, “The provisions of this subpart apply to the control of air emissions from storage vessels for which another subpart references the use of this subpart for such air emission control...” This facility will be subject to 40 CFR Part 63 Subpart YY, which references this subpart. However; the applicant has elected to comply with control requirements for affected storage vessels under 40 CFR §63.1103(e) Table 7 (b)(1)(ii) rather than comply with the requirements of 40 CFR Part 63 Subpart WW.

National Emission Standards for Ethylene Manufacturing Process Units: Heat Exchange Systems and Waste Operations from 40 CFR Part 63 Subpart XX will apply to this facility. Per 40 CFR §63.1083, “The provisions of this subpart apply to your heat exchange system if you own or operate an ethylene production unit expressly referenced to this subpart XX from subpart YY of this part...” This facility will be subject to these provisions through 40 CFR Part 63

Subpart YY which references this subpart. Applicable requirements for heat exchange systems include cooling water monitoring and leak repair, recordkeeping, and reporting. Per 40 CFR §63.1093, "The waste stream provisions of this subpart apply to your waste streams if you own or operate an ethylene production facility expressly referenced to this subpart XX from subpart YY of this part..." This facility will be subject to these provisions through 40 CFR Part 63 Subpart YY which references this subpart. Applicable requirements include compliance with 40 CFR Part 61 Subpart FF with additional requirements even if generating less than 10 tons of benzene waste per year.

NESHAPS for Source Categories: Generic Maximum Achievable Control Technology Standards from 40 CFR Part 63 Subpart YY will apply to this facility. Per 40 CFR §63.1100, this subpart is applicable to storage vessels, process vents, transfer racks, equipment leaks, wastewater streams, and heat exchange systems at ethylene production facilities. Ethylene cracking furnaces and associated decoking operations are also listed later as affected sources. Applicable requirements include subjecting affected sources to 40 CFR Part 63 Subparts UU, WW, and XX (as appropriate); control of organic HAP emissions; and notification, recordkeeping, and reporting.

NESHAPS: Miscellaneous Organic Chemical Manufacturing from 40 CFR Part 63 Subpart FFFF will apply to this facility. Per 40 CFR §63.2435(a), "You are subject to the requirements in this subpart if you own or operate miscellaneous organic chemical manufacturing process units (MCPU) that are located at, or are part of, a major source of hazardous air pollutants (HAP) emissions as defined in section 112(a) of the Clean Air Act (CAA)." Each of the three polyethylene manufacturing lines will be classified as an organic chemical MCPU located at a major source of HAP and will therefore be subject to this subpart.

Specific requirements of 40 CFR Part 63 Subpart FFFF are applicable to continuous and batch process vents, storage tanks, transfer racks, equipment leaks, wastewater streams and liquid streams in open systems within an MCPU, and heat exchange systems. These requirements generally include emission reduction values or work practice standards along with associated notifications, recordkeeping, and reporting. Applicable emission reduction values or work practice standards of 40 CFR Part 63 Subpart FFFF will be met or superseded by more stringent VOC LAER requirements.

NESHAPS for Stationary Combustion Turbines from 40 CFR Part 63 Subpart YYYY will apply to the turbines at this facility. Per 40 CFR §60.6085, "You are subject to this subpart if you own or operate a stationary combustion turbine located at a major source of HAP emissions." The proposed turbines will be located at a major source of HAP emissions and therefore be subject to this subpart.

Per 40 CFR §63.6095(d), "*Stay of standards for gas-fired subcategories.* If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in §63.6145 but need not comply with any other requirement of this subpart until the United States Environmental Protection Agency ("EPA") takes final action to require compliance and publishes a document in the

Federal Register.” The proposed turbines will be lean premix gas-fired stationary combustion turbines and therefore only subject to the applicable initial notification requirements.

Per 25 Pa. Code §127.35(c), “If the Administrator of the EPA has not promulgated a standard to control the emissions of hazardous air pollutants for a category or subcategory of major stationary sources under section 112 of the Clean Air Act pursuant to the schedule established under section 112(c) of the Clean Air Act, the Department will establish a performance or emission standard on a case-by-case basis for individual sources or a category of sources for those major stationary sources.” A case-by-case maximum achievable control technology (MACT) determination is not required because EPA did promulgate a standard pursuant to the schedule established under section 112(c) of the Clean Air Act. A proposed rule by EPA on April 7, 2004, to delist the lean premix gas-fired turbine subcategory is still pending. However; Shell has elected to comply with the formaldehyde limit, oxidation catalyst requirements, and monitoring and recordkeeping that would be applicable under Subpart YYYY in order to satisfy BAT requirements.

NESHAPS for Stationary Reciprocating Internal Combustion Engines (RICE) from 40 CFR Part 63 Subpart ZZZZ will apply to the diesel-fired emergency generator and fire pump engines at this facility. Per 40 CFR §63.6585, “You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.” This facility will be a major source of HAP emissions and will not include stationary RICE test cells/stands. The proposed diesel-fired emergency generator and fire pump engines therefore will be subject to 40 CFR Part 63 Subpart ZZZZ.

According to 40 CFR §63.6590(a)(2)(i), these engines will be classified as new stationary RICE. However, in accordance with 40 CFR §63.6590(b), they will not have to meet the requirements of Subpart ZZZZ or Subpart A of 40 CFR Part 63 except for the initial notification requirements of 40 CFR §63.6645(f). This is because these engines will be new emergency stationary RICE rated greater than 500 bhp that will not operate or be contractually obligated to be available for more than 15 hours per calendar year for the purpose of emergency demand response or deviation of voltage or frequency. There are no further requirements under 40 CFR Part 63 Subpart ZZZZ.

NESHAPS for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters from 40 CFR Part 63 Subpart DDDDD will not apply to this facility. Per 40 CFR §63.7491, “The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart... (f) An ethylene cracking furnace covered by subpart YY of this part.” The proposed ethylene cracking furnaces will be subject to the requirements of 40 CFR Part 63 Subpart YY and will therefore not be subject to 40 CFR Part 63 Subpart DDDDD.

40 CFR Part 64 – Compliance Assurance Monitoring will apply to this facility. Per 40 CFR §64.2, “*General applicability.* Except for backup utility units that are exempt under paragraph (b)(2) of this section, the requirements of this part shall apply to a pollutant-specific emissions unit at a major source that is required to obtain a part 70 or 71 permit if the unit satisfies all of the following criteria:

- 1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under paragraph (b)(1) of this section;
- 2) The unit uses a control device to achieve compliance with any such emission limitation or standard; and
- 3) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. For purposes of this paragraph, "potential pre-control device emissions" shall have the same meaning as "potential to emit," as defined in §64.1, except that emission reductions achieved by the applicable control device shall not be taken into account."

This facility will be classified as a major source and will be required to obtain a part 70 (Title V) operating permit. It will include units subject to emission limitations or standards, equipped with control devices, and with pre-control device emissions greater than major source thresholds. In accordance with the requirements of 40 CFR §64.5, Shell will submit a Compliance Assurance Monitoring (CAM) plan with its initial Title V Operating Permit application.

40 CFR Part 68 – Chemical Accident Prevention Provisions will apply to this facility. Per 40 CFR §68.10(a), "An owner or operator of a stationary source that has more than a threshold quantity of a regulated substance in a process, as determined under §68.115, shall comply with the requirements of this part..." Regulated substances in an amount greater than the threshold quantity at this facility may include but are not limited to aqueous ammonia, ethylene, hydrogen, C₃+ (propane+), isobutane, isopentane, and butene. The primary requirement of this part is the development and implementation of a Risk Management Plan (RMP) including an accidental release prevention program and emergency response program. Preparation and implementation of a RMP, if required by Section 112(r) of the Clean Air Act, is included as Section B. Condition #012 in all Plan Approvals.

40 CFR Parts 72, 73, and 75 – Permits Regulation, Sulfur Dioxide Allowance System, and Continuous Emission Monitoring will apply to this facility. Per 40 CFR §72.6(a), "Each of the following units shall be an affected unit, and any source that includes such a unit shall be an affected source, subject to the requirements of the Acid Rain Program:... (3) A utility unit, except a unit under paragraph (b) of this section, that: (i) Is a new unit..." The proposed combined cycle turbines will meet the definition of *Utility unit* under 40 CFR §72.2 because they will supply more than one-third of their potential electrical output capacity and more than 25 MWe output to a power distribution system for sale. These will be affected units subject to the Acid Rain Program and Shell will be required to comply with all applicable Parts.

Per 25 Pa. Code §127.531(b), "The owner or operator or the designated representative of each affected source under section 405 of the Clean Air Act (42 U.S.C.A. § 7651d) shall submit a permit application and compliance plan for the affected source to the Department within 120 days from notice by the Department to submit an application but no later than January 1, 1996, for sulfur dioxide, and no later than January 1, 1998, for NO_x, that meets the requirements of this chapter, the Clean Air Act and the regulations thereunder." This Acid Rain permit application is required to be submitted at least 24 months before any of the turbines commences operation.

Applicable requirements under the Acid Rain Program will be incorporated into this separate Acid Rain Permit.

Mandatory Greenhouse Gas (GHG) Reporting for General Stationary Fuel Combustion Sources from 40 CFR Part 98 Subpart C, Electricity Generation from 40 CFR Part 98 Subpart D, and Petrochemical Production from 40 CFR Part 98 Subpart X are applicable to this facility. Affected sources will include the ethane cracking furnaces, turbines, duct burners, incinerators, ethylene manufacturing process vents and flares. However, the Department has been advised by EPA that emissions reporting under the Mandatory Reporting Rule is not currently considered an “applicable requirement” under EPA regulations implementing Title V and therefore does not have to be included in permits for minor or major sources. 40 CFR Part 98 and associated subparts may be applicable but this is to be determined by EPA. Applicable greenhouse gas reporting conditions may be included in an operating permit at a later date. The Department has elected to require the reporting of GHG emissions for all sources under 25 Pa. Code §127.12b as GHG are now a regulated pollutant under the Clean Air Act.

Prevention of Significant Deterioration Review

On May 31, 1980, PA DEP adopted Prevention of Significant Deterioration (“PSD”) requirements promulgated by the EPA under the Clean Air Act. These requirements have been adopted in their entirety and incorporated by reference in 25 Pa. Code Chapter 127 Subchapter D. Per 40 CFR 52.21(a)(2)(i), “The requirements of [40 CFR Part 52.21, *Prevention of Significant Deterioration of Air Quality*] apply to the construction of any new major stationary source... in an area designated as attainment or unclassifiable under sections 107(d)(1)(A)(ii) or (iii) of the Act.” Attainment or unclassifiable designations (listed under 40 CFR §81.339 for Pennsylvania) are established in reference to the National Ambient Air Quality Standards (“NAAQS”) established under 40 CFR Part 50.

Per 40 CFR §81.339, Potter and Center Townships, Beaver County are designated as areas of attainment for all NAAQS except for annual (1997) and 24-hour (2006) PM_{2.5}, 8-hour ozone (1997 and 2008), and Pb (2008). Additionally, Potter Township, Beaver County is designated as an area of nonattainment for SO₂ (2010). All of the Commonwealth of Pennsylvania is located in the Northeast Ozone Transport Region and is therefore treated like a moderate ozone nonattainment area. Recognized precursor pollutants for PM_{2.5} are SO₂, NO_x, VOC, and ammonia (NH₃); and for ozone are NO_x and VOC. NO_x is unique in that it is potentially subject to both PSD and nonattainment new source review (NNSR) by virtue of its standing as an attainment criteria pollutant (NO₂) and as a nonattainment ozone precursor.

Effective April 15, 2015, Beaver County will be redesignated as unclassifiable/attainment for the annual (2012) PM_{2.5} primary³ NAAQS.⁴ Designation as unclassifiable/attainment with the new (2012) annual primary standard would also meet the existing (1997) annual secondary standard, although the annual (1997) PM_{2.5} classification for this township/county does not appear to have been updated at this time. There has been no change to or redesignation of the 24-hour (2006)

³ The annual (2012) PM_{2.5} primary NAAQS is 12 µg/m³, while the annual (1997) PM_{2.5} secondary NAAQS of 15 µg/m³ remains unchanged.

⁴ *Federal Register*, Vol. 80, No. 10, Thursday, January 15, 2015, Rules and Regulations, p. 2266.

PM_{2.5} NAAQS which remains classified as nonattainment. Per 40 CFR §52.21(i)(2), “The requirements of paragraphs (j) through (r) of this section shall not apply to a major stationary source or major modification with respect to a particular pollutant if the owner or operator demonstrates that, as to that pollutant, the source or modification is located in an area designated as nonattainment under section 107 of the Act.” Paragraphs (j) through (r) of 40 CFR §52.21 contain the PSD requirements including *control technology review, source impact analysis, air quality models, air quality analysis, source information, additional impacts analysis, sources impacting Federal Class I areas – additional requirements, public participation, and source obligation*. Therefore, only NNSR requirements have been applied to PM_{2.5}. This is also consistent with EPA’s guidance on implementing permitting requirements to areas with distinct designations for separate averaging times of the PM_{2.5} NAAQS.⁵ Application of LAER (through NNSR) to PM_{2.5} is expected to be more stringent than BACT because LAER does not include consideration of the economic, energy, or other environmental factors as part of its definition. LAER is generally considered to be the most stringent level of control required under the Clean Air Act. Application of NNSR will further require the procurement of emission offsets ensuring that the region’s total PM_{2.5} emissions do not increase as a result of this project.

A major stationary source is defined as either: (a) a source in one of the 28 source categories identified in 40 CFR 52.21 that has a potential to emit 100 tons or more per year of any regulated NSR pollutant⁶, or (b) any other stationary source that has the potential to emit 250 tons or more per year of a regulated NSR pollutant (separate GHG emission thresholds are described below). Once PSD requirements are triggered for one air contaminant, a review must be conducted for the other regulated NSR pollutants to determine if they exceed the significant levels as defined in 40 CFR 52.21(b)(23). This facility will qualify for multiple listed categories including chemical process plant and fossil fuel-fired steam electric plants of more than 250 MMBtu/hr of heat input. Therefore the threshold for PSD applicability is 100 tons per year of a regulated pollutant (except GHG).

EPA determined on December 07, 2009, that GHGs are a threat to public health and welfare. This determination was made final effective on January 14, 2010.⁷ GHG emissions are those emissions of carbon dioxide, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, perfluorocarbons, and other fluorinated greenhouse gases defined in 40 CFR Part 98 Subpart A. Each different GHG emission is considered to impact global warming at varying levels. Carbon dioxide equivalent (“CO₂e”) emissions are the combined impact of each GHG emission after it is normalized to the impact of CO₂ as a reference. On May 13, 2010, EPA issued a final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (“GHG Tailoring Rule”) which became effective on August 2, 2010.⁸ This rule established an applicability timeline and GHG emission thresholds for requiring facilities to be permitted for GHG emissions. Implementation occurred in steps with the last “Step 3” being finalized on June 29, 2012. PSD major source thresholds were established at 100,000 tons of CO₂e PTE for new sources and 75,000 tons of CO₂e PTE for existing major facilities. Title V permitting requirements applied to facilities with a potential to emit of at least 100,000 tpy CO₂e.

⁵ *Federal Register*, Vol. 78, No. 10, Tuesday, January 15, 2013, Rules and Regulations, p. 3263.

⁶ For purposes of PSD regulations, a regulated NSR pollutant is defined under 40 CFR §52.21(b)(50).

⁷ *Federal Register*, Vol. 74, No. 239, Tuesday, December 15, 2009, Rules and Regulations, p. 66496.

⁸ *Federal Register*, Vol. 75, No. 106, Thursday, June 3, 2010, Rules and Regulations, p. 31514

Recently, on June 23, 2014, the Supreme Court of the United States ruled that “EPA exceeded its statutory authority when it interpreted the Clean Air Act to require PSD and Title V permitting for stationary sources based on their greenhouse-gas emissions. Specifically, the Agency may not treat greenhouse gases as a pollutant for purposes of defining a “major emitting facility” (or a “modification” thereof) in the PSD context or a “major source” in the Title V context. To the extent its regulations purport to do so, they are invalid. EPA may, however, continue to treat greenhouse gases as a “pollutant subject to regulation under this chapter” for purposes of requiring BACT for “anyway” sources.”⁹ In effect, the GHG Tailoring Rule and included GHG major source thresholds have been rescinded. However, this facility will be an “anyway” source because of its NO₂, CO, and PM₁₀ PTE. BACT requirements will apply to other pollutants with a PTE that exceeds the *Significant* thresholds under 40 CFR §52.21(b)(23). Pollutants with a PTE below these thresholds are considered *de minimis* for PSD purposes and will not be subject to BACT requirements. EPA has not yet formally identified a *de minimis* threshold for GHG emissions, but it intends to continue using a 75,000 tpy CO_{2e} threshold pending further developments.¹⁰

Per 40 CFR §52.21(j)(2), “A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.” This is a new facility and the PTE from each individual source shall be considered to determine if the facility is a “new major stationary source”. Shell will exceed the PSD major source threshold for NO₂, CO, and PM₁₀; and the PSD significant thresholds for PM and CO_{2e}. There is currently no formally established significant threshold for GHG although Shell’s CO_{2e} PTE will be greater than any *de minimis* threshold for GHG (when established). Shell is therefore subject to BACT requirements for NO₂, CO, PM, PM₁₀, and CO_{2e}.

Nonattainment New Source Review

On May 19, 2007, PA DEP adopted revised New Source Review regulations in 25 Pa. Code Chapter 127 Subchapter E. Per 25 Pa. Code §127.201(a), “a person may not cause or permit the construction or modification of an air contamination facility in a nonattainment area... unless the Department... has determined that the requirements of this subchapter have been met.” Per 25 Pa. Code §127.203(a), “This subchapter applies to the construction of a new major facility...” In accordance with the definition of *Major facility* under 25 Pa. Code §121.1, this facility is major if the potential to emit exceeds 100 tons of PM_{2.5}, 100 tons of NO_x, 50 tons of VOC, 100 tons of SO₂, or 100 tons of Pb per year. VOC and NH₃ as PM_{2.5} precursors are not evaluated because Pennsylvania or EPA have not yet made the required technical demonstration to show that these precursors contribute to PM_{2.5} concentrations in this nonattainment area.

⁹ *Utility Air Regulatory Group v. EPA*, Docket No. 12-1146, June 23, 2014, http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf, p.29.

¹⁰ EPA memorandum, Next Steps and Preliminary Views of the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court’s Decision in *Utility Air Regulatory Group v. EPA*, July 24, 2014, pp. 3-4.

Per 25 Pa. Code §127.205(1), “A new or modified facility subject to this subchapter shall comply with LAER...” Shell will exceed the NNSR major source threshold for NO_x, VOC, and PM_{2.5}. Shell is therefore subject to LAER requirements for NO_x, VOC, and PM_{2.5}.

Per 25 Pa. Code §127.205(5), “...an analysis shall be conducted of alternative sites, sizes, production processes and environmental control techniques for the proposed facility, which demonstrates that the benefits of the proposed facility significantly outweigh the environmental and social costs imposed within this Commonwealth as a result of its location, construction or modification.” Shell has conducted analyses of alternative sites, sizes, production processes, and environmental control techniques as part of its pre-application project development and for this plan approval application. These analyses; associated economic, environmental, and community benefits analyses; and final comparison of benefits to environmental and social costs are provided in Appendix E of the application. Alternative environmental control techniques are primarily considered in the Control Technology Analysis section of the application and described in the following BACT/LAER/BAT section of this memo. These alternatives analyses and comparison of benefits to environmental and social costs are considered acceptable and meet the requirements of 25 Pa. Code §127.205(5).

Per 25 Pa. Code §127.210, “The emissions offset ratios for NSR purposes and ERC transactions subject to the requirements of this subchapter must be in an amount equal to or greater than the ratios specified in the following table:

Table 2: Required Emission Offsets From Existing Sources, Expressed in Tons per Year

Pollutant/Area	Flue Emissions	Fugitive Emissions
VOC/Transport Region	1.15:1	1.3:1
NO _x /Transport Region	1.15:1	1.15:1
PM _{2.5}	1:1	1:1

Table 3: Calculated Offsets, Expressed in Tons per Year

Pollutant/Area	Flue PTE / Offsets	Fugitive PTE / Offsets	Total Offsets
VOC/Transport Region	396 / 456	126 / 164	620
NO _x /Transport Region	348 / 400	0	400
PM _{2.5}	159 / 159	0 ^a	159

^a Fugitive PM_{2.5} PTE is greater than zero but minimal compared to flue PM_{2.5} PTE. Facility-wide PM_{2.5} PTE is represented as flue PM_{2.5} for convenience in this table because the ratio does not change and it makes no difference.

The applicant will be required by plan approval condition and regulation under 25 Pa. Code §127.206 to secure the above amount of ERCs which have been certified by the Department prior to commencement of operation.

Table 4: PSD/NNSR Applicability (tpy)

	NO ₂ ^a	CO	VOC	PM ^b	PM ₁₀	PM _{2.5}	SO ₂	H ₂ SO ₄	Pb	CO _{2e}
Facility-Wide PTE	348	1,012	522	71	164	159	21	0.8	0.0	2,248,293
PSD Applicability										
PSD Major Source/Significant Increase Threshold ^c	100/40	100/100	N/A ^d	100/25	100/15	N/A ^d	N/A ^d	100/7	N/A ^d	100,000/75,000 ^e
Subject to PSD?	Yes	Yes	No	Yes	Yes	No	No	No	No	Yes ^f
NNSR Applicability										
NNSR Major Source Threshold	100	N/A ^f	50	N/A ^f	N/A ^f	100	100	N/A ^f	100	N/A ^f
Subject to NNSR?	Yes	No	Yes	No	No	Yes	No	No	No	No

^a For purposes of this applicability analysis, all NO_x emissions are assumed to be NO₂.

^b PM is defined as total filterable particulate matter for purposes of this applicability analysis because historically only the filterable fraction had been considered for NSR purposes as well as the first set of NSPS for PM and PM NAAQS in 1971.

^c Significant increase thresholds are included because once a facility is subject to PSD for any pollutant then it may be subject for any other pollutant which exceeds the significant increase threshold.

^d These pollutants are not applicable because this area is/treated as an area of nonattainment for these pollutants.

^e These thresholds are no longer applicable as of June 23, 2014, when the Supreme Court of the United States concluded that EPA's rewriting of statutory thresholds was impermissible. It is expected that this facility will emit more than a *de minimis* amount of GHG. The *de minimis* threshold for GHG has not been formally defined but EPA intends to use 75,000 tons at this time. A BACT analysis remains appropriate in this case.

^f These pollutants are not applicable because this is either an area of attainment or there is no ambient air quality standard for these pollutants.

BACT/LAER/BAT

The applicant has conducted a BACT analysis for NO₂, CO, PM, PM₁₀, and GHG following a 5 step “top-down” analysis which has been recommended by EPA for traditional attainment pollutants as well as the new GHG pollutants.¹¹ The steps of this analysis are summarized as follows:

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

PM and PM₁₀ BACT analyses will be equivalent for this facility. Gaseous fuel-fired and diesel-fired combustion source (also including the incinerators and flares) PM emissions will all be PM₁₀ or smaller. Cooling tower and facility roadway vehicle traffic PM and PM₁₀ emissions are not equivalent; however the control devices and work practices selected are applicable to both pollutants.

The applicant has conducted a LAER analysis for NO_x, VOC, and PM_{2.5} following a 3 step analysis summarized as follows:

1. Identify existing permit limits and SIP limits.
2. Identify existing permit limits and SIP limits that have been achieved in practice.
3. Identify LAER based on the most stringent limit that has been achieved in practice.

This analysis approach will satisfy the definition of LAER under 25 Pa. Code §121.1, which is the more stringent of:

1. The most stringent emission limitation which is contained in the implementation plan of a state for the class or category of source unless the owner or operator of the proposed source demonstrates that the limitations are not achievable.
2. The most stringent emission limitation which is achieved in practice by the class or category of source.

BACT and LAER must also be at least as stringent as any NSPS that is applicable to that source. LAER for NO_x is considered to be at least as stringent as BACT for NO₂ for each of these proposed air contamination sources.

Remaining pollutants including SO_x, HAP, and NH₃ are subject to BAT.

Tail Gas- and Natural Gas-Fired Ethane Cracking Furnaces¹²

LAER for control of NO_x has been determined to be installation and operation of current generation low-NO_x burners (LNB) and SCR. Good combustion practices, and proper operation

¹¹U.S. Environmental Protection Agency, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, p. 12.

¹² See Air Quality Plan Approval Application, Petrochemicals Complex, Shell Chemical Appalachia LLC, Beaver County, PA, February 2015 Update (“Application”) pages 5-8 – 5-70.

and maintenance will also be required. The following NO_x limits have been determined to comply with LAER in this case:

- 0.010 lb/MMBtu on a 12-month rolling average.
- 0.015 lb/MMBtu on a 24-hour rolling average.
- 31.1 lb/hr during startup, shutdown, decoking, hot steam standby, feed in, and feed out modes.

The proposed limits are more stringent than any NO_x limit promulgated under 40 CFR Part 60 for steam generating units (although those limits are not applicable to these furnaces). The proposed emission limits are also found to be equivalent to or more stringent than NO_x limits found in EPA's RACT/BACT/LAER Clearinghouse (RBLC) database for tail gas-fired cracking furnaces. Limit values account for the higher thermal NO_x generation expected as a result of the higher temperatures needed for cracking ethane (compared to making steam) and the higher base flame temperature associated with combusting hydrogen (compared to methane). Short term NO_x limits are higher than the annual limit, and appropriate to represent that these furnaces will undergo operational mode cycling for decoking and also be shut down periodically for maintenance.

Flue gas recirculation (FGR), over-fire-air (OFA), selective non-catalytic reduction (SNCR), and EMx as NO_x control possibilities have also been examined by the applicant for feasibility. FGR and OFA were ruled out as technically infeasible due to modern LNB's integration of internal FGR with staged combustion. SNCR was ruled out as technically infeasible because the temperature profile of the furnaces would place reagent injection within the tube section. SCR will be capable of achieving a higher control efficiency in any case. EMx was ruled out as technically infeasible because its capability to adjust to, or follow, a changing load is undemonstrated. These control options were not found to be utilized or proposed on any other ethane cracking furnaces.

BAT for control of NH₃ has been determined to be proper design, operation, and maintenance of the SCR control devices for the minimization of ammonia slip in conjunction with maximization of NO_x reduction to meet the proposed NO_x LAER limit. Proper design includes selecting the catalyst material, size, and location such that it is capable of operating within the designed temperature range; and locating and configuring NH₃ injection points to ensure proper mixing of NH₃ with the NO_x. Proper operation includes operating the furnaces such that the exhaust gas temperature stays within the designed temperature range of the catalyst and injecting sufficient NH₃ to promote the reaction of NO_x with injected NH₃. Proper maintenance includes periodic cleaning and/or replacement of the catalyst to keep activity high and promote the reaction of NO_x with injected NH₃. The following NH₃ limit has been determined as representative of the application of BAT in this case:

- 10 ppmvd at 3% O₂.

There are no NH₃ limits contained in any NSPS applicable to boilers or process heaters. The proposed emission limit is found to be equivalent to NH₃ limits applied to other cracking furnaces. Long operational runs (up to 5 years) between scheduled maintenance intervals and the intervening catalyst activity decline are considerations for cracking furnace NH₃ limits.

LAER for control of VOC, and BAT for control of HAP has been determined to be good combustion practices and proper operation and maintenance. The following VOC limit has been determined to comply with LAER in this case:

- 1.18 lb/hr.*

*Based on EPA Methods 18 and 25.

There are no VOC limits contained in any NSPS applicable to boilers or process heaters. The proposed 1.18 lb/hr emission limit is derived from 0.0019 lb/MMBtu at rated heat input and found to be equivalent to (on a lb/MMBtu basis) the most stringent VOC limit found in EPA's RBLC database and achieved in practice for cracking furnaces. Catalytic oxidation is a known control technology capable of reducing VOC emissions. The applicant has separately examined the feasibility of this control in CO BACT analysis section of the application. Catalytic oxidation was ruled out as technically infeasible for cracking furnaces because tube leaks could result in damage of the catalyst due to excessive hydrocarbon loading. This control option was not found to be utilized or proposed on any other ethane cracking furnace.

LAER for control of PM_{2.5}, BACT for control of PM and PM₁₀, and BAT for control of SO_x has been determined to be combustion of a low ash and low sulfur fuel. Good combustion practices, and proper operation and maintenance will also be required. Good combustion practices will include routing decoking emissions through a separator and back into the furnace combustion chamber. All particulate matter emissions from gaseous fuel combustion are expected to be PM_{2.5}. Therefore this control will also satisfy BACT for PM and PM₁₀. The following PM₁₀ and PM_{2.5} limits have been determined to comply with LAER in this case:

- 3.10 lb/hr except during decoking.*
- 1.86 lb/hr during decoking operation.*

*Based on EPA Methods 5 and 202 (filterable plus condensable)

The proposed limits are more stringent than any PM limit promulgated under 40 CFR Part 60 Subpart Da for electric utility steam generating units (although those limits are not applicable to these furnaces). The proposed 3.1 lb/hr emission limit is derived from 0.005 lb/MMBtu at rated heat input and found to be equivalent to (on a lb/MMBtu basis) the most stringent PM limit found in EPA's RBLC database and achieved in practice for cracking furnaces. Decoking PM emissions are expected to be inherently higher (on a lb/MMBtu basis) and a separate limit is appropriate for this mode of operation. The mass emission limit is lower during decoking compared to normal operation because the furnace will not operate at max capacity.

BACT for control of CO has been determined to be good combustion practices and proper operation and maintenance. The following CO limits have been determined to comply with BACT in this case:

- 0.035 lb/MMBtu on a 12-month rolling average.
- 52.2 lb/hr during decoking, startup, and shutdown modes.

There are no individual CO limits contained in any NSPS applicable to boilers and process heaters. The proposed emission limit is found to be equivalent to (on a lb/MMBtu basis) the most stringent CO limit found in EPA's RBLC database and achieved in practice for cracking furnaces. Decoking CO emissions are expected to be inherently higher (on a lb/MMBtu basis) and a separate limit is appropriate for this mode of operation. This is also acceptable for startup and shutdown modes where achieving complete combustion is more difficult. Catalytic oxidation has been ruled out by the applicant as technically infeasible as summarized in the above VOC LAER paragraphs and the applicant's CO BACT analysis. This control option was not found to be utilized or proposed on any other ethane cracking furnace.

BACT for control of GHG (CO₂e) has been determined to be low carbon fuel, energy efficiency measures, and proper operation and maintenance. CO₂ is the primary GHG pollutant of concern as CH₄ and N₂O emissions account for approximately 0.15% of the furnace CO₂e PTE. The following requirements have been determined to comply with BACT in this case:

- Exhaust gas generated from each of the ethane cracking furnaces shall not exceed 350 °F on a 12-month rolling average; excluding periods of startup, shutdown, hot steam standby, or decoking.
- Routine furnace tune-ups in accordance with 40 CFR Part 63 Subpart DDDDD (Process Heaters and Boiler MACT).
- 1,048,670 tons of CO₂e from all furnaces combined in any consecutive 12-month period.

Low carbon fuel will include recovering tail gas (primarily hydrogen) from the ethane cracking process and mixing it with natural gas (primarily methane) to be combusted in the furnaces. No GHG emissions will be generated as a product of combustion of the hydrogen component of the fuel. This has the effect of lowering the overall CO₂e emission rate from the furnaces compared to firing just natural gas (or any other carbon-based fuel). The average CO₂ emission rate from combustion of natural gas is 117 lb/MMBtu while the average CO₂ emission rate of these furnaces will be 59.5 lb/MMBtu. There are no GHG limits contained in any NSPS applicable to any combustion units. CO₂e emission rates for these furnaces are found to be lower than GHG rates in EPA's RBLC database for cracking furnaces or any natural gas-fired combustion source.

Energy efficiency measures will include designing for maximization of heat exchange within the furnaces, exhaust gas heat recovery for generation of steam, recovering steam condensate, and limiting excess air to the level necessary for complete combustion. Preheating combustion air to reduce overall fuel usage has been ruled out because heat will already be recovered from the exhaust stream for the purpose of generating steam needed for the cracking process. The exhaust gas temperature limit is representative of the application of these energy efficiency measures.

Carbon Capture and Sequestration¹³

Carbon capture and sequestration (CCS) as potential BACT for control of GHG has been evaluated by the applicant on a larger scale for all the large combustion sources (furnaces and turbines) combined. This is appropriate because the seven ethane cracking furnaces and three combustion turbines are the primary sources of potential CO₂ emissions, constituting greater than 90% of the total GHG PTE for this facility. Expanding, and limiting, the evaluation to these sources combined is expected to generate the result most favorable to implementing CCS. The

¹³ See Application pages 5-144 – 5-166.

applicant's conclusions from this evaluation are that CCS is both technically and economically infeasible for this project.

CCS for CO₂ control is a recognized control technology potentially available for facilities with high CO₂ emission rates. It has been considered and studied most often for application to coal-fired electric generating units (EGU), which have the largest CO₂ emission rates per unit of energy output for utility electric generators. However; CCS may also be applied to any fossil fuel-fired EGU or industrial process generating large amounts of CO₂. The Department is aware that this control technology has been applied at multiple facilities in the U.S. and worldwide. The majority of operational installations are either utilized for enhanced oil recovery (EOR) or relatively small scale pilot projects which are government supported or subsidized. Larger-scale CCS demonstration projects planned or in progress include natural gas-fired combined cycle turbines. No such projects are active in Pennsylvania at this time.

CCS steps include capture, compression, transportation, and finally underground injection for long term storage. The applicant has identified and considered multiple CO₂ capture techniques, and amine absorption was identified as the only potentially available option. Other capture-related options that have been considered and ruled out by the applicant include pre-combustion fuel treatment, oxygen firing, post-combustion physical solvent absorption, calcium cycle separation, cryogenic separation, membrane separation, and adsorption. These techniques would either constitute a redefinition of the air contamination source, are undemonstrated for CO₂ removal from exhaust gas streams, or unavailable for the low CO₂ concentration expected in the furnace and turbine exhaust streams. Amine absorption is currently used to remove H₂S and/or CO₂ from process gas streams at facilities such as refineries, petrochemical plants, and natural gas processing plants; and is also identified as the only commercially demonstrated technology for CO₂ capture from exhaust gas streams. However; the applicant demonstrates that their exhaust streams will have a lower CO₂ concentration (< 4%) than those for which CO₂ capture has been commercially demonstrated. The turbines will be natural gas-fired with high excess air while the furnaces will be primarily tail gas-fired with high hydrogen fuel content. CCS with amine-based CO₂ capture is being planned and designed for on a commercial scale for at least one natural gas-fired turbine but it has not yet been constructed or demonstrated in practice.¹⁴

Captured CO₂ would then be separated from the absorption media and compressed to higher pressures suitable for transport. Transport would be accomplished by pipeline of which existing infrastructure is primarily limited to parts of the western U.S engaged in EOR. Final permanent sequestration of the CO₂ would be in geologic formations underground. The applicant has also identified and considered multiple CO₂ sequestration options including depleted oil and gas reservoirs, unmineable coal seams, saline formations, basalt and organic rich shale formations, and terrestrial ecosystems. Each of these options has been ruled out as either unavailable until long term storage feasibility has been assessed, or undemonstrated in practice or to the scale of this project. However; saline formations are later considered in the economic feasibility analysis as the most likely option for long-term storage. Such formations are generally expected to be the most wide-ranging and have the largest storage capacities.

Cost analysis for control of CO₂ by CCS was performed by the applicant utilizing reports and publications on CO₂ control and methodology from the EPA Air Pollution Control Cost Manual. The annual cost to control CO₂ was calculated to be \$122 per ton for a total annual cost of

¹⁴ <http://sequestration.mit.edu/tools/projects/peterhead.html>

approximately \$148 million. Capture efficiency of 90% is assumed and generally accepted from current studies. Sequestration efficiency of 100% is assumed and represents the designed best case scenario. Costs are broken up by category for capital costs to capture, concentrate, compress, and inject CO₂; and annualized costs for capital recovery, electricity, steam, operation & maintenance, and other administrative costs. Capture, concentration, and compression cost data for a comparable 474 MW natural gas-fired combined cycle power plant was extracted from a National Energy Technology Laboratory report on fossil energy plants.¹⁵ Injection well sequestration cost data for a large project saline formation was extracted from an EPA cost analysis for its final Geologic Sequestration Rule.¹⁶ Cost data was then scaled based on the consumer price index to March, 2014 dollars. CO₂ generation due to additional steam and electricity consumption is also factored into the analysis as a net reduction of the total CO₂ controlled. It is noted that additional other pollutants would be generated as a result of the additional steam and electricity consumption. The cost of any additional compression for long range transport was not included in the analysis.

EPA's most recent reviews of GHG BACT determinations for large combustion units have consistently stated that CCS is considered technically feasible, but in each case is also considered economically infeasible. It is also of note that EPA has excluded implementation of CCS for natural gas-fired combustion turbines in the proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units under 40 CFR Part 60 Subpart TTTT. Annual cost to control CO₂ for EPA's case-by-case determinations of economic infeasibility is generally less than the \$122 per ton calculated cost for this project. CCS has therefore been deemed economically infeasible for this project.

A facility-wide CO₂e limit of 2,248,289 tpy has been applied to this facility (in addition to limits placed on the large combustion sources). EPA states that "since the environmental concern with GHGs is with their cumulative impact in the environment, metrics should focus on longer-term averages (e.g., 30- or 365-day rolling average) rather than short-term average (e.g., 3- or 24-hour rolling average)."¹⁷ The limit has been established as a 12-month rolling average consistent with the long-term average recommendation and with the fuel usage data already required by plan approval condition. Fugitive GHG emissions are included in this limitation because this facility belongs to one of the 28 source categories for which fugitive emissions are included for determining a major stationary source and PSD applicability. Compliance with this limitation will be demonstrated through records of operational hours, fuel usage, actual fuel gas analyses, and Department-approved emission factors and test results. Shell will be required to report CO₂e emissions from this facility annually as part of an Annual Emission Inventory Report.

Combined Cycle Turbines with Duct Burners¹⁸

¹⁵ National Energy Technology Laboratory, DOE/NETL-2010/1397, *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*, Revision 2, November 2010, http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Coal/BitBase_FinRep_Rev2.pdf

¹⁶ U.S. Environmental Protection Agency, EPA 816-R10-013, *Cost Analysis for the Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells (Final GS Rule)*, November 2010, <http://water.epa.gov/type/groundwater/uic/class6/upload/uiccostanalysisforfederalrequirementsunderuicforco2nov2010.pdf>

¹⁷ U.S. Environmental Protection Agency, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, Page 46.

¹⁸ See Application pages 5-70 – 5-103.

LAER for control of NO_x has been determined to be installation and operation of current generation dry-low-NO_x (DLN) combustors, and SCR. Good combustion practices, proper operation and maintenance, and minimization of startup and shutdown events will also be required. The following NO_x limits have been determined to comply with LAER in this case:

- 2 ppmvd @ 15% O₂ on a 1-hour average, excluding startup and shutdown.
- 113 lb/hr during startup and shutdown.
- 65.4 tons from all turbines and duct burners combined in any consecutive 12-month period.

The proposed limit is more stringent than any NO_x limit promulgated under 40 CFR Part 60 Subpart KKKK for turbines (of which the lowest is 15 ppm @ 15% O₂). The proposed emission limit is also found to be equivalent to or more stringent than NO_x limits found in EPA's RBLC database for natural gas-fired turbines. NO_x emission rates will be higher during startup and shutdown (when the turbine is transitionally operating below the SCR's minimum effective operating temperature) and a separate short term limit is appropriate during these periods. The combined annual NO_x limit represents full time operation with up to 7 total hours of startup and shutdown operation.

BAT for control of NH₃ has been determined to be proper design, operation, and maintenance of the SCR control devices for the minimization of ammonia slip in conjunction with maximization of NO_x reduction to meet the proposed NO_x LAER limit. Proper design includes selecting the catalyst material, size, and location such that it is capable of operating within the designed temperature range; and locating and configuring NH₃ injection points to ensure proper mixing of NH₃ with the NO_x. Proper operation includes operating the furnaces such that the exhaust gas temperature stays within the designed temperature range of the catalyst and injecting sufficient NH₃ to promote the reaction of NO_x with injected NH₃. Proper maintenance includes periodic cleaning and/or replacement of the catalyst to keep activity high and promote the reaction of NO_x with injected NH₃. The following NH₃ limit has been determined as representative of the application of BAT in this case:

- 5 ppmvd at 15% O₂.

There are no NH₃ limits contained in any NSPS applicable to turbines. The proposed emission limit is found to be equivalent to NH₃ limits applied to other turbines and consistent with other recent BAT determinations for similar sources.

LAER for control of VOC, and BAT for control of HAP has been determined to be installation and operation of oxidation catalysts, good combustion practices, and proper operation and maintenance. The following VOC limits have been determined to comply with LAER in this case:

- 1 ppmvd @ 15% O₂ on a 1-hour average.
- 10.24 tons in any consecutive 12-month period.

There are no VOC limits contained in any NSPS applicable to turbines. The proposed emission limit is found to be equivalent to or more stringent than VOC limits found in EPA's RBLC database for natural gas-fired turbines without duct burning. A lower VOC limit of 0.6 ppmvd

@ 15% O₂ was found in the San Joaquin Valley Unified Air Pollution Control District's BACT guidelines and identified as technologically feasible however it is noted that this limit is for turbines without heat recovery, based on a three-hour average, and has not been achieved in practice or contained in the SIP.

LAER for control of PM_{2.5}, BACT for control of PM and PM₁₀, and BAT for control of SO_x has been determined to be combustion of a low ash and low sulfur fuel. Good combustion practices, and proper operation and maintenance will also be required. The following particulate matter and sulfur content limits have been determined to comply with LAER in this case:

- 0.0066 lb/MMBtu.*
- 19.2 tons in any consecutive 12-month period.
- Fuel gas sulfur content shall not exceed 0.5 grains per 100 dscf.

*Based on EPA Methods 5 and 202 (filterable plus condensable)

There are no PM limits contained in any NSPS applicable to turbines and the fuel sulfur content limit is more stringent than any SO₂ limit promulgated under 40 CFR Part 60 Subpart KKKK for turbines (of which the lowest is 26 ng/J or 0.060 lb SO₂/MMBtu heat input). The proposed PM emission limit is found to be equivalent to (on a lb/MMBtu basis) the most stringent PM limit found in EPA's RBLC database and achieved in practice for combustion turbines with an oxidation catalyst and without duct burning. The fuel sulfur content limit is consistent with EPA's definition of pipeline natural gas under 40 CFR §72.2 of the Acid Rain Program general provisions.

BACT for control of CO has been determined to be installation and operation of oxidation catalysts, good combustion practices, and proper operation and maintenance. The following CO limits have been determined to comply with BACT in this case:

- 2 ppmvd @ 15% O₂ on a 1-hour average, excluding startup and shutdown.
- 276 lb/hr during startup and shutdown.
- 42.0 tons from all turbines and duct burners combined in any consecutive 12-month period.

CO emissions will be higher during startup and shutdown (when the turbine is transitionally operating below the oxidation catalyst's minimum effective operating temperature) and a separate short term limit is appropriate during these periods. The combined annual CO limit represents full time operation with up to 7 total hours of startup and shutdown operation.

There are no CO limits contained in any NSPS applicable to turbines. The applicant has identified a single lower CO limit of 1.45 ppmvd @ 15% O₂ on a 1-hour average for gas-fired turbines with duct burners at the Kleen Energy Systems, LLC power plant in Connecticut. My search of EPA's RBLC database has clarified this limit as actually being 1.7 ppmvd @ 15% O₂ on a 1-hour average for gas-fired turbines with duct burners (also found in the Title V operating permit for this facility). Regardless, the limit is lower than the 2 ppmvd value which has been proposed as BACT and the applicant has continued the analysis to rule out a lower limit based on economic infeasibility. An incremental and total cost effectiveness analysis conducted by the Bay Area Air Quality Management District ("BAAQMD") for the Oakley Generating Station

application in January, 2011, has been cited and referenced by the applicant. At that time the Oakley Generating Station was proposed to include a similar source category of two combined cycle gas-fired turbines (although without duct burners). This analysis also identified the Kleen Energy Systems limit and examined the costs of complying with an emission limit of 1 ppmvd vs. 2 ppmvd on both a total and incremental cost per ton basis. BAAQMD determined that additional CO reductions (below 2 ppmvd) would not be justified as BACT given the costs.¹⁹ This same analysis is given by the applicant with the additional consideration of the economy of scale comparing the applicant's 40.6 MW GE Frame 6B turbines to the Oakley Generating Station's 213 MW GE Frame 7FA turbines. The proposed 2 ppmvd @ 15% O₂ on a 1-hour average limit is consistent with the most stringent limits found in more recent determinations, including draft determinations in EPA's RBLC database and recently issued and proposed plan approvals for similar sources in Pennsylvania. This limit is determined to comply with BACT in this case.

BACT for control of GHG (CO₂e) has been determined to be low carbon fuel, energy efficiency measures, and proper operation and maintenance. CO₂ is the primary GHG pollutant of concern as CH₄ and N₂O emissions account for approximately 0.10% of the turbine CO₂e PTE. The following CO₂e limit has been determined to comply with BACT in this case:

- 1,030 lbs CO₂e/MWh from all turbines and duct burners combined on a 30-day rolling average.
- 340,558 tons of CO₂e from each turbine and duct burner in any consecutive 12-month period.

Low carbon fuel will include combusting natural gas in the turbines and duct burners. Tail gas (primarily hydrogen) may also be mixed into the duct burner fuel if more is recovered than can be combusted in the furnaces. Any hydrogen added to the fuel will have the effect of lowering the overall CO₂e emission rate from the turbines compared to firing just natural gas (or any other carbon-based fuel) as described for the furnaces above. The average CO₂ emission rate from combustion of natural gas is 117 lb/MMBtu and is found to be the most stringent GHG limit in EPA's RBLC database for natural gas-fired combustion sources.

Energy efficiency measures will include designing for maximization of heat exchange within the HRSG, insulation to minimize heat losses, and limiting excess air to the level necessary for complete combustion. Utilization of a solar array, or other alternative energy source, to reduce demand on the duct burners would constitute a redefinition of the air contamination source and is not applicable. Inlet air-cooling has also been ruled out as a redefinition of the air contamination source because it is employed to offset peaking demand in warmer climates. The proposed CO₂e lb/MWh limit is representative of the application of energy efficiency measures in this case, and considering that some of the energy recovered will be used to generate steam for the process. It is also more stringent than the CO₂ limit (1,100 lb CO₂/MWh) under the proposed 40 CFR Part 60 Subpart TTTT that would be applicable to this size category (> 250 MMBtu/hr and ≤ 850 MMBtu/hr) of turbine. Additional discussion of this proposed Subpart can be found earlier in the Regulatory Analysis section.

¹⁹ Final Determination of Compliance, Oakley Generating Station, BAAQMD Application 20798, pp. 40-41, <http://www.baaqmd.gov/~media/Files/Engineering/Public%20Notices/2011/20798/Oakley%20FDOC%20January%202011.ashx?la=en>

Diesel-Fired Internal Combustion Engines²⁰

LAER for control of NO_x, VOC, and PM_{2.5}; BACT for control of CO, PM, PM₁₀, and GHG; and BAT for control of SO_x and HAP has been determined to be good combustion practices and proper operation and maintenance including certification to applicable federal emission standards and fuel sulfur content limits. An additional more stringent NO_x limit of 4.6 g/bhp-hr for the generator engines has been determined to comply with LAER in this case. The generator engines and fire pump engines will all be classified as emergency engines and subject to 40 CFR Part 60 Subpart III. This allows up to 100 hours of operation per year in non-emergency situations. Diesel fuel sulfur content will be limited to a maximum of 15 ppm. Add-on controls are not installed on emergency generator and fire pump engines and are not considered feasible considering the limited and unpredictable operating hours for such engines.

Polyethylene Production Process Vents²¹

LAER for control of VOC, and BAT for control of HAP has been determined to be routing VOC-containing process vents to the LP System or HP System as applicable, and limiting polyethylene pellet residual VOC content to less than 50 ppmw.

Polyethylene gas phase technology manufacturing lines shall be controlled as follows:

- Continuous VOC-containing process vent located upstream of and including the product purge bin shall be routed to the LP System.
- Compressor seal vents and intermittent VOC-containing process vents located upstream of and including the product purge bin shall be routed to the HP System.
- Polyethylene residual VOC content downstream of the product purge bin shall be less than 50 ppmw.

Polyethylene slurry phase technology manufacturing line shall be controlled as follows:

- Continuous VOC-containing process vent located upstream of the degasser shall be routed to the LP System.
- Compressor seal vents and intermittent VOC-containing process vents located upstream of the degasser shall be routed to the HP System.
- Polyethylene residual VOC content downstream of and including the degasser shall be less than 50 ppmw.

The proposed residual VOC limit of 50 ppmw at the first uncontrolled point is equivalent to or more stringent than polyethylene residual VOC limits found in EPA's RBLC database and achieved in practice for polyethylene pellet manufacturing. It is also more stringent than the 80 pounds of VOC/million pounds of high density polyethylene pellets limit found in Texas Commission on Environmental Quality (TCEQ) BACT guidelines.²² These polyethylene manufacturing lines will also be subject to requirements of 40 CFR Part 60 Subpart DDD and 40 CFR Part 63 Subpart FFFF for which there are no residual VOC limits.

²⁰ See Application pages 5-103 – 5-135.

²¹ See Application pages 5-166 – 5-182.

²² TCEQ Air Permits Division, New Source Review Boilerplate Special Conditions, https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bpc_polys.pdf, August 2011

The proposed VOC control systems are equivalent to or more stringent than polyethylene residual VOC limits found in EPA's RBLC database and achieved in practice for polyethylene pellet manufacturing. Applicable Subparts DDD and FFFF (as referenced in the paragraph above) do include control efficiency requirements which will be met or exceeded by the VOC control systems. Control efficiencies to be achieved by the LP and HP Systems are discussed in further detail in the below VOC Control Systems section.

LAER for control of PM_{2.5}, and BACT for control of PM and PM₁₀, has been determined to be equipping particulate matter-emitting process vents (excluding pellet dryer vents) with fabric, sintered metal, or HEPA filters designed not to exceed 0.005 gr/dscf at the outlet. Pellet dryer vents are expected to be high in moisture content and will be limited not to exceed 0.01 gr/dscf at the outlet. The proposed PM limit of 0.005 gr/dscf is more stringent than any limit found in EPA's RBLC database for polyethylene pellet manufacturing. It is also more stringent than the particulate matter grain loading limit of 0.01 gr/dscf of air from any vent found in TCEQ BACT guidelines.²³ The 0.005 gr/dscf limit is consistent with Department BAT determinations for fabric filter-controlled material handling equipment and storage silos.

Cooling Towers²⁴

LAER for control of VOC, and BAT for control of HAP from the process cooling tower has been determined to be limitation of the cooling water VOC content and implementation of LDAR on the heat exchange system. Good engineering and work practices will also be required, which includes heat recovery within the process where possible. The following VOC limit has been determined to comply with LAER in this case:

- 0.5 lb VOC/MMgal cooling water

Heat exchange systems for ethylene production are subject to LDAR and related requirements of 40 CFR Part 63 Subpart XX, referenced by 40 CFR Part 63 Subpart YY. Heat exchange systems for polyethylene production are subject to LDAR and related requirements of 40 CFR Part 63 Subpart F, referenced by 40 CFR Part 63 Subpart FFFF. The proposed LDAR will be consistent with 40 CFR Part 63 Subpart F, but with more frequent monitoring on a weekly, rather than monthly or quarterly basis. VOC emissions from the process cooling tower will not exceed 40.1 tpy.

LAER for control of PM_{2.5}, and BACT for control of PM and PM₁₀, has been determined to be installation and operation of high efficiency drift eliminators. A maximum drift loss of 0.0005% and total dissolved solids (TDS) limit of 2,000 mg/l have been determined as representative of the application of LAER in this case. There is no NSPS limit on particulate matter that is applicable to cooling towers. The limits have been found to be equivalent to the most stringent drift loss and TDS limits for cooling towers found in recent determinations in EPA's RBLC database.²⁵ They are also equivalent to the limits currently proposed for Tenaska Pennsylvania Partners, LLC's Westmoreland Generating Station. All particulate matter emissions from the cooling tower are expected to be filterable and also controlled by the drift eliminators. Therefore

²³ *Id.*

²⁴ See Application pages 5-187 – 5-200.

²⁵ Includes cooling towers in draft determinations for Chronus Chemicals, LLC (IL-0114); Midwest Fertilizer Corporation (IL-0173/IL-0180); and Arcadis, US, Inc., Oregon Clean Energy Center (OH-0352).

this control will also satisfy BACT for PM and PM₁₀. Combined PM_{2.5} emissions from both cooling towers are not expected to exceed 0.02 tpy.

Polyethylene Pellet Handling²⁶

LAER for control of PM_{2.5}, and BACT for control of PM and PM₁₀, has been determined to be enclosed handling and transfer with emission points controlled by fabric filters. A maximum outlet filterable particulate matter emission rate of 0.005 gr/dscf has been determined to comply with LAER in this case. There is no NSPS limit on particulate matter that is applicable to polyethylene pellet handling. The outlet emission rate is more stringent than both the PA SIP limit applicable to process particulate matter emissions and limits found in EPA's RBLC database and in permits for polyethylene manufacturing units. However; a 0.005 gr/dscf rate is consistent with Department BAT determinations for fabric filter-controlled material handling equipment and storage silos. It is also consistent with the rate proposed for controlled process vents in this application. All particulate matter emissions from pellet handling are expected to be filterable and also controlled by fabric filters. Therefore this control will also satisfy BACT for PM and PM₁₀.

Low Vapor Pressure (< 0.5 psia) Liquid Loadout (coke residue/tar, recovered oil)²⁷

LAER for control of VOC, and BAT for control of HAP has been determined to be work practice standards of submerged loading with vapor capture and low-leak disconnect couplings, and routing to the process or spent caustic vent incinerator. There is no NSPS limit or 25 Pa. Code Chapter 129 Standard applicable to the loadout of these low vapor pressure organic liquids. A minimum VOC control efficiency of 99% is required through the application of LAER in this case. Combined VOC emissions from low vapor pressure liquid loadout are not expected to exceed 0.47 tpy.

High Vapor Pressure (> 0.5 psia) Liquid Loadout (light gasoline, pyrolysis fuel oil)²⁸

LAER for control of VOC, and BAT for control of HAP has been determined to be submerged loading with vapor capture and low-leak disconnect couplings, and routing to the LP incinerator. A minimum VOC control efficiency of 99.9% is required through the application of LAER in this case. This level of control results in an equivalent VOC emission rate of approximately 0.9 mg/L of light gasoline loaded. Both the control efficiency and resultant emission rate are equivalent to or more stringent than any limits found in EPA's RBLC database, NSPS, or 25 Pa. Code Chapter 129 Standard applicable to gasoline loadout. Combined VOC emissions from high vapor pressure liquid loadout are not expected to exceed 0.04 tpy.

Pressurized Liquid Loadout (C₃+ mixture)²⁹

LAER for control of VOC has been determined to be work practice standards of closed-loop pressurized loading with low-leak disconnect couplings. Use of automatic stop-fill devices and proper operation and maintenance will also be required. Losses will only occur from hose disconnects after each fill and are fugitive in nature. There is no NSPS limit applicable to the loadout of this C₃+ mixture. The applicant has compared this pressurized liquid loadout to pressurized loadout of LPG for which no limits were found in EPA's RBLC database. Proposed work practice and equipment standards are found to be equivalent to or more stringent than SIP

²⁶ See Application pages 5-206 – 5-209.

²⁷ See Application pages 5-212 – 5-214.

²⁸ See Application pages 5-214 – 5-217.

²⁹ See Application pages 5-217 – 5-218.

limits for VOC loading. VOC emissions from pressurized C₃+ liquid loadout are not expected to exceed 17.3 tpy.

Low Vapor Pressure (< 0.5 psia) Diesel Fuel Storage Tanks³⁰

LAER for control of VOC has been proposed by the applicant to be fixed roofs and carbon canisters. The Department will require these controls on these sources of minor significance. A minimum VOC control efficiency of 95% is expected to be achieved through the application of LAER in this case, and is consistent with the BAAQMD BACT guidelines for fixed roof organic liquid-containing storage tanks < 20,000 gallons in capacity. This level of control is found to be equivalent to or more stringent than controls found in EPA's RBLC database for similar sources. Maximum designed capacity of these storage tanks is expected not to exceed 38 m³ (~10,000 gallons) and will not exceed 20,000 gallons. They will supply fuel intermittently to locomotives, emergency generator engines, and fire pump engines. VOC emissions from diesel fuel storage tanks are expected to be negligible.

Low Vapor Pressure (< 0.5 psia) VOC-Containing Storage Tanks (recovered oil, equalization wastewater, and spent caustic)³¹

LAER for control of VOC, and BAT for control of HAP has been determined to be IFR and vapor capture and routing to the spent caustic vent incinerator. A minimum VOC control efficiency of 99% is required through the application of LAER in this case. This exceeds the BAAQMD BACT guidelines (\geq 98% control efficiency) for fixed roof organic liquid-containing storage tanks \geq 20,000 gallons, and IFR organic liquid-containing storage tanks. This level of control is found to be equivalent to or more stringent than controls found in EPA's RBLC database for similar sources. Maximum designed capacity of these storage tanks is expected not to exceed 2,810 m³ (~742,000 gallons) and will exceed 20,000 gallons. VOC emissions from these storage tanks are represented in loading to the spent caustic vent incinerator.

High Vapor Pressure ($>$ 0.5 psia) VOC-Containing Storage Tanks (light gasoline, pyrolysis fuel oil, and hexene)³²

LAER for control of VOC, and BAT for control of HAP has been determined to be IFR (excluding the pyrolysis fuel oil tanks) and vapor capture and routing to the LP incinerator. A minimum VOC control efficiency of 99.9% is required through the application of LAER in this case. This exceeds the BAAQMD BACT guidelines (\geq 98% control efficiency) for IFR organic liquid-containing storage tanks. This level of control is found to be equivalent to or more stringent than controls found in EPA's RBLC database for similar sources.

IFR has been ruled out as technically infeasible for the pyrolysis fuel oil tanks because this byproduct will have a high viscosity and is required to be heated for handling. Those tanks will be fixed cone roof tanks controlled by vapor capture and routing to the LP incinerator. VOC emissions from the high vapor pressure VOC-containing storage tanks are represented in loading to the LP incinerator. This source category excludes the pressurized and refrigerated storage tanks from which there are no air emissions under normal operating conditions. Any pressure relief related emissions from those storage tanks are required to be capture and routed to the HP system.

³⁰ See Application pages 5-183 – 5-187.

³¹ *Id.*

³² *Id.*

VOC Control Systems (LP and HP Systems, and Spent Caustic Vent incinerator)³³
LAER for control of NO_x, VOC, and PM_{2.5}; BACT for control of CO, PM, PM₁₀, and GHG; and BAT for control of SO_x and HAP has been determined to be good combustion practices and proper operation and maintenance including operating in accordance with an approved flare minimization plan. The LP incinerator, MPGF, HP ground flares, HP elevated flare, and Spent Caustic Vent incinerator will function as air cleaning devices primarily, but also meet the definition of an air contamination source because the pilot light and combustion of organic vapors will generate products of combustion. Good combustion practices will include maximizing the complete combustion of VOC waste gas streams and minimizing the products of incomplete combustion. The flare minimization plan and associated work practices were derived from those implemented in the Shell Deer Park Consent Decree (Consent Decree)³⁴.

No-add on control technologies have been identified as technically feasible due to the inherent design of flares and the high combustion temperatures of flares and incinerators. Add-on control technologies to control ancillary emissions from a control device are not used in practice. Flare gas recovery for use as fuel has been ruled out as technically infeasible because the recovered gases would have different combustion characteristics than the low carbon fuels that the furnaces and turbines will be designed to combust. Similarly, flare gas recovery for use as process feedstock has been ruled out as technically infeasible because recovered gases would be relatively impure compared to the on-site manufactured ethylene and imported co-monomers used in the polyethylene manufacturing process. Exceptions to this are the hydrogen, methane, and ethane recovered from normal operation of the ethane cracking process. Hydrogen and methane tail gas recovered from the ethane cracking process will be utilized as fuel for the furnaces. Unreacted ethane recovered from the ethane cracking process will be utilized as feedstock for the cracking process

Work practices for the VOC control systems will include the following:

- The facility will minimize flaring resulting from startups, shutdowns, and unforeseeable events by operating at all times in accordance with an approved flare minimization plan. The plan shall include the following elements:
 - Procedures for operating and maintaining the HP and LP Systems during periods of process unit startup, shutdown and unforeseeable events.
 - A program of corrective action for malfunctioning process equipment.
 - Procedures to minimize discharges either directly to the atmosphere or to the HP and LP Systems during the planned and unplanned startup or shutdown of process unit and air pollution control equipment.
 - Procedures for conducting root cause analyses.
 - Procedures for taking identified corrective actions.
- The facility shall conduct a root cause analysis within 45 days after any startup, shutdown and unforeseeable flaring event. Flaring event shall be defined as an event that exceeds the baseline by 500,000 scf within a 24 hour period. The analysis shall address the following elements:
 - The date and time that the flaring event started and ended.
 - The total quantity of gas flared during each event.

³³ See Application pages 5-218 – 5-241.

³⁴ United States of America v. Shell Oil Company, Deer Park Refining Limited Partnership, and Shell Chemical LP; No. 4:13-cv-2009; <http://www2.epa.gov/sites/production/files/2014-07/documents/sdp-cd.pdf>

- An estimate of the quantity of VOC that was emitted and the calculations used to determine the quantities.
- The steps taken to limit the duration of the flaring event or the quantity of emissions associated with the event.
- A detailed analysis that sets forth the root cause and all significant contributing causes of the flaring event to the extent determinable.
- An analyses of the measures that are available to reduce the likelihood of a recurrence of a flaring event resulting from the same root cause or significant contributing causes in the future.
- A demonstration that the actions taken during the flaring event are consistent with the procedures specified in the flare minimization plan.
- In response to a flaring event, the facility shall implement, as expeditiously as practicable, such interim and/or long-term corrective actions as are consistent with good engineering practice to minimize the likelihood of a recurrence of the root cause and all significant contributing causes of that flaring event.
- The flares shall be designed to meet limitations on maximum exit velocity, as set forth in the general provisions at 40 CFR § 60.18 and § 63.11.
- The flares shall be operated to meet minimum net heating value requirements for gas streams combusted in the flares, as set forth at 40 CFR § 60.18 and § 63.11.
- HP Ground Flares and the MPGF shall be equipped with the following automated controls:
 - Control of the supplemental gas flow rate to the flare.
 - Control of the total steam mass flow rate (if applicable) to the flare.
- Net Heating Value of Combustion Zone Gas (NHVcz)
 - The MPGF and HP Flare Header shall be operated such that the NHVcz, on a three-hour rolling average basis, rolled every fifteen minutes, is equal to or greater than 500 Btu/scf, using a Net Heating Value for hydrogen of 1,212 Btu/scf.

Shell will be required to define the baseline flow to the VOC control systems in accordance with the provisions of 40 CFR Part 60 Subpart Ja. Achieving a minimum net heating value of the combustion zone of 500 Btu/scf is consistent with the Consent Decree and more stringent than the 200 or 300 Btu/scf requirement of both 40 CFR §60.18 and §63.11. The elevated net heating value for hydrogen is also consistent with the Consent Decree and is due to the increased combustion efficiency expected for hydrogen-fueled flares. Both the LP incinerator and HP ground flares are to be utilized in their respective services over the MPGF and elevated flare which are primarily reserved for backup and emergency use. Work practices will also include smokeless design of flares with visible emissions not to exceed 0% except for a total of five minutes during any consecutive two-hour period. This is consistent with both 40 CFR §60.18 and §63.11. Additional emission limitations on the flares are not considered feasible in this case because it will not be feasible to perform stack testing. There will be no stack from the point of combustion for the MPGF and elevated flare, while the ground flares will be approximately 30 feet in diameter with all flares combusting primarily intermittent high pressure waste streams. Compounds in organic compound service which are part of the VOC control systems will also be included in the facility-wide LDAR requirement described later for component fugitives.

A minimum VOC control efficiency of 98% is required from the flares through the application of LAER in this case. This is the minimum control efficiency expected to be achieved by flares adhering to the work practice standards of 40 CFR §60.18 and/or §63.11, and the highest level of

flare control efficiency required by any NSPS or NESHAP. Control efficiencies in the range of 99% to 99.5% are achievable by flares combusting steady-state streams of propane or propylene³⁵, for which ethylene is similar. However; flares at this facility will primarily serve in a backup or emergency capacity, or to combust intermittent and high pressure waste streams. The above work practice standards will be more stringent than those for which the higher destruction efficiencies are deemed acceptable for those referenced compounds and operational scenarios.

The following emission limits have been determined to comply with LAER and BACT for the LP and Spent Caustic Vent incinerators:

- NO_x – 0.0680 lb/MMBtu
- CO – 0.0824 lb/MMBtu
- PM₁₀ – 0.0075 lb/MMBtu
- PM_{2.5} – 0.0075 lb/MMBtu.
- VOC – 99.9% destruction efficiency (LP incinerator)
- VOC- 99% destruction efficiency (Spent Caustic Vent incinerator)

There are no NSPS limits on NO_x, CO, PM₁₀, or PM_{2.5} that are applicable to thermal incinerators combusting gaseous waste streams. The NO_x rate is from AP-42 Chapter 13.5 for industrial flares and appropriate for the high temperatures needed to achieve oxidation. The CO, PM₁₀, and PM_{2.5} rates are from AP-42 Chapter 1.4 for natural gas combustion and appropriate for the gaseous nature, continuous flow, and residence time for combustion of the waste streams. A minimum VOC control efficiency of 99.9% for the LP incinerator is identified as the highest control efficiency currently achieved in practice for similar sources. A lower minimum control efficiency of 99% for the Spent Caustic Vent incinerator is appropriate in consideration of the lower flow rate of organics expected from the spent caustic vent; recovered oil, equalization wastewater, and spent caustic storage tanks; and recovered oil loadout. Both control efficiencies are more stringent than the 98% control efficiency for VOC or organic HAPs required by any NSPS or NESHAP. Work practices will also be consistent with the requirements of 40 CFR Part 63 Subpart SS as applicable to incinerators.

Component Fugitives³⁶

LAER for control of VOC, BACT for control of GHG, and BAT for control of HAP has been determined to be implementation of an LDAR program on facility components in organic compound service. The actual control efficiency for implementation of LDAR will vary depending upon component type, frequency of detection (and subsequent repair), and the leak detection threshold. Control efficiencies have been considered to be equivalent to those found in EPA's *Protocol for Equipment Leak Emission Estimates* for equipment subject to the hazardous organic NESHAP, although greater control efficiency is expected in this case. All aspects of the LDAR program are to be consistent with 40 CFR Part 63 Subpart UU - National Emission Standards for Equipment Leaks – Control Level 2 Standards except as follows:

- LDAR shall be applied to equipment in organic compound service (including fuel gas equipment).

³⁵ TCEQ, *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers*, RG-109 (Draft), October 2000, pp. 20-21.

³⁶ See Application pages 5-135 – 5-144.

- Organic compound service means that piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 wt% of organic compounds as determined according to the provisions of 40 CFR §63.180(d) of Subpart H [except that “organic compound” replaces instances of “organic HAP”]. The provisions of 40 CFR §63.180(d) of Subpart H also specify how to determine that a piece of equipment is not in organic compound service.
- Leak detection shall be conducted on a monthly basis for non-bellows seal valves unless 98.0% or greater of the non-bellows seal gas/vapor and/or light liquid valves are found to leak at a rate less than 100 ppmv for two consecutive months, then the detection frequency may be changed to a quarterly basis. The annual monitoring frequency for valves (skip periods) is not applicable.
- Equipment with inherently leakless design features will be installed as practicable; and
- All sampling systems in organic compound service shall be closed-purge, closed loop, or closed-vent systems. In-situ sampling systems shall be exempt.
- Equipment is also defined to include screwed connections, heat exchanger heads, sight glasses, meters, gauges, sampling connections, bolted manways, and hatches.
- Leak detection thresholds for organic compounds shall be as follows:
 - 100 ppmv from pump seals, compressor seals, flanges, and valves in gas/vapor and light liquid service;
 - 200 ppmv from atmospheric pressure relief devices without a rupture disk; and
 - 500 ppmv for all other equipment.
- A first attempt at repair shall be required for all leaking components within 5 days of detection and repair shall be completed within 15 days for all components unless the repair would require a unit shutdown that would create more emissions than the repair would eliminate, and if so, the repair may be delayed until the next scheduled shutdown, except the first attempt at repair for:
 - Any leak > 10,000 ppmv & < 25,000 ppmv – 2 days;
 - Atmospheric pressure relief device leak without a rupture disk > 200 & < 25,000 ppmv – 2 days;
 - Any leak > 25,000 ppmv – 1 day;
 - Heavy liquid components > 500 ppmv – 1 day; and
 - Any leak in HRVOC service > 10,000 ppmv – 1 day.
- Compressors equipped with a closed vent system that capture and transport leakages to the VOC Control System shall meet the LAER requirements for the VOC Control System.

The applicant’s designed LDAR program incorporates elements of BACT guidelines and SIP rules from the BAAQMD, South Coast Air Quality Management District (SCAQMD), and Texas Commission on Environmental Quality (TCEQ). It also incorporates elements from the Chevron El Segundo refinery Title V Operating Permit and expands the program to include all organic compounds rather than just volatile or hazardous organic compounds. This includes methane and effectively extends the LDAR program to cover fuel gas systems at the facility. The resultant LDAR program will be more stringent than that which is found in any NSPS or NESHAP (applicable or not), EPA’s RBLC database for other sources, and SIP programs such as TCEQ’s 28LAER LDAR program.

WWTP³⁷

LAER for control of VOC, and BAT for control of HAP has been determined to be compliance with the applicable waste/wastewater stream requirements of 40 CFR Part 63 Subparts XX and FFFF, and control of the flow equalization wastewater and oil recovery storage tanks by internal floating roofs and vapor capture and routing to the spent caustic vent incinerator. A minimum VOC control efficiency of 99% is required for the flow equalization and oil recovery storage tanks. This control has also been identified in the above section for low vapor pressure (< 0.5 psia) VOC-containing storage tanks. The proposed controls are found to be equivalent to or more stringent than controls found in EPA's RBLC database and achieved in practice for similar sources. VOC emissions from the WWTP after the flow equalization and oil recovery storage tanks will be fugitive in nature and not expected to exceed 0.42 tpy.

Roadways³⁸

LAER for control of PM_{2.5}, and BACT for control of PM and PM₁₀, has been determined to be paving of all in-plant roadways, and development and implementation of a roadway dust control plan. Dust control will include watering and sweeping as necessary. Roadway watering will include the application of winterized surfactant as necessary during colder months. There is no NSPS limit on particulate matter applicable to fugitive dust from facility roadway traffic. Applicable Pennsylvania restrictions include the prohibition of certain fugitive emissions and fugitive particulate matter under 25 Pa. Code §§123.1 and 123.2. The proposed controls have been found to be equivalent to controls required for haul roads in EPA's RBLC database. All particulate matter emissions from the facility roadways are expected to be filterable and also controlled by paving, sweeping, and watering. Therefore this control will also satisfy BACT for PM and PM₁₀. PM_{2.5} emissions from paved roadway vehicle traffic are not expected to exceed 0.026 tpy.

Single Facility Analysis

The aggregation of emissions from this facility with other air contamination sources has been examined for permitting purposes. The nearest currently active air contamination sources I have identified using the eMapPA application are BASF Corporation's Monaca Pant, Interstate Chemical Company's Vanport Terminal - West, AES Beaver Valley, and Nova Chemicals' Beaver Valley Plant. Each of the following three criteria must be met for emission sources to be considered a single facility under PSD regulations:

1. Are the sources under common control?
2. Do the sources belong to the same industrial grouping?
3. Are the sources located on contiguous or adjacent properties?

Similarly, per the definition of facility in 25 Pa. Code 127.1, each of the following two criteria must be met for emission sources to be considered a single facility under NNSR regulations:

1. Are the sources owned or operated by the same person under common control?
2. Are the sources located on one or more contiguous or adjacent properties?

³⁷ See Application pages 5-200 – 5-206.

³⁸ See Application pages 5-241 – 5-244.

Common Control.

Shell Chemical Appalachia LLC is identified in the Air Pollution Control Act Compliance Review Form submitted with this application as a limited liability company owned 100% by Shell Oil Company. No other Pennsylvania facilities, plan approvals, or operating permits have been identified for Shell or any "related parties" in the same form. BASF Corporation's Monaca Plant is a batch producer of carboxylated styrene-butadiene and acrylic latex dispersions. Interstate Chemical Company's Vanport Terminal – West is a solvent bulk terminal receiving products by barge for transfer to tanks and subsequent loadout to trucks. AES Beaver Valley is a coal-fired cogeneration plant providing electric power to the grid and steam to nearby Nova and BASF. Nova Chemicals' Beaver Valley Plant is a producer of expandable polystyrene resins and advanced foam resins. There is no common ownership between Shell and any of these other companies or facilities. Common control however may still be demonstrated even without common ownership if one entity were to have decision-making authority over the operation of the other through contractual agreement or voting interest, or if a support/dependency relationship exists. Case-by-case facts pertaining to the possible common control of these facilities are as follows:

- There will be no common ownership.
- There will be no financial arrangements, legal or lease agreements, or contracts for service or goods. (Excluding any potential purchase of ERCs)
- There will be no sharing of workforces, management, payroll, or benefits.
- There will be no support or dependency relationship.

The common control criterion is therefore not satisfied for Shell and any of the aforementioned facilities. As all applicable criteria need to be met in order for emission sources to be aggregated, the remaining criteria do not need to be examined at this time for Shell and these other facilities.

EMISSIONS & CONTROLS

Emission calculations were carried out by the applicant for the tail gas- and natural gas-fired ethane cracking furnaces based upon LAER and BACT emission limits, manufacturer's emissions data, mass balance, AP-42 Chapter 1.4 emission factors, and 40 CFR Part 98 Subpart C emission factors. A worst case annual operation time of 8,760 hours is assumed for each of the 7 furnaces. However; only 6 furnaces are to be cracking ethane at any one time and the annual operation time includes scheduled cycling of the units for the purpose of decoking, and a single shutdown/startup event to account for maintenance. It is expected that each furnace will actually operate for 2 to 3 years (or more) between scheduled maintenance periods. Decoking will occur up to 12 times annually and 36 hours per event. After decoking, that furnace will remain operating in standby mode for up to 60 hours until the next one needs to be decoked. Standby mode maintains an elevated temperature within the furnace combustion chamber preventing thermal stresses that would be generated by regular cycling from hot to cold temperatures. This is expected to result in better long term combustion efficiency, less downtime for maintenance, and less startup/shutdown cycles during which the flue gas temperature would be below the SCR operating temperature. When any furnace is not cracking ethane it will be operated at a reduced heat input capacity depending on the specific mode of operation.

NO_x emissions will be controlled by low-NO_x burners and SCR capable of achieving an outlet emission rate of 0.010 lb/MMBtu on a 12-month rolling average, which is considered LAER for these furnaces. The highest short term emission rate of 31.1 lb/hr is expected only during startup and shutdown events at the point when the exhaust temperature is just below the SCR's effective operating temperature range. Actual annual emissions of NO_x are expected to be less because each furnace will typically operate for 2 to 3 years (or more) between scheduled maintenance periods. Any actual startup and shutdown event will also encompass a period of zero emissions while the maintenance is being performed. Aqueous ammonia or urea will be injected upstream of the SCR control device and ammonia slip shall not exceed 10 ppmvd @ 3% O₂. SCR operational parameters such as ammonia injection rate and injection temperature range have yet to be finalized. Shell will be required to operate the control device within manufacturer's specifications, or those developed and approved specifically for these furnaces, and monitor operating parameters.

CO, PM, PM₁₀, PM_{2.5}, VOC, HAP, and CO_{2e} emissions will be controlled by good combustion practices with emission rates representative of BACT and LAER where applicable. Emissions of these pollutants will also be inherently low compared to natural gas combustion because the furnaces will combust a low carbon fuel. The tail gas and natural gas mixture of fuel to be combusted is expected to contain approximately 48.3% hydrogen that does not oxidize into CO or CO_{2e} upon combustion, or form PM, PM₁₀, PM_{2.5}, VOC, HAP, or CH₄ as products of incomplete combustion. Higher short term emission rates for these pollutants are generally expected during the decoking process due to the excess carbon available to be oxidized or pass through the combustion chamber during decoking. Decoking exhaust gases are to be routed through a separator to remove any large particles and then through the furnace combustion chamber to promote complete combustion. PM₁₀ and PM_{2.5} emissions are considered equivalent for these sources due to combustion of gaseous fuel. Emission factors from 40 CFR Part 98 Subpart C used to calculate CO₂ emissions were modified to account for the hydrogen content of the fuel gas mixture. For simplicity, default natural gas emission factors for CH₄ and N₂O were applied across all operating modes as these pollutants have minimal impact on the overall CO_{2e} emission rate.

NO_x and CO rates will be monitored by CEMs while other pollutant rates will be demonstrated by source testing. All calculations were found to be acceptable.

Table 5: Ethane Cracking Furnaces PTE^a

Air Contaminant	Single Furnace Normal Emission Rate ^b (lb/hr)	Single Furnace Annual Emission Rate ^c (tpy)	Combined Annual Emission Rate ^d (tpy)
NO _x	6.20	25.9	181.3
CO	21.7	95.8	670.4
PM (Filterable)	1.24	4.87	34.1
PM ₁₀	3.10	12.4	86.8
PM _{2.5}	3.10	12.4	86.8
SO _x	0.12	0.51	3.57
VOC	1.18	4.63	32.4
Hexane	0.57	2.48	17.3
Formaldehyde	0.02	0.10	0.72
HAP (Total)	0.59	2.60	18.2
Ammonia	3.02	13.22	92.52
CO _{2e}	36,948	149,810	1,048,670

^a Seven furnaces rated at 620 MMBtu/hr each.

^b Normal operation is expected for 7,509 hours per year.

^c Annual PTE for a single furnace over all operational modes for 8,760 hours per year.

^d Annual PTE for all seven furnaces combined over all operational modes for 8,760 hours per year.

Emission calculations were carried out by the applicant for the natural gas-fired combustion turbines with natural gas- and tail gas-fired duct burners based upon LAER and BACT emission limits, mass balance, AP-42 Chapters 1.4 and 3.1 emission factors, and 40 CFR Part 98 Subpart C emission factors. A worst case annual operation time of 8,760 hours is assumed for each of the 3 turbines and duct burners including up to 7 hours of startup and shutdown events where applicable.

NO_x emissions will be controlled by low-NO_x burners and SCR capable of achieving an outlet emission rate of 2 ppmvd @ 15% O₂ on a 1-hour average, which is considered LAER for these turbines. The highest short term emission rate of 113 lb/hr is expected only during startup events at the point when the exhaust temperature is just below the SCR's effective operating temperature range. Aqueous ammonia or urea will be injected upstream of the SCR control device and ammonia slip shall not exceed 5 ppmvd @ 3% O₂. SCR operational parameters such as ammonia injection rate and injection temperature range have yet to be finalized. Shell will be required to operate the control device within manufacturer's specifications, or those developed and approved specifically for these furnaces, and monitor operating parameters.

CO, VOC, and organic HAP emissions will be controlled by oxidation catalysts capable of achieving an outlet emission rate of 2 ppmvd @ 15% O₂ on a 1-hour average for CO, and 1 ppmvd @ 15% O₂ (as propane) on a 1-hour average for VOC. These rates are considered representative of BACT and LAER respectively. The highest short term CO emission rate of 276 lb/hr is expected only during startup events at the point when the exhaust temperature is just below the oxidation catalyst's effective operating temperature range. A minimum control efficiency of 90% due to the oxidation catalyst has been applied to the AP-42 organic HAP emission factors.

PM, PM₁₀, PM_{2.5}, and CO_{2e} emissions will be controlled by good combustion practices with emission rates representative of BACT and LAER where applicable. PM₁₀ and PM_{2.5} emissions are considered equivalent for these sources due to combustion of gaseous fuel. Although some excess tail gas may be combusted as fuel by the duct burners, no modifications were made to the emission factors from 40 CFR Part 98 Subpart C. Firing only natural gas is expected to be the normal mode of operation and assuming all natural gas results in a more conservative PTE.

NO_x and CO rates will be monitored by CEMs while other pollutant rates will be demonstrated by source testing. All calculations were found to be acceptable.

Table 6: GE Frame 6B Combustion Turbines with Duct Burners PTE^a

Air Contaminant	Single Unit Normal Emission Rate ^b (lb/hr)	Single Unit Annual Emission Rate ^c (tpy)	Combined Annual Emission Rate ^d (tpy)
NO _x	4.89	21.8	65.4
CO	2.97	14.0	42.0
PM (Filterable)	1.24	5.42	16.26
PM ₁₀	4.38	19.19	57.57
PM _{2.5}	4.38	19.19	57.57
SO _x	0.98	4.28	12.84
VOC	2.34	10.24	30.72
Formaldehyde	0.047	0.21	0.62
Toluene	0.009	0.04	0.11
HAP (Total)	0.068	0.30	0.90
Ammonia	4.51	19.78	59.33
CO _{2e}	77,753	340,558	1,021,675

^a Three turbines rated at 475 MMBtu/hr each with three duct burners rated at 189 MMBtu/hr each.

^b Normal operation is expected for 8,753 hours per year.

^c Annual PTE for a single turbine/duct burner over all operational modes for 8,760 hours per year.

^d Annual PTE for all three turbines/duct burners combined over all operational modes for 8,760 hours per year.

Emission calculations were carried out by the applicant for the diesel-fired emergency generator and fire pump engines based upon applicable federal emission standards and limitations, manufacturer's emissions data, mass balance, AP-42 Chapter 3.4, and 40 CFR Part 98 Subpart C emission factors. The emergency generator engines will be sized at 5,028 bhp (~3.0 MWe) each and will be subject to EPA Tier II emission standards. The fire pump engines will be sized at 700 bhp each and will be subject to NSPS Subpart III Table 4 emission limits. These engines are not required to be equipped with a post-combustion control device in order to meet these emission standards, and are not otherwise required to be equipped with a control device because of their classification as emergency engines. Total sulfur content of diesel fuel may not exceed 15 ppm. Operation of each of these engines may not exceed 100 hours annually for any non-emergency situations in order to retain this classification as emergency engines under 40 CFR Part 60 Subpart III. Operation in emergency situations is not limited.

I have made some corrections to the emission calculations by calculating PTE for NO_x + NMHC, NO_x, CO, and PM from not to exceed (NTE) values derived from the applicable emission standards (and proposed LAER emission standard) in accordance with 40 CFR §60.4212(c).

This does not have an impact on regulatory applicability or actual emissions. PM, PM₁₀, and PM_{2.5} emissions are considered approximately equivalent for these sources, but have been scaled slightly using particle size distributions from AP-42 Appendix B.2. The majority of particulate matter emissions from diesel engines greater than 600 bhp³⁹, is considered to be < 1µm in diameter. Actual emissions from the engines are expected to be less than PTE because they will normally only be operated for readiness checks, and also because manufacturer's nominal emission data is substantially below the applicable emission standards and derived NTE values.

All calculations were found to be acceptable.

Table 7: Emergency Generator Engines and Fire Pump Engines PTE

Air Contaminant	Emergency Generator Engines ^a			Fire Pump Engines ^b		
	Emission Standard ^c (g/bhp-hr)	Single Engine Emission Rate (lb/hr)	Combined Emission Rate ^d (tpy)	Emission Standard ^e (g/bhp-hr)	Single Engine Emission Rate (lb/hr)	Combined Emission Rate ^d (tpy)
NO _x +NMHC	4.6	63.74	12.75	3.0	5.79	0.87
NO _x	-	60.51	12.10	-	5.34	0.80
CO	2.6	36.19	7.24	2.6	5.02	0.75
PM	0.15	2.07	0.41	0.15	0.29	0.04
PM ₁₀	-	1.99	0.40	-	0.28	0.04
PM _{2.5}	-	1.86	0.37	-	0.26	0.04
SO _x	-	0.05	0.01	-	0.008	0.001
VOC	-	3.23	0.65	-	0.45	0.07
HAP	-	0.06	0.01	-	0.008	0.001
CO _{2e}	-	5,758	1,152	-	802	120

^a Four diesel-fired emergency generator engines rated at 5,028 bhp each.

^b Three diesel-fired fire pump engines rated at 700 bhp each.

^c Subject to EPA Tier II emission standards for a model year 2006 or newer engine rated greater than 560 KW and the proposed LAER NO_x + NMHC emission standard.

^d Calculated at 100 hrs/yr/engine.

^e Subject to NSPS Subpart IIII Table 4 emission standards for a model year 2009 or newer stationary fire pump engine rated ≥ 600 bhp and < 750 bhp.

Emission calculations were carried out by the applicant for the LP incinerator based upon AP-42 Chapters 1.4 & 13.5 emission factors, mass balance, design parameters, and 40 CFR Part 98 Subpart C emission factors. A worst case operating time of 8,760 hours at the maximum designed heat input of 140 MMBtu/hr is assumed. Organic vapors recovered from continuous polyethylene manufacturing process vents, pyrolysis fuel oil and light gasoline storage tanks and loading, and hexene storage tanks will be controlled by this device. Minimum designed control efficiency is 99.9% for these high VOC concentration streams. SO₂ PTE is negligible because minimal natural gas assist will be necessary. PM₁₀ and PM_{2.5} emissions are considered equivalent for this source due to combustion of gaseous fuel. I have made a correction to the PM PTE calculations using only the PM (filterable) emission factor consistent with the methodology

³⁹ See AP-42, Fifth Edition, Volume I Chapter 3: Stationary Internal Combustion Engines, Table 3.4-2, <http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s04.pdf>, p 3.4-6.

for the larger combustion sources, spent caustic vent incinerator, and flares. Otherwise, all calculations were found to be acceptable.

Table 8: LP Incinerator PTE

Air Contaminant	Emission Rate (lb/hr)	Emission Rate (tpy)
NO _x	9.53	41.7
CO	11.54	50.5
PM (Filterable)	0.26	1.14
PM ₁₀	1.04	4.57
PM _{2.5}	1.04	4.57
SO _x	0.00	0.00
VOC	3.53	15.46
Hexane	0.25	1.08
HAP	0.26	1.16
CO _{2e}	20,453	89,582

Emission calculations were carried out by the applicant for the spent caustic vent incinerator based upon AP-42 Chapters 1.4 & 13.5 emission factors, mass balance and design parameters, and 40 CFR Part 98 Subpart C emission factors. A worst case annual operating time of 8,760 hours at the maximum designed heat input of 10.7 MMBtu/hr is assumed. Organic vapors recovered from the spent caustic oxidizer stripper; and flow equalization wastewater, recovered oil, and spent caustic storage tanks will be controlled by this device. Minimum designed control efficiency is 99% for these low VOC concentration streams. PM₁₀ and PM_{2.5} emissions are considered equivalent for this source due to combustion of gaseous fuel. H₂S is also expected to be present in the inlet stream as the caustic is used to remove H₂S from the ethylene product stream. All calculations were found to be acceptable.

Table 9: Spent Caustic Vent Incinerator PTE

Air Contaminant	Emission Rate (lb/hr)	Emission Rate (tpy)
NO _x	0.73	3.2
CO	0.88	3.86
PM (Filterable)	0.02	0.09
PM ₁₀	0.08	0.35
PM _{2.5}	0.08	0.35
SO _x	0.94	4.13
VOC	0.32	1.42
Benzene	0.11	0.48
HAP	0.14	0.63
CO _{2e}	1,340	5,870

Emission calculations were carried out by the applicant for the MPGF, HP enclosed ground flares, and HP elevated flare based upon AP-42 Chapters 1.4 & 13.5 emission factors, design parameters, and 40 CFR Part 98 Subpart C emission factors. Organic vapors recovered from intermittent polyethylene manufacturing process vents, compressor seal vents, and ethylene

manufacturing startup/shutdown/maintenance/upsets will be controlled by the HP enclosed ground flares with the HP elevated flare only used as a backup in case of emergency. Organic vapors recovered from initial filling, de-inertization, and upsets of the refrigerated ethylene storage tank; as well as low pressure upsets of the polyethylene manufacturing process will be controlled by the MPGF. It will also serve as backup to the LP incinerator in case of emergency. Annual operation of these flares includes continuous pilot lights and sweep gas, worst case expected vent rates, and worst case projected startup/shutdown events. VOC PTE from the MPGF and HP elevated flare is comparatively low because those units function primarily as backup units with natural gas as the only normal combustion gas. The designed annual average VOC flow to the HP enclosed ground flares is 1.16 metric tons per hour and minimum designed control efficiency for the flares is 98% consistent with LAER, NSPS Part 60 Subpart DDD, and NESHAP Part 63 Subpart YY. All calculations were found to be acceptable.

Table 10: MPGF, HP Ground Flares, HP Elevated Flare PTE

Air Contaminant	MPGF ^a Emission Rate (tpy)	HP Ground Flares ^b Emission Rate (tpy)	HP Elevated Flare ^c Emission Rate (tpy)
NO _x	0.98	27.2	15.4
CO	5.30	148.1	83.8
PM (Filterable)	0.03	0.75	0.42
PM ₁₀	0.10	2.98	1.69
PM _{2.5}	0.10	2.98	1.69
SO _x	0.02	0.59	0.33
VOC	0.05	226	1.22
Hexane	0.02	0.71	0.40
HAP	0.03	0.74	0.42
CO _{2e}	1,741	52,824	26,520

^a One multipoint ground flare rated at 100 MMBtu/hr with 1.0 MMBtu/hr pilot gas.

^b Two enclosed ground flares with a combined rating of 2,637 MMBtu/hr with 1.0 MMBtu/hr pilot gas.

^c One steam-assisted backup elevated flare rated at 1,500 metric tons/hr with 1.0 MMBtu/hr pilot gas and 1 metric ton/hr sweep gas.

Emission calculations were carried out by the applicant for the process and cogen cooling towers based upon tower design specifications, and mass balance calculations in conjunction with LAER and BACT emission limits. A worst case annual operating time of 8,760 hours at the maximum designed cooling water flow rates is assumed for each tower. Maximum water flow through the process and cogen cooling towers is 18.3 MMgal/hr and 4.44 MMgal/hr respectively. Each cooling tower will be equipped with high efficiency drift eliminators designed to limit water loss from the towers to 0.0005% or less of the total circulated water. It is then assumed that any solids in the drift loss will become PM emissions based upon the TDS limit of 2,000 ppmw. PM₁₀ and PM_{2.5} fractions of the total particulate are estimated using the Reisman & Frisbie method at 63.5 and 0.21 wt% of the total PM emissions respectively. VOC emissions from the process cooling tower will be minimized through maximization of process heat recovery and implementation of an LDAR program for the cooling water heat exchanger. VOC content of the cooling water will be limited to not exceed 0.5 lb/MMgal of circulated water. All calculations were found to be acceptable.

Table 11: Cooling Towers PTE

Air Contaminant	Process Cooling Tower		Cogen Cooling Tower	
	Emission Rate (lb/hr)	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tpy)
PM	1.53	6.68	0.37	1.62
PM ₁₀	0.97	4.24	0.24	1.03
PM _{2.5}	0.003	0.01	0.001	0.00
VOC	9.15	40.1	-	-
Hexane	0.92	4.01	-	-
HAP	0.92	4.01	-	-

Emission calculations were carried out by the applicant for particulate matter emissions from polyethylene manufacturing process vents based upon designed fabric filter outlet emission rates and process vent counts, flow rates, and service types. Each emission point (excluding the pellet dryer vents) will be controlled by a fabric filter with an outlet emission rate not to exceed 0.005 gr/dscf. Pellet dryer vents are expected to be high in moisture content and uncontrolled with an outlet emission rate not to exceed 0.01 gr/dscf. Process vent particulate matter emissions will be filterable and have been assumed to be 100% PM_{2.5} as a worst case scenario. Chromium PTE represents potential losses from the electrically heated catalyst activation systems which are part of the slurry technology polyethylene manufacturing line. Annual emissions have been calculated from intermittent vents at 333 days (7,992 hours) per year and from continuous vents at 365 days (8,760 hours) per year. All calculations were found to be acceptable.

Table 12: Polyethylene Units Process Vents PTE

Source	PM	PM ₁₀	PM _{2.5}	Chromium
	Emission Rate (tpy)	Emission Rate (tpy)	Emission Rate (tpy)	Emission Rate (tpy)
PE Units 1 & 2 Process Vents	2.17	2.17	2.17	-
PE Unit 3 Process Vents	0.93	0.93	0.93	0.0013
Total	3.10	3.10	3.10	0.0013

Emission calculations were carried out by the applicant for VOC emissions from finished polyethylene pellets based upon mass balance techniques and pellet throughput in conjunction with the LAER limit. No organic HAP is expected to be present in the finished product. Residual VOC content of the finished pellets will be limited not to exceed 50 ppmw as determined through the application of LAER. It is then assumed that 100% of the residual VOC is emitted from the finished pellets at the maximum pellet production rate, 8,760 hours per year. However; maximum annual pellet production is to be limited by plan approval condition not to exceed 1,600,000 metric tons while the value used in the calculations is 1,931,247 tons (1,751,998 metric tons). I have made a correction to the VOC PTE calculations using the maximum annual pellet production rate (limited by plan approval condition) of 1,600,000 metric tons. Otherwise, this calculation methodology was found to be acceptable.

Table 13: Polyethylene Pellet Residual VOC PTE

Source	VOC Emission Rate (tpy)
Finished Polyethylene Pellets	88.2

Emission calculations were carried out by the applicant for finished polyethylene pellet blending, handling, storage, and loading based upon designed bin vent filter outlet emission rates and total volume of air flow through each step. The facility will include up to 14 blending silos, 12 railcar handling and storage silos, 38 truck handling and storage silos, and 25 DeDuster vents. Each emission point will be controlled by a bin vent filter with an outlet emission rate not to exceed 0.005 gr/dscf and air flow rates are determined based upon the maximum short term, and annual average production rates. Maximum polyethylene pellet production will be 1,600,000 metric tons per year. Blending has been estimated at 187.5% of total production (3,000,000 metric tons) with a 10 to 1 pellet to air mass ratio representing forced air flow. Railcar and truck handling and storage have been estimated at 95% and 20% of total production also with a 10 to 1 pellet to air mass ratio representing forced air flow. Railcar and truck loadout have also been estimated at 95% and 20% of total production but with a 1 to 1 pellet to air volume ratio (displacement air). This results a conservatively higher total PTE from these activities because only 100% of the product will be available for loadout. DeDusting will be performed on 100% of total production with a 22 to 1 pellet to air mass ratio representing forced air flow.

I have made one correction to the DeDuster vent PTE calculations by calculating PM₁₀ and PM_{2.5} as 17% of PM consistent with the supporting information for polyethylene pellet handling PM emissions size distribution. The applicant had calculated DeDuster vent PM₁₀ and PM_{2.5} at 1% of PM in this case but had not supported this lower size distribution ratio. Otherwise, these calculations were found to be acceptable.

Table 14: Polyethylene Pellet Blending, Handling, Storage, and Loading PTE

Source	PM	PM ₁₀	PM _{2.5}
	Emission Rate (tpy)	Emission Rate (tpy)	Emission Rate (tpy)
Blending Silos	3.16	0.54	0.54
Railcar Handling & Storage	1.60	0.27	0.27
Truck Handling & Storage	0.34	0.06	0.06
DeDuster Vents	0.96	0.16	0.16
Railcar Loading	0.021	0.021	0.021
Truck Loading	0.004	0.004	0.004
Total	6.09	1.06	1.06

Emission calculations were carried out by the applicant for fugitive losses from C₃+ liquid loadout based upon SCAQMD emission factors for LPG vehicle loading, maximum liquid throughput, and number of loadouts. A maximum of 78.7 million gallons (~1.87 million barrels) of C₃+ will be produced as a byproduct of ethylene production. This byproduct will be stored in and loaded out into pressurized storage vessels. The only losses will be fugitive in nature from connector and hose disconnects after loading is completed. Losses are assumed to be 100% VOC and no organic HAPs are expected to be present in this mixture.

Emission calculations were carried out by the applicant for fugitive losses from recovered oil, coke residue/tar, pyrolysis fuel oil, and light gasoline loadout based upon AP-42 Section 5.2 loading loss emission factors, maximum liquid throughputs, and liquid material properties. Liquid loadout temperatures were conservatively set at 86°F except for the pyrolysis fuel oil which is to be heated to 356°F. Appropriate material surrogates were used to estimate worst case true vapor pressures and vapor molecular weights. Recovered oil and coke residue/tar are considered low vapor pressure organic liquids and vapor pressure was set to a worst case upper limit of 0.50 psia. Vapors recovered from the loading of these two byproducts will be routed through a closed system to the Spent Caustic Vent incinerator and back to the process respectively. However, no control efficiencies have been estimated in this case and VOC emissions from loadout of these two byproducts are less than de minimis levels in any case. Pyrolysis fuel oil and light gasoline are not considered low vapor pressure organic liquids and vapors recovered from the loading of these two byproducts will be routed through a closed system to the LP System incinerator. Control efficiency of the incinerator will be a minimum of 99.9%. Losses are assumed to be both 100% VOC and organic HAP.

I have made a correction to the emission calculations by applying the stated 99.9% control efficiency of the LP incinerator rather than 99.5%. A minimum control efficiency of 99.9% was determined to be representative of the application of LAER in this case. This does not have an impact on regulatory applicability, and VOC emissions from loadout of these two byproducts are less than de minimis levels using either control efficiency. Actual emissions from liquids loadout are expected to be less because the average annual temperature for this region is approximately 51°F (compared to the 86°F used in the calculations). Also, maximum true vapor pressure of the recovered oil and coke residue/tar is expected to be less than the 0.050 psia used in the calculations. All calculations were found to be acceptable.

Table 15: Liquid Loadout PTE

Source	VOC	HAP
	Emission Rate (tpy)	Emission Rate (tpy)
C ₃ +	17.3	-
Recovered Oil	0.10	0.10
Coke Residue and Tar	0.37	0.37
Pyrolysis Fuel Oil	0.01	0.01
Light Gasoline	0.03	0.03
Total	17.81	0.51

Emission calculations were carried out by the applicant for storage tanks not controlled by a common control device (LP System) based upon EPA TANKS 4.09 for working and breathing losses. Flashing losses are expected to be negligible because these liquids will not be transferred under pressure and not undergo a large pressure drop when entering the storage tanks. These tanks include all diesel fuel storage tanks and the spent caustic storage tank. Maximum throughputs of each liquid have been used in the calculations. Diesel fuel tanks will each be fixed roof but controlled at an estimated 95% by carbon canisters. The spent caustic tank will also be fixed roof but controlled at an estimated 99% by the spent caustic vent incinerator. HAP emissions have been conservatively set equal to VOC emissions. Potential emissions are expected to be less than de minimis and nearly negligible. All calculations were found to be acceptable.

Table 16: Diesel Fuel and Spent Caustic Storage Tanks PTE

Storage Tank	Capacity (gallons)	Max Throughput (gal/yr)	VOC (tpy)	HAP (tpy)
Locomotive Diesel x 1	10,000	412,000	0.000	0.000
Generator Diesel x 4	10,000	55,000	0.000	0.000
Fire Water Pump Diesel x 2	1,849	7,200	0.000	0.000
Spent Caustic x 1	237,755	26,515,000	0.001	0.001
Total	-	-	0.001	0.001

Emission calculations were carried out by the applicant for fugitive losses from the WWTP based upon the EPA WATER9 program. WATER9 is a wastewater treatment model which can be used for an entire facility with multiple wastewater inlet streams and collection systems, and complex treatment configurations. The applicant's identified wastewater constituents, and inputs to the WATER9 model, were set as equal parts benzene and phenol (VOCs/HAPs). Emission rate outputs are nearly 100% benzene with a negligible fraction as phenol. This model accounts for all phases of the WWTP excluding the flow equalization wastewater and oil recovery storage tanks which are individually controlled by the spent caustic vent incinerator. All calculations were found to be acceptable.

Table 17: WWTP PTE^a

Air Contaminant	Emission Rate (lb/hr)	Emission Rate (tpy)
VOC	0.010	0.042
Benzene	0.010	0.042

^a Includes all WWTP equipment except the flow equalization and oil removal tanks which are separately accounted for and controlled by the spent caustic vent incinerator.

Emission calculations were carried out by the applicant for fugitive emissions from facility component leaks based upon EPA and Texas Commission on Environmental Quality (TCEQ) average emission factors for equipment leaks in the synthetic organic chemical manufacturing industry (SOCMI), estimated facility component counts, and 8,760 hours of annual operation. This includes any potentially leaking components in gas/vapor, light liquid, or heavy liquid service which contain or contact VOC, HAP, or CH₄. Control efficiencies ranging from 93% to 97% were applied to the emission factors consistent with implementation of a LAER LDAR program at this facility and supported by a TCEQ guidance document⁴⁰. Components associated with polyethylene manufacturing have been assumed to contain 100% VOC, up to 5% HAP, and no CH₄ while components associated with the cracking furnaces have been assumed to contain 100% VOC/CH₄ and between 0% and 100% HAP depending on the service. Additionally, components which are considered "outside the boundary limits" (OSBL) have been assumed to contain 100% CH₄ if in fuel or natural gas service and 100% VOC otherwise. All calculations were found to be acceptable.

⁴⁰ See http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/control_eff.pdf

Table 18: Component Fugitives PTE

Source	VOC	HAP	CO ₂ e
	Emission Rate (tpy)	Emission Rate (tpy)	Emission Rate (tpy)
PE Units 1 & 2	36.6	2.09	0
PE Unit 3	8.27	0.29	0
Cracking Furnaces	17.4	1.17	103
OSBL ^a	5.7	0.27	36
Total	67.97	3.82	139

^a Components outside of the ethylene and polyethylene manufacturing lines; including tanks, cogeneration plant, engines, cooling towers, and wastewater treatment.

Emission calculations were carried out by the applicant for fugitive dust emissions from facility roadway vehicle traffic based upon AP-42 Chapter 13.2.1 emission factors for paved roadways. Site relevant data and design estimates such as average days of precipitation of at least 0.01", roadway surface silt loading, average vehicle weight and numbers, and roadway length has been provided. Silt loading of the roadway surface is a variable in the calculations which cannot be specifically designed for but is expected to not exceed 0.20 g/m² due to the application of LAER for PM_{2.5} in this case. This variable falls within the range of values found during testing a development of the equation and is the appropriate method to account for implementation of a roadway dust control plan. No additional factor (other than the precipitation correction factor) has been applied to the equation to represent a control efficiency.

I have made some corrections to the emission calculations by using the appropriate daily precipitation correction term and converting the throughput maximum from units of metric tons to tons. This results in more conservative (higher PTE) estimates but the overall change is less than de minimis thresholds. Actual emissions are expected to be less because the majority of pellet loadout is planned to occur by rail. All calculations were found to be acceptable.

Table 19: Paved Roadway Vehicle Traffic PTE

Source	PM (tpy)	PM ₁₀ (tpy)	PM _{2.5} (tpy)
Paved Roadways	0.520	0.104	0.026

Compliance with emission limitations will be demonstrated through NO_x and CO CEMS for the ethane cracking furnaces and combustion turbines with duct burners, source testing requirements where practicable, and implementation of work practice standards and monitoring as necessary. Facility-wide PTE is summarized in the table below.

Table 20: Facility-Wide PTE

Air Contaminant	Emission Rate ^a (tpy)
NO _x	348
CO	1,012
PM (filterable)	71
PM ₁₀	164
PM _{2.5}	159
SO _x	21
VOC	522
Hexane	26
Formaldehyde	1.44
Benzene	0.99
Toluene	0.34
Naphthalene	0.31
1, 3-Butadiene	0.30
HAP	30.5
Ammonia	151.85
CO ₂ e	2,248,293

^a Values may be slightly inconsistent out to the final significant digit due to rounding.

PSD Modeling

Refined air dispersion modeling was performed and submitted with the plan approval application in order to demonstrate that Shell does not cause or contribute to air pollution in violation of any NAAQS or PSD increments. This modeling was required for NO₂, CO, and PM₁₀ due to this project triggering PSD review for those pollutants. The applicant submitted a modeling protocol to the Department on February 18, 2014, which was approved prior to receipt of this application. Modeling results and data received with this application were sent to the Department's Air Quality Modeling Section and reviewed by Andrew Fleck, Environmental Group Manager. This air quality analysis portion of the application was determined to be administratively complete on May 15, 2014. An update to the application's air quality analysis for PSD was received on October 15, 2014, including the addition of a refined air quality analysis for CO and PM₁₀. Technical review of this air quality analysis was completed on March 19, 2015.

Input emission rates are found to be consistent with other submitted plan approval application materials. Nearby source emissions data has also been verified to be consistent with the Department's records.

Results of the facility-specific modeling show no significant impact to Class I areas for 24-hour PM₁₀, annual PM₁₀, and 1-hour NO₂. There is no significant impact level (SIL) for CO or 1-hour NO₂. Class I areas located within 300km of this site include Shenandoah National Park – VA, managed by the National Park Service; and wilderness areas Otter Creek – WV and Dolly Sods – WV, both managed by the USDA Forest Service. Federal Land Managers (FLMs) for the USDA Forest Service and National Park Service have both stated that they are not requesting an air quality related values (AQRV) analysis for this application. This has been confirmed via email communications from each FLM.

Table 21: PSD Class I Significant Impact Level Modeling Results^a

Air Contaminant	Averaging Period	Class I SIL ^b	Modeled Impact	Significant Impact?
NO ₂	1-hour	N/A ^c	-	N/A
	Annual	0.10	0.02	No
CO	1-hour	N/A ^c	-	N/A
	8-hour	N/A ^c	-	N/A
PM ₁₀	24-hour	0.30	0.27	No
	Annual	0.20	0.02	No

^a All values are in units of µg/m³.

^b Proposed by EPA at *Federal Register*, Vol. 61, No. 142, Tuesday, July 23, 1996, Proposed Rules, p. 38292.

^c There is no SIL for 1-hour NO₂ or 1-hour and 8-hour CO for Class I areas.

Results of the facility-specific modeling show no significant impact to Class II areas for annual NO₂. However; modeling results do show significant impacts to Class II areas for 1-hour NO₂, 1-hour CO, 8-hour CO, 24-hour PM₁₀, and annual PM₁₀. Therefore; refined modeling was conducted for each NAAQS and PSD increment except for annual NO₂.

Table 22: PSD Class II Significant Impact Level Modeling Results^a

Air Contaminant	Averaging Period	Class II SIL ^b	Modeled Impact	Significant Impact?
NO ₂	1-hour	7.5	48.7	Yes
	Annual	1.0	0.93	No
CO	1-hour	2000	2,614	Yes
	8-hour	500	862	Yes
PM ₁₀	24-hour	5.0	8.44	Yes
	Annual	1.0	2.34	Yes

^a All values are in units of µg/m³.

^b From 40 CFR §51.165(b)(2), excluding the interim 1-hour NO₂ SIL.

Results of the refined NAAQS modeling, including nearby sources and background, show no exceedance of the 1-hour CO or 8-hour CO NAAQS. There is no annual PM₁₀ NAAQS to model for. However; modeling results do show an exceedance of the 1-hour NO₂ and 24-hour PM₁₀ NAAQS. Therefore; modeling data was further analyzed to determine Shell's impact at each receptor where exceedances have been modeled. Shell's contribution at each receptor with a modeled exceedance does not exceed the Class II SIL and the maximum contribution at any such receptor is shown in the table below.

Table 23: PSD NAAQS Modeling Results^a

Air Contaminant	Averaging Period	NAAQS	Total Conc. ^b	Exceeds NAAQS?	Shell's Contribution ^c	Class II SIL	Significant Impact?
NO ₂	1-hour	188.0	2,835	Yes	6.90	7.5	No
	Annual	100.0	N/A ^d	N/A	N/A	N/A	N/A
CO	1-hour	40,000	6,692	No	N/A	N/A	N/A
	8-hour	10,000	3,866	No	N/A	N/A	N/A
PM ₁₀	24-hour	150.0	10,432	Yes	2.86	5.0	No
	Annual	N/A	N/A	N/A	N/A	N/A	N/A

^a All values are in units of $\mu\text{g}/\text{m}^3$.

^b Includes background concentrations.

^c Highest contribution at any receptor with a total value in excess of the NAAQS.

^d Annual NO_2 modeled impact was earlier determined to be insignificant.

Results of the PSD increment modeling, including nearby sources and background, show no exceedance of the annual PM_{10} increment. There is no PSD increment for CO or 1-hour NO_2 . However; modeling results do show an exceedance of the 24-hour PM_{10} increment. Therefore; modeling data was further analyzed to determine Shell's contribution at each receptor where exceedances have been modeled. Shell's contribution at each receptor with a modeled exceedance does not exceed the Class II SIL and the maximum contribution at any such receptor is shown in the table below.

Table 24: PSD Increment Modeling Results^a

Air Contaminant	Avg. Period	Class II Increment	Increment Consumption	Exceeds Increment?	Shell's Contrib. ^b	Class II SIL	Significant Impact?
NO_2	1-hour	N/A	N/A	N/A	N/A	N/A	N/A
	Annual	25	N/A ^c	N/A	N/A	N/A	N/A
CO	1-hour	N/A	N/A	N/A	N/A	N/A	N/A
	8-hour	N/A	N/A	N/A	N/A	N/A	N/A
PM_{10}	24-hour	30	37.3	Yes	1.84	5.0	No
	Annual	17	9.4	No	N/A	N/A	N/A

^a All values are in units of $\mu\text{g}/\text{m}^3$.

^b Highest contribution at any receptor with a total value in excess of the increment.

^c Annual NO_2 modeled impact was earlier determined to be insignificant.

The Department's technical review⁴¹ concludes that Shell's air quality analysis satisfies the requirements of the PSD rules and is consistent with EPA's *Guideline on Air Quality Models* (40 CFR Part 51, Appendix W) and EPA's air quality modeling policy and guidance. Additionally, Shell's air quality analysis is consistent with the methods and procedures described in Shell's modeling protocol established with the Department.

The Department's technical review concludes that, in accordance with 40 CFR §52.21(k), Shell's air quality analysis demonstrates that Shell's proposed emissions will not cause or contribute to air pollution in violation of the NAAQS for CO, NO_2 , or PM_{10} ; or the increments for NO_2 or PM_{10} . The degree of Class II and Class I increment consumption expected to result from the operation of the Shell facility is provided in the following tables:

Table 25: Degree of Class II Increment Consumption from Operation of Shell Facility

Pollutant	Averaging Period	Degree of Class II Increment Consumption		Class II Increment $\mu\text{g}/\text{m}^3$
		$\mu\text{g}/\text{m}^3$	% of Class II Increment	
NO_2	Annual	< 0.93919	< 3.76 %	25
PM_{10}	24-Hour	< 8.43834	< 28.13 %	30
	Annual	< 2.34454	< 13.79 %	17

⁴¹ Andrew Fleck, Environmental Group Manager, Air Quality Modeling Section, Pennsylvania Department of Environmental Protection, Bureau of Air Quality, *Air Quality Analysis for Prevention of Significant Deterioration*, Shell Chemical Appalachia LLC, March 19, 2015.

Table 26: Degree of Class I Increment Consumption from Operation of Shell Facility

Pollutant	Averaging Period	Degree of Class I Increment Consumption		Class I Increment
		$\mu\text{g}/\text{m}^3$	% of Class I Increment	$\mu\text{g}/\text{m}^3$
NO ₂	Annual	< 0.02342	< 0.94 %	2.5
PM ₁₀	24-Hour	< 0.27234	< 3.40 %	8
	Annual	< 0.01954	< 0.49 %	4

In accordance with 40 CFR 52.21(l)(2), where an air quality model specified in the EPA's *Guideline on Air Quality Models* (40 CFR Part 51, Appendix W) is inappropriate, the model may be modified on a case-by-case basis. Written approval of the EPA Regional Administrator must be obtained for the use of a modified model. In addition, the use of a modified model must be subject to notice and opportunity for public comment under procedures developed in accordance with 40 CFR § 52.21(q). The air quality analysis for NO₂ for the proposed facility utilizes the Plume Volume Molar Ratio Method (PVMRM), which is currently implemented as a non-regulatory-default option within the EPA's recommended near-field dispersion model, the American Meteorological Society / Environmental Protection Agency Regulatory Model (AERMOD). In accordance with the recommendations under subsection 3.2 of the EPA's *Guideline on Air Quality Models*, the Department submitted a request to EPA Region III for approval of the use of the PVMRM in Shell's air quality analysis for NO₂ on March 31, 2014. The EPA Regional Administrator approved the DEP's request on April 21, 2014.

The Department's technical review concludes that, in accordance with 40 CFR §52.21(o), Shell provided a satisfactory analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the Shell facility and general commercial, residential, industrial, and other growth associated with the Shell facility. Additionally, in accordance with 40 CFR §52.21(p), written notice of the proposed project has been provided to the Federal Land Managers of nearby Class I areas as well as initial screening calculations to demonstrate that Shell's proposed emissions will not adversely impact visibility and air quality related values (AQRV) in nearby Class I areas

Risk Assessment Modeling

RTP has submitted an inhalation risk assessment on behalf of Shell received by the Department on January 28, 2015. This assessment has been submitted in order to evaluate potential cancer and noncancer inhalation risks from Shell's air emissions. The applicant submitted a modeling protocol to the Department on January 7, 2015, which was approved prior to receipt of this risk assessment. Modeling results and data received with this submittal were sent to both the Department's Air Toxics and Risk Assessment Section; and Air Quality Modeling Section and reviewed by Craig Evans, Environmental Group Manager; and Andrew Fleck, Environmental Group Manager.

Input emission rates are found to be acceptable and consistent with other submitted plan approval application materials. This is a facility-specific assessment and does not include any other source emission data. Emission rates of compounds of potential concern (COPC) have been modeled to derive exposure concentrations. The highest modeled exposure concentrations were then multiplied or divided by compound-specific unit risk factors or reference concentrations, respectively. Chronic risks for each COPC were then summed and compared against the

Department's benchmark excess lifetime cancer risk and health index (HI) values. Acute risks for each COPC were compared against the Department's benchmark hazard quotient (HQ) value. Results of the modeling show that worst case chronic cancer, chronic noncancer, and acute noncancer risks do not exceed the Department's benchmarks.

The Department's technical review⁴² concludes that Shell's inhalation risk assessment was conducted according to the Department-approved protocol and is acceptable. Furthermore, the Department's independent inhalation risk assessment concludes that chronic cancer and noncancer risks as well as acute noncancer risks do not exceed the Department's benchmarks. Results of both risk assessments are nearly identical for many of the COPC. Two notable exceptions are the modeled chronic cancer risk for PAH (as benzo(a)pyrene) acute noncancer risk for benzene. The Department's modeled risk for both compounds is lower than Shell's. This has a negligible impact on the combined excess cancer lifetime risk (for PAH), but reduces the maximum HQ for the facility by approximately 62%. This is because the Department used a different acute reference concentration for benzene based upon an internal hierarchy.

Table 27: Inhalation Risk Assessment Modeling Results

Inhalation Risk	Department Benchmark	Shell Modeled Risk	Less Than Benchmark?	Department Modeled Risk	Less Than Benchmark?
Excess Lifetime Cancer Risk	1 in 100,000	0.8 in 100,000	Yes	0.79 in 100,000	Yes
Chronic Noncancer Risk	HI < 0.25	HI = 0.07	Yes	HI = 0.075	Yes
Acute Noncancer Risk	HQ < 1	HQ = 0.21 ^a	Yes	HQ = 0.08 ^a	Yes

^a Modeled and calculated result for benzene.

RECOMMENDATIONS

Shell Chemical Appalachia LLC has shown that emissions will be minimized through the use of appropriate BAT, BACT, and LAER in this application for a petrochemicals complex to be located in Potter and Center Townships, Beaver County. I recommend issuance of a Plan Approval for a period of 4 years subject to the standard conditions in Section B of all plan approvals along with the special conditions below.

SPECIAL CONDITIONS

1. This Plan Approval is to allow the construction and temporary operation of a petrochemicals complex by Shell Chemical Appalachia LLC to be located in Potter and Center Townships, Beaver County [25 Pa. Code §127.12b].
2. Air contamination sources and air cleaning devices authorized to be installed at the Facility under this Plan Approval are as follows [25 Pa. Code §127.12b]:

⁴² Craig Evans, Chief, Air Toxics and Risk Assessment Section, Pennsylvania Department of Environmental Protection, Bureau of Air Quality, *Air Quality Modeling and Inhalation Risk Evaluation*, Shell Chemical Appalachia LLC, March 19, 2015.

- Seven (7) tail gas- and natural gas-fired ethane cracking furnaces, 620 MMBtu/hr heat input rating each; equipped with low-NO_x burners and controlled by selective catalytic reduction (SCR).
- One (1) ethylene manufacturing line, 1,500,000 metric tons/yr; compressor seal vents and startup/shutdown/maintenance/upsets controlled by the high pressure header system (HP System).
- Two (2) gas phase polyethylene manufacturing lines, 550,000 metric tons/yr each; VOC emission points controlled by the low pressure header system (LP System) or HP System, PM emission points controlled by filters.
- One (1) slurry technology polyethylene manufacturing line, 500,000 metric tons/yr; VOC emission points controlled by the LP System or HP System, PM emission points controlled by filters.
- One (1) LP System; routed to the LP incinerator, 10 metric tons/hr capacity, with backup multipoint ground flare (MPGF), 74 metric tons/hr total capacity.
- One (1) HP System; routed to two (2) HP enclosed ground flares 150 metric tons/hr capacity each, with backup emergency elevated flare, 1,500 metric tons/hr capacity.
- Three (3) General Electric, Frame 6B, natural gas-fired combustion turbines, 40.6 MW (475 MMBtu/hr heat input rating) each, including natural gas- or tail gas-fired duct burners, 189 MMBtu/hr heat input rating each; controlled by SCR and oxidation catalysts.
- Four (4) diesel-fired emergency generator engines, 5,028 bhp rating each.
- Three (3) diesel-fired fire pump engines, 700 bhp rating each.
- One (1) process cooling tower, 28 cell counter-flow mechanical draft, 18.3 MMgal/hr water flow capacity; controlled by drift eliminators.
- One (1) cogen cooling tower, 6 cell counter-flow mechanical draft, 4.44 MMgal/hr water flow capacity; controlled by drift eliminators.
- Polyethylene pellet blending, handling, storage, and loadout; controlled by fabric filters.
- Liquid loadout, coke residue/tar and recovered oil; controlled by vapor capture and routing back to the process or Spent Caustic Vent incinerator, and low-leak couplings.
- Liquid loadout, pyrolysis fuel oil and light gasoline; controlled by vapor capture and routing to the LP System, and low-leak couplings.
- Liquid loadout, C₃+; controlled by pressurized transfer with vapor balance and low-leak couplings.
- One (1) recovered oil; one (1) spent caustic, and two (2) equalization wastewater storage tanks, 23,775 to 742,324 gallon capacities; controlled by internal floating roofs (IFR) and vapor capture routed to the Spent Caustic Vent incinerator, 8 metric tons/hr capacity.
- One (1) light gasoline, and two (2) hexene storage tanks; 85,856 and 607,596 gallon capacities; controlled by IFR and vapor capture routed to the LP System.
- Two (2) pyrolysis fuel oil storage tanks; 85,856 gallon capacity; controlled by vapor capture routed to the LP System.
- Miscellaneous storage tanks, diesel fuel, 1,849 to 10,038 gallon capacities; controlled by carbon canisters.
- Miscellaneous components in gas, light liquid, and heavy liquid service; controlled by leak detection and repair (LDAR).
- Wastewater treatment plant (WWTP).

- Plant roadways; controlled by paving and a road dust control plan including sweeping and watering (as necessary).
3. Sulfur content of the gaseous fuels combusted at this facility shall not exceed 0.5 grains per 100 dscf [25 Pa. Code §127.12b].
 4. The Owner/Operator shall inform the Department of the specific make and model of equipment and design details prior to startup for all air contamination sources and all air cleaning devices by submitting appropriate pages of the Plan Approval application forms [25 Pa. Code §127.12b].
 5. No person may permit air pollution as that term is defined in the act [25 Pa. Code §121.7].
 6. Fugitive emissions are prohibited from the Facility in accordance with 25 Pa. Code §123.1.
 7. The Owner/Operator may not permit fugitive particulate matter to be emitted into the outdoor atmosphere from a source specified in 25 Pa. Code §123.1(a)(1)-(9) (relating to prohibition of certain fugitive emissions) if the emissions are visible at the point the emissions pass outside the Owner/Operator's property [25 Pa. Code §123.2].
 8. The Owner/Operator may not permit the emission into the outdoor atmosphere of any malodorous air contaminants from any source in such a manner that the malodors are detectable outside of the property of the Facility [25 Pa. Code §123.31].
 9. Throughputs for facility production and/or loadout shall not exceed the following during any consecutive 12-month period [25 Pa. Code §127.12b]:
 - a. Polyethylene – 1,600,000 metric tons.
 - b. C₃+ Liquids – 78.7 million gallons
 10. The Owner/Operator shall secure 400 tons of NO_x, 620 tons of VOC, and 159 tons of PM_{2.5} ERCs. ERCs shall be properly generated, certified by the Department and processed through the registry in accordance with 25 Pa. Code §127.206(d)(1). Upon transfer, the Owner/Operator shall provide the Department with documentation clearly specifying the details of the ERC transaction. This facility may not commence operation until the required emissions reductions are certified and registered by the Department [25 Pa. Code §127.206].
 11. Emissions from the Facility shall not exceed the following in any consecutive 12-month period [25 Pa. Code §127.12b]:

Air Contaminant	Emission Rate (tpy)
NO _x	348
CO	1,012
PM (filterable)	71
PM ₁₀	164
PM _{2.5}	159
SO _x	21
VOC	522
VOC (ERC) ^a	620
HAP	30.5
Ammonia	152
CO ₂ e	2,248,293

^a This limit is included to ensure that the proper amount of VOC ERCs are secured by the applicant in accordance with the VOC offset ratios for flue and fugitive emissions under 25 Pa. Code §127.210. Compliance with this limit will be determined by actual VOC emissions at the Facility and the following equation:

$$\text{VOC (ERC)} = 1.15 * \sum(\text{flue VOC emissions}) + 1.3 * \sum(\text{fugitive VOC emissions}) \quad (\text{Eq. 1})$$

Where:

Flue VOC emissions are actual emissions from the ethane cracking furnaces, combustion turbines/duct burners, incinerators, flares, engines, miscellaneous storage tanks, and polyethylene pellet residual VOC.

Fugitive VOC emissions are actual emissions from liquid loadout, component leaks, the process cooling tower, and wastewater treatment plant.

12. The Owner/Operator shall conduct an inhalation risk assessment for the Facility based upon the final as-built design parameters of the air contamination sources. The inhalation risk assessment shall be conducted in accordance with the protocol previously submitted to the Department on January 7, 2015, which has already been approved. The inhalation risk assessment shall be submitted to the Department within 180 days of startup of the Facility [25 Pa. Code §127.12b].
13. Facility personnel shall conduct observations of all air contamination sources, air cleaning devices, stacks, fugitive emission areas, and process equipment at a minimum of once per shift while the Facility is in operation. These observations are to ensure continued compliance with source-specific visible emission limitations, fugitive emissions prohibited under 25 Pa. Code §§123.1 or 123.2, and malodors prohibited under 25 Pa. Code §123.31. Observations shall be conducted for the presence of the following [25 Pa. Code §127.12b]:
 - a. Visible stack emissions;
 - b. Fugitive emissions; and
 - c. Potentially objectionable odors.

If visible stack emissions, fugitive emissions, or potentially objectionable odors are apparent; the Owner/Operator shall take corrective action. Each observation of a visible stack

emission, fugitive emission, or potentially objectionable odor shall be reported to a centralized incident coordinator and recorded. Records of each reported observation shall be maintained in a log and at the minimum include the date, time, name and title of the observer, along with any corrective action taken as a result.

14. Facility personnel shall be trained to observe air contamination sources, air cleaning devices, stacks, fugitive emission areas, and process equipment to demonstrate compliance with Condition 13 above [25 Pa. Code §127.12b].
 - a) New personnel shall be trained upon hiring.
 - b) Existing personnel shall be trained prior to source startup.
 - c) Personnel shall be given refresher training annually.
 - d) A copy of the written personnel training program shall be maintained at the Facility. The training program shall include provisions for the following:
 - 1) Equipment and areas to be observed;
 - 2) That observation is to be made for the presence of visible stack emissions, fugitive emissions, and potentially objectionable odors;
 - 3) Information to be collected in the event of an affirmative observation; and
 - 4) Whom at the Facility to report affirmative observations to.
 - e) Records of successful completion of initial and annual training shall be maintained for a minimum of five years for each employee trained.
15. The Owner/Operator shall provide the Department with a statement; in a form as the Department may prescribe; for classes or categories of sources; showing the actual emissions of NO_x, CO, VOC, SO_x, PM₁₀, PM_{2.5}, HAP (per the Department's Emissions Inventory Reporting Instructions), NH₃, and GHG (including but not limited to CO₂, CH₄, and N₂O) for each reporting period. A description of the method used to calculate the emissions and the time period over which the calculation is based shall be included. The statement shall also contain a certification by a company officer or the plant manager that the information contained in the statement is accurate [25 Pa. Code §127.12b].
16. Annual emission reporting shall be conducted as follows [25 Pa. Code §135.3]:
 - a. The Owner/Operator shall submit by March 1 of each year, a source report for the preceding calendar year. The report shall include information for all previously reported sources, new sources which were first operated during the preceding calendar year, and sources modified during the same period which were not previously reported.
 - b. A person who received initial notification by the Department that a source report is necessary shall submit an initial source report within 60 days after receiving the notification or by March 1 of the year following the year for which the report is required, whichever is later.
 - c. A source Owner/Operator may request an extension of time from the Department for the filing of a source report, and the Department may grant the extension for reasonable cause.
17. All air contamination sources and air cleaning devices authorized under this Plan Approval shall be operated and maintained in accordance with the specifications and maintenance schedule recommended by the manufacturer, developed and approved by the engineering procurement and construction contractor, or developed by the Owner/Operator in accordance

with industry standards. Developed maintenance plans shall be in place and available within 180 days of startup of each air contamination source or air cleaning device [25 Pa. Code § 127.12b]:

18. The Owner/Operator shall maintain the following comprehensive and accurate records [25 Pa. Code §127.12b]:

- a. Rolling 12-month totals of the hours of operation in each defined operating mode for each ethane cracking furnace and each combustion turbine.
- b. Rolling 12-month totals for each diesel-fired emergency generator and fire pump engine of (and as defined in 40 CFR Part 60 Subpart IIII):
 - 1) Hours of operation for maintenance, testing, or emergency demand response.
 - 2) Hours of operation in all non-emergency situations.
 - 3) Hours of operation.
- c. Rolling 12-month totals (in MMscf) of tail gas and natural gas consumed by each ethane cracking furnace, combustion turbine, and duct burner.
- d. Rolling 12-month totals (in MMscf) of gas combusted by the LP incinerator, MPGF, HP ground flares, emergency elevated flare, and Spent Caustic Vent incinerator.
- e. Rolling 12-month totals (in metric tons) of produced ethylene and polyethylene.
- f. Rolling 12-month totals (in gallons) of C₃+, coke residue/tar, recovered oil, pyrolysis fuel oil, and light gasoline loaded out from the Facility.
- g. Rolling 12-month totals of calculated VOC (ERC) emissions in accordance with Equation 1 specified in this Plan Approval.
- h. Rolling 12-month averages of measured TDS from each cooling tower.
- i. Records including a description of testing methods, results, all operating data collected during tests, and a copy of the calculations performed to determine compliance with emission standards for the ethane cracking furnaces, combustion turbines, and incinerators.
- j. Copies of manufacturer's or EPC contractor's equipment design specifications necessary to determine compliance with required control efficiencies or outlet emission rates.
- k. Copies of maintenance procedures and schedules for all air contamination sources and air cleaning devices authorized under this plan approval.
- l. Records of any maintenance conducted on the air contamination sources and air cleaning devices authorized under this plan approval.
- m. Records that diesel fuel's total sulfur content does not exceed 15 ppm, and that either cetane index is a minimum of 40 or aromatic content does not exceed 35 % by volume.
- n. Records that each gaseous fuel's total sulfur content does not exceed 0.5 grains per 100 dscf. This may be demonstrated by a current, valid purchase contract, tariff sheet or transportation contract for the fuel; or fuel total sulfur content monitoring in accordance with 40 CFR §§60.4360 and 60.4370, applicable to the turbines.
- o. Records of observations of visible stack emissions, fugitive emissions, and potentially objectionable odors including the date, time, name, and title of the observer, along with any corrective action taken as a result.

19. All logs and required records shall be maintained on site, or at an alternative location acceptable to the Department, for a minimum of five years and shall be made available to the Department upon request [25 Pa. Code §127.12b].

20. The Facility is subject to New Source Performance Standards from 40 CFR Part 60 Subparts Kb, VV, VVa, DDD, NNN, RRR, IIII, and KKKK; National Emission Standards for Hazardous Air Pollutants from 40 CFR Part 61 Subparts J, V, and FF; and National Emission Standards for Hazardous Air Pollutants from 40 CFR Part 63 Subparts SS, UU, XX, YY, FFFF, YYYY, and ZZZZ. In accordance with 40 CFR §§60.4, 61.04, and 63.13; copies of all requests, reports, applications, submittals and other communications regarding affected sources shall be forwarded to both EPA and the Department at the addresses listed below unless otherwise noted.

Director
Air Protection Section
Mail Code 3AP00
U.S. EPA, Region III
1650 Arch Street
Philadelphia, PA 19103-2029

PADEP
Air Quality Program
400 Waterfront Drive
Pittsburgh, PA 15222-4745

21. The Owner/Operator shall provide EPA with the notifications required by 40 CFR Part 60 Subpart A, 40 CFR Part 61 Subpart A, and 40 CFR Part 63 Subpart A [25 Pa. Code §127.12b].
22. The Owner/Operator shall comply with the applicable Compliance Assurance Monitoring (CAM) submittal requirements specified in 40 CFR §64.4.
23. The Owner/Operator shall comply with the applicable CAM information submittal deadlines (to be submitted with the initial Title V Operating Permit application) specified in 40 CFR §64.5.
24. Malfunction notification, reporting, and responses shall be conducted as follows [25 Pa. Code §127.12b]:
- a. For purpose of this condition a malfunction is defined as any sudden, infrequent, and not reasonably preventable failure of air pollution control or monitoring equipment, or the unauthorized operation of a source that may result in an increase in the emission of air contaminants above allowable levels. Examples of malfunctions may include, but are not limited to: large dust plumes, heavy smoke, a spill or release that results in a malodor that is detectable outside the property of the person on whose land the source is being operated.
 - b. Notify the Department by phone no later than one hour after discovery of a malfunction which poses an imminent and substantial danger to the public health and safety or the environment. The notification shall include the items identified in (d) to the extent known.
 - c. Notify the Department by phone no later than the next business day after discovery of all other malfunctions. The notification shall include the items identified in (d) to the extent known.
 - d. The notification shall describe the:

- i. Name and location of the facility;
 - ii. Nature and cause of the malfunction or breakdown;
 - iii. Time when the malfunction or breakdown was first observed;
 - iv. Expected duration of excess emissions; and
 - v. Estimated rate of emissions.
- e. The Owner/Operator shall submit a written report to the Department no later than thirty (30) days following the end of a malfunction. The report shall include the following:
 - i. The date and time that the malfunction started and ended.
 - ii. An estimate of the emissions associated with the malfunction and the calculations that were used to determine that quantity;
 - iii. The steps, if any, that the facility took to limit the duration and/or quantity of emissions associated with the malfunction;
 - iv. A detailed analysis that sets forth the Root Cause of the malfunction, to the extent determinable;
 - v. An analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of a malfunction resulting from the same Root Cause or contributing causes in the future. The analysis shall discuss the alternatives, if any, that are available, the probable effectiveness and cost of the alternatives. Possible design, operational, and maintenance changes shall be evaluated. If the facility concludes that corrective action(s) is (are) required, the report shall include a description of the action(s) and, if not already completed, a schedule for implementation, including proposed commencement and completion dates. If the facility concludes that corrective action is not required the report shall explain the basis for that conclusion;
 - vi. To the extent that investigations of the causes and/or possible corrective action(s) still are underway on the due date of the report, a statement of the anticipated date by which a follow-up report will be submitted.
- f. To the extent that completion of the implementation of corrective action(s), if any, is not finalized at the time of the submission of the report under subsection (e), then, by no later than 30 days after completion of the implementation of corrective action(s), the Owner/Operator shall submit a written report identifying the corrective action(s) taken and the date(s) of completion of implementation.
- g. In response to any malfunction, the Owner/Operator, as expeditiously as practicable, shall take such interim and/or longer-term corrective actions, if any, as are consistent with good engineering practice to minimize the likelihood of a recurrence of the Root Cause and all contributing causes of that malfunction.
- h. Malfunction phone notifications and written reports shall be submitted to the Department at the following address:

PA DEP
Office of Air Quality
400 Waterfront Drive
Pittsburgh, PA 15222-4745
412-442-4000

25. Open burning operations [25 Pa. Code §129.14]:

- a. *Air basins*. No person may permit the open burning of material in an air basin.
- b. *Outside of air basins*. N/A
- c. *Exceptions*. The requirements of subsections a) and b) do not apply where the open burning operations result from:
 - 1) A fire set to prevent or abate a fire hazard, when approved by the Department and set by or under the supervision of a public officer.
 - 2) Any fire set for the purpose of instructing personnel in fire fighting, when approved by the Department.
 - 3) A fire set for the prevention and control of disease or pests, when approved by the Department.
 - 4) A fire set in conjunction with the production of agricultural commodities in their unmanufactured state on the premises of the farm operation.
 - 5) A fire set for the purpose of burning domestic refuse, when the fire is on the premises of a structure occupied solely as a dwelling by two families or less and when the refuse results from the normal occupancy of the structure.
 - 6) A fire set solely for recreational or ceremonial purposes.
 - 7) A fire set solely for cooking food.
- d. *Clearing and grubbing wastes*. The following is applicable to clearing and grubbing wastes:
 - 1) As used in this subsection the following terms shall have the following meanings:

Air curtain destructor - A mechanical device which forcefully projects a curtain of air across a pit in which open burning is being conducted so that combustion efficiency is increased and smoke and other particulate matter are contained.

Clearing and grubbing wastes - Trees, shrubs and other native vegetation which are cleared from land during or prior to the process of construction. The term does not include demolition wastes and dirt laden roots.
 - 2) Subsection (a) notwithstanding, clearing and grubbing wastes may be burned in a basin subject to the following requirements:
 - i. Air curtain destructors shall be used when burning clearing and grubbing wastes.
 - ii. Each proposed use of air curtain destructors shall be reviewed and approved by the Department in writing with respect to equipment arrangement, design and existing environmental conditions prior to commencement of burning. Proposals approved under this subparagraph need not obtain plan approval or operating permits under Chapter 127 (relating to construction, modification, reactivation and operation of sources).
 - iii. Approval for use of an air curtain destructor at one site may be granted for a specified period not to exceed 3 months, but may be

extended for additional limited periods upon further approval by the Department.

- iv. The Department reserves the right to rescind approval granted if a determination by the Department indicates that an air pollution problem exists.

3) N/A

- 4) During an air pollution episode, open burning is limited by Chapter 137 (relating to air pollution episodes) and shall cease as specified in that chapter.

26. Performance testing shall be conducted as follows [25 Pa. Code §127.12b and §139.11]:

- a. The Owner/Operator shall submit three copies of a pre-test protocol to the Department for review at least 45 days prior to the performance of any EPA Reference Method stack test. The Owner/Operator shall submit three copies of a one-time protocol to the Department for review for the use of a portable analyzer and may repeat portable analyzer testing without additional protocol approvals provided that the same method and equipment are used. All proposed performance test methods shall be identified in the pre-test protocol and approved by the Department prior to testing.
- b. The Owner/Operator shall notify the Regional Air Quality Manager at least 15 days prior to any performance test so that an observer may be present at the time of the test. This notification may be sent by email. Notification shall also be sent to the Division of Source Testing and Monitoring. Performance testing shall not be conducted except in accordance with an approved protocol.
- c. Pursuant to 40 CFR Part 60.8(a) and 40 CFR Part 63.9(h), a complete test report shall be submitted to the Department no later than 60 calendar days after completion of the on-site testing portion of an emission test program.
- d. Pursuant to 40 CFR Part 61.13(f), a complete test report shall be submitted to the Department no later than 31 calendar days after completion of the on-site testing portion of an emission test program.
- e. Pursuant to 25 Pa. Code Section 139.53(b) a complete test report shall include a summary of the emission results on the first page of the report indicating if each pollutant measured is within permitted limits and a statement of compliance or non-compliance with all applicable permit conditions. The summary results will include, at a minimum, the following information:
 - 1. A statement that the owner or operator has reviewed the report from the emissions testing body and agrees with the findings.
 - 2. Permit number(s) and condition(s) which are the basis for the evaluation.
 - 3. Summary of results with respect to each applicable permit condition.
 - 4. Statement of compliance or non-compliance with each applicable permit condition.
- f. Pursuant to 25 Pa. Code § 139.3 all submittals shall meet all applicable requirements specified in the most current version of the Department's Source Testing Manual.

- g. All testing shall be performed in accordance with the provisions of Chapter 139 of the Rules and Regulations of the Department of Environmental Protection.
 - h. Pursuant to 25 Pa. Code Section 139.53(a)(1) and 139.53(a)(3) all submittals, besides notifications, shall be accomplished through PSIMS*Online available through <https://www.depgreenport.state.pa.us/ecommm/Login.jsp> when it becomes available. If internet submittal can not be accomplished, three copies of the submittal shall be sent to the Pennsylvania Department of Environmental Protection, Bureau of Air Quality, Division of Source Testing and Monitoring, 400 Market Street, 12th Floor Rachael Carson State Office Building, Harrisburg, PA 17105-8468 with deadlines verified through document postmarks.
 - i. The permittee shall ensure all federal reporting requirements contained in the applicable subpart of 40 CFR are followed, including timelines more stringent than those contained herein. In the event of an inconsistency or any conflicting requirements between state and the federal, the most stringent provision, term, condition, method or rule shall be used by default.
27. Upon determination by the Owner/Operator that the source(s) covered by this Plan Approval are in compliance with all operative conditions of the Plan Approval the Owner/Operator shall contact the Department and schedule the Initial Operating Permit Inspection [25 Pa. Code §127.12b].
28. Upon completion of the Initial Operating Permit Inspection and determination by the Department that the source(s) covered by this Plan Approval are in compliance with all conditions of the Plan Approval the Owner/Operator shall submit a Title V Operating Permit application for this Facility [25 Pa. Code §127.12b].
29. If, at any time, the Department has cause to believe that air contaminant emissions from the sources listed in this Plan Approval may be in excess of the limitations specified in, or established pursuant to this plan approval or the permittee's operating permit, the permittee may be required to conduct test methods and procedures deemed necessary by the Department to determine the actual emissions rate. Such testing shall be conducted in accordance with 25 Pa. Code Chapter 139, where applicable, and in accordance with any restrictions or limitations established by the Department at such time as it notifies the company that testing is required [25 Pa. Code §127.12b].
30. In-plant roadways shall be paved and maintained so as to prevent fugitive emissions [25 Pa. Code §127.12b].
31. The Owner/Operator shall develop and implement a roadway dust control plan to prevent fugitive emissions. Dust control shall include roadway watering, sweeping, and application of winterized surfactant as necessary during colder months [25 Pa. Code §127.12b].
32. The Owner/Operator may only operate an ethane cracking furnace in a defined operating mode. Operating modes of the ethane cracking furnaces are defined as follows [25 Pa. Code §127.12b]:

- Startup – Beginning when fuel is introduced to the furnace and ending when the SCR catalyst bed reaches its design operating temperature.
 - Hot Steam Standby – When the furnace is firing at or below 50% of the maximum allowable firing rate and no hydrocarbon feed is being charged to the furnace, and not operating in startup or shutdown mode.
 - Feed In – Beginning when hydrocarbon feed is introduced to the furnace and ending when the furnace reaches 70% of the maximum allowable firing rate.
 - Normal – When the furnace is firing at or above 70% of the maximum allowable firing rate with hydrocarbon feed being charged to the furnace.
 - Feed Out – Beginning when the furnace drops below 70% of its maximum allowable firing rate and ending when hydrocarbon feed is isolated from the furnace.
 - Shutdown – Beginning when the SCR catalyst bed drops below its design operating temperature and ending upon removing all fuel from the furnace.
 - Decoking – Beginning when air is introduced to the furnace for the purpose of decoking and ending when decoking air is removed.
33. Only one ethane cracking furnace may be operating in decoking mode at any time, and no more than two furnaces may be operating in a defined non-normal operating mode at any time, except in cases where a furnace must be taken offline for unscheduled maintenance [25 Pa. Code §127.12b].
34. Exhaust gas temperature from each of the ethane cracking furnace stacks shall not exceed 350°F on a 12-month rolling average; excluding periods of startup, shutdown, hot steam standby, or decoking [25 Pa. Code §127.12b].
35. The Owner/Operator shall perform a tune-up of each ethane cracking furnace at a minimum of once every 5 years as follows [25 Pa. Code §127.12b]:
- a) Inspect the burner, as applicable, and clean or replace any components of the burner as necessary (the burner inspection may be delayed until the next scheduled unit shutdown). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;
 - b) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;
 - c) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly;
 - d) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_x requirement to which the unit is subject;
 - e) Record the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made. Concentrations may be taken from CEM data; and
 - f) Maintain on-site and submit, if requested by the Department, a report containing the following information:

- 1) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater; and
 - 2) A description of any corrective actions taken as a part of the tune-up.
36. GHG emissions from the ethane cracking furnaces shall not exceed 1,048,670 tons of CO_{2e} from all furnaces combined in any consecutive 12-month period. Compliance with this limit may be determined through CO_{2e} calculations in accordance with 40 CFR §98.34(b)(3) or utilizing an in-line gas chromatograph [25 Pa. Code §127.12b].
37. Exhaust gas generated from each of the ethane cracking furnaces while operating in decoking mode shall be directed through a separator and back into the furnace firebox to ensure complete combustion [25 Pa. Code §127.12b].
38. Visible emissions from each of the ethane cracking furnace stacks shall not exceed the following [25 Pa. Code §127.12b]:
- Equal to or greater than 10% opacity for a period or periods aggregating more than 3 minutes in any one hour.
 - Equal to or greater than 30% opacity at any time.
39. NO_x emissions from the ethane cracking furnaces shall not exceed the following [25 Pa. Code §127.12b]:
- 0.010 lb/MMBtu from each furnace on a 12-month rolling average, excluding periods of defined non-normal operating modes.
 - 0.015 lb/MMBtu from each furnace on a 1-hour average, excluding periods of defined non-normal operating modes.
 - 9.30 lb/hr from each furnace during periods of decoking, hot steam standby, feed in, or feed out.
 - 31.1 lb/hr from each furnace during periods of startup or shutdown.
 - 181.3 tons from all furnaces combined in any consecutive 12-month period.
40. VOC emissions from each of the ethane cracking furnaces shall not exceed 1.18 lb/hr [25 Pa. Code §127.12b].
41. CO emissions from the ethane cracking furnaces shall not exceed the following [25 Pa. Code §127.12b]:
- 0.035 lb/MMBtu from each furnace on a 12-month rolling average; excluding periods of startup, shutdown, and decoking.
 - 52.2 lb/hr from each furnace during periods of startup, shutdown, and decoking.
 - 670.4 tons from all furnaces combined in any consecutive 12-month period.
42. PM₁₀ and PM_{2.5} emissions from each of the ethane cracking furnaces shall not exceed the following [25 Pa. Code §127.12b]:
- 3.10 lb/hr, excluding periods of decoking.

- 1.86 lb/hr during periods of decoking.
 - 12.4 tons in any consecutive 12-month period.
43. NH₃ emissions from each of the ethane cracking furnaces shall not exceed 10 ppmvd at 3% O₂ [25 Pa. Code §127.12b]:
44. The Owner/Operator shall continuously monitor and record the catalyst bed inlet and outlet temperature for each SCR system [25 Pa. Code §127.12b].
45. The Owner/Operator shall install and operate NO_x continuous monitoring systems to monitor NO_x emissions from each ethane cracking furnace and combustion turbine in accordance with 25 Pa. Code §123.51.
46. The Owner/Operator shall install and operate CO continuous monitoring systems to monitor CO emissions from each ethane cracking furnace and combustion turbine. The following sub-requirements shall be met and in compliance with 25 Pa. Code Chapter 139, Subchapter C [25 Pa. Code §127.12b]:
- a. Other monitoring systems shall be installed and operated to convert data to required reporting units.
 - b. Results shall be submitted on a regular schedule and in a format acceptable to the Department.
 - c. Installed monitors shall meet the minimum data availability requirements.
47. The Owner/Operator shall monitor for ammonia slip from each ethane cracking furnace and combustion turbine in accordance with any one of the following methods [25 Pa. Code §127.12b]:
- a) Mass balance. Ammonia emissions are calculated as the difference between the input ammonia, measured by the ammonia injection rate, and the ammonia reacted, measured by the differential NO_x upstream and downstream of the control device that injects urea or ammonia into the exhaust stream. The ammonia emissions must be calculated using the following equation:

$$\text{NH}_3 @ 3\% \text{ O}_2 = [(a/b * 10^6) - c] * d \quad (\text{Furnaces})$$

$$\text{NH}_3 @ 15\% \text{ O}_2 = [(a/b * 10^6) - c] * d \quad (\text{Turbines})$$

Where:

a = ammonia injection rate (in pounds per hour (lb/hr))/17 pound per pound-mole (lb/lb-mol);

b = dry exhaust flow rate (lb/hr)/29 lb/lb-mol;

c = change in measured NO_x concentration across catalyst (ppmv at reference oxygen); and

d = correction factor, the ratio of measured slip to calculated ammonia slip, where the measured slip is obtained from the stack testing for ammonia during the initial demonstration of compliance required by this Plan Approval.

- b) Oxidation of ammonia to nitric oxide (NO). Convert ammonia to NO using a molybdenum oxidizer and measure ammonia slip by difference using a NO analyzer. The NO analyzer must be quality assured in accordance with the manufacturer's specifications and with a quarterly cylinder gas audit with a 10 ppmv reference sample of ammonia passed through the probe and confirming monitor response to within ± 2.0 ppmv for the furnaces. The NO analyzer must be quality assured in accordance with the manufacturer's specifications and with a quarterly cylinder gas audit with a 5 ppmv reference sample of ammonia passed through the probe and confirming monitor response to within ± 1.0 ppmv for the turbines.
- c) Stain tubes. Measure ammonia using a sorbent or stain tube device specific for ammonia measurement in the 5.0 to 10.0 ppmv range for the furnaces. Measure ammonia using a sorbent or stain tube device specific for ammonia measurement in the 1.0 to 5.0 ppmv range for the turbines. Every effort must be made to sample near the normal highest ammonia injection rate.
- d) Other methods as approved by the Department.

Ammonia slip monitoring shall be conducted at a minimum of once each day for each source for the first 60 days of operation. Monitoring may subsequently be reduced to a minimum of once each week for each source if operating procedures have been developed to prevent excess amounts of ammonia from being introduced in the control device and when operation of the control device has been proven successful with regard to controlling ammonia slip. Daily monitoring must resume when the catalyst is within 30 days of its useful life expectancy.

- 48. The Owner/Operator shall perform VOC, PM₁₀, PM_{2.5}, and NH₃ emission testing upon each of the seven ethane cracking furnaces while operating in normal operating mode and according to the requirements of 25 Pa. Code Chapter 139. Initial performance testing is required within 180 days of startup of the furnaces or on an alternative schedule as approved by the Department. Subsequent performance testing is required at minimum of once every 5 years thereafter. Extension to the initial and subsequent performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified. EPA Reference Method performance testing shall be conducted for the initial and subsequent performance tests [25 Pa. Code § 127.12b].
- 49. The Owner/Operator shall perform PM₁₀ and PM_{2.5} emission testing upon each of the seven ethane cracking furnaces while operating in decoking mode and according to the requirements of 25 Pa. Code Chapter 139. Initial performance testing is required during the first decoking cycle after startup of the furnaces or on an alternative schedule as approved by the Department. Testing shall be performed as early as practicable after commencement of the decoking cycle. Subsequent performance testing is required at minimum of once every 5 years thereafter. Extension to the initial and subsequent performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified. EPA Reference Method performance testing shall be conducted for the initial and subsequent performance tests [25 Pa. Code § 127.12b].

50. Visible emissions from each of the combustion turbine and duct burners stack shall not exceed 10% opacity at any time [25 Pa. Code §127.12b]

51. NO_x emissions from the combustion turbines with duct burners shall not exceed the following [25 Pa. Code §127.12b]:

- 2 ppmvd @ 15% O₂ from each turbine/duct burner on a 1-hour average, excluding periods of defined startup or shutdown.
- 113 lb/hr from each turbine/duct burner during periods of startup or shutdown.
- 65.4 tons from all turbines and duct burners combined in any consecutive 12-month period.

For purposes of determining compliance with these NO_x limits, startup is defined as beginning when fuel is introduced into the turbine and ending when the SCR catalyst bed reaches its design operating temperature.

For purposes of determining compliance with these NO_x limits, shutdown is defined as beginning when the SCR catalyst bed drops below its design operating temperature and ending upon removing all fuel from the turbine.

52. VOC emissions from each of the combustion turbines with duct burners shall not exceed the following [25 Pa. Code §127.12b]:

- 1 ppmvd @ 15% O₂ on a 1-hour average.

53. CO emissions from the combustion turbines with duct burners shall not exceed the following [25 Pa. Code §127.12b]:

- 2 ppmvd @ 15% O₂ from each turbine/duct burner on a 1-hour average, excluding periods of defined startup or shutdown.
- 276 lb/hr from each turbine/duct burner during periods of startup or shutdown.
- 42.0 tons from all turbines and duct burners combined in any consecutive 12-month period.

For purposes of determining compliance with these CO limits, startup is defined as beginning upon commencement of ignition and ending when the combustion turbine reaches 55% of its baseload operating level.

For purposes of determining compliance with these CO limits, shutdown is defined as beginning when the combustion turbine drops below 55% of its baseload operating level and ending when fuel is cut to this unit. Each shutdown event shall not exceed 30 minutes in duration.

54. PM₁₀ and PM_{2.5} emissions from each of the combustion turbines with duct burners shall not exceed the following [25 Pa. Code §127.12b]:

- 0.0066 lb/MMBtu.
- 19.2 tons in any consecutive 12-month period.

55. GHG emissions from the combustion turbines with duct burners shall not exceed the following [25 Pa. Code §127.12b]:

- 1,030 lbs CO₂e/MWh from all turbines and duct burners combined on a 30-day rolling average.
- 340,558 tons of CO₂e in any consecutive 12-month period.

Compliance with these limits may be determined through CO₂ calculations in accordance with 40 CFR Part 75 Appendix G and multiplied by a factor of 1.0010.

56. HCHO emissions from each of the combustion turbines with duct burners shall not exceed 91 ppbvd @ 15% O₂ [25 Pa. Code §127.12b].

57. NH₃ emissions from each of the combustion turbines with duct burners shall not exceed 5 ppmvd at 15% O₂ [25 Pa. Code §127.12b].

58. The Owner/Operator shall perform VOC, PM₁₀, PM_{2.5}, HCHO, and NH₃ emission testing upon each of the three combustion turbines with duct burners according to the requirements of 25 Pa. Code Chapter 139. Initial performance testing is required within 180 days of startup of the turbines or on an alternative schedule as approved by the Department. Subsequent performance testing is required at minimum of once every 5 years thereafter. Extension to the initial and subsequent performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified. EPA Reference Method performance testing shall be conducted for the initial and subsequent performance tests [25 Pa. Code § 127.12b].

59. The Owner/Operator shall continuously monitor and maintain the 4-hour rolling average of each combustion turbine's oxidation catalyst inlet temperature within its designed operating temperature range [25 Pa. Code § 127.12b].

60. The Owner/Operator shall maintain records of the 4-hour rolling average of each combustion turbine's oxidation catalyst inlet temperature [25 Pa. Code § 127.12b].

61. The three combustion turbines with heat recovery steam generators and duct burners are classified as Utility units and subject to the requirements of the Acid Rain Program as specified in 40 CFR §72.6(a).

62. The Owner/Operator shall comply with the applicable permit requirements, including the requirement to submit a complete Acid Rain permit application (at least 24 months before the date on which the unit commences operation), as specified in 40 CFR §72.9(a).

63. The Owner/Operator shall comply with the applicable requirements of 40 CFR Part 97 Subpart AAAAAA – TR NO_x Annual Trading Program for each of the three combustion turbines with heat recovery steam generators and duct burners [25 Pa. Code § 127.12b].

64. The Owner/Operator shall comply with the applicable requirements of 40 CFR Part 97 Subpart BBBBB – TR NO_x Ozone Season Trading Program for each of the three combustion turbines with heat recovery steam generators and duct burners [25 Pa. Code § 127.12b].
65. The Owner/Operator shall comply with the applicable requirements of 40 CFR Part 97 Subpart CCCCC – TR SO₂ Group 1 Trading Program for each of the three combustion turbines with heat recovery steam generators and duct burners [25 Pa. Code § 127.12b].
66. Maximum designed water circulation rates of the cooling towers shall not exceed the following [25 Pa. Code § 127.12b]:
 - a. Process Cooling Tower – 18,600,000 gallons per hour.
 - b. Cogen Cooling Tower – 4,440,000 gallons per hour.
67. Cooling towers shall be equipped with drift/mist eliminators designed not to exceed 0.0005% drift loss [25 Pa. Code § 127.12b].
68. Cooling tower water total dissolved solids (TDS) shall not exceed 2,000 ppmw on a 12-month rolling average [25 Pa. Code § 127.12b].
69. The Owner/Operator shall perform TDS and electrical conductivity testing upon cooling tower water from each of the cooling towers according to ASTM Methods D5907-13 and D5391-14 (or other methods deemed acceptable by the Department). Samples and/or measurements for both tests are required to be performed under identical operating conditions, at a point which is representative of the water being evaporated to the atmosphere, and over the same time frame as applicable to each test method. A factor shall be derived from test results correlating TDS and electrical conductivity such that TDS may be approximated by future electrical conductivity measurements. Initial testing is required within 180 days of startup of the cooling towers or on an alternative schedule as approved by the Department. Subsequent TDS and electrical conductivity testing is required at minimum of once every 5 years thereafter. Extension to the initial and subsequent performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified [25 Pa. Code § 127.12b].
70. The Owner/Operator shall, at a minimum of once per month, calculate TDS for the cooling tower water from each cooling tower. TDS shall be calculated by measuring electrical conductivity according to ASTM Method D5391-14 (or other method deemed acceptable by the Department) and multiplying the result by the correlation factor derived during the most recent simultaneous TDS and electrical conductivity test [25 Pa. Code § 127.12b].
71. The Owner/Operator shall maintain a 12-month rolling average of each cooling tower's calculated TDS value [25 Pa. Code § 127.12b].
72. Process cooling tower water VOC content shall not exceed 0.5 lb/MMgal [25 Pa. Code § 127.12b].
73. The Owner/Operator shall develop and implement a leak detection and repair (LDAR) program for the process cooling tower heat exchanger. The developed LDAR program shall

be submitted to the Department for review prior to implementation and at a minimum of 45 days prior to facility startup. Cooling water shall be monitored for VOC. Monitoring shall be conducted on a weekly basis. Other aspects of the LDAR program shall be consistent with the "heat exchange system requirements" under 40 CFR Part 63 Subpart F [25 Pa. Code § 127.12b].

74. No person may permit the emission into the outdoor atmosphere of a waste gas stream from an ethylene production plant or facility unless the gas stream is properly burned at no less than 1,300°F for at least .3 seconds; except that no person may permit the emission of volatile organic compounds in gaseous form into the outdoor atmosphere from a vapor blowdown system unless these gases are burned by smokeless flares [25 Pa. Code § 129.65].
75. Spent caustic vent vapors shall be captured and routed through a closed system to the Spent Caustic Vent incinerator [25 Pa. Code §127.12b].
76. Compressor seal vent, startup, shutdown, maintenance, emergency, or malfunction event gases associated with the ethylene manufacturing line shall be captured and routed to the HP System. Hydrocarbon-containing equipment shall be drained, depressurized, and purged with nitrogen to the HP System prior to being opened to the atmosphere [25 Pa. Code §127.12b].
77. Compressor seal gas vents; intermittent VOC process vents; and startup, shutdown, maintenance, emergency, or malfunction events associated with the gas phase polyethylene manufacturing lines shall be routed to the HP System. Hydrocarbon-containing equipment shall be drained, depressurized, and purged with nitrogen to the HP System prior to being opened to the atmosphere [25 Pa. Code §127.12b].
78. Compressor seal gas vents; intermittent VOC process vents; and startup, shutdown, maintenance, emergency, or malfunction events associated with the slurry phase polyethylene manufacturing line shall be routed to the HP System. Hydrocarbon-containing equipment shall be drained, depressurized, and purged with nitrogen to the HP System prior to being opened to the atmosphere [25 Pa. Code §127.12b].
79. Continuous VOC-containing process gas vents located upstream of and including the product purge bin in each gas phase technology polyethylene manufacturing line or upstream of the degasser in the slurry polyethylene manufacturing line shall be routed to the LP System [25 Pa. Code §127.12b].
80. Polyethylene manufacturing line particulate matter process vents (excluding the pellet dryer vents) shall be equipped with and controlled by fabric, sintered metal, or HEPA filters [25 Pa. Code § 127.12b].
81. PM (filterable) emissions from each polyethylene manufacturing line pellet dryer vent shall not exceed 0.01 gr/dscf [25 Pa. Code § 127.12b].
82. The Owner/Operator shall perform PM (filterable) emission testing upon each polyethylene manufacturing line pellet dryer vent according to the requirements of 25 Pa. Code Chapter 139 and a Department-approved pre-test protocol. Initial performance testing is required within 180 days of startup of each polyethylene manufacturing line or on an alternative

schedule as approved by the Department. Subsequent performance testing is required at a minimum of once every 5 years thereafter. Extension to the initial and subsequent performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified [25 Pa. Code § 127.12b].

83. The Owner/Operator shall perform chromium emission testing upon each polyethylene manufacturing line chromium catalyst activation vent according to the requirements of 25 Pa. Code Chapter 139 and a Department-approved pre-test protocol. Initial performance testing is required within 180 days of startup of each polyethylene manufacturing line or on an alternative schedule as approved by the Department. Subsequent performance testing is required at minimum of once every 5 years thereafter. Extension to the initial and subsequent performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified [25 Pa. Code § 127.12b].
84. Polyethylene pellet blending silos, handling, storage, and loadout shall be enclosed and controlled by fabric filters [25 Pa. Code § 127.12b].
85. Fabric, sintered metal, and HEPA filters shall be designed not to exceed 0.005 gr/dscf at the outlet [25 Pa. Code § 127.12b].
86. Visible emissions from any fabric, sintered metal, or HEPA filter-controlled process vent, blending silo, handling and storage silos, or loadout operation shall not equal or exceed 10% opacity at any time [25 Pa. Code § 127.12b].
87. Polyethylene residual VOC content shall not exceed 50 ppmw on a monthly average for each polyethylene manufacturing line* [25 Pa. Code § 127.12b].

*As measured downstream of the product purge bin in the gas phase technology polyethylene manufacturing line and downstream of and including the degasser at the slurry polyethylene manufacturing line
88. Polyethylene residual VOC content shall be measured no less than once per calendar month and once per product formulation change for each polyethylene manufacturing line. Measurement shall be conducted by methods and techniques acceptable to the Department. A minimum of three samples shall be taken before the first uncontrolled emission point downstream of the product purge bin in each gas phase technology polyethylene manufacturing line or downstream of the degasser in the slurry polyethylene manufacturing line for each measurement [25 Pa. Code § 127.12b].
89. Vapors displaced or generated by the loadout of coke residue/tar shall be captured and routed through a closed system back to the process [25 Pa. Code § 127.12b].
90. Vapors displaced or generated by the loadout of recovered oil shall be captured and routed through a closed system to the Spent Caustic Vent incinerator [25 Pa. Code § 127.12b].
91. Vapors displaced or generated by the loadout of pyrolysis fuel oil or light gasoline shall be captured and routed through a closed system to the LP System [25 Pa. Code § 127.12b].

92. Vapor recovery systems and control devices shall be operated at all times while liquids are being loaded to, or vapors being purged from, loadout storage tanks [25 Pa. Code § 127.12b].
93. Emissions from the LP incinerator shall not exceed the following [25 Pa. Code § 127.12b]:
- a) NO_x - 0.0680 lb/MMBtu
 - b) CO - 0.0824 lb/MMBtu
 - c) PM₁₀ - 0.0075 lb/MMBtu
 - d) PM_{2.5} - 0.0075 lb/MMBtu
94. The Owner/Operator shall perform NO_x, CO, PM₁₀, and PM_{2.5} emission testing upon the LP incinerator according to the requirements of 25 Pa. Code Chapter 139. Initial performance testing is required within 180 days of startup of the LP incinerator or on an alternative schedule as approved by the Department. Subsequent performance testing is required at minimum of once every 5 years thereafter. Extension to the initial and subsequent performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified. EPA Reference Method performance testing shall be conducted for the initial and subsequent performance tests [25 Pa. Code § 127.12b].
95. Visible emissions from both the LP incinerator and MPGF shall not exceed 0% except for a total of five minutes during any consecutive two-hour period [25 Pa. Code § 127.12b].
96. The LP incinerator shall be designed and operated to reduce collected VOC emissions by a minimum of 99.9% [25 Pa. Code § 127.12b].
97. The LP incinerator shall, at all times that vapors are being collected by the LP System, be operated at or above the minimum temperature at which at least 99.9% destruction efficiency is guaranteed by the manufacturer or demonstrated during performance testing [25 Pa. Code § 127.12b].
98. Monitoring for compliance with the 99.9% destruction efficiency requirement for the LP incinerator shall be performed in accordance with 40 CFR §63.985(c). Operating parameter monitoring shall include combustion temperature at a minimum [25 Pa. Code § 127.12b].
99. The Owner/Operator shall minimize flaring resulting from startups, shutdowns, and unforeseeable events by operating at all times in accordance with an approved flare minimization plan. The plan shall include the following [25 Pa. Code § 127.12b]:
- a) Procedures for operating and maintaining the HP and LP Systems during periods of process unit startup, shutdown, and unforeseeable events.
 - b) A program of corrective action for malfunctioning process equipment.
 - c) Procedures to minimize discharges either directly to the atmosphere or to the HP and LP Systems during the planned and unplanned startup or shutdown or process unit and air pollution control equipment.
 - d) Procedures for conducting root cause analyses.
 - e) Procedures for taking identified corrective actions.

- f) The baseline flow to the HP and LP Systems determined in accordance with the provisions of 40 CFR §60.103a(a)(4).
100. The Owner/Operator shall conduct a root cause analysis within 45 days after any startup, shutdown and unforeseeable flaring event. Flaring event shall be defined as an event that exceeds the baseline by 500,000 scf within a 24 hour period. The analysis shall address the following [25 Pa. Code § 127.12b]:
- a) The date and time that the flaring event started and ended.
 - b) The defined baseline flow to the applicable system.
 - c) The total quantity of gas flared during each event.
 - d) An estimate of the quantity of VOC that was emitted and the calculations used to determine the quantities.
 - e) The steps taken to limit the duration of the flaring event of the quantity of emissions associated with the event.
 - f) A detailed analysis that sets forth the root cause and all significant contributing causes of the flaring event to the extent determinable.
 - g) An analyses of the measures that are available to reduce the likelihood of a recurrence of a flaring event resulting from the same root cause or significant contributing causes in the future.
 - h) A demonstration that the actions taken during the flaring event are consistent with the procedures specified in the flare minimization plan.
 - i) In response to a flaring event, the Owner/Operator shall implement, as expeditiously as practicable, such interim and/or long-term corrective actions as are consistent with good engineering practice to minimize the likelihood of a recurrence of the root cause and all significant contributing causes of that flaring event.
 - j) If any items required to be addressed in this analysis are still under investigation 45 days after the flaring event, the Owner/Operator shall include a statement of the anticipated date by which a follow-up report fully conforming to the requirements of this Condition shall be completed.
101. The MPGF shall be designed and operated to reduce collected VOC emissions by a minimum of 98% [25 Pa. Code § 127.12b].
102. Monitoring for compliance with the 98% destruction efficiency requirement for the MPGF shall be performed in accordance with 40 CFR §63.987(c). Operating parameter monitoring shall include flame detection at a minimum [25 Pa. Code § 127.12b].
103. The MPGF shall be equipped with automated controls for control of the supplemental gas flow rate to the flare [25 Pa. Code § 127.12b].
104. Net heating value of the combustion zone gas at the MPGF header shall be calculated and recorded at a minimum of once every 15 minutes. An adjusted net heating value of hydrogen of 1,212 Btu/scf may be used for this calculation [25 Pa. Code § 127.12b].
105. Net heating value of the combustion zone gas at the MPGF header shall equal or exceed 500 Btu/scf on a three-hour rolling average, calculated every 15 minutes [25 Pa. Code § 127.12b].

106. Atmospheric pressure liquid loadout storage tanks shall be filled by submerged loading and utilize preset stop-fill devices during loading [25 Pa. Code § 127.12b].
107. The Owner/Operator shall monitor liquid level within loadout storage tanks during loading to avoid overfilling and fugitive emission releases from pressure relief devices [25 Pa. Code § 127.12b].
108. The Owner/Operator shall monitor for pressure relief valve releases during liquid loadout operations. Records of any pressure relief event shall be maintained on site and include the following details at a minimum [25 Pa. Code § 127.12b]:
 - a. Date and time of the pressure relief event;
 - b. Name and title of the observer;
 - c. Duration of the event;
 - d. Estimated emission rate during the event, and;
 - e. Corrective action taken as a result of the event.
109. The provisions of this section apply to above ground stationary storage tanks with a capacity equal to or greater than 2,000 gallons which contain volatile organic compounds with vapor pressure greater than 1.5 psia (10.5 kilopascals) under actual storage conditions. Storage tanks covered under this section shall have pressure relief valves which are maintained in good operating condition and which are set to release at no less than .7 psig (4.8 kilopascals) of pressure or .3 psig (2.1 kilopascals) of vacuum or the highest possible pressure and vacuum in accordance with state or local fire codes or the National Fire Prevention Association guidelines or other national consensus standards acceptable to the Department. Section 129.56(g) (relating to storage tanks greater than 40,000 gallons capacity containing VOCs) applies to this section. Petroleum liquid storage vessels which are used to store produced crude oil and condensate prior to lease custody transfer shall be exempt from the requirements of this section [25 Pa. Code § 129.57].
110. The Owner/Operator shall take any and all reasonable actions to avoid excess drainage of liquids or the emission of excess vapors during the disconnection of hoses after loading of a storage tank [25 Pa. Code §127.12b].
111. Liquid loadout hoses shall be equipped with OPW's Drylok™ Dry Disconnect Coupling (or equivalent) low-leak couplings [25 Pa. Code §127.12b].
112. C₃+ liquids shall be loaded out with vapor balance to pressurized storage tanks capable of maintaining working pressures sufficient at all times to prevent vapor or gas loss to the atmosphere and with no venting during loading operations [25 Pa. Code §127.12b].
113. Pressurized truck and rail storage tanks shall be equipped with pressure relief valves calibrated properly for the pressure level of the tank. Release of a pressure relief valve during loading shall cause the emergency shutdown of loading operations for that tank [25 Pa. Code §127.12b].
114. The Owner/Operator shall develop and implement a leak detection and repair (LDAR) program for this facility. All aspects of the LDAR program shall be consistent with 40 CFR

Part 63 Subpart UU – National Emission Standards for Equipment Leaks – Control Level 2 Standards, except as follows [25 Pa. Code §127.12b]:

- a. LDAR shall be applied to equipment in organic compound service (including fuel gas equipment).
 - b. Organic compound service means that piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 wt% of organic compounds as determined according to the provisions of 40 CFR §63.180(d) of Subpart H [except that “organic compound” replaces instances of “organic HAP”]. The provisions of 40 CFR §63.180(d) of Subpart H also specify how to determine that a piece of equipment is not in organic compound service.
 - c. Leak detection shall be conducted on a monthly basis for non-bellows seal valves unless 98.0% or greater of the non-bellows seal gas/vapor and/or light liquid valves are found to leak at a rate less than 100 ppmv for two consecutive months, then the detection frequency may be changed to a quarterly basis. The annual monitoring frequency for valves (skip periods) is not applicable.
 - d. Equipment is also defined to include screwed connections, heat exchanger heads, sight glasses, meters, gauges, sampling connections, bolted manways, and hatches.
 - e. Leak detection thresholds for organic compounds shall be as follows:
 - i. 100 ppmv from pump seals, compressor seals, flanges, and valves in gas/vapor and light liquid service;
 - ii. 200 ppmv from atmospheric pressure relief devices without a rupture disk; and
 - iii. 500 ppmv for all other equipment.
 - f. A first attempt at repair shall be required for all leaking components within 5 days of detection and repair shall be completed within 15 days for all components unless the repair would require a unit shutdown that would create more emissions than the repair would eliminate, and if so, the repair may be delayed until the next scheduled shutdown, except the first attempt at repair for:
 - i. Any leak > 10,000 ppmv & < 25,000 ppmv – 2 days;
 - ii. Atmospheric pressure relief device leak without a rupture disk > 200 & < 25,000 ppmv – 2 days;
 - iii. Any leak > 25,000 ppmv – 1 day;
 - iv. Heavy liquid components > 500 ppmv – 1 day; and
 - v. Any leak in HRVOC service > 10,000 ppmv – 1 day.
 - g. Compressors equipped with a closed vent system that captures and transports leakages to the HP System shall meet the LAER requirements for the HP System.
115. Equipment with inherently leakless design features will be installed as practicable [25 Pa. Code §127.12b].

116. All sampling systems in organic compound service shall be closed-purge, closed loop, or closed-vent systems. In-situ sampling systems shall be exempt [25 Pa. Code §127.12b].
117. A second valve, blind flange, plug, cap or other equivalent sealing system shall be installed on open ended lines subject to LDAR, except for safety pressure relief valves [25 Pa. Code §127.12b].
118. Storage tanks greater than 40,000 gallons capacity containing VOCs [25 Pa. Code §129.56]
- a. No person may permit the placing, storing or holding in a stationary tank, reservoir or other container with a capacity greater than 40,000 gallons of volatile organic compounds with a vapor pressure greater than 1.5 psia (10.5 kilopascals) under actual storage conditions unless the tank, reservoir or other container is a pressure tank capable of maintaining working pressures sufficient at all times to prevent vapor or gas loss to the atmosphere or is designed and equipped with one of the following vapor loss control devices:
 - 1) *An external or an internal floating roof.* This control equipment may not be permitted if the volatile organic compounds have a vapor pressure of 11 psia (76 kilopascals) or greater under actual storage conditions.
 - 2) *Vapor recovery system.* A vapor recovery system, consisting of a vapor gathering system capable of collecting the volatile organic compound vapors and gases discharged and a vapor disposal system capable of processing such volatile organic vapors and gases so as to prevent their emission to the atmosphere. Tank gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place. The vapor recovery system shall be maintained in good working order and recover at least 80% of the vapors emitted by such tank.
 - b. N/A
 - c. An internal floating roof shall be fitted with a primary seal and shall comply with the following equipment requirements:
 - 1) A closure seal or seals, to close the space between the roof edge and tank wall is used.
 - 2) There are no holes, tears or other openings in the seal or a seal fabric or materials.
 - 3) Openings except stub drains are equipped with covers, lids or seals such that:
 - i. The cover, lid or seal is in the closed position at all times except when in actual use.
 - ii. Automatic bleeder vents are closed at all times except when the roof is floated off or landed on the roof leg supports.
 - iii. Rim vents, if provided are set to open when the roof is being floated off the roof leg supports or at the recommended setting of the manufacturer.
 - d. This section does not apply to petroleum liquid storage vessels which:
 - 1) Are used to store waxy, heavy pour crude oil.

- 2) Have capacities less than 420,000 gallons and are used to store produced crude oil and condensate prior to lease custody transfer.
- e. For the purposes of this section, the petroleum liquid storage vessels listed in this subsection comply with the equipment requirements of this section. These tanks shall comply with the maintenance, inspection and reporting requirements of this section. These petroleum liquid storage vessels are those:
- 1) Which contain a petroleum liquid with a true vapor pressure less than 4 psia (27.6 kilopascals) and which are of welded construction and which presently possess a metallic-type shoe seal, a liquid-mounted foam seal, a liquid-mounted liquid filled type seal or other closure device of demonstrated equivalence approved by the Department.
 - 2) Which are of welded construction, equipped with a metallic-type shoe primary seal and has a secondary seal from the top of the shoe seal to the tank wall (shoe-mounted secondary seal).
- f. The owner or operator of a petroleum liquid storage vessel with a floating roof subject to this regulation shall:
- 1) Perform routine inspections annually in order to insure compliance with subsection (b) or (c). The inspection shall include a visual inspection of the secondary seal gap when inspecting external floating roof tanks.
 - 2) For external floating roof tanks, measure the secondary seal gap annually in accordance with subsection (b)(1)(iii) when the floating roof is equipped with a vapor-mounted primary seal.
 - 3) Maintain records of the types of volatile petroleum liquids stored, the maximum true vapor pressure of the liquid as stored, and the results of the inspections performed in subsection (f)(1) and (2). Copies of the records shall be retained by the owner or operator for a period of 2 years after the date on which the record was made and shall be made available to the Department upon written or verbal request at a reasonable time.
- g. For volatile organic compounds whose storage temperature is governed by ambient weather conditions, the vapor pressure under actual storage conditions shall be determined using a temperature which is representative of the average storage temperature for the hottest month of the year in which the storage takes place.
- h. If a failure is detected during inspections required in this section, the owner or operator, or both, shall repair the items or empty and remove the storage vessel from service within 45 days. If this failure cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Department. A request for an extension shall document that alternate storage capacity is unavailable and specify a schedule of actions the owner or operator will take that will assure that the equipment will be repaired or the vessel will be emptied as soon as possible but within the additional 30-day time requested.

119. Ethylene, C₃+, C₃+ refrigerant, butene, isopentane, isobutane, aqueous ammonia, and dimethyl disulfide shall be stored in pressurized and/or refrigerated storage tanks with no uncontrolled vent directly to the atmosphere [25 Pa. Code §127.12b].
120. Emergency relief vents for pressurized or refrigerated storage tanks shall vent to the HP System [25 Pa. Code §127.12b].
121. Pyrolysis fuel oil, light gasoline, and hexene storage tanks shall be controlled by vapor recovery routed to the LP System [25 Pa. Code §127.12b].
122. Storage tanks containing light gasoline, hexene, recovered oil, flow equalization wastewater, or spent caustic shall be equipped with an internal floating roof [25 Pa. Code §127.12b].
123. Storage tanks containing recovered oil, flow equalization wastewater, or spent caustic shall be controlled by vapor recovery routed to the Spent Caustic Vent incinerator [25 Pa. Code §127.12b].
124. Diesel fuel storage tank vents shall be controlled by carbon canisters designed to reduce VOC emissions by a minimum of 95% [25 Pa. Code §127.12b].
125. The Owner/Operator shall monitor carbon canisters in accordance with the manufacturer's recommendations to ensure that the adsorption media is regenerated or replaced prior to breakthrough. Breakthrough shall be defined as a VOC reading above background for a single canister and greater than or equal to 50 ppmv for all canisters operated as part of a primary and secondary system [25 Pa. Code §127.12b].
126. Visible emissions from both the HP ground flares and emergency elevated flare shall not exceed 0% except for a total of five minutes during any consecutive two-hour period [25 Pa. Code § 127.12b].
127. The HP ground flares and emergency elevated flare shall be designed and operated to reduce collected VOC emissions by a minimum of 98% [25 Pa. Code § 127.12b].
128. The HP ground flares shall, at all times that vapors are being collected by the HP System, be operated at or above the minimum temperature at which at least 98% destruction efficiency is guaranteed by the manufacturer or demonstrated during performance testing [25 Pa. Code § 127.12b].
129. Monitoring for compliance with the 98% destruction efficiency requirement for the HP ground flares shall be performed in accordance with 40 CFR §63.987(c). Operating parameter monitoring shall include flame detection at a minimum [25 Pa. Code § 127.12b].
130. The HP ground flares shall be equipped with automated controls for control of the supplemental gas flow rate to the flares [25 Pa. Code § 127.12b].
131. Net heating value of the combustion zone gas at the HP ground flare header shall be calculated and recorded at a minimum of once every 15 minutes. An adjusted net heating value of hydrogen of 1,212 Btu/scf may be used for this calculation [25 Pa. Code § 127.12b].

132. Net heating value of the combustion zone gas at the HP ground flare header shall equal or exceed 500 Btu/scf on a three-hour rolling average, calculated every 15 minutes [25 Pa. Code § 127.12b].
133. Vapors collected by the HP System shall only be routed to the HP elevated flare in the event that the combined capacities of the HP ground flares is exceeded due to malfunction or emergency, or due to maintenance of the HP ground flare(s) [25 Pa. Code § 127.12b].
134. The emergency elevated flare shall be equipped with automated controls for control of the total steam mass flow rate to the flare [25 Pa. Code § 127.12b].
135. The Owner/Operator shall comply with the applicable flare monitoring and work practice requirements, including limits on maximum exit velocity and minimum net heating value requirements, specified in 40 CFR §60.18(c) through (f) and 40 CFR §63.11(b) [25 Pa. Code § 127.12b].
136. Visible emissions from the Spent Caustic Vent incinerator shall not exceed 0% except for a total of five minutes during any consecutive two-hour period [25 Pa. Code § 127.12b].
137. The Spent Caustic Vent incinerator shall be operated to reduce collected VOC emissions by a minimum of 99% [25 Pa. Code §127.12b].
138. Emissions from the Spent Caustic Vent incinerator shall not exceed the following [25 Pa. Code § 127.12b]:
 - a) NO_x - 0.0680 lb/MMBtu
 - b) CO - 0.370 lb/MMBtu
 - c) PM₁₀ - 0.0075 lb/MMBtu
 - d) PM_{2.5} - 0.0075 lb/MMBtu
139. The Owner/Operator shall perform NO_x, CO, PM₁₀, and PM_{2.5} emission testing upon the Spent Caustic Vent incinerator according to the requirements of 25 Pa. Code Chapter 139. Initial performance testing is required within 180 days of startup of the Spent Caustic Vent incinerator or on an alternative schedule as approved by the Department. Subsequent performance testing is required at minimum of once every 5 years thereafter. Extension to the initial and subsequent performance testing deadlines may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified. EPA Reference Method performance testing shall be conducted for the initial and subsequent performance tests [25 Pa. Code § 127.12b].
140. The Spent Caustic Vent incinerator shall, at all times that vapors are being collected, be operated at or above the minimum temperature at which at least 99% destruction efficiency is guaranteed by the manufacturer or demonstrated during performance testing [25 Pa. Code § 127.12b].
141. Monitoring for compliance with the 99% destruction efficiency requirement for the Spent Caustic Vent incinerator shall be performed in accordance with 40 CFR §63.985(c).

Operating parameter monitoring shall include combustion temperature at a minimum [25 Pa. Code § 127.12b].

142. Total benzene quantity from facility waste shall not equal or exceed 11 tons per year as determined through 40 CFR §61.355. [This limit is for the purpose of compliance with limited requirements of 40 CFR Part 61 Subpart FF for a facility with benzene waste less than 10 Mg (11 tons) per year] [25 Pa. Code § 127.12b].

143. Visible emissions from each diesel-fired emergency generator engine shall not exceed the following [25 Pa. Code §127.12b and 40 CFR §89.113]:

- a) Equal to or greater than 10% for a period or periods aggregating more than three (3) minutes in any one (1) hour;
- b) Greater than 20% during the acceleration mode;
- c) Greater than 15% during the lugging mode; and
- d) Equal to or greater than 30% at any time.

144. Visible emissions from each diesel-fired fire pump engine shall not exceed the following [25 Pa. Code §127.12b]:

- a) Equal to or greater than 10% for a period or periods aggregating more than three (3) minutes in any one (1) hour; and
- b) Equal to or greater than 30% at any time.

145. Each diesel-fired emergency generator engine shall be certified to meet the following emission standard for NMHC + NO_x and Tier 2 Emission Standards for CO and PM [25 Pa. Code §127.12b]:

- a) 4.6 g/bhp-hr of NMHC + NO_x
- b) 2.6 g/bhp-hr of CO
- c) 0.15 g/bhp-hr of PM

40 CFR Part 60 Subpart Kb

146. The two hexene and two pyrolysis fuel oil storage tanks are subject to the requirements of 40 CFR Part 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 [40 CFR §60.110b].

147. All terms used in 40 CFR Part 60 Subpart Kb shall have the meaning given in 40 CFR §60.111b or else in the Clean Air Act and 40 CFR Part 60 Subpart A [40 CFR §60.111b].

148. The Owner/Operator shall comply with the applicable storage tank VOC standards specified in 40 CFR §60.112b(a).

149. The Owner/Operator shall comply with the applicable storage tank testing and procedures specified in 40 CFR §60.113b(a) and/or (c) or (d).

150. The Owner/Operator shall comply with the applicable storage tank testing and procedures specified in 40 CFR §60.113b(c) or (d).
151. The Owner/Operator shall comply with the applicable storage tank reporting and recordkeeping requirements specified in 40 CFR §60.115b(a) and/or (c) or (d).
152. The Owner/Operator shall comply with the applicable storage tank reporting and recordkeeping requirements specified in 40 CFR §60.115b(c) or (d).
153. The Owner/Operator shall comply with the applicable storage tank monitoring requirements specified in 40 CFR §60.116b.

40 CFR Part 60 Subpart VV

154. The Owner/Operator shall comply with the applicable general standards specified in 40 CFR §60.482-1.
155. The Owner/Operator shall comply with the applicable standards for pumps in light liquid service; compressors; pressure relief devices in gas/vapor service; sampling connection systems; open-ended valves or lines; valves in gas/vapor service and in light liquid service; pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors; delays of repair; and closed vent systems and control devices specified in 40 CFR §§60.482-2 through 60.482-10.
156. The Owner/Operator may comply with applicable alternative standards for valves specified in 40 CFR §§60.483-1 and 60.483-2.
157. The Owner/Operator may apply to the Administrator for a determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in 40 CFR Part 60 Subpart VV as specified in 40 CFR §60.484.
158. The Owner/Operator shall comply with the applicable test methods and procedures specified in 40 CFR §60.485.

The following provision may be used in addition to §60.485(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method D86-78, 82, 90, 95, or 96 (incorporated by reference as specified in §60.17).

159. The Owner/Operator shall comply with the applicable recordkeeping requirements specified in 40 CFR §60.486.
160. The Owner/Operator shall comply with the applicable reporting requirements specified in 40 CFR §60.487.

40 CFR Part 60 Subpart VVa

161. The ethylene manufacturing line is subject to the requirements of 40 CFR Part 60 Subpart VVa - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 [40 CFR §60.480a].
162. All terms used in 40 CFR Part 60 Subpart VVa shall have the meaning given in 40 CFR §60.481a or else in the Clean Air Act and 40 CFR Part 60 Subpart A [40 CFR §60.481a].
163. The Owner/Operator shall comply with the applicable general standards specified in 40 CFR §60.482-1a.
164. The Owner/Operator shall comply with the applicable standards for pumps in light liquid service; compressors; pressure relief devices in gas/vapor service; sampling connection systems; open-ended valves or lines; valves in gas/vapor service and in light liquid service; pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service; delays of repair; closed vent systems and control devices; and connectors in gas/vapor service and in light liquid service specified in 40 CFR §§60.482-2a through 60.482-11a.
165. The Owner/Operator may comply with the applicable alternative standards for valves specified in 40 CFR §§60.483-1a and 60.483-2a.
166. The Owner/Operator may apply to the Administrator for a determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in 40 CFR Part 60 Subpart VVa as specified in 40 CFR §60.484a.
167. The Owner/Operator shall comply with the applicable test methods and procedures specified in 40 CFR §60.485a.
168. The Owner/Operator shall comply with the applicable recordkeeping requirements specified in 40 CFR §60.486a.
169. The Owner/Operator shall comply with the applicable reporting requirements specified in 40 CFR §60.487a.
170. Chemicals produced by affected facilities under 40 CFR Part 60 Subpart VVa include ethylene and are listed in 40 CFR §60.489 as referenced by 40 CFR §60.489a.

40 CFR Part 60 Subpart DDD

171. The polyethylene manufacturing line affected process emissions and equipment leaks are subject to the requirements of 40 CFR Part 60 Subpart DDD - Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry [40 CFR §60.560].
172. All terms used in 40 CFR Part 60 Subpart DDD shall have the meaning given in 40 CFR §60.561 or else in the Clean Air Act or 40 CFR Part 60 Subparts A or VV [40 CFR §60.561].

173. The Owner/Operator shall comply with the applicable standards for polyethylene manufacturing process emissions specified in 40 CFR §60.562-1.
174. The Owner/Operator shall comply with the applicable standards for polyethylene manufacturing equipment leaks of VOC specified in 40 CFR §60.562-2.
175. The Owner/Operator shall comply with the applicable monitoring requirements specified in 40 CFR §60.563.
176. The Owner/Operator shall comply with the applicable test methods and procedures specified in 40 CFR §60.564.
177. The Owner/Operator shall comply with the applicable reporting and recordkeeping requirements specified in 40 CFR §60.565.

40 CFR Part 60 Subpart NNN

178. The ethylene manufacturing line distillation units are subject to the requirements of 40 CFR Part 60 Subpart NNN - Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations [40 CFR §60.660].
179. All terms used in 40 CFR Part 60 Subpart NNN shall have the meaning given in 40 CFR §60.661 or else in the Clean Air Act and 40 CFR Part 60 Subpart A [40 CFR §60.661].
180. The Owner/Operator shall comply with at least one of the applicable distillation unit vent stream standards specified in 40 CFR §60.662.
181. The Owner/Operator shall comply with the applicable monitoring of emissions and operations requirements for the chosen distillation unit vent stream standard as specified in 40 CFR §60.663.
182. The Owner/Operator shall comply with the applicable test methods and procedures specified in 40 CFR §60.664.
183. The Owner/Operator shall comply with the applicable reporting and recordkeeping requirements specified in 40 CFR §60.665.
184. Chemicals affected by 40 CFR Part 60 Subpart NNN include ethylene and are listed in 40 CFR §60.667.

40 CFR Part 60 Subpart RRR

185. The ethylene manufacturing line reactor processes are subject to limited requirements of 40 CFR Part 60 Subpart RRR - Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes [40 CFR §60.700].

186. The Owner/Operator shall comply with the applicable exemption criteria specified in 40 CFR §60.700(c)(5) [40 CFR §60.700].
187. All terms used in 40 CFR Part 60 Subpart RRR shall have the meaning given in 40 CFR §60.701 or else in the Clean Air Act and 40 CFR Part 60 Subpart A [40 CFR §60.701].
188. The Owner/Operator shall comply with the applicable reporting and recordkeeping requirements specified in 40 CFR §60.705(r).
189. Chemicals affected by 40 CFR Part 60 Subpart RRR include ethylene and are listed in 40 CFR §60.707.

40 CFR Part 60 Subpart IIII

190. Each diesel-fired fire pump engine shall be certified to meet the following Emission Standards for Stationary Fire Pump Engines in Table 4 to Subpart IIII of Part 60 [40 CFR §60.4205(c)]:
- a) 3.0 g/bhp-hr of NMHC + NO_x
 - b) 2.6 g/bhp-hr of CO
 - c) 0.15 g/bhp-hr of PM
191. The four diesel-fired emergency generator engines and three diesel-fired fire pump engines are subject to the requirements of 40 CFR Part 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines [40 CFR §60.4200].
192. Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine [40 CFR §60.4206].
193. Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must purchase diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel [40 CFR §60.4207].
194. Beginning June 1, 2010. Except as otherwise specifically provided in [40 CFR Part 80 Subpart I], all NR and [N/A] diesel fuel is subject to the following per-gallon standards [40 CFR §80.510(b)]:
- 1) Sulfur content:
 - i. 15 ppm maximum for NR diesel fuel.
 - ii. N/A
 - 2) Cetane index or aromatic content, as follows:
 - i. A minimum cetane index of 40; or
 - ii. A maximum aromatic content of 35 volume percent.

195. The Owner/Operator shall install non-resettable hour meters as specified in 40 CFR §60.4209(a).
196. The Owner/Operator shall meet the applicable compliance requirements specified in 40 CFR §60.4211(a), (c), and (f).
197. The Owner/Operator shall comply with the applicable recordkeeping requirements specified in 40 CFR §60.4214(b).
198. The Owner/Operator shall comply with the applicable General Provisions in §§60.1 through 60.19 listed in Table 8 to 40 CFR Part 60 Subpart IIII as specified in 40 CFR §60.4218.
199. All terms used in 40 CFR Part 60 Subpart IIII shall have the meaning given in 40 CFR §60.4219 or else in the Clean Air Act and 40 CFR Part 60 Subpart A [40 CFR §60.4219].

40 CFR Part 60 Subpart KKKK

200. The three combustion turbines with heat recovery steam generators and duct burners are subject to the requirements of 40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines [40 CFR §60.4305].
201. The Owner/Operator shall comply with the applicable NO_x limits specified in 40 CFR §60.4320. [Compliance with the LAER NO_x limit of 2 ppmvd @ 15% O₂ will show compliance with this requirement.]
202. The Owner/Operator shall comply with the applicable SO₂ limits specified in 40 CFR §60.4330. [Compliance with the natural gas fuel sulfur limit of 0.5 grains/100 dscf will show compliance with this requirement.]
203. The Owner/Operator shall comply with the applicable general requirements specified in 40 CFR §60.4333.
204. The Owner/Operator shall comply with the applicable NO_x continuous compliance demonstration requirements specified in 40 CFR §60.4340.
205. The Owner/Operator shall comply with the applicable NO_x CEMS requirements specified in 40 CFR §60.4345.
206. The Owner/Operator shall comply with the applicable continuous monitoring data excess emissions requirements specified in 40 CFR §60.4350.
207. The Owner/Operator shall comply with the applicable fuel sulfur content determination requirements specified in 40 CFR §60.4360.
208. The Owner/Operator shall comply with the applicable fuel sulfur monitoring exemption requirements specified in 40 CFR §60.4365.

209. The Owner/Operator shall comply with the applicable reporting requirements specified in 40 CFR §60.4375.
210. The Owner/Operator shall comply with the applicable NO_x excess emissions and monitor downtime requirements specified in 40 CFR §60.4380.
211. The Owner/Operator shall comply with the applicable reporting deadlines specified in 40 CFR §60.4395.
212. The Owner/Operator shall comply with the applicable NO_x performance testing requirements specified in 40 CFR §60.4400.
213. The Owner/Operator shall comply with the applicable initial NO_x performance test specified in 40 CFR §60.4405.
214. The Owner/Operator shall comply with the applicable sulfur performance testing requirements specified in 40 CFR §60.4415.
215. All terms used in 40 CFR Part 60 Subpart KKKK shall have the meaning given in 40 CFR §60.4420 or else in the Clean Air Act and 40 CFR Part 60 Subpart A [40 CFR §60.4420].

40 CFR Part 61 Subpart J

216. Equipment in benzene service is subject to the requirements of 40 CFR Part 61 Subpart J - National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene [40 CFR §61.110].
217. All terms used in 40 CFR Part 61 Subpart J shall have the meaning given in 40 CFR §61.111 or else in the Clean Air Act and 40 CFR Part 61 Subparts A and V [40 CFR §61.111].
218. The Owner/Operator shall comply with the applicable standards specified in 40 CFR §61.112.

40 CFR Part 61 Subpart V

219. Equipment in benzene service is subject to the requirements of 40 CFR Part 61 Subpart V - National Emission Standard for Equipment Leaks (Fugitive Emission Sources) [40 CFR §61.240].
220. All terms used in 40 CFR Part 61 Subpart V shall have the meaning given in 40 CFR §61.241 or else in the Clean Air Act, 40 CFR Part 61 Subpart A, or other specific subparts of Part 61 [40 CFR §61.241].
221. The Owner/Operator shall comply with the applicable standards for pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, valves, pressure relief devices in liquid service and connectors, surge control vessels

and bottoms receivers, delay of repair, and closed-vent systems and control devices specified in 40 CFR §§61.242-2 through 61.242-11.

222. The Owner/Operator may apply to the Administrator for permission to use an alternative means of emission limitation as specified in 40 CFR §61.244.
223. The Owner/Operator shall comply with the applicable test methods and procedures specified in 40 CFR §61.245.
224. The Owner/Operator shall comply with the applicable recordkeeping requirements specified in 40 CFR §61.246.
225. The Owner/Operator shall comply with the applicable notification and reporting requirements specified in 40 CFR §61.247.

40 CFR Part 61 Subpart FF

226. The ethylene and polyethylene manufacturing lines are subject to limited requirements of 40 CFR Part 61 Subpart FF – National Emission Standard for Benzene Waste Operations [40 CFR §61.340].
227. The following waste streams are exempt from the requirements of 40 CFR Part 61 Subpart FF [40 CFR §61.340]:
 - a. Waste in the form of gas or vapor emitted from process fluids.
 - b. Waste that is contained in a segregated storm water sewer system.
228. All terms used in 40 CFR Part 61 Subpart FF shall have the meaning given in 40 CFR §61.341 or else in the Clean Air Act [40 CFR §61.341].
229. The Owner/Operator shall comply with the applicable general standards for a facility with benzene waste less than 10 Mg per year (11 tons per year) as specified in 40 CFR §61.342(a), (g), and (h).
230. The Owner/Operator shall comply with the applicable monitoring requirements for benzene waste operations specified in 40 CFR §61.354.
231. The Owner/Operator shall determine total annual benzene quantity from facility waste as specified in 40 CFR §61.355(a) through (c).
232. The Owner/Operator shall comply with the applicable recordkeeping requirements for benzene waste operations specified in 40 CFR §61.356.
233. The Owner/Operator shall comply with the applicable reporting requirements for benzene waste operations specified in 40 CFR §61.357.

40 CFR Part 63 Subpart SS

234. Closed vent systems, control devices, and routing of air emissions to a fuel gas system or process, subject to 40 CFR Part 63 Subpart UU or as referenced in 40 CFR Part 63 Subparts YY and FFFF, are subject to the requirements of 40 CFR Part 63 Subpart SS - National Emission Standards for Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process [40 CFR §63.980].
235. All terms used in 40 CFR Part 63 Subpart SS shall have the meaning given in 40 CFR §63.981 or else in the Clean Air Act [40 CFR §63.981].
236. The Owner/Operator shall comply with the applicable requirements for organic HAP-containing storage tanks, process vents and equipment leaks specified in 40 CFR §63.982(a) and (b).
237. The Owner/Operator shall comply with the applicable closed vent system requirements for organic HAP-containing storage tanks, process vents and equipment leaks specified in 40 CFR §63.983.
238. The Owner/Operator shall comply with the applicable flare requirements for the MPGF, and HP ground flares and elevated flare specified in 40 CFR §63.987.
239. The Owner/Operator shall comply with the applicable incinerator requirements for the LP incinerator specified in 40 CFR §63.988.
240. The Owner/Operator shall comply with the applicable general monitoring requirements for the Spent Caustic Vent incinerator, LP System, and HP System specified in 40 CFR §63.996.
241. The Owner/Operator shall comply with the applicable performance testing and compliance assessment requirements for the Spent Caustic Vent and LP incinerators, MPGF, and HP flares specified in 40 CFR §63.997.
242. The Owner/Operator shall comply with the applicable recordkeeping requirements for organic HAP-containing storage tanks, process vents and equipment leaks specified in 40 CFR §63.998.
243. The Owner/Operator shall comply with the applicable notification and reporting requirements for organic HAP-containing storage tanks, process vents and equipment leaks specified in 40 CFR §63.999.

40 CFR Part 63 Subpart UU

244. Ethylene manufacturing line equipment containing or contacting greater than or equal to 5 wt% organic HAP (and not in vacuum service) is subject to the requirements of 40 CFR Part 63 Subpart UU – National Emission Standards for Equipment Leaks – Control Level 2 Standards [40 CFR §63.1019].
245. All terms used in 40 CFR Part 63 Subpart UU shall have the meaning given in 40 CFR §63.1020 or else in the Clean Air Act [40 CFR §63.1101].

246. The Owner/Operator shall comply with the applicable ethylene manufacturing line affected equipment identification and designation requirements specified in 40 CFR §63.1022.
247. The Owner/Operator shall comply with the applicable ethylene manufacturing line instrument and sensory monitoring requirements applicable to equipment leaks as specified in 40 CFR §63.1023.
248. The Owner/Operator shall comply with the applicable ethylene manufacturing line equipment leak repair requirements specified in 40 CFR §63.1024.
249. The Owner/Operator shall comply with the applicable standards for ethylene manufacturing line valves in gas/vapor service and light liquid service specified in 40 CFR §63.1025.
250. The Owner/Operator shall comply with the applicable standards for ethylene manufacturing line pumps in light liquid service specified in 40 CFR §63.1026.
251. The Owner/Operator shall comply with the applicable standards for ethylene manufacturing line connectors in gas/vapor service and light liquid service specified in 40 CFR §63.1027.
252. The Owner/Operator shall comply with the applicable standards for ethylene manufacturing line agitators in gas/vapor service and light liquid service specified in 40 CFR §63.1028.
253. The Owner/Operator shall comply with the applicable standards for ethylene manufacturing line pumps, valves, connectors, and agitators in heavy liquid service; pressure relief devices in liquid service; and instrumentation systems specified in 40 CFR §63.1029.
254. The Owner/Operator shall comply with the applicable standards for ethylene manufacturing line pressure relief devices in gas/vapor service specified in 40 CFR §63.1030.
255. The Owner/Operator shall comply with the applicable standards for ethylene manufacturing line compressors specified in 40 CFR §63.1031.
256. The Owner/Operator shall comply with the applicable standards for ethylene manufacturing line sampling connection systems specified in 40 CFR §63.1032.
257. The Owner/Operator shall comply with the applicable standards for ethylene manufacturing line open-ended valves or lines specified in 40 CFR §63.1033.
258. The Owner/Operator shall comply with the applicable standards for ethylene manufacturing line closed vent systems and control devices; or emissions routed to a fuel gas system or process specified in 40 CFR §63.1034.
259. The Owner/Operator shall comply with the quality improvement program for ethylene manufacturing line pumps specified in 40 CFR §63.1035.

260. The Owner/Operator shall comply with the applicable recordkeeping requirements for ethylene manufacturing line equipment leaks specified in 40 CFR §63.1038.

261. The Owner/Operator shall comply with the applicable reporting requirements for ethylene manufacturing line equipment leaks specified in 40 CFR §63.1039.

40 CFR Part 63 Subpart XX

262. All terms used in 40 CFR Part 63 Subpart XX shall have the meaning given in 40 CFR §63.1082 or else in the Clean Air Act, §63.1103(e), or §61.341 [40 CFR §63.1082].

263. Ethylene manufacturing line heat exchange systems are subject to the requirements of 40 CFR Part 63 Subpart XX - National Emission Standards for Ethylene Manufacturing Process Units: Heat Exchange Systems and Waste Operations [40 CFR §63.1083].

264. The Owner/Operator shall comply with the applicable ethylene manufacturing line heat exchange system general requirements specified in 40 CFR §63.1085.

265. The Owner/Operator shall comply with the applicable ethylene manufacturing line heat exchange system cooling water leak monitoring requirements specified in 40 CFR §63.1086.

266. The Owner/Operator shall comply with the applicable ethylene manufacturing line heat exchange system leak repair requirements specified in 40 CFR §63.1087.

267. The Owner/Operator may delay repair of ethylene manufacturing line heat exchange system leaks in accordance with the criteria specified in 40 CFR §63.1088.

268. The Owner/Operator shall comply with the applicable recordkeeping requirements for ethylene manufacturing line heat exchange systems specified in 40 CFR §63.1089.

269. The Owner/Operator shall comply with the applicable reporting requirements for ethylene manufacturing line heat exchange systems specified in 40 CFR §63.1090.

270. Ethylene manufacturing line waste streams are subject to the requirements of 40 CFR Part 63 Subpart XX - National Emission Standards for Ethylene Manufacturing Process Units: Heat Exchange Systems and Waste Operations [40 CFR §63.1093].

271. The following waste streams are exempt from the requirements of 40 CFR Part 63 Subpart XX [40 CFR §63.1094]:

- a. Waste in the form of gas or vapor emitted from process fluids.
- b. Waste that is contained in a segregated storm water sewer system.

272. The Owner/Operator shall comply with the specific requirements applicable to ethylene manufacturing line waste streams containing benzene specified in 40 CFR §63.1095(b).

273. The Owner/Operator shall comply with the applicable notice and certification requirements for off-site waste transfer specified in 40 CFR §63.1096.

40 CFR Part 63 Subpart YY

274. The Owner/Operator shall comply with the applicable General Provisions in §§63.1 through 63.5, and §§63.12 through 63.15 as specified in 40 CFR §63.1100(b).
275. All terms used in 40 CFR Part 63 Subpart YY shall have the meaning given in 40 CFR §63.1101 or else in the Clean Air Act or §63.2 (General Provisions) [40 CFR §63.1101].
276. The ethylene manufacturing line affected storage vessels, process vents, transfer racks, equipment, waste streams, heat exchange systems, and cracking furnaces and associated decoking operations are subject to the requirements of 40 CFR Part 63 Subpart YY – National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards [40 CFR §63.1103].
277. The Owner/Operator shall comply with the applicable requirements for storage vessels containing organic HAP as specified in Table 7(b)(1) to 40 CFR §63.1103(e).
278. The Owner/Operator shall reduce emissions of total organic HAP from the light gasoline and pyrolysis fuel oil storage tanks by [a minimum of] 98 wt% by venting emissions through a closed vent system to any combination of control devices and meet the requirements of §63.982(a)(1) as specified in Table 7(b)(1)(ii) to 40 CFR §63.1103(e). [Compliance with the LAER VOC control requirements to install an IFR and capture and route vapors to the LP System will show compliance with this requirement]
279. The Owner/Operator shall comply with the applicable requirements for ethylene process vents as specified in Table 7(d)(1) to 40 CFR §63.1103(e).
280. The Owner/Operator shall comply with the applicable requirements for transfer racks as specified in Table 7(e)(1) to 40 CFR §63.1103(e).
281. The Owner/Operator shall comply with the applicable requirements for equipment containing or contacting organic HAP as specified in Table 7(f)(1) to 40 CFR §63.1103(e).
282. The Owner/Operator shall comply with the applicable requirements for waste streams containing benzene, cumene, ethyl benzene, hexane, naphthalene, styrene, toluene, o-xylene, m-xylene, p-xylene, or 1,3-butadiene as specified in Table 7(g)(1) to 40 CFR §63.1103(e).
283. The Owner/Operator shall comply with the applicable requirements for heat exchange systems as specified in Table 7(h) to 40 CFR §63.1103(e).
284. The Owner/Operator shall comply with the applicable applicability assessment procedures and methods for process vents from continuous unit operations specified in 40 CFR §63.1104.
285. The Owner/Operator shall comply with the applicable requirements for transfer racks as specified in 40 CFR §63.1105.

286. The Owner/Operator shall comply with the applicable applicability assessment procedures and methods for equipment leaks specified in 40 CFR §63.1107.
287. The Owner/Operator shall comply with the applicable compliance with standards and operation and maintenance requirements for ethylene production specified in 40 CFR §63.1108(a)(1), (2), and (5) through (7).
288. The Owner/Operator shall comply with the applicable compliance assessment procedures for ethylene production specified in 40 CFR §63.1108(b).
289. The Owner/Operator shall comply with the applicable recordkeeping requirements for ethylene production specified in 40 CFR §63.1109.
290. The Owner/Operator shall comply with the applicable reporting requirements for ethylene production specified in 40 CFR §63.1110.

40 CFR Part 63 Subpart FFFF

291. The polyethylene manufacturing line affected miscellaneous organic chemical manufacturing process units (process vents, equipment leaks, and wastewater and liquid streams) are subject to the requirements of 40 CFR Part 63 Subpart FFFF – National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing [40 CFR §63.2435].
292. The Owner/Operator shall comply with the applicable compliance deadline and notification requirements specified in 40 CFR §63.2445.
293. The Owner/Operator shall comply with the applicable general compliance requirements specified in 40 CFR §63.2450.
294. The Owner/Operator shall comply with the applicable requirements for polyethylene manufacturing line continuous process vents specified in 40 CFR §63.2455.
295. The Owner/Operator shall comply with the applicable requirements for polyethylene manufacturing line process vents that emit HAP metals specified in 40 CFR §63.2465(a) and (d).
296. The Owner/Operator shall comply with the applicable requirements for polyethylene manufacturing line equipment leaks specified in 40 CFR §63.2480.
297. The Owner/Operator shall comply with the applicable requirements for polyethylene manufacturing line wastewater streams and liquid streams in open systems within an MCPU specified in 40 CFR §63.2485.
298. The Owner/Operator shall comply with the applicable requirements for polyethylene manufacturing line heat exchange systems specified in 40 CFR §63.2490.
299. The Owner/Operator shall comply with the applicable notification requirements specified in 40 CFR §63.2515.

300. The Owner/Operator shall comply with the applicable reporting requirements specified in 40 CFR §63.2520.
301. The Owner/Operator shall comply with the applicable recordkeeping requirements specified in 40 CFR §63.2525.
302. The Owner/Operator shall comply with the applicable General Provisions in §§63.1 through 63.15 listed in Table 12 to 40 CFR Part 63 Subpart FFFF as specified in 40 CFR §63.2540.
303. All terms used in 40 CFR Part 63 Subpart FFFF shall have the meaning given in 40 CFR §63.2550 or else in the Clean Air Act or other specifically referenced subpart.

40 CFR Part 63 Subpart YYYY

304. The three combustion turbines are subject to limited requirements of 40 CFR Part 63 Subpart YYYY – National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines [40 CFR §63.6085].
305. The Owner/Operator of lean premix stationary combustion turbines is only required to comply with the initial notification requirements of 40 CFR Part 63 Subpart YYYY as specified in 40 CFR §63.6095.
306. The Owner/Operator shall comply with the applicable initial notification requirements of 40 CFR Part 63 Subpart YYYY as specified in 40 CFR §63.6145(c).
307. All terms used in 40 CFR Part 63 Subpart YYYY shall have the meaning given in 40 CFR §63.6175 or else in the Clean Air Act and 40 CFR Part 63 Subpart A [40 CFR §60.6175].

40 CFR Part 63 Subpart ZZZZ

308. The four diesel-fired emergency generator engines and three diesel-fired fire pump engines are subject to limited requirements of 40 CFR Part 63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [40 CFR §63.6585].
309. The Owner/Operator shall comply with the criteria for limited requirements as specified in 40 CFR §63.6590(b)(1)(i).
310. The Owner/Operator shall comply with the applicable initial notification requirements specified in 40 CFR §63.6645(f).
311. All terms used in 40 CFR Part 63 Subpart ZZZZ shall have the meaning given in 40 CFR §63.6675 or else in the Clean Air Act and 40 CFR Part 63 Subpart A [40 CFR §63.6675].