

Appendix E
BACT Analysis

**Project ASCENT
Best Available Control Technology
(BACT) Analysis**

May 2014

E.1 BACT Analysis Overview

E.1.1 Best Available Control Technology

As described in Section 4 of this application, a Best Available Control Technology (BACT) analysis is required for projects triggering a significant emissions increase under the federal Prevention of Significant Deterioration (PSD) regulations. Based on projected potential emissions, a BACT evaluation is required for the ASCENT Project for nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM), PM of less than 10 micrometers in aerodynamic diameter (PM₁₀), PM of less than 2.5 micrometers in aerodynamic diameter (PM_{2.5}), volatile organic compound (VOC), and greenhouse gas (GHG) emissions. Since this is a new facility, all Project emissions sources (i.e., pyrolysis furnaces, combustion turbine with heat recovery steam generation (HRSG), emergency generators, fire water pump engines, flares, thermal oxidizers, emergency flares, material handling, wastewater treatment, cooling tower, storage tanks, and fugitive sources) are subject to the BACT review.

E.1.2 BACT Analysis Process

BACT is defined in the PSD regulations at 40 CFR 52.21(b)(12) as:

“an emissions limitation ... based on the maximum degree of reduction for each pollutant subject to regulation ... which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs, determines is achievable ... through application of production processes or available methods, systems and techniques ... for control of such pollutant.”

Additionally, in 45 CSR 14-2.12 of the West Virginia Department of Environmental Protection (WVDEP) air pollution control regulations, West Virginia has defined BACT as:

“an emissions limitation ... based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification which the Secretary, on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant

which would exceed the emissions allowed by any federally enforceable emissions limitations or emissions limitations enforceable by the Secretary. If the Secretary determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.”

Each BACT analysis is conducted on a case-by-case basis, where the reviewing authority evaluates the energy, environmental, economic and other costs associated with each alternative technology, as well as the benefit of the expected reduced emissions that each technology would yield. In no event, however, can a technology be recommended that would not meet any applicable standard of performance under the New Source Performance Standards (40 CFR Part 60) or the National Emission Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63). Additionally, if the reviewing authority finds during the course of a BACT analysis that there is no economically reasonable or technologically feasible way to accurately measure the emissions, and hence to impose an enforceable emissions standard, it may require the source to use design, alternative equipment, work practices or operational standards to reduce emissions of the pollutant.

BACT analyses are conducted according to a top-down process, where all available control technologies are ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent or “top” alternative. This alternative is to be selected as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not “achievable” in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

Under the “top-down” approach, as described in United States Environmental Protection Agency’s (USEPA’s) *Draft New Source Review Workshop Manual*, the five basic steps of a “top-down” BACT analysis are as follows:

- Step 1:** Identify potential control technologies;
- Step 2:** Eliminate technically infeasible options;
- Step 3:** Rank remaining control technologies by control effectiveness;

Step 4: Evaluate most effective controls based on economic, energy, and environmental impacts; and

Step 5: Select BACT

The first step is to identify potentially “available” control options for each emission unit triggering PSD, for each pollutant under review. Available options consist of a comprehensive list of those technologies with a potentially practical application to the emission unit in question. The list includes technologies used to satisfy BACT requirements, innovative technologies, and controls applied to similar source categories.

During this BACT review, a combination of the following sources were investigated to identify potentially available control technologies:

- USEPA’s RACT/BACT/LAER Clearinghouse (RBLC) database;
- USEPA’s New Source Review website;
- In-house experts;
- Similar permitting projects;
- State air regulatory agency contacts;
- Technical books and articles;
- The USEPA Region 4 National Combustion Turbine Spreadsheet;¹
- State permits issued for similar sources that have not yet been entered into the RBLC; and
- Guidance documents and personal communications with state agencies.

After identifying potential technologies, the second step is to eliminate technically infeasible options from further consideration. To be considered feasible for BACT, a technology must be both “available” and “applicable.” The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern. If the highest ranked technology is proposed as BACT, it is not necessary to perform any further technical or economic evaluation. Potential adverse impacts of implementing such technology, however, must still be identified and evaluated.

¹ Compiled by USEPA Region 4 staff, available at:
http://www.epa.gov/region4/air/permits/national_ct_list.xls.

The fourth step entails an evaluation of energy, environmental, and economic impacts for determining a final level of control. The evaluation begins with the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts.

The economic or “cost-effectiveness” analysis is conducted in a manner consistent with USEPA’s Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual, Fifth Edition (USEPA, 1996) and subsequent revisions.

The fifth and final step is to select as BACT the emission limit resulting from application of the most effective of the remaining technologies under consideration for each pollutant of concern.

E.2 BACT Analyses

E.2.1 NO_x BACT Analysis

Generally, NO_x is formed during combustion processes by the thermal oxidation of nitrogen in the combustion air (thermal NO_x) and the oxidation of nitrogen in the fuel (fuel-bound NO_x). The main variables affecting NO_x generation in the proposed equipment for Project ASCENT are temperature, the availability of nitrogen, the availability of oxygen, and the degree of contact between oxygen and nitrogen during the combustion process.

E.2.1.1 Pyrolysis Furnaces and Auxiliary Boilers

Step 1 - Identify Potential Control Technologies

Several combustion and post-combustion technologies are available for controlling NO_x emissions from combustion sources such as the pyrolysis furnaces and the auxiliary boilers. Combustion controls minimize the amount of NO_x created during the combustion process, and post-combustion controls remove NO_x from the exhaust stream after combustion has occurred.

Identified control technologies and techniques for NO_x emissions include:

- Low-NO_x/Ultra-low NO_x burners (LNBS/ULNBs);
- Flue gas recirculation (FGR);
- Selective catalytic reduction (SCR);
- Selective non-catalytic reduction (SNCR); and
- EM_xTM;

It is noted that the pyrolysis furnaces operate at a much higher temperature than the auxiliary boiler and thus have inherently higher NO_x emission rates, even when both units apply the same emissions control technology.

Step 2 - Eliminate Technically Infeasible Options

Low-NO_x and Ultra-low NO_x burners

Low emitting NO_x burners employ design features, such as air staging or fuel staging, to minimize NO_x formation during combustion.

Flue Gas Recirculation

In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products that act as inerts during combustion of the fuel/air mixture which reduces combustion temperatures, thus suppressing the thermal NO_x mechanism. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone.

Selective Catalytic Reduction

SCR is a catalytic post-combustion control technology designed to control NO_x emissions. The catalyst is composed of a support system with an external catalyst coating. The coating material is typically titanium dioxide (TiO₂), vanadium pentoxide (V₂O₅), or zeolite. The ammonia, in this case aqueous ammonia with a concentration of less than 20% by weight, is vaporized and injected directly into the exhaust stream, where it reacts with NO_x and O₂ in the presence of the catalyst to form N₂ and water vapor.

These reactions normally occur at relatively high temperatures (e.g., 1,600 °F to 2,100 °F). However, the placement of a catalyst in the exhaust stream lowers the activation energy of the reaction, which allows the reaction to take place at lower temperatures (typically 650 °F to 850 °F).

Typically, a small amount of ammonia is not consumed in the reactions and is emitted in the exhaust stream. These ammonia emissions are referred to as “ammonia slip.”

Selective Non-Catalytic Reduction

SNCR involves injection of ammonia or urea CO(NH₂)₂ with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires temperatures in the range of 1,600 °F to 2,100 °F.

EM_xTM

The EM_xTM system (formerly SCONO_xTM) uses a single catalyst to remove NO_x emissions from combustion exhaust gas by oxidizing nitric oxide (NO) to nitrogen dioxide (NO₂) and then absorbing the NO₂ onto a catalytic surface using a potassium carbonate (K₂CO₃) absorber coating. The potassium carbonate coating reacts with NO₂ to form potassium nitrites and nitrates, which are deposited onto the catalyst surface. The optimal temperature window for operation of the EM_xTM catalyst ranges from 300 °F to 700 °F. EM_xTM does not use ammonia. Therefore, there are no ammonia emissions from this technology.

When all of the potassium carbonate absorber coating has been converted to N₂ compounds, NO_x can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of oxygen. Hydrogen in the gas reacts with the nitrites and nitrates to form water and N₂. Carbon dioxide in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst.

The demonstrated application for EM_xTM is currently limited to combined-cycle combustion turbines under approximately 50 megawatts (MW) in size. The EM_xTM system has not been demonstrated on any type of combustion source other than a combustion turbine. There are technical differences between the proposed pyrolysis heaters and auxiliary boilers versus those few sources where this technology has been demonstrated in practice. These significant technical differences preclude a determination that the EM_xTM system has been demonstrated to function efficiently on sources that are similar to the proposed furnaces and boilers.

All other technologies identified are considered technically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The remaining control technologies are ranked below in order from most effective to least effective for reduction of NO_x emissions:

- SCR;
- LNB/ULNB;
- SNCR; and
- FGR.

Step 4 - Evaluate Most-Effective Controls and Document Results

Project ASCENT is proposing to install ULNB technology for the pyrolysis furnaces and the auxiliary boilers. Since ULNBs are the second-most effective control technology, the cost-effectiveness evaluation is limited to evaluation of the use of SCR in addition to ULNB.

The use of ULNB will not cause any adverse energy, environmental, or economic impacts. The highest ranked control option, SCR, when considered in comparison to UNLB alone, will cause adverse energy and economic impacts and will yield both beneficial and adverse environmental impacts. The adverse energy impact is caused by the electrical requirements of the SCR system operation and the reduction in energy efficiency due to the pressure drop across the SCR catalyst.

The adverse environmental impacts due to the addition of the SCR system include ammonia emissions and the handling and disposal of a spent catalyst as a solid waste stream. More significantly, ammonia “slip,” or ammonia that is injected into the SCR system and is not consumed through the chemical reduction of NO_x emissions, leads directly to emissions of ammonia and can lead indirectly to the formation of secondary particulate matter. The impact of ammonia slip increases with catalyst age, because as the catalyst ages, its activity decreases, and a higher amount of ammonia is required to maintain desired NO_x levels.

The final consideration regarding the application of SCR is the economic impact. It is noted that that the design and operating requirements for the pyrolysis furnaces require separate stacks for each of the six furnaces. This is driven in part by the need to control operating conditions while periodically taking a furnace off-line for required decoking. The impact of this design requirement is that, if SCR were to be implemented, there would need to be six separate SCR systems for control of the pyrolysis furnaces.

A cost analysis shows the incremental cost effectiveness of adding SCR systems as follows:

- For the pyrolysis furnaces, adding SCR to reduce NO_x from UNLB levels of 0.06 lb/MMBtu to 0.01 lb/MMBtu will cost more than \$6,400 per ton of NO_x emission reduction;
- For the auxiliary boilers, incremental cost effectiveness of SCR to reduce NO_x from 0.02 lb/MMBtu to 0.005 lb/MMBtu is more than \$22,000 per ton of NO_x reduction.

The cost-effectiveness evaluations for the application of SCR to the pyrolysis furnaces and auxiliary boilers are provided at the end of this Appendix as **Attachment E-1**.

Considering the adverse economic impact, as well as adverse environmental impacts, ASCENT concludes that requiring SCR for the pyrolysis furnaces or for the auxiliary boilers cannot be justified and does not represent BACT.

While there are applications of SCR for both of these source types, these are generally applied for projects that are required to meet lowest achievable emission rates (LAER) in ozone non-attainment areas.

Step 5 - Select BACT

For the pyrolysis furnaces, the BACT control strategy is the use of ULNB. For each of the heaters, the proposed NO_x emission limit is as follows:

- 0.06 lb/MMBtu (higher heating value [HHV]), based on a daily rolling 365-day average, with no exclusion for periods of startup or shutdown.

For the auxiliary boilers, the BACT control strategy is the use of ULNB. For each of the boilers, the proposed NO_x emission limit is as follows:

- 0.02 lb/MMBtu (HHV), based on a daily rolling 365-day average, with no exclusion for periods of startup, shutdown, and malfunction.

E.2.1.2 Combustion Turbines/Duct Burners

For the top-down BACT evaluation as applicable to the combustion turbines and duct burners, the following sources were reviewed: the RBLC database, recent permits issued from across the U.S., the USEPA Region 4 Combustion Turbine Spreadsheet, and other available literature.

Step 1 - Identify Potential Control Technologies

The following technologies were considered to be potentially available for the combustion turbine with integrated HRSG:

- LNB (duct burners);
- Dry low-NO_x (DLN) combustors (combustion turbine);
- Diluent (nitrogen or steam) injection (combustion turbine);
- EM_xTM;
- SCR; and
- SNCR.

Low-NO_x burners

Low emitting NO_x burners employ design features, such as air staging or fuel staging, to minimize NO_x formation during combustion. DLN Combustors

Conventional combustors are diffusion-controlled, with fuel and air injected separately. This method of combustion results in combustion “hot spots,” which produce higher levels of thermal NO_x. Lean premix and catalytic technologies are two available types of DLN combustors that are alternatives to conventional diffusion-controlled combustors. DLN combustors reduce the combustion hot spots that result in thermal NO_x formation.

With lean premix DLN combustors, the mechanisms for reducing thermal NO_x through formation are:

- Using excess air to reduce flame temperatures (i.e., lean combustion);
- Reducing combustor residence time to limit exposure in a high-temperature environment;
- Mixing fuel and air in an initial “pre-combustion” stage to produce a lean and uniform fuel/air mixture that is delivered to a secondary stage where combustion takes place; and/or
- Achieving two-stage combustion using a primary fuel-rich combustion stage to limit the amount of O₂ available to combine with N₂, and then a secondary lean burn-stage to complete combustion in a cooler environment.

Lean premix DLN combustors have only been developed for gas fuel-fired combustion turbines. The more-advanced designs are capable of achieving 70 to 90% NO_x emission reductions.

As the name implies, catalytic combustors use a catalyst to allow the combustion reactions to occur at lower peak flame temperatures, which reduce thermal NO_x formation. Catalytic combustors use a flameless catalytic combustion module, followed by completion of combustion at lower temperatures downstream of the catalyst.

Diluent (Water or Steam) Injection

The injection of water or steam into a combustion turbine’s combustors quenches the flame and absorbs heat, thus reducing combustion temperatures. The reduced temperatures in turn reduce the formation of thermal NO_x. Combined with a post-combustion control technology, water or steam injection typically can achieve NO_x emissions levels of 25 ppmvd

@15% O₂, but with the added economic, energy, and environmental expense of producing, storing, and consuming demineralized water.

EM_xTM

EM_xTM uses a single catalyst to remove NO_x emissions from combustion turbine exhaust gas by oxidizing nitric oxide (NO) to nitrogen dioxide (NO₂) and then absorbing the NO₂ onto a catalytic surface using a potassium carbonate (K₂CO₃) absorber coating. The potassium carbonate coating reacts with NO₂ to form potassium nitrites and nitrates, which are deposited onto the catalyst surface. The optimal temperature window for operation of the EM_xTM catalyst is from 300 °F to 700 °F. EM_xTM does not use ammonia. Therefore, there are no ammonia emissions from this technology.

When all of the potassium carbonate absorber coating has been converted to N₂ compounds, NO_x can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of oxygen. Hydrogen in the gas reacts with the nitrites and nitrates to form water and N₂. Carbon dioxide in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst.

Combined with DLN combustors or water/steam injection, EM_xTM is capable of achieving NO_x emissions levels of 2 ppmvd @ 15% O₂ for combined-cycle combustion turbines.

Selective Catalytic Reduction

SCR is a post-combustion control technology designed to control NO_x emissions from combustion turbines. SCR systems for combined-cycle combustion turbines are typically placed inside the HRSGs, and consist of a catalyst bed with an ammonia injection grid located upstream of the catalyst.

Combined with DLN combustors or water/steam injection, SCR is capable of achieving NO_x emissions levels of 2 ppmvd @ 15% O₂ for combined-cycle combustion turbines.

Selective Non-Catalytic Reduction

SNCR is not available for combustion turbines, because combustion turbine exhaust temperatures are typically 1,000 °F, significantly below the 1,600 °F minimum temperature required for effective SNCR performance.

Step 2 - Eliminate Technically Infeasible Options

DLN Combustors

DLN combustors are a feasible technology for reducing NO_x emissions from the proposed combustion turbines. When combined with SCR, DLN combustors can achieve NO_x emissions levels of 2 ppmvd @ 15% O₂.

Diluent (Water or Steam) Injection

The use of water or steam injection is considered a feasible technology for reducing NO_x emissions to about 25 ppmvd @ 15% O₂ when firing gaseous fuel under most ambient conditions. Combined with SCR, water or steam injection can achieve NO_x levels of 2 ppmvd @ 15% O₂, but at slightly lower thermal efficiencies compared to DLN combustors.

Selective Catalytic Reduction

SCR, with an ammonia slip of less than 5 ppmvd @ 15% O₂, is considered a feasible technology for reducing combustion turbine NO_x emissions to 2 ppmvd @ 15% O₂ when firing gaseous fuel. SCR has been successfully installed and used on numerous simple-cycle and combined-cycle combustion turbines.

EM_xTM

The EM_xTM technology is not considered feasible. The demonstrated application for EM_xTM is currently limited to combined-cycle combustion turbines under approximately 50 MW in size. The combustion turbine proposed for this Project is a nominal 78 MW unit. More importantly, SCR and oxidation catalyst, which have been demonstrated to be effective on larger combustion turbines, can achieve similar emission levels as the EM_xTM system.

Selective Non-Catalytic Reduction

SNCR requires a temperature window that is higher than the exhaust temperatures from gaseous fuel-fired combustion turbines. Therefore, SNCR is not considered technically feasible for the proposed combustion turbines.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following remaining technologies are ranked in order most effective to least effective for NO_x removal for the combustion turbine with integrated HRSG:

- SCR (in conjunction with DLN and LNB for duct burners);
- Diluent (nitrogen or steam) injection (combustion turbine); and
- DLN combustors (combustion turbine) / LNBS (duct burners).

Based on the preceding discussions, the use of water/steam injection, DLN combustors, and SCR are the technically feasible NO_x control technologies available for the proposed combustion turbines.

DLN combustors were selected because they can achieve lower NO_x emission rates from the combustion turbines than either water or steam injection. Additionally, the DLN combustors do not have the economic, energy, and environmental downsides of producing, storing, and consuming demineralized water, which is necessary for water or steam injection.

Furthermore, DLN combustors result in slight improvements in thermal efficiency over water/steam injection NO_x control alternatives. When used in combination with SCR, these technologies can control NO_x emissions from the combustion turbines to 2.0 ppmvd @ 15% O₂ with and without duct firing.

There are potential environmental and energy impacts associated with the use of SCR. First, SCRs require replacement of the catalyst beds after several years. The waste catalyst must be disposed of in accordance with state and federal regulations regarding normal waste disposal. Because of the precious metal content of the catalysts, they may also be recycled to recover the precious metals. Sulfur compounds in the exhaust gas may react with the ammonia reagent, forming ammonia salts, which may increase PM, PM₁₀, and PM_{2.5} emissions. SCRs also have energy impacts. Due to their location downstream of the combustion turbine exhaust, SCR catalysts increase the back pressure on the combustion turbines, which results in slightly decreased power output. This slightly decreased output leads to slightly increased pollutant emissions on a mass per unit power output basis.

Although there are potential environmental and energy impacts associated with the use of SCR, these impacts are not considered significant enough to preclude the use of SCR for NO_x emission control.

Available permits and BACT determinations were reviewed to identify NO_x emission rates that have been achieved in practice for other comparable gaseous fuel-fired combustion turbine projects. The majority of the projects had permitted NO_x emission rates equal to or greater than 2.0 ppmvd @ 15% O₂.

Only one facility, for an IDC Bellingham combined-cycle plant proposed in Massachusetts, had a NO_x emission limit below the 2.0 ppmvd @ 15% O₂ level proposed as BACT for Project ASCENT. The IDC Bellingham facility was permitted with a not-to-exceed limit of 2.0 ppmvd @ 15% O₂, but the permit also required the unit to maintain emissions below 1.5 ppmvd @ 15% O₂ during normal operations. However, the IDC Bellingham facility was never built. Therefore, these emission limits were not achieved in practice. As a result, the proposed emission rate of 2.0 ppmvd @ 15% O₂ with and without duct firing is the lowest NO_x emission rate achieved in practice for similar sources and, therefore, application of DLN with SCR represents BACT for NO_x emissions.

Step 4 - Evaluate Most-Effective Controls and Document Results

Based on the information presented in this BACT analysis, the proposed NO_x emission rate of 2.0 ppmvd @ 15% O₂ with and without duct firing is the lowest NO_x emission rate achieved in practice at similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

Step 5 - Select BACT

The proposed BACT for NO_x emissions from the proposed combustion turbines is the use of DLN combustors and SCR, along with good combustion practices. These technologies are expected to control NO_x emissions to 2.0 ppmvd @ 15% O₂ on a rolling 365-day basis with and without duct firing.

E.2.1.3 Burners - Thermal Oxidizer and Regenerative Thermal Oxidizer (RTO)

ASCENT proposes to utilize thermal oxidizer and a regenerative thermal oxidizer for the control of various volatile organic compound (VOC) emissions from the proposed facility. Due to the nature of the flows coming into and the operation of these control devices, the only technology available to reduce NO_x emissions from these units is the design of the burners.

ASCENT is specifying the use of low-NO_x burners as part of the design for the burners for these control devices, with a NO_x emission rate of 0.04 lb/MMBtu. In a review of other permits and RBLC, ASCENT did not identify any oxidizers of similar size, in similar service that currently demonstrate in practice emission rates below the proposed BACT rate of 0.04 lb/MMBtu.

E.2.1.4 Burners - Flares

An emission limit of 0.068 lb NO_x/MMBtu is technically feasible for the proposed flares when utilizing continuous pilot and purge gas flows. This is the lowest NO_x limit achieved in practice for chemical plant and refinery flares.

E.2.1.5 Emergency Generators

ASCENT proposes BACT for NO_x and VOCs for the 2,800-kW and 350-kW Emergency Generators to be the applicable emission rates specified in 40 CFR 60, Subpart IIII. The Subpart IIII emission standard is 4.8 g/hp-hr for NO_x plus non-methane hydrocarbons (NMHC) for emergency generators greater than 560 kW. The standard is 3.0 g/hp-hr NO_x plus NMHC for emergency generators between 75 kW and 560 kW in size. Although there are several determinations that list NO_x emission rates below 4.8 g/hp-hr, when combined NO_x plus NMHC (NMHC is conservatively assumed to be equivalent to VOC) is evaluated, none of the engines listed have limits more stringent than 4.8 g/hp-hr.

Given the intended use of the Emergency Generators, with its operations limited to emergency events and no more than 100 hr/yr for maintenance and readiness testing, the environmental benefit associated with establishing emission limits below the Subpart IIII limit of 4.8 g/hp-hr is very small.

As BACT for the Emergency Generators, ASCENT proposes an emission limit of 3.0 g/hp-hr or 4.8 g/hp-hr for NO_x plus NMHC (depending on the size of the Emergency Generator) along with the use of ultra-low sulfur diesel (ULSD) fuel and good combustion practices, and limiting operations to emergency events and no more than 100 hr/yr planned operation for maintenance and readiness testing.

E.2.1.6 Fire Water Pump Engines

ASCENT proposes BACT for NO_x and VOCs for the 485-kW Fire Water Pump Engines to be the applicable emission rates specified in 40 CFR 60, Subpart IIII. The Subpart IIII emission standard is 3.0 g/hp-hr for NO_x plus NMHC. The Fire Water Pump Engines will use ULSD fuel to ensure operation can take place, even during periods when natural gas is unavailable.

Review of the RBLC determinations and recent permits for similar equipment indicates emission limits equal to 3.0 g/hp-hr, or at less stringent levels (e.g., Live Oaks, Wolverine Power Supply Cooperative, Avenal, and Pioneer Valley). As with the Emergency Generators, although there are several determinations that list NO_x or VOC emission levels below 3.0 g/hp-

hr, when combined NO_x plus NMHC is evaluated, no listings have limits more stringent than 3.0 g/hp-hr. For example, although the RBLC determination for Cricket Valley lists a NO_x emission level of 2.6 g/hp-hr, it also lists a VOC emission level of 0.97 g/hp-hr. Therefore, the comparable NO_x plus NMHC value for Cricket Valley is 3.57 g/hp-hr (2.6+0.97), compared to ASCENT's proposed limit of 3.0 g/hp-hr.

Based on the review of existing permit limits for engines of similar size and duty as the Fire Water Pump Engine, ASCENT concludes that BACT for NO_x and VOCs is the use of ULSD and good combustion practices, along with limiting use to emergency events and no more than 100 hr/yr planned operation for maintenance and readiness testing. The proposed BACT is a combined NO_x plus NMHC emission rate of 3.0 g/hp-hr.

The proposed NO_x BACT for all sources is summarized in Table E-2.

E.2.1.7 Catalyst Activator Heater

The Polyethylene Plant A process will require heat to support activation of the catalyst using a heater with a rating of up to 10 MMBtu/hr. This heater will not be used continuously, but rather will only operate when needed for activation. The unit will be specified to have low NO_x burners and ASCENT proposes an emission limit of 0.049 lb NO_x/MMBtu. ASCENT has not identified a lower emission rate for similar small, non-continuous use heaters.

Table E-2 Proposed NO_x BACT

Emission Source	Proposed NO_x BACT
Pyrolysis Furnaces	0.06 lb/MMBtu Use of good combustion practices, ULNB.
Auxiliary Boilers	0.02 lb/MMBtu Use of good combustion practices and ULNB.
Combustion Turbine/Duct Burner	2 ppmvd @ 15% O ₂ (with and without duct firing) Use of SCR, dry low-NO _x combustor design, and efficient combustion (i.e., good combustion practices).
Thermal Oxidizer / RTO	0.04 lb/MMBtu Use of good combustion practices, LNB
Flares	0.068 lb/MMBtu Use of good combustion practices
Emergency Generators	3.0 g/hp-hr (NMHC+NO _x) for 350 kW units and 4.8 g/hp-hr (NMHC+NO _x) for 2800 kW units. Use of ULSD fuel and good combustion practices; operation limited to emergency use and no more than 100 hr/yr planned operation for maintenance and readiness testing.
Fire Water Pump Engines	3.0 g/hp-hr (NMHC+NO _x) Use of ULSD fuel and good combustion practices; operation limited to emergency use and no more than 100 hr/yr for maintenance and readiness testing.
Catalyst Activator Heater	0.049 lb/MMBtu Use of good combustion practices, LNB

E.2.2 CO BACT Analysis

Carbon monoxide will be emitted from the Project ASCENT combustion sources due to incomplete combustion of hydrocarbons in the fuel.

E.2.2.1 Pyrolysis Furnaces, Auxiliary Boilers, Oxidizers, and Flare pilots

Step 1 - Identify Potential Control Technologies

Potentially available control technologies for CO emissions from heaters, boilers, and oxidizers include good combustion practices and the use of an oxidation catalyst. Potentially available control technologies for CO emissions from flares include good combustion practices.

Good Combustion Practices

Good combustion practices include the following:

- Proper fuel gas supply system design and operation to minimize fluctuations in fuel gas quality;
- Proper burner and fired equipment design;
- Good burner maintenance and operation; and
- Good air/fuel mixing.

Oxidation Catalyst

Oxidation catalysts are exhaust treatment devices which enhance oxidation of CO to CO₂, without the addition of any chemical reagents, because there is sufficient O₂ in the exhaust gas stream for the oxidation reactions to proceed in the presence of the catalyst alone. Typically, precious metals are used as the catalyst to promote oxidation. Catalyst volume is dependent upon the exhaust flow, temperature, and the desired removal efficiency. The catalyst material is subject to loss of activity over time due to physical deterioration or chemical deactivation.

Based on a review of USEPA's RBLC database and literature, including other permits issued for petrochemical facilities, no documented cases of oxidation catalysts being implemented on similarly sized furnaces or boilers were identified. Therefore, installation of oxidation catalyst for furnaces and boilers of the size proposed in Project ASCENT has not been demonstrated and is not available.

Step 2 - Eliminate Technically Infeasible Options

While documented application of oxidation catalysts for large furnaces and boilers such as the ones in Project ASCENT has not been identified, ASCENT nonetheless carried the technology forward to the next steps.

Use of oxidation catalyst is not possible to reduce CO emissions from a flare due to the nature of its design and the requirement to handle a very large range of flow.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The two available technologies for minimizing CO emissions, ranked in order most effective to least effective, are as follows:

- Oxidation catalysts; and

- Good combustion practices.

Step 4 - Evaluate Most-Effective Controls and Document Results

While the use of an oxidation catalyst has not been identified as a demonstrated technology for the pyrolysis furnaces or large boilers, ASCENT has estimated the cost effectiveness at > \$20,000 per ton of CO emissions reductions (see Appendix E-1). Since emissions from oxidizers are low due to basic design, cost effectiveness values are even higher than for the pyrolysis furnaces and boilers.

A USEPA guidance document was used as the basis for this analysis and limitations regarding stack temperatures relative to required catalyst operating temperatures were ignored. The USEPA Air Pollution Control Technology Fact Sheet for Regenerative Incinerator (EPA-452/F-03-021) shows that capital costs range from \$51.50 to \$206 per cubic foot per minute (cfm) and operation and maintenance costs range from \$8.80 to \$29.40 per cfm (costs escalated from 2002 to 2012 dollars). Conservatively, ASCENT estimated cost effectiveness using \$51.50 per cfm for capital costs and \$8.80 per cfm for operation and maintenance costs.

The estimates of potential emission reductions that could be achieved through the application of an oxidation catalyst, and corresponding control effectiveness costs (\$/ton), are calculated based on the total CO emissions from the sources. As shown in the cost analysis provided in **Attachment E-2**, even when using the most conservative (lowest expected) capital and annual operating and maintenance costs and ignoring potential issues regarding flue gas temperatures, the installation of oxidation catalyst for CO control would not be considered cost effective.

Step 5 - Select BACT

Aside from the technical issues discussed above, the installation of oxidation catalyst for CO control is not considered cost effective and is eliminated from further analysis for the pyrolysis furnaces, auxiliary boilers and oxidizers.

BACT for CO emissions from the proposed pyrolysis furnaces is use of good combustion practices and this is expected to achieve an emissions limit of 0.01 lb/MMBtu.

There have been several auxiliary boilers permitted with CO limits between 0.02 and 0.04 lb/MMBtu. The proposed CO emission level for the Auxiliary Boiler is 0.035 lb/MMBtu. This emission level is equivalent to those found in the RBLC for recently permitted units of similar design. Therefore, BACT is

the use of good combustion practices and is expected to achieve an emissions limit of 0.035 lb/MMBtu for the Auxiliary Boiler.

BACT for CO emissions from the proposed oxidizers is use of good combustion practices and is expected to achieve an emissions limit of 0.04 lb/MMBtu.

BACT for CO emissions from the proposed flare pilot burners is use of good combustion practices and an emission limit of 0.4 lb NO_x/MMBtu. This level is technically feasible for the proposed flares when utilizing continuous pilot and purge gas flows. This is the lowest CO limit achieved in practice for chemical plant and refinery flares.

E.2.2.2 Combustion Turbine/Duct Burners

Step 1 - Identify Potential Control Technologies

Effective combustor design and post-combustion controls using an oxidation catalyst or EM_xTM technology are the potential technologies for controlling CO emissions from combustion turbines. A description of the EM_xTM technology was discussed in the NO_x BACT analysis.

Combustion Controls

CO formation is minimized by designing the combustion system to allow complete mixing of the combustion air and fuel and maximize the oxidization of fuel carbon to CO₂. Higher combustion temperatures tend to reduce CO formation, but increase NO_x formation. Water/steam injection or DLN combustors tend to lower combustion temperatures in order to reduce NO_x formation, potentially increasing CO formation. However, using good combustor design and following best operating practices minimizes CO formation while reducing combustion temperatures and NO_x emissions.

Oxidation Catalysts

Oxidation catalysts typically use precious metal catalyst beds. Like SCR systems for combined-cycle combustion turbines, oxidation catalysts are typically located within the HRSG where the temperature is in the range of 700 °F to 1,100 °F. The catalyst enhances oxidation of CO to CO₂, without the addition of any chemical reagents, because there is sufficient O₂ in the exhaust gas stream for the oxidation reactions to proceed in the presence of the catalyst alone. Catalyst volume is dependent upon the exhaust flow, temperature, and the desired removal efficiency. The catalyst material is subject to loss of activity over time due to physical deterioration or chemical deactivation. Oxidation catalyst vendors typically guarantee catalyst life for three years.

Both efficient combustion and add-on controls, such as oxidation catalysts, can be used alone or in combination to achieve CO emission reductions. Oxidation catalysts have been successfully installed and used on numerous simple-cycle and combined-cycle combustion turbines.

Step 2 - Eliminate Technically Infeasible Options

As noted above in the NO_x BACT analysis, the EM_xTM technology was determined not to be feasible for the proposed combustion turbines, so the technology has not been considered further for CO emissions.

Using good combustor design, following best operating practices, and using oxidation catalyst are technically feasible options for controlling CO emissions from the proposed combustion turbines.

There are potential environmental and energy impacts associated with the use of oxidation catalysts. Oxidation catalysts require replacement of the catalyst beds after several years. The waste catalyst must be disposed of in accordance with state and federal regulations regarding normal waste disposal. Because of the precious metal content of the catalyst, they may also be recycled to recover the precious metals. Any SO₂ in the exhaust gas will oxidize to sulfur trioxide (SO₃). The higher the operating temperature, the higher the potential for oxidation of SO₂ to SO₃ oxidation. The SO₃ may react with moisture in the flue gas to form H₂SO₄. The increase in H₂SO₄ emission may increase PM10 and PM2.5 emissions.

Oxidation catalysts also have energy impacts. Due to their location downstream of the combustion turbine exhaust, oxidation catalysts increase the backpressure on the combustion turbines, which results in slightly decreased power output. This slightly decreased output leads to increased pollutant emissions on a mass per unit power output basis. Although there are potential environmental and energy impacts associated with the use of oxidation catalysts, these impacts are not considered significant enough to preclude their use for CO emission control.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Based on the preceding discussion, good combustion practices and oxidation catalysts are both available and technically feasible technologies to control CO emissions from combustion turbines. Together, DLN combustors oxidation catalyst and good combustion practices, although primarily used to minimize NO_x emissions, have been effective in minimizing CO emissions from combustion turbines, including those with duct firing. These are the only practical efficient combustion alternatives currently available and used on combined-cycle combustion turbines/ duct burners.

ASCENT proposes to control CO emissions these techniques and is proposing to meet a CO emission limit of 2.0 ppmvd @ 15% O₂ with and without duct firing on a rolling 365-day basis.

Step 4 - Evaluate Most-Effective Controls and Document Results

The proposed CO emission rate of 2.0 ppmvd @ 15% O₂ with and without duct firing is the lowest CO emission rate achieved or verified with long-term compliance records for other similar facilities. Since ASCENT is proposing to use combustion turbines with DLN combustors and oxidation catalysts to reduce CO emissions (i.e., the top control alternative), an assessment of the economic and environmental impacts is not necessary.

Step 5 - Select BACT

BACT for CO emissions from the proposed combustion turbines is good combustion design and the use of oxidation catalysts to control CO emissions to 2.0 ppmvd @ 15% O₂ with and without duct firing.

E.2.2.3 Emergency Generators and Fire Water Pump Engines

ASCENT proposes that BACT for the Emergency Generators and Fire Water Pumps is the CO emission rate of 2.6 g/hp-hr specified in 40 CFR 60, Subpart III. This emergency equipment will be operated on ULSD fuel.

Generally, for engines of the sizes proposed for the Project, good combustion practices are used to limit CO emissions. Review of recent permits and the RBLC for similar equipment indicates that good combustion practices are considered BACT.

Based on the limited hours of operation for the Fire Water Pump Engine (i.e., only for emergency purposes; < 100 hr/yr), the decrease in CO emissions should the Fire Water Pump Engines be required to comply with a limit as low as 0.25 g/hp-hr would be < 0.1 tons/yr. ASCENT believes that there is no appreciable environmental benefit from an emission rate below the NSPS Subpart III limits.

Based on these findings, CO BACT for the Emergency Generators and Fire Water Pump Engines is good combustion practices and the use of ULSD fuel, in combination with limited annual operating hours, and achieving a CO emission level of 2.6 g/hp-hr.

E.2.2.4 Catalyst Activator Heater

The Polyethylene Plant A process will require heat to support activation of the catalyst using a heater with a rating of up to 10 MMBtu/hr. This heater

will not be used continuously, but rather will only operate when needed for activation. ASCENT proposes an emission limit of 0.082 lb CO/MMBtu. ASCENT has not identified a lower emission rate for similar small, non-continuous use heaters.

The proposed CO BACT for all sources is summarized in Table E-1.

Table 3-3 Proposed CO BACT

Emission Source	Proposed CO BACT
Pyrolysis Furnaces	0.01 lb/MMBtu Use of good combustion practices.
Auxiliary Boilers	0.035 lb/MMBtu Use of good combustion practices.
Combustion Turbine/Duct Burner	2 ppmvd @ 15% O ₂ (with and without duct firing) Use of CO catalyst and efficient combustion (i.e., good combustion practices).
Thermal Oxidizer / RTO	0.04 lb/MMBtu Use of good combustion practices.
Flare Pilot Burners	0.4 lb/MMBtu Use of good combustion practices.
Emergency Generators	2.6 g/hp-hr (NSPS IIII) Use of ULSD fuel and good combustion practices; operation limited to emergency use and no more than 100 hr/yr for maintenance and readiness testing.
Fire Water Pump Engines	2.6 g/hp-hr (NSPS IIII) Use of ULSD fuel and good combustion practices; operation limited to emergency use and no more than 100 hr/yr for maintenance and readiness testing.
Catalyst Activator Heater	0.082 lb/MMBtu Use of good combustion practices.

E.2.3 Particulate Matter (PM, PM10, and PM2.5) BACT Analysis

Particulate matter emissions result from each combustion source associated with the Project, as well as decoking operations from the pyrolysis furnaces, the mechanical draft Cooling Tower, and material handling operations.

The following summarizes the BACT evaluation conducted for each significant piece of equipment with respect to PM, PM10, and PM2.5 emissions.

E.2.3.1 Combustion Turbine/Duct Burner

Particulate matter emissions from gaseous fuel combustion has been estimated to be less than 1 micron in equivalent aerodynamic diameter, has filterable and condensable fractions, and usually consists of hydrocarbons of larger molecular weight that are not fully combusted². Because the particulate matter typically is less than 2.5 microns in diameter, this BACT discussion assumes the control technologies for PM, PM10, and PM2.5 are the same.

Step 1 – Identify Potential Control Technologies

Pre-Combustion Control Technologies

The major sources of PM, PM10, and PM2.5 emissions from gaseous fuel-fired combustion turbines equipped with SCR for post-combustion control of NO_x emissions are:

- The conversion of fuel sulfur to sulfates and ammonium sulfates;
- Unburned hydrocarbons that can lead to the formation of PM in the exhaust stack; and
- PM in the ambient air entering the combustion turbines through their inlet air filtration systems, and the aqueous ammonia dilution air.

The use of clean-burning, low-sulfur gaseous fuels will result in minimal formation of PM, PM10, and PM2.5 during combustion. Best combustion practices will ensure proper air/fuel mixing ratios to achieve complete combustion, minimizing emissions of unburned hydrocarbons that can lead to the formation of PM emissions. In addition to good combustion practices, the use of high-efficiency filtration on the inlet air and SCR dilution air systems will minimize the entrainment of PM into the combustion turbine exhaust streams.

Post-Combustion Control Technologies

There are several post-combustion PM control systems potentially feasible to reduce PM, PM10, and PM2.5 emissions from the combustion turbine/duct burner, including:

² USEPA, 2006 http://www.epa.gov/ttnchie1/conference/ei15/training/pm_training.pdf

- Cyclones/centrifugal collectors;
- Fabric filters/baghouses;
- Electrostatic precipitators (ESPs); and
- Scrubbers.

Cyclones/centrifugal collectors are generally used in industrial applications to control large diameter particles (>10 microns). Cyclones impart a centrifugal force on the gas stream, which directs entrained particles outward. Upon contact with an outer wall, the particles slide down the cyclone wall, and are collected at the bottom of the unit. The design of a centrifugal collector provides for a means of allowing the clean gas to exit through the top of the device. Cyclones are inefficient at removing small particles.

Fabric filters/baghouses use a filter material to remove particles from a gas stream. The exhaust gas stream flows through filters/bags onto which particles are collected. Baghouses are typically employed for industrial applications to provide particulate emission control at relatively high efficiencies.

ESPs are used on a wide variety of industrial sources, including certain boilers. ESPs use electrical forces to move particles out of a flowing gas stream onto collector plates. The particles are given an electric charge by forcing them to pass through a region of gaseous ion flow called a “corona.” An electrical field generated by electrodes at the center of the gas stream forces the charged particles to ESP’s collecting plates.

Removal of the particles from the collecting plates is required to maintain sufficient surface area to clean the flowing gas stream. Removal must be performed in a manner to minimize re-entrainment of the collected particles. The particles are typically removed from the plates by “rapping” or knocking them loose, and collecting the fallen particles in a hopper below the plates.

Scrubber technology may also be employed to control PM in certain industrial applications. With wet scrubbers, flue gas passes through a water (or other solvent) stream, whereby particles in the gas stream are removed through inertial impaction and/or condensation of liquid droplets on the particles in the gas stream.

Step 2 - Eliminate Technically Infeasible Options

Pre-Combustion Control Technologies

The pre-combustion control technologies identified above (i.e., clean-burning, low-sulfur fuels, good combustion practices, high-efficiency filtration of the combustion turbine inlet and SCR dilution air systems) are available and technically feasible for reducing PM emissions from the combustion turbine exhaust streams.

Post-Combustion Control Technologies

Each of the post-combustion control technologies described above (i.e., cyclones, baghouses, ESPs, scrubbers) are generally available. However, none of these technologies is considered practical or technically feasible for installation on gaseous fuel-fired combustion turbines.

The particles emitted from gaseous fuel-fired are typically less than 1 micron in diameter. Cyclones are not effective on particles with diameters of 10 microns or less. Therefore, a cyclone/centrifugal collection device is not a technically feasible alternative.

Baghouses, ESPs, and scrubbers have never been applied to commercial combustion turbines burning gaseous fuels. Baghouses, ESPs, and scrubbers are typically used on solid or liquid-fuel fired sources with high PM emission concentrations, and are not used in gaseous fuel-fired applications, which have inherently low PM emission concentrations. None of these control technologies is appropriate for use on gaseous fuel-fired combustion turbines because of their very low PM emissions levels, and the small aerodynamic diameter of PM from gaseous fuel combustion. Review of the RBLC, as well as USEPA and State permit databases, indicates that post-combustion controls have not been required as BACT for gaseous fuel-fired fired combined-cycle combustion turbines. Therefore, the use of baghouses, ESPs, and scrubbers is not considered technically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The use of clean-burning fuels, good combustion practices, and inlet air filtration are the technically feasible technologies to control PM, PM₁₀, and PM_{2.5} emissions to no more than 7.6 lb/hr (equivalent to 0.005 lb/MMBtu) with or without duct firing.

Step 4 - Evaluate Most Effective Controls and Document Results

Based on the information presented in this BACT analysis, using the proposed good combustion practices and inlet air filtration to control PM, PM10, and PM2.5 emissions to no more than 7.6 lb/hr with or without duct firing. This is consistent with BACT at other similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

Step 5 - Select BACT

ASCENT proposes BACT for PM, PM10, and PM2.5 emissions from the combustion turbines is the use of clean-burning fuels, good combustion practices, and inlet air filtration to control PM, PM10, and PM2.5. Emissions will be limited to 0.005 lb/MMBtu.

E.2.3.2 Combustion Sources - Pyrolysis Furnaces, Auxiliary Boilers, Thermal Oxidizer, Flare Pilot Burners

The technologies potentially available to control PM, PM10, and PM2.5 emissions from the pyrolysis furnaces, auxiliary boilers, and thermal oxidizers are the same as those described above for combustion turbines/duct burners, namely:

- Cyclones/centrifugal collectors;
- Fabric filters/baghouses;
- ESPs; and
- Scrubbers.

The use of cyclones is technically infeasible due to their inability to control particles smaller than 10 microns in diameter. In addition, the other add-on particulate control techniques have not been employed to remove PM from similar combustion sources operated at petrochemical facilities.

A review of the RBLC, as well as USEPA and state permit databases indicates that there are no furnaces, boilers, or similar oxidizers employing post-combustion control equipment to reduce PM, PM10, and PM2.5 to achieve BACT. The determinations identify the selection of clean fuels (i.e., low-sulfur, low-ash content) and good combustion practices as BACT for PM, PM10, and PM2.5 emissions.

The proposed Auxiliary Boilers are capable of firing pipeline quality natural gas and will employ good combustion practices to minimize PM, PM10, and PM2.5 to achieve proposed BACT emission levels of 0.002 lb/MMBtu, which matches the lowest emission rates identified in a RBLC and literature search.

Similarly, the pyrolysis furnaces are capable of firing gaseous fuels with very low sulfur levels (e.g. pipeline quality natural gas as well as a blend of natural gas and process tail gas). The furnaces will employ good combustion practices to minimize PM, PM10, and PM2.5 to achieve proposed BACT emission levels of 0.009 lb/MMBtu. ASCENT evaluated the consistency of other relevant permits to identify the level of emissions determined as BACT. The proposed PM emission rates are comparable to similar units noted in the RBLC and in recently issued permits. The RBLC and other permits reviewed for equipment that is installed and operating identify the use of natural gas and good combustion practices as BACT for PM, PM10, and PM2.5.

Finally, the thermal oxidizer and flare pilots will only be firing low sulfur streams and will employ good combustion practices to minimize PM, PM10, and PM2.5 to achieve BACT emission levels.

E.2.3.4 Pyrolysis Furnaces Decoking Operations

Step 1 - Identification of PM, PM10, and PM2.5 Control Options

Process Emissions

Over time, the radiant tubes within the Pyrolysis Furnaces gradually become coated with a layer of coke reducing the efficiency of the units. Periodically (an average of every 60 to 70 days), the Pyrolysis Furnaces will need to undergo a process known as decoking in order to remove this fouling layer. This process results in additional PM emissions from the coke build-up. A review of the RBLC database and available permits identified no specific controls for PM emissions from decoking operations. ASCENT has identified the following potential strategies to reduce PM emissions from Decoking of the Pyrolysis Furnaces.

Good Combustion Practices

Pyrolysis furnaces are operated at approximately 30% load during decoking operations to minimize combustion emissions during Decoking events.

Proper Design and Operation

Proper design and operation of the Pyrolysis Furnaces according to the manufacturer's recommendations will minimize the amount of coke generated.

Step 2 - Eliminate Technically Infeasible Options

Both technologies discussed above, good combustion practices and proper design and operations of the furnaces are technically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Both good combustion practices and minimizing the formation of coke through proper furnace design and operation were identified as technically feasible. Proper furnace design and operation is considered more effective as a PM reduction strategy as this strategy actually limits the amount of coke material generated.

Step 4 - Evaluate Most Effective Controls and Document Results

Reduced combustion load will help minimize PM emissions during decoking events but is not a control that reduces the amount of coke build-up. Proper furnace design and operation minimizing coke formation in the Pyrolysis Furnaces is the fundamental factor for controlling the PM emissions from decoking operations and potentially reducing the number of required Decoking events per year.

Step 5 - Select BACT

ASCENT proposes that BACT for Decoking operations is minimization of coke formation through proper design and operation of the furnaces and adoption of the manufacturer's recommended best practices for the units. Decoking events shall be limited to no greater than 12 events per calendar year per pyrolysis furnace, a rate matching other recently permitted ethane cracker units in the US.

E.2.3.4 Emergency Generators and Fire Water Pump Engines

ASCENT proposes that BACT for PM for Emergency Generators and the Fire Water Pump Engines is a PM emission limit of 0.15 g/hp-hr. This emissions standard is specified in 40 CFR Part 60, Subpart IIII. The emission limits in 40 CFR Part 60, Subpart IIII only reflect filterable PM emissions. Therefore, for BACT for PM10 and PM2.5 for Emergency Generators and the Fire Water Pump Engines, ASCENT proposes an emission limit of 0.17 g/hp-hr based on 40 CFR Part 60, Subpart IIII for the filterable portion and EPA's AP-42 Chapter 3.4 for the 0.02 g/hp-hr condensable portion.

A literature review to establish a list of potential control technologies available for emergency engines concludes that there are currently no facilities employing post-combustion controls on RICE engines of these sizes to achieve BACT for PM, PM10, and PM2.5. The use of good combustion

practices and clean fuels, such as ULSD, are relied upon to achieve BACT for PM, PM10, and PM2.5.

As evidenced by the wide variety of emission levels listed in the RBLC, different engine vendors and models specify a wide range of PM, PM10, and PM2.5 emissions. Given the expected limited hours of operation for the Emergency Generator (<100 hr/yr), the decrease in PM emissions if the engine were required to achieve an emission level of 0.03 g/hp-hr for PM, PM10, and PM2.5 would be < 0.1 tons/yr.

For the Fire Water Pump Engines, a review of recent permits and the RBLC for similar equipment indicates values in line with a 0.15-0.17 g/hp-hr limit or higher.

However, there are instances of permit limits below the NSPS Subpart III standard of 0.15 g/hp-hr. For example, Cricket Valley lists a PM limit of 0.0875 g/hp-hr, and the RBLC lists a limit as low as 0.07 g/hp-hr (i.e., Mankato Energy Center) for a similar sized RICE. However, based on the expected limited hours of operation for the Fire Water Pump (< 100 hr/yr), the net potential decrease in PM emissions if the engine were required to comply with a limit as low as 0.07 g/hp-hr would be < 0.1 tons/yr.

Given the limited operating role of the equipment to support the facility during emergency periods and for periodic maintenance and readiness testing, and the small emission reductions associated with achieving the lower PM, PM10, and PM2.5 emission rates listed in the RBLC; there is no appreciable environmental benefit associated with achieving PM, PM10, and PM2.5 emission levels below the proposed values.

Therefore, BACT for PM, PM10, and PM2.5 for the Emergency Generators and Fire Water Pump Engines is the exclusive use of ULSD and good combustion practices to the proposed emission rates. ASCENT proposes that BACT for PM, PM10, and PM2.5 for the Emergency Generators and the Fire Water Pump Engines is to fire ULSD. ASCENT proposes to demonstrate compliance with the PM emissions limit of 0.15 g/hp-hr and the PM10/PM2.5 emissions limit of 0.17 g/hp-hr.

E.2.3.5 Cooling Tower

Step 1 - Identify Potential Control Technologies

Actual drift loss rates from wet cooling systems, including those proposed for this Project, are affected by a variety of factors, including the type and design of the cooling system, capacity, velocity of air flow, density of the air in the Cooling Tower, and the TDS concentration in the circulating water. Commercially available techniques used to limit PM, PM10, and PM2.5 drift

from wet Cooling Towers, with the most efficient options presented first, are the following:

- Drift eliminators;
- Limiting TDS concentrations in the circulating water; and
- Maintaining low air velocities.

Drift eliminators are incorporated into Cooling Tower system design to remove as many water droplets from the air leaving the system as possible. Types of drift eliminators include herringbone (blade-type), wave form, and cellular (or honeycomb) designs; system materials of construction may include ceramics, fiber reinforced cement, fiberglass, metal, plastic, or wood. Designs may include other features, such as corrugations and water removal channels, to enhance the drift removal further. Drift eliminators are considered standard in the power sector. The drift rate as a percentage of circulating water flow rates varies with the specific project, and typically ranges from 0.01 to 0.0005% of circulating water flow rates. Higher efficiency drift eliminators can achieve drift loss rates of 0.0005% of the circulating water flow rates.

Limiting TDS Concentrations in the Circulating Water

In general, water droplets released as drift from wet Cooling Towers contain TDS concentrations equivalent to the solids concentrations in the circulating water. Reducing the TDS concentrations in the water, including by managing the cycles of concentrations, minimizes drift. In any particular project, TDS concentrations are defined primarily by the water source and the concentration cycles.

Maintaining Low Air Velocities

Particulate entrainment rates are influenced by air velocities in the system, so maintaining low (or optimum design) air velocities can reduce the drift.

Step 2 - Eliminate Technically Infeasible Options

All proposed methods are technically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The two available technologies for minimizing PM, PM10, and PM2.5 emissions, ranked in order most effective to least effective, are as follows:

- Drift eliminators;
- Limiting TDS concentrations in the circulating water; and

- Maintaining low air velocities.

Step 4 - Evaluate Most-Effective Controls and Document Results

A review of the RBLC data and several other recently permitted cooling towers throughout the U.S. indicated that the levels proposed for Project ASCENT were either equivalent to, or lower than, those for other permitted sources. Therefore, the proposed BACT for the Cooling Tower is the installation of the high efficiency mist eliminators with a drift loss of 0.0005%.

Step 5 - Select BACT

ASCENT proposes to install a Cooling Tower equipped with high-efficiency drift eliminators that will achieve a minimum of a 0.0005% drift, which is the most effective technique to reduce PM, PM10, and PM2.5 emissions based on a review of RBLC determinations, recent permits, and evaluation of available literature.

E.2.3.6 Polyethylene Plants Material Handling

Particulate emissions can occur from material handling operations at any of the three polyethylene plants including, but not limited to, the following: extrusion, silo storage, additive feed, additive tanks, blending, and loading. Control of these emissions will be obtained through the use of by cyclones and baghouses and is expected to be greater than 99.9 percent or have an exhaust particulate concentration of less than 0.01 grain/scf. Other particulate control devices may be used if equivalent control efficiency is shown. Loading will also be done so that all particulate emissions are directed to a control device.

The planned control of fugitive particulate emissions from the PE plants incorporate the best demonstrated controls in practice and is consistent with the latest BACT determinations and guidance from the State of Texas,³ where a large number of chemical plants are permitted, therefore, no further BACT analysis is required.

E.2.3.7 Catalyst Activator Heater

The Polyethylene Plant A process will require heat to support activation of the catalyst using a heater with a rating of up to 10 MMBtu/hr. This heater

³http://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/polys/nsr_fac_p_olys.html

will not be used continuously, but rather will only operate when needed for activation. ASCENT proposes natural gas firing and an emission limit of 0.0075 lb PM/MMBtu. ASCENT has not identified a lower emission rate for similar small, non-continuous use heaters.

The proposed PM, PM10, and PM2.5 BACT for all sources is summarized in Table E-4.

Table E-4 Proposed PM, PM10, and PM2.5 BACT

Emission Source	Proposed PM, PM10, and PM2.5 BACT
Combustion Turbine/Duct Burner	Use of pipeline-quality natural gas, good combustion practices, combustion turbine inlet air filtration, SCR dilution air filtration. 0.005 lb/MMBtu with or without duct firing
Pyrolysis Furnaces	Use of pipeline-quality natural gas or a blend of pipeline-quality natural gas and inherently low sulfur process gas and good combustion practices. 0.009 lb/MMBtu during normal operation Decoking events will be limited to 12 events per year per furnace.
Auxiliary Boilers	0.002 lb/MMBtu Use of pipeline-quality natural gas and good combustion practices
Thermal Oxidizer/RTO/Flare Pilot Burners	Only combustion of low sulfur fuel mixtures and good combustion practices. Natural gas to be used for pilots.
Emergency Generators	0.15 g/hp-hr for PM; 0.17 g/hp-hr for PM10/PM2.5 Use of ULSD and good combustion practices
Fire Water Pump Engines	0.15 g/hp-hr for PM; 0.17 g/hp-hr for PM10/PM2.5 Use of ULSD and good combustion practices
Cooling Tower	Use of high efficiency drift eliminators with a drift loss of < 0.0005%
Polyethylene Plants Material Handling	Baghouses, cyclones, or equivalent technology that ensures particulate matter grain loading shall not exceed 0.01 grains per dscf of air from any vent.
Catalyst Activator Heater	0.0075 lb/MMBtu Use of pipeline-quality natural gas and good combustion practices

E.2.4 VOC BACT Analysis

E.2.4.1 Ethane Cracker - Process Vent Streams

Project ASCENT is designed to minimize the generation of waste, thereby reducing the amount of waste streams generated, including streams contacting VOCs. However, as described in the main application text, there are certain process streams (from the quench tower and spent caustic system) that are not able to be return to the process due to their composition (e.g. high water content). Therefore, these streams are routed to a thermal oxidizer capable of achieving 99.9% destruction. A RBLC and literature query for thermal oxidizers did not identify destruction efficiency for ethane cracking unit thermal oxidizers more stringent than the proposed design; therefore, no further BACT analysis is required.

E.2.4.2 Polyethylene Plants - Process Vent Streams

Project ASCENT is designed to minimize the generation of waste, as any material wasted in the polyethylene units represents lost product. However, as described in the main application text, there are certain process streams that are not able to be return to the process due to their composition and the variable (infrequent) nature at which they are generated. These include all vent streams that are significant sources of VOC as well as some gas streams from polymer purging activities that occur prior to product finishing operations.

These VOC-containing streams will be routed to either a flare or RTO. The RTO is capable of achieving 99% destruction efficiency. The flare will meet 40 CFR 60.18 and various other NSPS rules besides 60.18 (e.g., 60.563, 60.564, and 60.565) with an assumed 98% destruction efficiency.

A RBLC and literature query did not identify controls for polyethylene units more stringent than those in the applicable rules and the 99% control proposed; therefore, no further BACT analysis is required.

E.2.4.3 Combustion Turbine/Duct Burners

Step 1 - Identify Potential Control Technologies

Like CO emissions, VOC emissions occur from incomplete combustion. Effective combustor design and post-combustion control using oxidation catalysts are the available technologies for controlling VOC emissions from combustion turbines. The GE Frame 7EA industrial combustion turbines proposed for Project ASCENT are able to achieve relatively low VOC emissions because their combustors have high firing temperatures with exhaust temperatures of approximately 1,000 °F. A DLN combustor-

equipped combustion turbine using an oxidation catalyst can achieve VOC emissions in the 1 to 2 ppmvd @ 15% O₂ range. As noted above in the NO_x BACT analysis, the EM_xTM technology was determined not to be feasible for the proposed combustion turbines, so they have not been considered further here.

Good Combustion Controls

VOC formation is minimized by designing the combustors to completely oxidize the fuel carbon to CO₂. This is achieved by ensuring that the combustors are designed to allow complete mixing of the combustion air and fuel at combustion temperatures with an excess of combustion air. Higher combustion temperatures tend to reduce VOC formation, but at the expense of increased NO_x formation. The use of water/steam injection or DLN combustors tends to lower combustion temperatures to reduce NO_x formation, but potentially increases VOC formation. However, good combustor design and best operating practices will minimize VOC formation while reducing the combustion temperatures and NO_x emissions.

Oxidation Catalysts

Oxidation catalysts typically use precious metal catalyst beds. Like SCR systems for combined-cycle combustion turbines, oxidation catalysts are typically placed inside the HRSGs. The catalyst enhances oxidation of VOC to CO₂, without the addition of any chemical reagents. Oxidation catalysts have been successfully installed on numerous simple- and combined-cycle combustion turbines.

Step 2 - Eliminate Technically Infeasible Options

Good combustor design and the use of oxidation catalysts are both technically feasible options for controlling VOC emissions from the proposed combustion turbines.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Based on the preceding discussions, using good combustor controls and oxidation catalysts are technically feasible combustion turbine VOC emission control technologies. ASCENT proposes to control VOC emissions using these techniques to meet VOC emission limits of 2.0 and 1.0 ppmvd @ 15% O₂ with and without duct firing, respectively..

Step 4 - Evaluate Most Effective Controls and Document Results

The proposed control technologies and VOC emission rates of 2.0 and 1.0 ppmvd @ 15% O₂ with and without duct firing, respectively, are consistent with the lowest VOC emission rates achieved or permitted for other similar facilities. Therefore, an assessment of the economic and environmental impacts is not necessary.

Step 5 - Select BACT

ASCENT proposes that BACT for VOC emissions from the combustion turbines is good combustion design and the use of oxidation catalysts. ASCENT proposes VOC emissions rates of 2.0 and 1.0 ppmvd @ 15% O₂ with and without duct firing, respectively.

E.2.4.4 Pyrolysis Furnaces and Auxiliary Boilers

VOCs will be emitted from the pyrolysis furnaces and auxiliary boilers. Minimization of VOC emissions is analogous to minimization of CO emissions and occurs by ensuring complete combustion is occurring. The CO BACT (Section E.2.2) describes the available control options, which are the same for VOCs.

ASCENT believes that the proposed CO emission limits serve as a surrogate for VOC emissions for the following reasons:

- The control technologies for both pollutants are the same. Effective control of CO emissions through adherence to good combustion practices will ensure effective control of VOC emissions; and
- Compliance with the CO emission limits for the pyrolysis furnaces and auxiliary boilers will be achieved through continuous emission monitoring. Compliance with separate VOC emissions would be demonstrated through infrequent performance testing (stack testing) that would yield no environmental benefit and would provide limited benefit in terms of compliance assurance.

For design purposes, ASCENT is prescribing VOC emission levels of 0.0013 lb/MMBtu for the Auxiliary Boiler and 0.003 lb/MMBtu for the pyrolysis furnaces. Several RBLC determinations have VOC emission levels in the 0.002 to 0.006 lb/MMBtu range, but the lowest emitting of these sources only fire natural gas and not a mixture of natural gas and process tail gas as is the case for the pyrolysis furnaces. ASCENT did not identify any pyrolysis furnaces meeting a lower VOC emission rate than the 0.003 lb/MMBtu value proposed. Further, a decrease in VOC emissions if the pyrolysis furnaces were required to achieve a VOC emission level of 0.002 lb/MMBtu would be no more than 0.4 tons/yr.

E.2.4.5 Emergency Generators and Fire Water Pump Engines

The VOC BACT analysis for emergency generators is discussed in the NO_x BACT analysis (Section E.2.1).

The proposed VOC BACT for all sources is summarized in Table E-5.

E.2.4.6 Cooling Tower

Step 1 - Identify Potential Control Technologies

VOC control options for the proposed cooling tower are:

- Replacement of the wet cooling tower with a dry cooling tower; and
- Heat exchanger leak detection and repair.

Although air cooling and dry cooling towers are an inherently less-polluting alternative to a wet cooling tower, air coolers and dry cooling towers are not technically feasible cooling options for process streams that must be cooled to 130 °F or less. As such, a wet cooling tower is required. VOC emissions from wet cooling towers occur when process fluids under higher pressure than the cooling water results in a leaking of the process fluid into the cooling water.

To minimize the leaking of VOC containing process fluids into cooling water, a heat exchanger leak detection and repair program for water-cooled heat exchangers is technically feasible and effective. This program involves monitoring cooling water for the presence of hydrocarbon, and finding and repairing leaks when hydrocarbons are found.

Step 2 - Eliminate Technically Infeasible Options

A dry cooling tower is a technically infeasible control option for the reasons described above.

Steps 3 - 4 - Rank and Evaluate Control Technologies

The only technically feasible control option is the implementation of a heat exchange leak detection and repair program. No adverse energy or environmental impacts are associated with this control option.

Step 5 - Select BACT

It should be noted that emission testing is not feasible for wet cooling towers due to exhaust characteristics, so the BACT determination is expressed as a work practice requirement rather than an emission limit.

E.2.4.7 Storage Tanks

As described in this application, Project ASCENT will include the installation of numerous storage vessels for volatile organic liquids, water, or inorganic liquids, as well as pressurized storage vessels.

The pressurized vessels are not sources of emissions and do not require a BACT analysis. Similarly, storage vessels containing water and inorganic materials are not sources of VOCs and do not require a BACT analysis. Large VOC storage tanks will be controlled by one of two flares; one for ambient liquid storage (e.g., “warm flare”) and one for cold VOL storage tanks (e.g., “cold flare”). A detailed listing of the proposed VOC emitting tanks and the associated control device is provided in Appendix D.

Step 1 - Identify Potential Control Technologies

Emissions of VOCs from storage tanks will be minimized through compliance with the applicable standards under 40 CFR Part 60 Subpart Kb and Ethylene Manufacturing MACT (40 CFR Part 63 Subpart XX).

VOC control options for storage tanks include:

- Routing vapors to a process via hard piping, such that the vessel operates with no emissions;
- Fixed roof in combination with an internal floating roof and with vapor collection in a closed vent system routed to a control device (e.g., thermal oxidizer or flare);
- Fixed roof with vapor collection by closed vent system to a control device (e.g., thermal oxidizer or flare)
- Fixed roof in combination with an internal floating roof; and
- External floating roof.

Step 2 - Eliminate Technically Infeasible Options

All of the proposed potential control technologies are technically feasible.

Steps 3 - 4 - Rank and Evaluate Control Technologies

The listing of control options is provided in general order of most effective least effective control.

Step 5 - Select BACT

ASCENT proposes that BACT for emissions from the atmospheric storage tanks containing volatile liquids is use of a fixed roof and routing vapors to a control device or to a process/fuel gas system via hard piping to achieve at least 98% destruction.

E.2.4.8 Wastewater Treatment Plant

As described in this application, the overall wastewater treatment plant (WWTP) can be divided into three blocks: wastewater collection, effluent treatment plant (ETP), and waste reused system and final discharge. All wastewater streams will be transferred by means of collection and lifting systems (effluent basins and pumping stations). The ETP will consist of the following main sections:

- Primary Treatment (De-Oiling and Chemical-Physical Treatment (CPI));
- Secondary Treatment (Biological Treatment);
- Sludge Dewatering;
- Treated Water Reuse;
- Salt Concentration (Optional); and
- Sludge Drying.

Emissions are primarily generated from the CPI and biological treatment units. These units use aeration to aid in water treatment which increases the amount of volatile compounds potentially emitted to the atmosphere.

The minimum emission standard that would meet BACT requirements for VOC emissions from the wastewater treatment plant are the equipment design and work practice standards set forth in Subpart FF of 40 CFR Part 61 for benzene waste operations. This rule generally requires water seal controls or more effective controls for the wastewater collection system drains and sumps. For the separators, primary Dissolved Air Floatation (DAF) unit, and equalization tanks, this rule requires either a floating roof or a closed vent system and control device.

Step 1 - Identify Potential Control Technologies

Identified control options for minimizing VOC emissions from wastewater collection and treatment include:

- Water seal controls on drains;
- Wastewater stripping;

- Floating roofs for treatment vessels; and
- Carbon adsorption or oxidation (incineration) of VOCs from the vent streams.

Step 2 - Eliminate Technically Infeasible Options

Wastewater stripping, floating roofs, and oxidation are technically infeasible for application to wastewater drains. All identified controls are technically feasible to the wastewater treatment operations.

Steps 3 - 4 - Rank and Evaluate Remaining Control Technologies

The most effective strategy for the wastewater collection system involves the use of closed vent systems and carbon canisters for drains. Water seal controls are a less effective control option.

The most effective control strategy for the wastewater treatment plant vessels consists of minimizing VOC content of streams through stripping where possible, and then routing VOCs recovered from vessels and the process to a control device capable of achieving at least 98% destruction.

Step 5 - Select BACT

ASCENT proposes to minimize VOC emissions from the wastewater treatment plant through equipment design and work practice standards set forth in Subpart FF of 40 CFR Part 61 for benzene waste operations.

A RBLC and literature query did not identify controls for ethane cracking and polyethylene unit waste water collection and treatment systems more stringent than the proposed design; therefore, no further BACT analysis is required.

E.2.4.9 Fugitive Emission - Piping and Equipment Components

Step 1 - Identify Potential Control Technologies

The fugitive VOC emission components associated with Project ASCENT include components associated largely associated with the ethylene plant. Fugitive VOC emissions will not vary during normal operation and startup/shutdown scenarios since fugitive VOC emission rates are not a function of material throughput of the unit.

Installation of Leak-less Technology Components

Leak-less technology includes leak-less valves and seal-less pumps and compressors. Common leak-less valves include bellows valves and diaphragm valves; and common seal-less pumps are diaphragm pumps, canned motor pumps, and magnetic drive pumps. Leaks from pumps can also be reduced by using dual seals with or without barrier fluid. In addition, welded connections in lieu of flanged or screwed connections may provide for leak-less operation. Leak-less technologies should be nearly 100% effective in eliminating leaks.

Implementation of Leak Detection and Repair

Leak Detection and Repair (LDAR) programs based on Audio/Visual/Olfactory (AVO) Leak Detection methods or USEPA Method 21 instrument monitoring are viable for streams containing combustible gases, including methane.

Implementation of Audio/Visual/Olfactory Leak Detection Methods

The effectiveness of Audio/Visual/Olfactory (AVO) Leak Detection methods, which are generally employed for natural gas or inorganic odorous compounds, are dependent on the system pressure, the odor of the process materials, and the frequency of the AVO inspections.

Use of Remote Sensing

Remote sensing of leaks has been proven as a technology using infrared camera, which has been approved by the USEPA as an alternative to the typical LDAR USEPA Method 21 monitoring under certain instances.

Step 2 - Eliminate Technically Infeasible Options

While welded connections will be utilized wherever possible, for safety reasons, the installation of all leak-less technology components for components associated with the project is not technically feasible. There are a number of flanges or connections that cannot be welded to be able to isolate process equipment including pumps and vessels.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Technologies for minimizing fugitive VOC emissions from the facility in order of effectiveness include:

- Implementation of LDAR;

- Remote Sensing; and
- Implementation of AVO Leak Detection Methods.

Step 4 - Evaluate Most Effective Controls and Document Results

Fugitive VOC components at the facility will be limited through the application of an LDAR program consistent with 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” (NSPS VVa). Implementation of LDAR is the most effective strategy for control of fugitive VOC emissions.

Step 5 - Select BACT

ASCENT proposes that implementation of a NSPS VVa compliant LDAR program is BACT for fugitive emission components. A RBLC and literature query did not identify a control approach for ethane cracking and polyethylene units that is more stringent than the proposed design; therefore, no further BACT analysis is required.

E.2.4.10 Fugitive Emissions - Materials Loading and Unloading

Emissions from any loading racks handling compounds with a true vapor pressure of 0.5 psig or greater will be routed to a control device (e.g., flare) with a control efficiency of 98% or greater. This may be achieved in some cases through vapor balancing with a storage vessel equipped with a VOC control device. The RBLC and literature query did not identify destruction efficiency for polyethylene plants more stringent than the proposed design; therefore, no further BACT analysis is required.

E.2.4.11 Catalyst Activator Heater

The Polyethylene Plant A process will require heat to support activation of the catalyst using a heater with a rating of up to 10 MMBtu/hr. This heater will not be used continuously, but rather will only operate when needed for activation. ASCENT proposes natural gas firing and an emission limit of 0.0054 lb VOC/MMBtu. ASCENT has not identified a lower emission rate for similar small, non-continuous use heaters.

Table E-5 Proposed VOC BACT

Emission Source	Proposed VOC BACT
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Ethane Cracker - Process Vent Streams	99.9% destruction via thermal oxidizer
Polyethylene Plants - Process Vent Streams	99% destruction via RTO; 98% destruction via flares
Combustion Turbine/Duct Burner	1 ppmvd @ 15% O ₂ without duct firing 2 ppmvd @ 15% O ₂ with duct firing oxidation catalysts and good combustion practices
Pyrolysis Furnaces	0.003 lb/MMBtu Use of pipeline-quality natural gas or a blend of pipeline-quality natural gas and process gas and good combustion practices
Auxiliary Boilers	0.0013 lb/MMBtu Use of gaseous fuel (e.g. pipeline-quality natural gas)
Thermal Oxidizer / RTO Burners	Firing of gaseous fuels and good combustion practices.
Emergency Generators	3.0 g/hp-hr (NMHC+NO _x) for 350 kW units; and 4.8 g/hp-hr (NMHC+NO _x) for 2800 kW units. Use of ULSD and good combustion practices
Fire Water Pump Engines	3.0 g/hp-hr NMHC+NO _x Use of ULSD and good combustion practices
Cooling Tower	Use of Leak Detection and Repair Program
Storage Tanks	Compliance with New Source Performance Standards (40 CFR 60 Subpart Kb) and Ethylene MACT
Wastewater Treatment System	Equipment design and work practice standards set forth in Subpart FF of 40 CFR Part 61 for benzene waste operations
Fugitive VOC equipment and piping emissions	Use of a Leak Detection and Repair Program (Compliance with Ethylene MACT / NSPS VVa)
Fugitive VOC loading / unloading operations	Collection System and 98% destruction treatment for handling of streams with vapor pressure > 0.5 psig
Catalyst Activator Heater	0.0054 lb/MMBtu Use of gaseous fuel (e.g. pipeline-quality natural gas)

E.2.5

BACT ANALYSIS FOR GREENHOUSE GAS

As described in Section 5.3, Project ASCENT is subject to PSD for greenhouse gases (GHGs as CO₂e) and is therefore required to demonstrate BACT under the requirements set-forth in section 165 (a)(4) of the Clean Air Act, 40 CFR 52.21 (j).

Once a project triggers PSD for GHGs, BACT (established on a CO₂e basis) must be demonstrated for all project associated emission sources. This section summarizes a top-down approach for determining GHG BACT.

In March 2011, USEPA published a GHG BACT guidance document⁴ for use by the states in performing review of applications triggering PSD for GHGs. The guidance is not a binding document, yet it provides USEPA's concepts and positions in how a BACT analysis should be performed. In this guidance, the USEPA reinforces the use of the "top-down" method for determining BACT for GHGs.

Since permitting for GHGs has only been occurring since 2011, limited data is available on control technology specific to GHGs, particularly in the RACT/BACT/LAER Clearinghouse (RBLC). Therefore, in the near-term, permit applicants and regulatory authorities will rely primarily on related guidance and sector-specific "White Papers" released by USEPA to aid in the process of determining GHG BACT. For the purposes of this application, control technologies were identified based primarily on recent USEPA guidance and supporting documents, USEPA comments on recent BACT analyses, as well as engineering analysis. A summary of recent GHG BACT determinations for similar facilities has been included as **Attachment E-4**.

For GHG emissions, USEPA recommends that carbon capture and sequestration (CCS) be considered for all BACT analyses. The following sections of this analysis describe each step of the top-down method for the selection of GHG BACT.

As discussed in Section 3 of this application, the sources of GHG emissions from Project ASCENT are combustion emissions from the Pyrolysis Furnaces, Auxiliary Boilers, Decoking of the Furnaces, Flares and Thermal Oxidizers, Combustion Turbine and Duct Burners, and Reciprocating Internal Combustion Engines and Fugitive GHG emissions. Each of these sources of GHG emissions is addressed below along with alternative "add-on" controls for the project, including carbon capture with dedicated sequestration or transport and sequestration (See Section G.26).

⁴ *PSD and Title V Permitting Guidance For Greenhouse Gases*, USEPA, OAQPS, Nov. 2010.

E.2.5.1 Pyrolysis Furnaces and Auxiliary Boilers

Step 1 - Identification of GHG Control Options

Pyrolysis Furnaces GHG Emissions

The six Pyrolysis Furnaces will be process gas-fired furnaces with a nominal firing duty of 396.8 MMBtu/hr each. ASCENT will also utilize purchased natural gas to supplement the process gases generated by processes to meet fuel demand and maintain a desired heating value of the fuel for proper combustion unit operation. The sections below discuss the expected GHG emissions from the Pyrolysis Furnaces during normal operation, startup and shutdown, and decoking scenarios.

Normal Operation

Based on projected process gas makeup and past operational knowledge from similar ASCENT sites, the process gas mixture used by the furnaces will have significantly different combustion characteristics (lower heating value and carbon content) as compared to purchased natural gas.

Startup/Shutdown

ASCENT anticipates that the Furnaces will be run continuously. The Furnaces will be decoked a maximum of 12 times per year, as presented in Section E.2.5.2 below. Furthermore, ASCENT does not anticipate emissions during startup and shutdown to exceed normal operation emissions profiles.

It is expected that natural gas will be the primary fuel used during initial unit startup and during any restarts following a complete plant shut down. For scenarios involving the startup or shutdown of an individual furnace, the composition of the process fuel gas being used as fuel during startup/shutdown scenarios is not expected to vary from the process fuel gas used as fuel during normal operation.

Decoking

A complete GHG BACT analysis for decoking is presented in Section E.2.5.2 below.

Inherently Lower-Emitting Processes/Practices/Designs

Technology that would fall under the first broad strategy for minimizing GHGs from combustion units like furnaces and boilers would be the use of low-carbon fuels and utilizing energy-efficient designs. The use of low-

carbon gaseous fuels such as natural gas and fuel gas reduce the production of CO₂ during the combustion process relative to burning solid fuels (e.g., petroleum coke) or liquid fuels (e.g., distillate or residual oils) directly. Likewise, a highly efficient operation requires less fuel for process heat, saving the facility money and decreasing the amount of CO₂ produced.

Combustion Efficiency

Several strategies are available to achieve higher energy efficiency for combustion systems. These technologies include efficient designs, use of low carbon fuels, use of combustion controls, good combustion practices, and combustion air preheating.

Efficient Designs

There are three key aspects in combustion unit design that affect its thermal efficiency: the maximum heat load, the amount of excess air, and fouling of the heat exchange systems. The proper design of a unit's maximum heat load and excess air ensures that the unit is operating at a maximum thermal efficiency. Simply increasing the heat load or excess air of the unit beyond its design capacity, which may occur with changes in process operations, will reduce the overall efficiency. Efficient designs balance these aspects and ensure that units are always operating at its peak efficiency without sacrificing operational flexibility. Other key features to efficient designs are increases in radiant surfaces and adding finned tubes in the convection sections of the unit. Current designs increase the amount of heat transfer surface area relative to older designs thus boosting thermal efficiency. Furthermore, advanced metallurgy and proper maintenance techniques have significantly reduced downtime caused by fouling heat exchanger components. USEPA estimates that focus on the use of efficient furnace designs can reduce GHG emissions up to approximately 20%.

Low Carbon Fuels

ASCENT has limited the discussion of low carbon fuels to fossil fuels as other low carbon fuel technologies have not been demonstrated in practice for industrial applications.

The use of low-carbon fossil fuels in combustion systems could be an effective CO₂ control technique. This control technique is a technically feasible option for most combustion systems. Carbon dioxide is produced as

a combustion product of any carbon-containing fuel⁵. All fossil fuels contain fuel bound carbon that is oxidized into CO and CO₂ during combustion. Table E-6 shows the approximate level of CO₂ formed when combusting various fossil fuels.

Table E-6 *CO₂ Emissions from Combustion of Fossil Fuels*

Fuel	CO ₂ (kg/MMBtu) ¹
Natural Gas	53.06
Refinery Fuel Gas ²	53.06
Distillate Fuel Oil	73.96
Residual Oil	75.10
Municipal Solid Waste	90.7
Coal	103.69
Petroleum Coke	113.67

¹ Table C-1 of 40 CFR 98.

² Assumed to be similar to natural gas based on actual refinery fuel gas analysis.

Table E-6 shows, through comparison of emission factors published in USEPA’s Greenhouse Gas Mandatory Reporting Rule, that the combustion of refinery gas and natural gas yields between 40 – 50% less CO₂ than the combustion of coal and petroleum coke, and approximately 25 – 30% less CO₂ than the combustion of distillate and residual oil.

Combustion Controls for Optimization

The use of combustion controls for optimization reduces the consumption of fuel by optimizing the quantity of usable energy transferred from the fuel to the process. Combustion efficiency is maximized when the combustion zone is provided the best possible mix of fuel and air conditions, influenced by factors such as fuel/air ratio, fuel temperature, combustion air temperature, combustion zone pressure, heat transfer area, etc.

However, competing environmental interests may arise when simply maximizing combustion efficiency. For example, increasing combustion efficiency may marginally improve GHG emissions, yet disproportionately increase emissions of NO_x due to higher flame temperatures. The use of

⁵ Note that hydrogen is not considered as a viable fuel for the pyrolysis furnaces as the full scale manufacturing of high-purity hydrogen fuel requires significant combustion of carbon-containing which more than offsets the benefits of using the hydrogen fuel.

combustion controls has been estimated by USEPA to reduce GHG emissions one to three percent.

Combustion Air Preheating

Combustion air preheating is a method of recovering heat from the hot exhaust gas of a combustion system through heat exchange with combustion air before it enters the combustion chamber. Preheating the combustion air reduces the amount of fuel required in the furnace because the combustion air does not have to be heated from ambient temperature to the fuel combustion temperature by combusting fuel. Typically, combustion air preheating is only cost-effective on combustion systems greater than 100 MMBtu/hr. The achievable reduction in fuel usage and CO₂, as estimated by the USEPA, is typically between 10 to 15%. This control option could be technically feasible, having measurable decreases in CO₂; however such a technology can increase emissions of non-GHG pollutants such as NO_x, given increases in overall combustion temperatures. For this reason, such a technology may be ranked lower on a list of control effectiveness.

Good Combustion Practices

Good combustion practices for furnaces fired with natural gas and process gas include approaches such as the following:

- Good air/fuel mixing in the combustion zone;
- Sufficient residence time to complete combustion;
- Proper fuel gas supply system design and operation;
- Good burner maintenance and operation;
- Implementing a maintenance program to monitor fouling conditions in the subject furnace; and
- Conduct a thermal tune-up annually, including inspection of the burner, flame pattern, and air/fuel ratio.

Good combustion practices do not necessarily directly reduce GHG emissions; however, their use results in longer equipment lives and more efficient operation.

Pyrolysis Unit Design

ASCENT is planning to install state-of-the-art pyrolysis furnace units. The six proposed furnaces will be identically designed and each will consist of a single cell radiant section with bottom and side fired burners, a convection section, and an induced draft fan.

The proposed furnace design incorporates a number of features intended to maximize the efficiency of the cracking process. The furnaces recover heat from the flue gases to heat both the hydrocarbon and mixed hydrocarbon steam feeds. Additionally, efficient heat transfer in the firebox is aided by radiant coils and venturis which ensure equal flow distribution.

Add-On Controls

A complete GHG BACT analysis for add-on controls is presented in Section E.2.5.7 below.

Step 2 - Eliminate Technically Infeasible Options

All identified technologies, except for combustion air preheating and add-on controls, are feasible control options.

Inherently Lower-emitting Processes/Practices/Designs

From a process standpoint, the pyrolysis furnaces are being designed to be as energy efficient as possible by recovering available heat from the process. Each furnace is being designed to transfer heat generated by the reactions to preheat the process feed as it enters the reactor. This practice results in a significant decrease in the fuel fired in the furnace.

Heat recovery will be maximized in the furnace exhaust. An induced draft design on the flue gas side is used to allow for higher flue gas mass velocities and pressure drops. This helps to obtain good flue gas distribution to achieve high thermal efficiency in an economical way.

Similarly, the auxiliary boiler is being designed to efficiently produce steam to supplement the steam production from the primary steam source, the combustion turbine equipped with a heat recovery steam generator.

Add-On Controls

A complete GHG BACT analysis for add-on controls is presented in Section E.2.5.7 below.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following technologies are available for minimizing GHG emissions from the Pyrolysis Furnaces and Auxiliary Boilers (shown with estimated level of reduction):

- Low carbon fuels (40-50%);

- Efficient furnace designs (1-20%);
- Good combustion practices (0-5%); and
- Combustion controls for optimization (1-3%).

Step 4 - Evaluate Most Effective Controls and Document Results

ASCENT is selecting all controls identified in Step 3 as BACT for GHGs for the proposed Furnaces.

Low Carbon Fuels

Process gas combustion results in significantly less CO₂ generation per unit of energy when compared to most other fuels as described above. Process gas is an essential fuel in the facility and will serve as the primary fuel for the Pyrolysis Furnaces.

Efficient Furnace Designs

ASCENT as a whole is always seeking to improve the thermal efficiency of its processes to be able to maximize the production of products while reducing the feedstock and fuel costs.

Heat Integration

The designs of the new pyrolysis units minimize wasted heat and thus minimize fuel consumption through heat integration within the process. ASCENT is designing for a furnace stack exhaust temperature of 310 °F, accomplished through maximization of heat recovery from furnace exhaust.

Good Combustion Practices

ASCENT will incorporate the pyrolysis furnaces into the facility's maintenance program to ensure that an annual tune-up is performed and the proper maintenance occurs.

Combustion Controls for Optimization

ASCENT plans to incorporate combustion controls into the process control logic for the pyrolysis furnaces to ensure that the furnaces are operating efficiently. Specifically, the furnaces will include instrumentation (O₂ sensors, etc.) that will support optimization of furnace operation.

Step 5 - Select BACT

ASCENT proposes that implementation of the following emission reduction strategies represents BACT for GHGs for the proposed Pyrolysis Furnaces and Auxiliary Boilers associated with Project ASCENT. The emission calculations and proposed permit limits incorporate these measures for GHG emission reduction.

- Firing of low carbon fuels (40-50% GHG reduction);
- Use of efficient heater designs (0-20% GHG reduction);
- Good combustion practices (0-5% GHG reduction); and
- Combustion controls for optimization (1-3% GHG reduction).

During the infrequent startup and shutdown periods, ASCENT will seek to minimize GHGs and other environmental impacts by following the operational and safety procedures for the new sources.

Operation of the unit with the GHG BACT controls specified above will be indicated by operation of the pyrolysis furnaces with a stack temperature less than the temperature specified in Table 4-2 of the permit application during period normal furnace operation. ASCENT also proposed a thermal efficiency of 77% for the auxiliary boiler. These proposed limits are consistent with other recent GHG permits issued by EPA in the gulf coast area.

E.2.5.2 Pyrolysis Furnaces Decoking Operations

Step 1 - Identification of GHG Control Options

Process Emissions

Over time, the radiant tubes within the Pyrolysis Furnaces gradually become coated with a layer of coke reducing the efficiency of the units. Periodically the Furnaces will need to undergo a process known as decoking in order to remove this fouling layer. GHG emissions from the decoking of the furnaces consist of CO₂ emissions from the combustion of the coke build-up. A review of the RBLC database and available permits identified no specific controls for GHG emissions from decoking operations. ASCENT has identified the following potential strategies to reduce GHG emissions from Decoking of the Pyrolysis Furnaces.

Limiting Air/Steam

Limiting air/steam to the decoking process will tend to drive the conversion of coke to CO rather than CO₂ due to incomplete combustion.

Proper Design and Operation

Proper design and operation of the Pyrolysis Furnaces according to the manufacturer's recommendations will minimize the amount of coke generated.

Add-On Controls

A complete GHG BACT analysis for add-on controls is presented in Section E.2.5.7 below.

Step 2 - Eliminate Technically Infeasible Options

Both technologies discussed above, limiting air/steam and proper design and operations of the furnaces, are technically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Both limiting air/steam and minimizing the formation of coke through proper furnace design and operation were identified as technically feasible. Proper furnace design and operation is considered more effective as a GHG reduction strategy due to the increase in CO associated with limiting air/steam in the decoking process.

Step 4 - Evaluate Most Effective Controls and Document Results

Limiting air/steam to the decoking process will result in a decrease in CO₂ emissions; however as a result, CO emissions from the process will increase proportionally to the decrease in CO₂. Controlling one pollutant category at the detriment of another is not considered beneficial. Additionally, limiting air/steam could result in an incomplete decoke and lead to increased frequency of decoking operations.

Proper furnace design and operation minimizing coke formation in the Pyrolysis Furnaces is the fundamental factor for controlling the CO₂ emissions from decoking operations.

Step 5 - Select BACT

ASCENT proposes that BACT for Decoking operations is minimization of coke formation through proper design and operation of the furnaces and adoption of the manufacturer's recommended best practices for the units. Decoking events shall be limited to no greater than 12 events per calendar year per Pyrolysis Furnace.

E.2.5.3 Flares and Thermal Oxidizers

Step 1 - Identification of GHG Control Options

Process Design

The routing of material to oxidizers and flares is a last resort for chemical plants. Materials that are wasted mean either lost product or lost intermediate which then requires more feedstock to replace. In either case, there is a direct material cost to waste, which leads to the natural minimization of the amount of material burned in a control device.

Low Carbon Fuels

As discussed in Section E.2.5.1 and shown in Table E-6, the combustion of natural gas yields between 40 - 50% less CO₂ than the combustion of coal and petroleum coke, and approximately 25 - 30% less CO₂ than the combustion of distillate and residual oil.

Good Combustion Practices

Although good combustion practices do not themselves necessarily directly reduce GHG emissions, using good combustion practices results in longer life of the equipment and more efficient operation.

Good combustion practices for flares include maintenance of the equipment (e.g., periodic flare tip maintenance) and operating within the recommended heating value and flare tip velocity as specified by its design.

Good combustion practices for thermal oxidizers include operation above the minimum combustion chamber temperature and efficient design including suitable residence time and turbulence to ensure adequate combustion.

Step 2 - Eliminate Technically Infeasible Options

All identified technologies are feasible control options.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Technologies for minimizing GHG emissions from the Flares and Oxidizers (estimated level of reduction) include:

- Process design (efficiency is not available);
- Low carbon fuels (40-50%); and

- Good combustion practices (0-5%).

Step 4 - Evaluate Most Effective Controls and Document Results

ASCENT proposes to implement all of the technically feasible control options; therefore, Step 4 is not necessary.

Step 5 - Select BACT

ASCENT proposes that implementation of the following emission reduction strategies represents BACT for GHGs for the proposed Flares and Thermal Oxidizers associated with Project ASCENT:

- Firing of low carbon fuels (40-50% GHG reduction);
- Control management plan (efficiency is not available); and
- Good combustion practices (0-5% GHG reduction).

During the infrequent startup and shutdown periods, ASCENT will seek to minimize GHG and other environmental impacts by following the control device management plan developed as part of best practices for the facility.

E.2.5.4 Combustion Turbine/Duct Burner

Step 1 - Identification of GHG Control Options

The combustion turbine proposed for Project ASCENT will be equipped with an HRSG unit, maximizing the recovery of heat from the combustion turbine exhaust while efficiently providing steam needed for plant operations.

For the top-down BACT evaluation, the following sources were reviewed: the RBLC database, recent permits issued from across the U.S., and other available literature. Available technologies considered for combustion turbines focus on energy efficiency solutions and clean fuel options.

There are several potential strategies for improving energy efficiency. These are discussed below.

Thermal Efficiency

An emissions reduction strategy focused on energy efficiency primarily deals with increasing the thermal efficiency of a combustion turbine. Higher thermal efficiency means that less fuel is required for a given output, which results in lower GHG emissions. Maximizing efficiency reduces the consumption of fuel required to generate a fixed amount of output. The

largest efficiency losses for a combined-cycle combustion turbine are inherent in the design of the combustion turbine and the heat recovery system. The mechanical input to the combustion turbine compressor consumes energy, and is integral to how a combustion turbine works. Therefore, there is no opportunity for efficiency gains other than the differences in design between manufacturers or models. Heat recovery in the exhaust gas is another point of efficiency loss. Heat recovery efficiency depends upon the design of the heat recovery system, and varies between manufacturers and models.

Combustion Air Cooling

A common method used to improve the energy efficiency of combustion turbines is to cool the combustion air entering the combustion turbines during the summer months. Cooling the combustion air via heat exchanger systems maximizes the expansion of the air molecules and enhances the work the expanding gases perform on the turbine blades, hence producing higher amounts of electricity. A higher electric output improves the overall efficiency of the turbine. Based on general guidance available and recent analyses conducted regarding combustion air cooling, achievable reductions in fuel usage and CO₂ emissions may range from 10 - 15%.

Cogeneration/Combined Heat & Power

Cogeneration, or Combined Heat and Power (CHP), is the operation of a combustion system to generate both heat for electric power generation and useful thermal energy for a process. The electric power is distributed for use, while the thermal energy is used locally to support heating systems or industrial processes. A CHP system allows for the use of energy in the form of heat to provide thermal energy that would otherwise be lost in cooling water for a traditional electricity generating unit. The use of this otherwise lost heat would thereby improve the overall efficiency of the EGU or process, and subsequently reduce overall CO₂ emissions, on an equivalent basis.

The use of a CHP system provides an opportunity to extract additional energy from heat otherwise lost in a traditional simple cycle turbine. The design of such systems is optimized based on facility needs of power and thermal energy or steam. Regardless, the advantage to a CHP system is the net improvement of overall fuel efficiency compared to a traditional combustion turbine operation.

Lower Carbon Fuels

Carbon dioxide is produced as a combustion product of any carbon-containing fuel. All fossil fuels contain varying amounts of fuel-bound

carbon that is converted during the combustion process to produce CO and CO₂. However, the use of lower carbon content gaseous fuels, such as pipeline-quality natural gas or ethane, compared to the use of higher carbon-containing fuels, such as coal, pet-coke or residual fuel oils, can reduce CO₂ emissions from combustion.

Natural gas and ethane combustion result in significantly lower GHG emissions than coal combustion (117.0 lb/MMBtu and 131.4 lb/MMBtu, for natural gas and ethane, respectively, versus 205.6 lb/MMBtu for bituminous coal). The use of lower carbon containing fuels in combustion turbines is an effective means to reduce the generation of CO₂ during the combustion process.

Add-On Controls

A complete GHG BACT analysis for add-on controls is presented in Section E.2.5.7 below.

Step 2 - Eliminate Technically Infeasible Options

Thermal Efficiency

The use of a high efficiency combustion turbine is technically feasible.

Combustion Air Cooling

Although combustion air cooling is considered technically feasible, other options such as a more efficient combustion turbine are considered more effective in terms of overall net environmental benefit. The proposed combustion turbines will evaluate inlet evaporative cooling systems, which are a form of combustion air cooling as part of the design of the system in light of the local climate (e.g., temperatures). Unlike in the US gulf coast, the benefits from evaporative cooling are more limited since the ambient temperature is not nearly as warm during most of the year.

Cogeneration/Combined Heat & Power

Combined heat & power is technically feasible for this project and is incorporated in to the planned design through the integration of heat recovery steam generators (HRSG) with the combustion turbine operation although the primary intent of the combined cycle unit will be to generate power.

Lower Carbon Fuels

The use of lower carbon content gaseous fuels, such as pipeline-quality natural gas or ethane, compared to the use of higher carbon-containing fuels, such as coal, pet-coke or residual fuel oils, is a technically feasible alternative to reduce CO₂ emissions.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Technologies for minimizing GHG emissions from the Combustion Turbines with HRSG, ranked in order of effectiveness in controlling GHG emissions, are as follows:

- Low carbon fuels (40-50%);
- Thermal efficiency (1-20%); and
- Combustion air cooling (0-20%).

Step 4 - Evaluate Most Effective Controls and Document Results

ASCENT proposes to use a high efficiency combustion turbine model, GE 7EA operated with a HRSG. A review of the RBLC database was conducted and the results are summarized in at the end of this section.

Comparisons among the various combustion turbines are somewhat complicated in that different bases can be used to establish certain parameters. For example, combustion turbine outputs can be specified on a net or gross basis, and can vary based on fuel, load, ambient temperature, whether duct firing is occurring, and other factors. GHG emission rates can be specified on a LHV or HHV basis. And finally, the presence and size of HRSG and thus amount of supplemental firing can vary. Nevertheless, in context, the ASCENT's combustion turbine compares favorably with other recent combustion turbine projects in terms of output-based GHG emission rates and heat rates, which indicates that the proposed combustion turbines represent an efficient design that has been accepted as BACT for GHGs in other PSD permits.

The proposed combustion turbines will be equipped with inlet evaporative cooling systems, which are a form of combustion air cooling.

ASCENT proposes the use of pipeline-quality natural gas for both the combustion turbine and the duct burners in the HRSG. Natural gas is the lowest carbon containing fossil fuel, yielding reduced GHG emissions.

Step 5 - Select BACT

Based on the information presented in this BACT analysis and consistent with BACT at other similar sources, ASCENT proposes to employ the following GHG control techniques for the combustion turbine with HRSG proposed for this Project:

- Use of a high thermal efficiency combustion turbine model, GE Frame 7EA, operated with a HRSG to reduce auxiliary boiler firing;
- Use of inlet evaporative cooling systems, which are a form of combustion air cooling; and
- Use of lower carbon containing fuel (pipeline-quality natural gas).

E.2.5.5 Emergency Generators and Fire Water Pump Engines

Step 1 - Identification of GHG Control Options

ASCENT proposes the use of nine emergency generator engines; seven (7) large emergency generators rated at 2,800 kW each and two (2) small emergency generators rated at 350 kW each; and three Fire Water Pump Engines rated at 485 kW each. The engines are designed to burn ULSD and will be limited to a maximum of 100 hours per year of non-emergency use (e.g., maintenance and testing). The emergency generators will act as a backup power supply for utility operations, product storage, and the cooling water area). Similar to other combustion sources at the facility, the following potential strategies are considered: good combustion practices, use of low carbon fuels, and add-on controls.

Good Combustion Practices

Although good combustion practices do not themselves necessarily directly reduce GHG emissions, using good combustion practices results in longer life of the equipment and more efficient operation. Good combustion practices for engines include maintenance of the equipment (such as periodic oil changes and filter changes) and operating within the recommended air to fuel ratio recommended by the manufacturer. Such practices indirectly reduce GHG emissions by supporting operation as designed and with consideration of other energy optimization practices incorporated into the integrated plant.

Low Carbon Fuels

The use of low-carbon fossil fuels in combustion systems could be an effective CO₂ control technique. This control technique is a technically feasible option for most combustion systems. Carbon dioxide is produced as

a combustion product of any carbon-containing fuel. All fossil fuels contain fuel bound carbon that is oxidized into CO and CO₂ during combustion. Typically gaseous fuels such as natural gas or process gas contain less carbon, and thus lower CO₂ potential, than liquid or solid fuels such as diesel or coal.

Add-On Controls

A complete GHG BACT analysis for add-on controls is presented in Section E.2.5.7 below.

Step 2 - Eliminate Technically Infeasible Options

Good Combustion Practices

Good combustion practices are considered technically feasible.

Low Carbon Fuels

Since the reciprocating internal combustion engines (RICE) proposed by the facility are intended for emergency use, these engines must be designed to use a non-volatile fuel such as diesel. Use of natural gas or process gas in an emergency situation could exacerbate a potentially volatile environment that may be present under certain conditions, resulting in unsafe operation. Therefore, ASCENT has proposed the use of diesel fuel for use in the emergency generators and fire-water pumps. The use of a lower-carbon fuel is considered technically infeasible for emergency generator operation and is not considered further in this analysis.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

ASCENT proposes to incorporate the remaining control measure identified as feasible (good combustion practices), so a ranking of the control technologies by effectiveness is not necessary for this application.

Step 4 - Evaluate Most Effective Controls and Document Results

ASCENT proposes to incorporate the remaining control measures identified as feasible (good combustion practices), so an evaluation of the energy, environmental, and economic impacts of the proposed measure is not necessary for this application.

Step 5 - Select BACT

ASCENT proposes to incorporate good combustion practices and limited use (<100 hr/yr) as BACT for controlling CO₂ emissions from the proposed Emergency Generators and Fire Water Pump Engines.

E.2.5.6 Fugitive Emission Components

Step 1 - Identification of GHG Control Options

The fugitive GHG emissions associated with Project ASCENT represent less than one percent of the GHG emissions for the total project. For completeness, ASCENT has provided this BACT analysis for fugitive GHG emission components.

Fugitive GHG Emissions

The fugitive GHG emission components associated with Project ASCENT include components mostly associated with the natural gas lines feeding the facility. Note that the fugitive GHG emissions will not vary during normal operation and startup/shutdown scenarios since fugitive GHG emission rates are not a function of material throughput of the unit.

Installation of Leak-less Technology Components

Leak-less technology includes leak-less valves and seal-less pumps and compressors. Common leak-less valves include bellows valves and diaphragm valves; and common seal-less pumps are diaphragm pumps, canned motor pumps, and magnetic drive pumps. Leaks from pumps can also be reduced by using dual seals with or without barrier fluid. In addition, welded connections in lieu of flanged or screwed connections may provide for leak-less operation. Leak-less technologies should be nearly 100% effective in eliminating leaks.

Implementation of Leak Detection and Repair

Leak Detection and Repair (LDAR) programs based on Audio/Visual/Olfactory (AVO) Leak Detection methods or USEPA Method 21 instrument monitoring are viable for streams containing combustible gases, including methane.

Implementation of Audio/Visual/Olfactory Leak Detection Methods

The effectiveness of Audio/Visual/Olfactory (AVO) Leak Detection methods, which are generally employed for inorganic odorous compounds, are dependent on the system pressure, the odor of the process materials, and

the frequency of the AVO inspections. Natural gas and some process fluids are odorous, making them detectable by olfactory means. Highly odorous compounds are detectable at lower concentrations than would be identified using instrument LDAR and/or remote sensing.

Use of Remote Sensing

Remote sensing of leaks has been proven as a technology using infrared camera, which has been approved by the USEPA as an alternative to the typical LDAR USEPA Method 21 monitoring under certain instances.

Step 2 - Eliminate Technically Infeasible Options

For safety reasons, the installation of leak-less technology components for components associated with the project is not technically feasible. There are a number of flanges or connections that cannot be welded to be able to isolate process equipment including pumps and vessels.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Technologies for minimizing fugitive GHG emissions from the facility include:

- Implementation of LDAR;
- Remote Sensing; and
- Implementation of AVO Leak Detection Methods.

Since pipeline natural gas is odorized with very small quantities of mercaptan, olfactory observation is a very effective method for identifying fugitive emissions at lower concentrations than remote sensing or an LDAR instrument. Additionally, the frequency of opportunities for AVO inspections, as a means of identifying fugitive emissions, are greater than LDAR programs or remote sensing since AVO inspections do not require specialized equipment or calibrations of any kind. Therefore, AVO is the most effective approach for odorized GHG sources that are not in VOC service, such as natural gas components.

Step 4 - Evaluate Most Effective Controls and Document Results

Implementation of LDAR

LDAR programs using instrument-based detection of leaks have traditionally been developed and implemented for control of VOC fugitive

emissions. BACT determinations related to fugitive component leaks in VOC service have been identified as an instrumented LDAR program. Although methane is not considered a VOC, it can be detected and quantified by using the same methods in USEPA Method 21. LDAR programs are widely implemented throughout the country for chemical plants, refineries and other manufacturing sites. However, fugitive emissions are estimates based on factors derived for a statistical sample which are not specific to any single piping component or to natural gas service. Additionally, the total contribution of fugitives to the project's GHG potential emissions is less than the statistical accuracy of the development of the factors themselves precluding any evaluation of the economic practicability of an LDAR program.⁶

Remote Sensing

Remote sensing of fugitive components in methane service can provide an effective means to identify fugitive leaks; however, remote sensing does not quantify GHG emissions from equipment leaks as USEPA Method 21 does. ASCENT is planning to implement an instrumented LDAR program as required under Ethylene MACT that has higher control efficiencies overall than remote sensing technology for this application. Therefore, remote sensing technologies for GHG BACT will not be considered further for fugitive GHG emission components.

Implementation of AVO Leak Detection Methods

AVO is the most effective approach for GHG sources that are not in VOC service, such as the natural gas and process gas components. Since mercaptans added to natural gas are detectable at a low odor threshold and there is a high frequency of opportunities for inspections during regular rounds, as observed AVO is an effective means of detecting leaking components for those sources.

Step 5 - Select BACT

ASCENT proposes implementation of an as observed AVO program for components in non-VOC GHG service. For any GHG components in VOC service, ASCENT proposes a LDAR program for components in accordance with 40 CFR 63 Subpart XX (Ethylene MACT) which references NSPS Part 60 Subpart VVa.

⁶ Appendix B, Table B-2-2, of EPA's Protocol for Equipment Leak Emissions Estimates (EPA 453/R-95-017), November 1995.

Step 1 - Identification of GHG Control Options

The strategy for controlling or minimizing GHG emissions from combustion sources (which represent over 99% of the GHG emissions from this project) through the use of add-on controls is discussed in the sections below.

The only add-on control technology specifically designed for controlling GHG emissions that is currently commercially available is carbon capture and sequestration (CCS), which can reduce GHG emissions by approximately 90%. This technology, however, presents some technical and economic challenges.

The USEPA indicates that CCS should be a listed technology in Step 1 of the top down BACT analysis for GHGs. Particularly, CCS should be researched for power plants and other industrial facilities with high-purity CO₂ streams. As with any BACT analysis, certain case-specific factors must be evaluated:

Factors to Consider for CSS

- Technical Feasibility
- Implementation Costs
- Facility Size
- Source Location (Proposed or Existing)
- Availability and Accessibility to Transportation and Storage

Carbon capture and storage involves three categories of technologies used to achieve the physical capture and storage of CO₂ produced from stationary sources: (1) The separation and capture of CO₂ from flue gas, (2) the pressurization and transport to a storage site, and (3) the injection and long-term storage or sequestration of the CO₂ captured.

The following technologies, at varying levels of development, are considered under BACT for Project ASCENT:

Separation and Capture of CO₂

- Chemical Absorption - Uses an aqueous solution of amines as chemical solvents for CO₂ absorption
- Physical Absorption - Uses a physical absorption process called Rectisol or Selexol

- Oxy-Combustion – Uses high-purity oxygen instead of air to combust fuel to produce a highly concentrated CO₂ stream for easier CO₂ capture; Oxy-Combustion typically would be used in combination with either chemical or physical absorption techniques

Pressurization and Transport of CO₂

- Direct injection to storage
- Pipeline

Sequestration and Storage of CO₂

- Geologic formations
- Depleted oil and gas reservoirs
- Unmineable coal seams
- Saline formations
- Basalt formations
- Terrestrial ecosystems
- Deep ocean formations

Since there is no local customer or use for captured CO₂ near the project site, Project ASCENT requires off-site CO₂ sequestration, involving utilization of a CO₂ pipeline in order to transport CO₂ to distant geologic formations that are conducive to sequestration. Building such a pipeline for dedicated use by a single facility will almost certainly make any project economically infeasible, from both an absolute and BACT-review perspective. However, such an option may be effective if adequate storage capacities exist, and if reasonable transportation prices can be arranged with a pipeline operator.

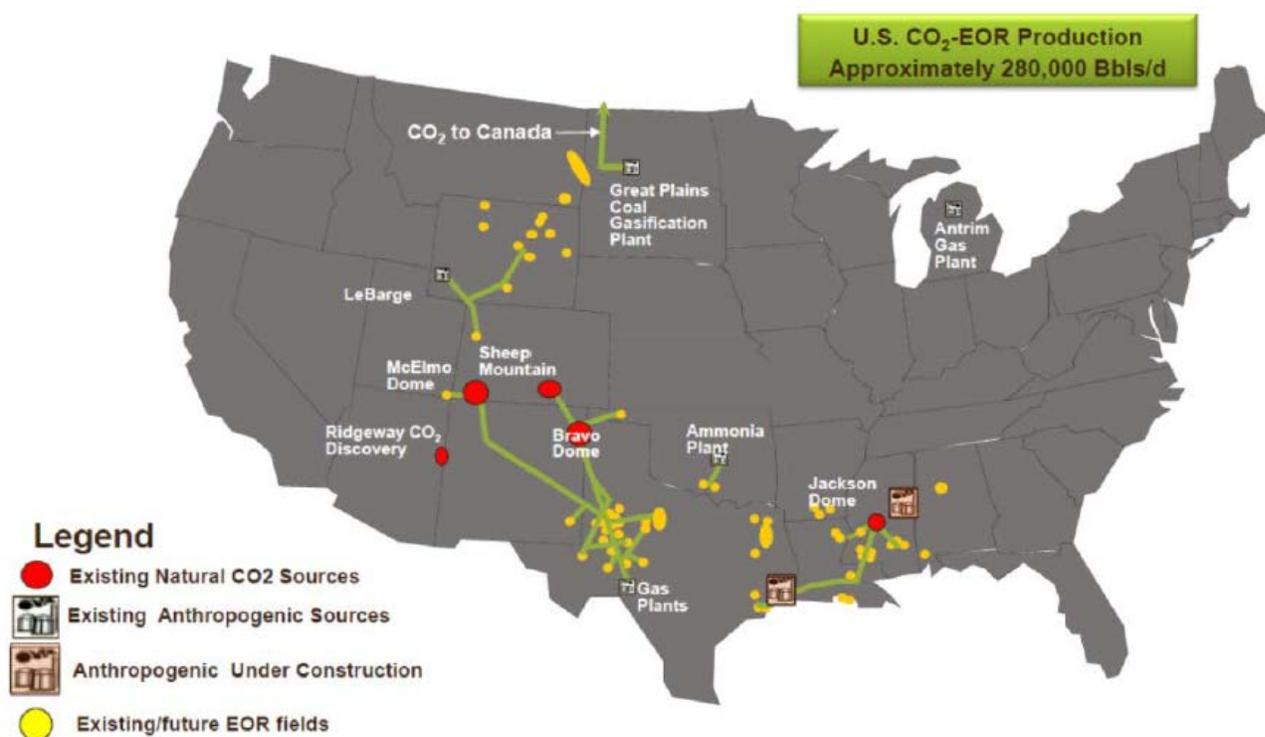
Post-combustion methods can be applied to conventional combustion process to isolate CO₂ from the combustion exhaust gases. However, because the air used for combustion contains over 75% nitrogen, the CO₂ concentration in the exhaust gases is only 5 to 20% depending on the amount of excess air and the carbon content of the fuel, making CO₂ very costly and energy intensive to capture.

Despite some of the challenges associated with CCS, CO₂ emissions from heaters and other combustion systems can theoretically be separated and captured through post-combustion methods. Therefore, such a method is identified in this analysis as an available technology to be considered as BACT. In addition, related pre-combustion techniques can also be used to overcome some of the challenges of and improve the efficiency of post-combustion capturing techniques.

Step 2 - Eliminate Technically Infeasible Options

As shown on the map in Figure G-1 below - taken from a June 2013 Eastern Interconnection States' Planning Council (EISPC) report produced for the United States Department of Energy (DOE),⁷ no CO₂ pipelines exist in the eastern United States. The closest existing CO₂ transport pipeline is located in the State of Mississippi, roughly 700 miles from the project location. While building a 700 mile pipeline is a technically feasible option for CO₂ transport, it would be cost prohibitive and would be expected to lead to increased CO₂ emissions because of the additional compression required to transport the captured CO₂ over such a large distance. Aside from the direct costs, such a pipeline project would face major permitting challenges. If permitting of such a line was even possible, it would take years to complete all of the necessary permitting.

Figure E-1 Map of Existing CO₂ Transport Pipelines (June 2013)



Dedicated geological sequestration of CO₂ requires close proximity to a favorable geologic formation. **Table E-7** below shows the US Department of

⁷ ICF Incorporated. Current State and Future Direction of Coal-fired Power in the Eastern Interconnection. Rep. N.p.: Eastern Interconnection States' Planning Council, n.d.

Energy's (DOE) National Energy Technology Laboratory (NETL) estimates of CO₂ storage resources from geological formations by State⁸.

Table E-7 CO₂ Storage Resource Estimates, Million Tons

State	Oil and Gas Reservoir Storage Resources	Unmineable Coal Storage Resource		Saline Formation Storage Resource		Total Storage Resource	
		Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
WV	1,840	310	450	4,490	17,940	6,640	20,230
VA	55	210	870	---	---	260	920
PA	142	230	330	6,920	27,670	10,220	31,070
United States	124,420	59,300	118,650	1,612,800	20,138,690	1,796,520	20,381,760

Table E-7 shows that there are depleted oil and gas reservoirs, unmineable coal areas, and saline formations in the State of West Virginia and in the areas near to the project site. Extensive characterization studies would be needed to determine the extent and storage potential for CO₂ from Project ASCENT sources. These studies would take several years of investigation, including drilling characterization wells, and would likely require small-scale injection testing before determining their full-scale viability.

Based on the analysis above and due to the fact that there are no proven CO₂ storage locations close to the project site, the use of add-on controls for carbon sequestration is considered to be technically infeasible. Nevertheless, ASCENT will voluntarily include a hypothetical Step 4 cost-effectiveness analysis for CCS in this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

CCS is the only add-on control technology identified and, if technically and economically feasible, would represent 90% control efficiency for GHG emissions.

⁸ The North American Carbon Storage Atlas, 1st Edition, NETL, 2012

Step 4 - Evaluate Most Effective Controls and Document Results

The fourth step in the top-down GHG BACT analysis involved the evaluation of energy, environmental, and economic impacts for determining a final level of control.

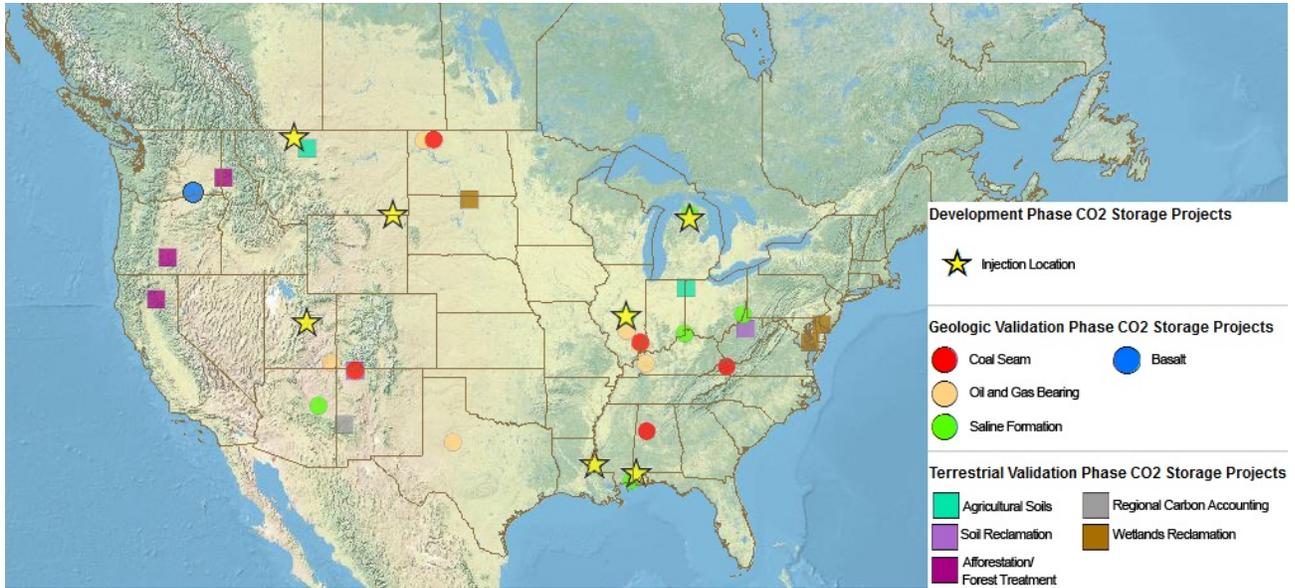
The U.S. Environmental Appeals Board noted that when evaluating the economic impacts of GHG control strategies in particular, “it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner,” particularly in the context of CCS. *In re: City of Palmdale (Palmdale Hybrid Power Project)*, PSD Appeal No. 11-07 (E.A.B. Sept. 17, 2012) (citing EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases* at 42 (Mar. 2011) (the “GHG Permitting Guidance”).

To implement CCS for the Project ASCENT combustion sources, ASCENT would need to install an amine-based scrubbing system and associated compressors; this is the most mature technology potentially available for CCS. As part of developing a cost estimate for CCS, ASCENT used cost information from a DOE-NETL study from 2010 to estimate the capital cost of the amine scrubbing system and associated compressors.

ASCENT utilized the DOE-NETL National Carbon Sequestration Database and Geographic Information System (NATCARB) to identify the nearest geologic carbon sequestration site that may be suitable for Project ASCENT. Costs to implement CCS includes a 12-inch diameter, 192-mile long pipeline to deliver the compressed CO₂ to the nearest test site that is undergoing small-scale validation testing, which was identified as a coal seam in Russell County, Virginia. A map of the DOE-NETL NATCARB⁹ carbon sequestration test sites is provided in Figure E-2 below.

⁹ NATCARB, USDOE - NETL, <http://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-natcarb>. 04 Feb. 2014

Figure E-2 NATCARB CO₂ Storage Projects



A 12-inch pipe is conservatively small and likely underestimates the costs for constructing the pipeline. Further, ASCENT’s cost-effectiveness estimate is biased low as the estimate does not include compressor stations which would likely be needed to transport the gases over this distance. Additionally, for this cost-effectiveness estimate, no allowance was provided for mitigation of the likely substantial ecological and social impacts of building a new pipeline over such a large distance.

For the cost-effectiveness calculations, the estimated costs for CCS were divided into three categories: post-combustion capture and compression costs; pipeline costs; and geological storage costs. Capital cost values for post-combustion capture and compression were taken from the US DOE Interagency Task Force report on CCS¹⁰, which were conservatively estimated at approximately \$103 per ton of CO₂ captured. Capital costs for post-combustion capture and compression ranged from \$54 to \$103 per ton of CO₂ captured, where the higher value was associated with new natural gas-fired combined-cycle units. Annual operation and maintenance (O&M) and fuel costs for the post-combustion capture and compression system were adapted from costs derived for similar systems on electric generating units found in a US DOE report for Fossil Energy Plants¹¹. For the capital and O&M costs related to the required pipeline and geologic storage of CO₂,

¹⁰ Report of the Interagency Task Force on Carbon Capture and Storage, US DOE, August 2010.

¹¹ Cost and Performance Baseline For Fossil Energy Plants, Volume 1: Bituminous and Natural Gas to Electricity, DOE/2010/1397, Revision 2, November 2010.

methodology developed by the NETL¹² was used based on the estimated pipeline length, pipeline diameter, and sequestration formation depth.

EPA typically uses a dollar per ton removed (\$/ton removed) basis when evaluating the cost-effectiveness of pollution control devices.

Enhanced oil recovery (EOR) was considered in the economic analysis of CCS, but no value was included in the economic analysis for CCS for the sale of CO₂. Currently there is not a significant market in the Midwest region for CO₂ for EOR. As such, it is ASCENT's opinion that EOR in the region has no economic value. Further, it is beyond the scope of the business purpose for this project to become contractually obligated to provide CO₂ for commercial purposes, including EOR.

The results of the cost-effectiveness analysis for CCS for Project ASCENT combustion sources are shown in Table E-8 below. Additional details for the cost-effectiveness calculations are shown in **Attachment E-3** of this submittal.

Table E-8 Carbon Capture and Sequestration Cost-Effectiveness for Project ASCENT

Parameter	Cost Estimate (2013 US Dollars)
Capital Cost	\$395,762,526
Annual O&M Costs	\$60,843,604
Capital Recovery ¹	\$37,357,180
Total Annualized Cost	\$98,200,784
Total CO ₂ Controlled (TPY) ²	2,025,971
CO ₂ Cost-Effectiveness (\$/ton removed)	\$48

1 Capital recovery based on economic life of 20 years for equipment and 7% interest rate.

2 Assumes 90% of CO₂ emissions are captured and controlled from Project ASCENT combustion sources.

Operation of the amine system and compressors which would be necessary for implementation of CCS for Project ASCENT would result in an estimated power consumption equal to running several thousand horsepower of compression and would generate dozens of tons of CO, NO_x, and PM emissions either directly or indirectly if electrified equipment is used for the compression. These negative environmental impacts are ignored in this analysis.

¹² Estimating Carbon Dioxide Transport and Storage Costs, DOE/NETL-2010/1447, March 2013.

Even with simplifying assumptions resulting in a likely underestimate of the overall cost, the use of CCS as an add-on control for GHG emissions is not considered cost-effective and is eliminated from further analysis.

E.2.5.8 GHG BACT Summary

As discussed above, add-on controls to reduce GHG emissions are neither technically feasible nor cost-effective. Table E-9 below summarizes the GHG BACT for each of the new sources associated with Project ASCENT.

Table E-9 GHG BACT Summary

Source	GHG BACT Summary
Combustion Sources	<ol style="list-style-type: none"> 1. Firing of Low Carbon Fuels 2. Use of Efficient Designs 3. Heat Integration, including pyrolysis stack effluent temperature limits of 310°F during normal operation. 4. Good Combustion Practices 5. Combustion Controls for Optimization
Decoking of Pyrolysis Furnaces	Limit decoking to no more than 12 times/year per pyrolysis furnace
Fugitive Emissions	AVO leak detection and repair for GHGs (natural gas lines)

ASCENT believes that implementation of the emission reduction strategies above represent BACT for GHGs for each of the new sources associated with Project ASCENT.

Project ASCENT
 PSD Air Permit Application, Appendix E - BACT Analysis
 Attachment E-1 Cost Analysis - NO_x Cost Effectiveness Summary

Control Option	Cost Effectiveness (\$/Ton)	
	Auxiliary Boilers	Pyrolysis Furnaces
SCR	\$ 21,938.10	\$ 6,392.60

Assumptions for all heaters:

Number of Years (n)	10
Interest Rate, % (i)	7
Annualized Cost Factor (ACF)	0.142

$$ACF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001 - Equation 2.8a

Year	Chemical Engineering Cost Index
1986	318.4
1991	361
2012	582.2
Cost Escalation Factor for SCR ¹	1.83
Cost Escalation Factor for LNB, SNCR, and FGR ²	1.61

¹ Cost data from *Alternative Control Techniques Document - NO_x Emissions from Process Heaters (Revised)* - EPA-453/R-93-034 scaled from 1986 to 2012 costs using the Cost Escalation Factor.

² Cost data from *Alternative Control Techniques Document - NO_x Emissions from Process Heaters (Revised)* - EPA-453/R-93-034 scaled from 1991 to 2012 costs using the Cost Escalation Factor.

Source	Control Efficiency	Comment	
Selective Catalytic Reduction	SCR	75%	Based on required BACT reduction to 0.01 lb/MMBtu
Ultra low-NO _x burners	ULNB	N/A	Based on vendor quote of 0.08 lb/MMBtu.

Source Name	Design Capacity (MMBtu/hr)	NO _x Emission Rate (lb/MMBtu)	Number of Burners	Summary of Technical Infeasibilities for NO _x Control
Auxiliary Boilers	206.0	0.020	26	None.
Furnaces	396.8	0.060	96	None.

Project ASCENT
PSD Air Permit Application, Appendix E - BACT Analysis
Attachment E-1 Cost Analysis - NOx Cost Effectiveness Summary

Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034
 All costs are scaled from 2012 U.S. dollars using the appropriate Cost Escalation Factor.

Capital Cost of Low NO_x Burners (page 6-4 and 6-5):

$$TCI = 30,000 + HQ[5,230 - (622 \times BQ) + (26.1 \times BQ^2)]$$

Where:

TCI = Total Capital Investment
 HQ = heater capacity (GJ/hr)
 BQ = burner heat release rate (GJ/hr)
 $BQ = HQ/NB \times (1.158 + 8/HQ)$
 NB = number of burners

Capital Cost of Ultra-low NO_x Burners:

See the "Refinery ULNB Control Costs" tab for capital cost details for Ultra-low NO_x Burners

Capital Cost of Selective Non-Catalytic Reduction (page 6-7):

$$TCI = 31,850(HQ)^{0.6}$$

HQ = heater capacity (GJ/hr)

Operating Cost of Selective Non-Catalytic Reduction (page 6-8):

$$NH_3 \text{ cost} = Q \times (lb/MMBtu) \times \left(\frac{1 \text{ mole } NO_x}{46 \text{ lb } NO_x}\right) \times \left(\frac{17 \text{ lb } NH_3}{1 \text{ mole } NH_3}\right) \times \left(\frac{1 \text{ mole } NH_3}{1 \text{ mole } NO_x}\right) \times \left(\frac{\$0.125}{lb \text{ } NH_3}\right) \times \left(8,760 \frac{\text{hours}}{\text{year}}\right)$$

Where:

Q = heater capacity, MMBtu/hr

$$\text{Electricity cost} = \left(\frac{0.3 \text{ kWh}}{\text{ton } NH_3}\right) \times \left(\frac{\text{ton } NH_3}{\text{year}}\right) \times \left(\frac{\$0.06}{\text{kWh}}\right)$$

Where:

$$\frac{\text{ton } NH_3}{\text{year}} = Q \times (lb \text{ } NO_x/MMBtu) \times \left(\frac{1 \text{ mole } NO_x}{46 \text{ lb } NO_x}\right) \times \left(\frac{17 \text{ lb } NH_3}{1 \text{ mole } NH_3}\right) \times \left(\frac{1 \text{ mole } NH_3}{1 \text{ mole } NO_x}\right) \times \left(\frac{\text{ton}}{2000 \text{ lb}}\right) \times \left(8,760 \frac{\text{hours}}{\text{year}}\right)$$

Capital Cost of Selective Catalytic Reduction (page 6-8):

$$TCI = 1,373,000 \times \left(\frac{Q}{48.5}\right)^{0.6} + 49,000 \times \left(\frac{Q}{485}\right)$$

Where:

Q = heater capacity, MMBtu/hr

Operating Cost of Selective Catalytic Reduction (page 6-9):

$$NH_3 \text{ cost} = Q \times (lb/MMBtu) \times \left(\frac{1 \text{ mole } NO_x}{46 \text{ lb } NO_x}\right) \times \left(\frac{17 \text{ lb } NH_3}{1 \text{ mole } NH_3}\right) \times \left(\frac{1 \text{ mole } NH_3}{1 \text{ mole } NO_x}\right) \times \left(\frac{\$0.125}{lb \text{ } NH_3}\right) \times \left(\frac{8,760 \text{ hours}}{\text{year}}\right)$$

Where:

Q = heater capacity, MMBtu/hr

Note the capacity factor has been assumed to be equal to 1; therefore, the capacity factor term has been omitted.

$$\text{Catalyst Replacement Cost} = 49,000 \times \frac{Q}{48.5} / 5 \text{ years}$$

$$\text{Electricity cost} = \left(\frac{0.3 \text{ kWh}}{\text{ton } NH_3}\right) \times \left(\frac{\text{ton } NH_3}{\text{year}}\right) \times \left(\frac{\$0.06}{\text{kWh}}\right)$$

Where:

$$\frac{\text{ton } NH_3}{\text{year}} = Q \times (lb \text{ } NO_x/MMBtu) \times \left(\frac{1 \text{ mole } NO_x}{46 \text{ lb } NO_x}\right) \times \left(\frac{17 \text{ lb } NH_3}{1 \text{ mole } NH_3}\right) \times \left(\frac{1 \text{ mole } NH_3}{1 \text{ mole } NO_x}\right) \times \left(\frac{\text{ton}}{2000 \text{ lb}}\right) \times \left(8,760 \frac{\text{hours}}{\text{year}}\right)$$

Capital Cost of Flue Gas Recirculation (page 6-9):

$$TCI = 12,800(HQ)^{0.6}$$

Where:

HQ = heater capacity (GJ/hr)

Operating Cost of Flue Gas Recirculation (page 6-10):

$$\text{Electricity cost} = (\text{motor hp}) \times \left(\frac{0.75 \text{ kW}}{\text{hp}}\right) \times \left(\frac{8,760 \text{ hours}}{\text{year}}\right) \times \left(\frac{\$0.06}{\text{kWh}}\right)$$

Where:

motor hp = FGR fan motor horsepower, $(1/5) \times (Q)$

Q = heater capacity, MMBtu/hr

Project ASCENT
 PSD Air Permit Application, Appendix E - BACT Analysis
 Attachment E-1 Cost Analysis - NOx Cost Effectiveness Summary

	A	B	C	D	E	F	G	H	I	J	
Control Option	Design Firing (MMBtu/hr)	Current Emission Rate (lb/MMBtu)	Potential Emissions (TPY)	Control Efficiency (%)	Controlled Emission Rate (lb/MMBtu)	Maximum Post Control Emissions @ Design Firing (TPY)	Potential NO _x Reduced (TPY)	2012 Total Capital Cost (\$)	2012 O&M Cost (\$)	2012 Annualized Cost ¹ (\$)	2012 Cost Effectiveness (\$/Ton)
SCR	206.0	0.02	18.0	75%	0.005	4.5	13.5	1,336,820	106,582	296,915	21,938
ULNB	206.0	0.02	18.0	N/A	0.020	18.0	0.0	N/A	N/A	N/A	N/A
Calculation			= A * B * 8760 / 2000			= C * (1 - D)	= C - F			= (G * ACF) + H	= I / G

Notes:

¹ See "Cost Summary" tab for details on the Annualized Cost Factor (ACF).

Project ASCENT
 PSD Air Permit Application, Appendix E - BACT Analysis
 Attachment E-1 Cost Analysis - NOx Cost Effectiveness Summary

Source	Auxiliary Boilers	
Control	SCR	
Rated Heat Input	206.0	MMBtu/hr
Number of Burners	26.0	Burners
Baseline Actual Emissions	18.05	tpy
Current Emission Rate	0.020	lb/MMBtu
Control Efficiency	75%	
Heater Capacity	217.3	GJ/hr
Burner Heat Release Rate	10.0	GJ/hr

Evaluated at New Firing Limit at 2012 Cost and Efficiencies

Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST (\$)
<i>DIRECT COSTS</i>	
<i>Purchased Equipment Costs</i>	
Equipment Cost (EC)	1,297,883
Instrumentation (Included in above costs)	---
Sales taxes (Included in above costs)	---
Freight (Included in above costs)	---
<i>Subtotal - Purchased Equipment Costs (PEC)</i>	1,297,883
<i>Direct Installation Costs</i>	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	---
<i>Subtotal - Direct Installation Costs</i>	0
<i>TOTAL DIRECT COSTS (TDC)</i>	1,297,883
<i>INDIRECT INSTALLATION COSTS</i>	
Engineering Costs (Included in above costs)	---
Construct. & Field Expenses (Included in above costs)	---
Contractor Fees (Included in above costs)	---
Start-up (Included in above costs)	---
Performance Test (Included in above costs)	---
Contingency (3% of PEC)	38,936
<i>TOTAL INDIRECT COSTS, IC</i>	38,936
TOTAL CAPITAL INVESTMENT (TCI)	1,336,820

Project ASCENT
 PSD Air Permit Application, Appendix E - BACT Analysis
 Attachment E-1 Cost Analysis - NOx Cost Effectiveness Summary

COST COMPONENT:	COST (\$)
<i>ANNUAL DIRECT COSTS</i>	
<i>Operation and Maintenance Labor</i>	
Maintenance Labor and Material	36,763
	<u>36,763</u>
<i>Annualized Cost Factor</i>	
Replacement Life (years) =	10
Interest Rate (%) =	7
Annualized Cost Factor	0.14
Replacement cost	
<i>Subtotal - Operation and Maintenance Labor</i>	
<i>Utilities</i>	
Ammonia Cost	2,689
Catalyst Replacement Cost	67,130
Electricity Cost	0.2
<i>Subtotal - Utilities</i>	69,819
TOTAL ANNUAL DIRECT COSTS^a	106,582

COST COMPONENT:	COST (\$)
TOTAL ANNUAL O&M COSTS	106,582
<i>Annualized Cost Factor</i>	
Equipment Life (years) =	10
Interest Rate (%) =	7
Annualized Cost Factor	0.14
<i>CAPITAL RECOVERY COSTS</i>	
TOTAL CAPITAL REQUIREMENT	1,336,820
TOTAL ANNUAL CAPITAL REQUIREMENT	190,333
TOTAL ANNUALIZED COST <i>(Total annual O&M cost and annualized capital cost)</i>	296,915

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PSD Air Permit Application, Appendix E - BACT Analysis

Attachment E-1 Cost Analysis - NOx Cost Effectiveness Summary

	A	B	C	D	E	F	G	H	I	J	
Control Option	Design Firing (MMBtu/hr)	Current Emission Rate (lb/MMBtu)	Potential Emissions (TPY)	Control Efficiency (%)	Controlled Emission Rate (lb/MMBtu)	Maximum Post Control Emissions @ Design Firing (TPY)	Potential NO _x Reduced (TPY)	2012 Total Capital Cost (\$)	2012 O&M Cost (\$)	2012 Annualized Cost ¹ (\$)	2012 Cost Effectiveness (\$/Ton)
SCR	396.8	0.06	104.3	85%	0.009	15.6	88.6	2,575,000	200,000	566,622	6,393
ULNB	396.8	0.06	104.3	N/A	0.060	104.3	0.0	N/A	N/A	N/A	N/A
Calculation			= A * B * 8760 / 2000			= C * (1 - D)	= C - F			= (G * ACF) + H	= I / G

Notes:

¹ See "Cost Summary" tab for details on the Annualized Cost Factor (ACF).

Project ASCENT
 PSD Air Permit Application, Appendix E - BACT Analysis
 Attachment E-1 Cost Analysis - NOx Cost Effectiveness Summary

Source	Auxiliary Boilers	
Control	SCR	
Rated Heat Input	396.8	MMBtu/hr
Number of Burners	96.0	Burners
Baseline Actual Emissions	34.76	tpy
Current Emission Rate	0.020	lb/MMBtu
Control Efficiency	75%	
Heater Capacity	418.6	GJ/hr
Burner Heat Release Rate	5.1	GJ/hr

Evaluated at New Firing Limit at 2012 Cost and Efficiencies

Costs derived from *Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)* - EPA-453/R-93-034

COST COMPONENT:	COST (\$)
<i>DIRECT COSTS</i>	
<i>Purchased Equipment Costs</i>	
Equipment Cost (EC)	2,500,000
Instrumentation (Included in above costs)	---
Sales taxes (Included in above costs)	---
Freight (Included in above costs)	---
<i>Subtotal - Purchased Equipment Costs (PEC)</i>	2,500,000
<i>Direct Installation Costs</i>	
Foundations & supports; handling & erection; electrical; piping; etc.	0
Site Preparation / Buildings- Included above	---
<i>Subtotal - Direct Installation Costs</i>	0
<i>TOTAL DIRECT COSTS (TDC)</i>	2,500,000
<i>INDIRECT INSTALLATION COSTS</i>	
Engineering Costs (Included in above costs)	---
Construct. & Field Expenses (Included in above costs)	---
Contractor Fees (Included in above costs)	---
Start-up (Included in above costs)	---
Performance Test (Included in above costs)	---
Contingency (3% of PEC)	75,000
<i>TOTAL INDIRECT COSTS, IC</i>	75,000
TOTAL CAPITAL INVESTMENT (TCI)	2,575,000

Project ASCENT
 PSD Air Permit Application, Appendix E - BACT Analysis
 Attachment E-1 Cost Analysis - NOx Cost Effectiveness Summary

COST COMPONENT:	COST (\$)
<i>ANNUAL DIRECT COSTS</i>	
<i>Operation and Maintenance Labor</i>	
Maintenance Labor and Material	65,514
	<u>65,514</u>
<i>Annualized Cost Factor</i>	
	Replacement Life (years) = 10
	Interest Rate (%) = 7
Annualized Cost Factor	0.14
Replacement cost	
<i>Subtotal - Operation and Maintenance Labor</i>	
<i>Utilities</i>	
Ammonia Cost	5,179
Catalyst Replacement Cost	129,307
Electricity Cost	0.4
<i>Subtotal - Utilities</i>	134,486
TOTAL ANNUAL DIRECT COSTS^a	200,000

COST COMPONENT:	COST (\$)
<i>TOTAL ANNUAL O&M COSTS</i>	200,000
<i>Annualized Cost Factor</i>	
	Equipment Life (years) = 10
	Interest Rate (%) = 7
Annualized Cost Factor	0.14
<i>CAPITAL RECOVERY COSTS</i>	
TOTAL CAPITAL REQUIREMENT	2,575,000
TOTAL ANNUAL CAPITAL REQUIREMENT	366,622
<i>TOTAL ANNUALIZED COST</i> <i>(Total annual O&M cost and annualized capital cost)</i>	566,622

Project ASCENT
 PSD Air Permit Application, Appendix E - BACT Analysis
 Attachment E-2 Cost Analysis - CO Cost Effectiveness Summary

Assumptions for all heaters:

Number of Years	10
Interest Rate (%)	7
Annualized Cost factor	0.142

Year	Chemical Engineering Cost Index
2002	395.6
2012	582.2
Cost Escalation Factor	1.47

Oxidation Catalyst Costs ¹	EPA, \$/cfm (2002 Basis)	EPA, \$/cfm (2012 Basis)
Capital Cost for Oxidation Catalyst	35.0	51.5
O&M Cost for Oxidation Catalyst	6.0	8.8

¹ Based on EPA Air Pollution Control Technology Fact Sheet for Regenerative Incinerator (EPA-452/F-03-021). Capital costs range from \$35 to \$140 per cfm and O&M costs range from \$6 to \$20 per cfm.

	A	B	C	D	E	F	G	H	I	J	K	L
Heater	Proposed Hourly Firing Limit (MMBtu/Hr) ¹	Projected Actual CO Emissions (TPY) ²	Control Efficiency (%)	Maximum Potential Post Control Emissions (TPY)	Potential CO Reduced (TPY)	Stack Flow (ACFM) ³	Stack Temp (°F) ⁴	Stack Flow (SCFM)	Capital Cost (\$)	O&M Cost (\$)	Annualized Cost (\$)	Cost Effectiveness (\$/Ton)
Pyrolysis Furnaces	396.8	21.4	92.0	1.7	19.7	102,040	270	73,845	3,803,666	652,057	1,193,613	60,683
Auxiliary Boilers	206.0	74.3	92.0	5.9	68.4	133,449	318	90,567	4,665,033	799,720	1,463,916	21,413
Cracker Thermal Oxidizer	130.0	46.9	92.0	3.8	43.1	170,410	662	80,193	4,130,677	708,116	1,296,232	30,048
PE Unit RTO	20.0	7.2	92.0	0.6	6.6	170,410	662	80,193	4,130,677	708,116	1,296,232	195,416
Large Emergency Generator	9.6	0.4	92.0	0.0	0.4	87,837	878	34,662	1,785,407	306,070	560,271	1,556,223
Fire Water Pump	1.7	0.1	92.0	0.0	0.1	15,215	1123	5,075	261,427	44,816	82,037	1,315,533
Small Emergency Generator	1.2	0.1	92.0	0.0	0.1	10,980	810	4,565	235,125	40,307	73,784	1,217,950
Calculation				= B * (1 - C)	= B - D			= F / ((460 + G)/(460+68))			= (I * ACF ⁵) + J	= K / E

Notes:

Trace levels of SO₂ will result in deactivation of the catalyst by sulfur-containing compounds. Oxidation catalysts are not typically installed on refinery fuel gas fired process heaters.

Oxidation catalysts typically operate at 650°F to 1,000°F. As shown above, none of the heaters in this analysis achieve stack temperatures within the typical operating range.

¹ Consistent with the proposed hourly firing rate limits requested in the Plan Approval application.

² Consistent with the future projected actual emissions in the Plan Approval application.

³ Stack flows (SCFM) were estimated using EPA Method 19 factor of 9,190 dscf/MMBtu.

⁴ Exhaust temperature were estimated using specifications from similarly sized emergency generator units.

⁵ See above for details on the Annualized Cost Factor (ACF).

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PSD Air Permit Application, Appendix E - BACT Analysis

Attachment E-3 Cost Analysis - GHG Cost Effectiveness Summary for Carbon Capture and Sequestration

Post-Combustion CO₂ Capture and Compression		
Base Capital ¹	\$93.44/ton CO ₂ captured	\$204,434,034
Annual O&M ²	\$7.54/ton CO ₂ captured	\$16,493,493
Annual Fuel ³	14.7% incremental fuel use at \$2.77/MMBtu	\$14,103,999

Pipeline Cost Breakdown ⁴		
L, Pipeline Length (miles)		192
D, Pipeline Diameter (inches)		12
Pipeline Costs		
Materials	$\$70,350 + \$2.01 \times L \times (330.5 \times D^2 + 686.7 \times D + 26,960)$	\$33,753,435
Labor	$\$371,850 + \$2.01 \times L \times (343.2 \times D^2 + 2074 \times D + 170,013)$	\$99,780,099
Miscellaneous	$\$147,250 + \$1.55 \times L \times (8,417 \times D + 7,234)$	\$34,108,963
Right of Way	$\$51,200 + \$1.28 \times L \times (577 \times D + 29,788)$	\$9,564,271
Other Capital		
CO ₂ Surge Tank	Fixed	\$1,312,043
Pipeline Control System	Fixed	\$117,959
O&M		
Fixed O&M (\$/year)	\$8,454 x L	\$1,710,955

Geologic Storage Costs ⁴		
Number of Injection Wells		2
Well Depth (m)	Depth of formation ⁵	1,825
CO ₂ Captured (tons)	90% capture	2,025,971
Capital		
Site Screening and Evaluation	Fixed	\$5,357,139
Injection Wells	$\$272,141 \times e^{0.0008 \times \text{Well Depth}}$	\$1,171,830
Injection Equipment	$\$106,305 \times (7,839 / (280 \times \text{Number of Injection Wells}))^{0.5}$	\$397,733
Liability Bond	Fixed	\$5,000,000
Declining Capital Funds		
Pore Space Acquisition	\$0.378/short ton CO ₂	\$765,020
O&M		
Normal Annual Expenses	\$13,076/Injection Well*365	\$9,545,511
Consumables	\$3,386/yr/ton CO ₂ /day	\$18,794,484
Surface Maintenance	$\$26,543 \times (7,839 / (280 \times \text{Number of Injection Wells}))^{0.5}$	\$99,309
Subsurface Maintenance	\$8.00/ft-depth/Injection Well	\$95,852

Annualized Cost Estimate		
Economic Life, years		20
Interest Rate (%)		7
Capital Costs		\$395,762,526
Annual O&M Costs		\$60,843,604
Capital Recovery		\$37,357,180
Total Annualized Cost		\$98,200,784
Total CO ₂ Controlled (tpy)		2,025,971
CO ₂ Cost-Effectiveness (\$/ton removed)		\$48

¹ Adapted from the DOE "Report of the Interagency Task Force on Carbon Capture and Storage" August 2010. Capital costs adjusted using the ENR Construction Cost Index to 2013 dollars.

² Adapted from Cost and Performance Baseline For Fossil Energy Plants, Volume 1: Bituminous and Natural Gas to Electricity, DOE/2010/1397 (Revision 2, November 2010). Plant output converted from CHP to equivalent Frame 7EA combined cycle output to enable use of cost information (www.ge-energy.com/products and services/products/gas turbines heavy duty/7ea heavy duty gas turbine.jsp). O&M costs adjusted using the ENR Construction Cost Index to 2013 dollars.

³ Fuel costs represent the additional fuel necessary to compensate for parasitic load caused by the addition of CCS. Based on review of review of the plant heat rates used in Case 13 and 14 presented in Cost and Performance Baseline For Fossil Energy Plants, Volume 1: Bituminous and Natural Gas to Electricity, DOE/2010/1397 (Revision 2, November 2010), CCS imposes a 14.7% increase in the plant heat rate; therefore, 14.7% more fuel is necessary to meet plant output. That amount of output need to come from somewhere, and is assumed to be equivalent to the cost of fuel.

⁴ Pipeline and Geologic Storage cost estimates based on National Energy Technology Laboratory (US DOE) document, *Estimating Carbon Dioxide Transport and Storage Costs*, DOE/NETL-2010/1447 (March 2010). Costs adjusted using the ENR Construction Cost Index to 2013 dollars.

⁵ Average depth of targeted coal seams per SECARB's Central Appalachian Coal Seam Project "Summary of Field Test Site and Operations".

Project ASCENT
PSD Air Permit Application, Appendix E- BACT Analysis
Attachment E-4 - GHG BACT Determinations Summary

Facility	Unit	BACT
BASF-FINA (Port Arthur, TX, 8/24/12)	Cracking Furnace	Flue gas exhaust $\leq 309^{\circ}\text{F}$
	Steam Package Boilers (2)	Thermal efficiency $\geq 77\%$
	Gas Turbine DBs (2)	Thermal efficiency $\geq 60\%$
	Decoke Drum	Proper furnace design and operation
Chevron-Phillips (Baytown, TX, 11/14/2012)	Cracking Furnace	Furnace gas exhaust $\leq 350^{\circ}\text{F}$
	VHP Boiler	Thermal efficiency $\geq 77\%$
	Low Profile Flare	Use of Low Carbon Fuel and Good Combustion Practices.
	VDU	Use of Low Carbon Fuel and Good Combustion Practices.
Equistar (La Porte, TX, 3/14/2013)	Cracking Furnace	Furnace gas exhaust $\leq 302^{\circ}\text{F}$, Thermal efficiency $\geq 91\%$
	ARU flare	
	Elevated flare	
	Decoke Drum (2)	
Exxon-Mobil (Baytown, TX, 5/21/2013)	Cracking Furnace	Furnace gas exhaust $\leq 340^{\circ}\text{F}$ Energy Efficient, low carbon fuel, good operating & maintenance practices
	DBs	Low carbon fuel, good operating & maintenance practices
	Staged Flares	Low carbon fuel, good operating & maintenance practices, staged flare
Exxon-Mobil (Mont Belview, TX, 9/15/2013)	Multi-point ground flare	Good Combustion Practices & maintenance
	Flameless thermal oxidizers (3)	Good Combustion Practices & maintenance
	Elevated flare	Good Combustion Practices & maintenance
	RTO	Maintain a minimum combustion temperature as determined by initial compliance testing.
	Boilers (2)	Thermal efficiency $\geq 77\%$
Occidental Chemical Corporation (Ingleside, TX, 12/21/2012)	Cracking Furnaces (5)	Use of Low Carbon Fuel, Good Combustion Practices, boiler feed water economizers on the furnace stacks. Stack gas temp < 400 F, process outlet gas <850F.
	Decoking	Proper furnace design and use of anti-coking agents
	Thermal Oxidizers (2)	High design efficiency, proper air/fuel ratio, and flame monitoring. Firebox Temp >1,300F.
	High Pressure Ground Flare	High efficiency pilots with flame monitoring.
	Emergency generator	Proper maintenance and Tier 2 level emissions.
	Low Pressure Enclosed Flare	High efficiency pilots with flame monitoring.
	Cooling Tower	None
Fugitives	TCEQ-styled 28MID LDAR program for VOC control.	